POLICY PROPOSAL 2016-07 | DECEMBER 2016

THE HAMILTON PROJECT

EPIC
ENERGY POLICY INSTITUTE
AT THE UNIVERSITY OF CHICAGO

Federal Minerals Leasing Reform and Climate Policy

Kenneth T. Gillingham and James H. Stock

THE HAMILTON PROJECT MISSION STATEMENT

The Hamilton Project seeks to advance America's promise of opportunity, prosperity, and growth.

We believe that today's increasingly competitive global economy demands public policy ideas commensurate with the challenges of the 21st Century. The Project's economic strategy reflects a judgment that long-term prosperity is best achieved by fostering economic growth and broad participation in that growth, by enhancing individual economic security, and by embracing a role for effective government in making needed public investments.

Our strategy calls for combining public investment, a secure social safety net, and fiscal discipline. In that framework, the Project puts forward innovative proposals from leading economic thinkers — based on credible evidence and experience, not ideology or doctrine — to introduce new and effective policy options into the national debate.

The Project is named after Alexander Hamilton, the nation's first Treasury Secretary, who laid the foundation for the modern American economy. Hamilton stood for sound fiscal policy, believed that broad-based opportunity for advancement would drive American economic growth, and recognized that "prudent aids and encouragements on the part of government" are necessary to enhance and guide market forces. The guiding principles of the Project remain consistent with these views.

THE HAMILTON PROJECT

EPIC MISSION STATEMENT

The Energy Policy Institute at the University of Chicago (EPIC) is confronting the global energy challenge by working to ensure that energy markets provide access to reliable, affordable energy, while limiting environmental and social damages. We do this using a unique interdisciplinary approach that translates robust, data-driven research into real-world impacts through strategic outreach and training for the next generation of global energy leaders.

EPIC | ENERGY POLICY INSTITUTE AT THE UNIVERSITY OF CHICAGO

THE HAMILTON PROJECT

Federal Minerals Leasing Reform and Climate Policy

Kenneth T. Gillingham
School of Forestry and Environmental Studies and Department of Economics, Yale University

James H. Stock
Department of Economics and Harvard Kennedy School, Harvard University

DECEMBER 2016

NOTE: This policy proposal is a proposal from the author(s). As emphasized in The Hamilton Project's original strategy paper, the Project was designed in part to provide a forum for leading thinkers across the nation to put forward innovative and potentially important economic policy ideas that share the Project's broad goals of promoting economic growth, broad-based participation in growth, and economic security. The author(s) are invited to express their own ideas in policy proposal, whether or not the Project's staff or advisory council agrees with the specific proposals. This policy proposal is offered in that spirit.

BROOKINGS

Abstract

Through its minerals leasing program, the U.S. government plays a large role in the extraction of oil, natural gas, and coal. This footprint is the largest for coal: 41 percent of U.S. coal is mined under federal leases, and burning this coal accounts for 13 percent of U.S. energy-related carbon dioxide (CO_2) emissions. Currently, producers and consumers of this coal do not bear the full social costs associated with its use. At the same time, the threat of climate change has led the international community, including the United States, to pledge significant reductions in CO_2 emissions. Over the past two decades Democratic and Republican administrations have taken steps to reduce U.S. CO_2 emissions by reducing use of fossil fuels. Despite growing public attention to the climate consequences of fossil fuel extraction, U.S. climate policy so far has not extended to the government's role as a major source of fossil fuels. We propose to incorporate climate considerations into federal coal leasing by placing a royalty adder on federal coal that is linked to the climate damages from its combustion. The magnitude of the royalty adder should be chosen to recognize both the substitution of nonfederal for federal coal, and the interaction of the royalty adder with other climate policies. A royalty adder set to 20 percent of the social cost of carbon would reduce total power sector emissions, raise the price of federal coal to align with coal mined on private land, increase coal mining employment in Appalachia and the Midwest, and provide additional government revenues to help coal communities. This proposal strikes a middle path between calling for a stop to all federal fossil fuel leasing on the one hand, and relying entirely on imperfect downstream regulation on the other.

Table of Contents

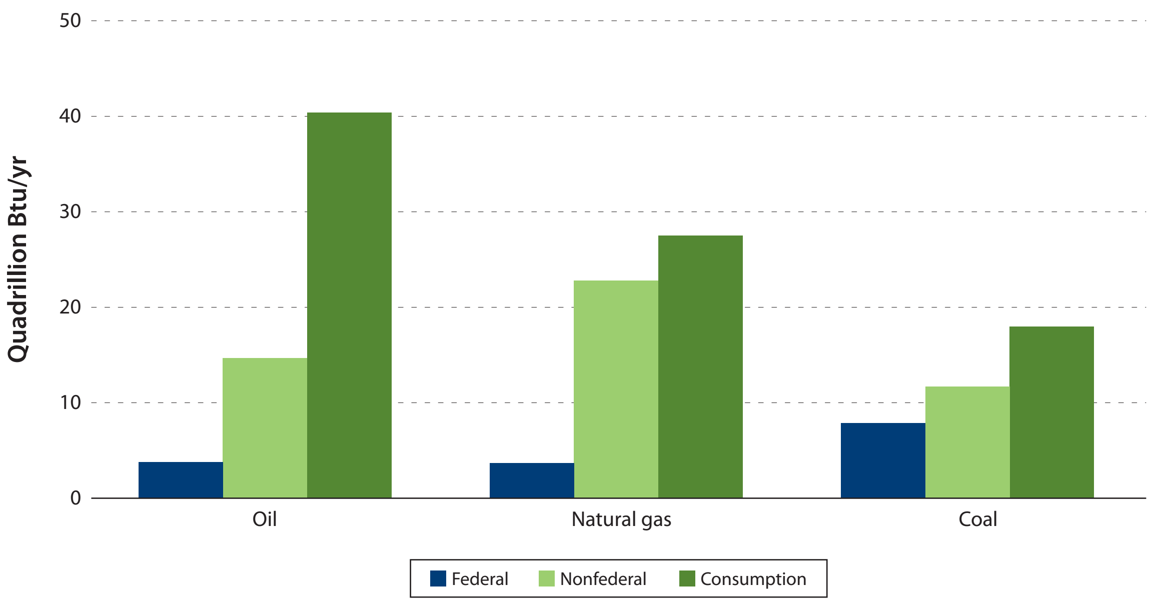
Chapter 1. Introduction

In fiscal year 2014 fossil fuel production on federal lands accounted for 21 percent of domestic crude oil production, 14 percent of domestic natural gas production, and 41 percent of domestic coal production (Energy Information Administration [EIA] 2015c). Figure 1 illustrates the federal component of domestic fossil fuel production and consumption. Federal production of oil and gas is small relative to domestic consumption, while federal coal constitutes a much larger fraction. These patterns reflect technological and economic conditions as well as the traditional goals of the federal minerals leasing program: promoting economic development and energy security.

The overwhelming consensus in the scientific community is that emissions of greenhouse gases (GHGs), primarily CO_2 from burning fossil fuels, produce current and future climate change; that climate change is already imposing economic costs; and that these costs will rise sharply as CO_2 concentrations, temperatures, and sea levels rise. In response to these threats, over the past two decades the federal government has taken deliberate steps to reduce GHG emissions. For example, in 2007 Congress and the George W. Bush administration worked together to pass legislation supporting ambitious goals for the development and use of advanced low-GHG biofuels and for improving energy efficiency (the Energy Independence and Security Act of 2007). The G.W. Bush administration set the goal of reversing the growth of U.S. CO_2 emissions by 2025 (White House 2008). As it happened, this reversal was achieved during that administration, with U.S. energy-related CO_2 emissions peaking in 2007 (EIA 2016d). The Obama administration accelerated this climate agenda, most notably by using the authority of the Clean Air Act to finalize regulations to strengthen corporate average fuel economy (CAFE) standards

FIGURE 1.

The Federal Footprint in Fossil Fuel Production



Source: Authors' calculations based on data from EIA.

Note: Domestic consumption is 19.1 million barrels/day for oil, 73.3 billion cubic feet/day for gas, and 918 million short tons/year for coal. Coal includes metallurgical coal. Oil production is crude oil production excluding natural gas plant liquids. Oil consumption is total refined petroleum product consumption. Federal production values are fiscal year 2014, and other values are calendar year 2014.

and to regulate CO_2 emissions by fossil-fuel-fired electric generators under the Clean Power Plan (CPP). In January 2016 a bipartisan agreement in Congress authorized a five-year extension of the renewable energy production tax credit and the solar investment tax credit, continuing credits that date to the Energy Policy Acts of 1992 and 2005, respectively. In addition, states have taken numerous steps to promote low-GHG sources of energy, including CO_2 emissions cap-and-trade programs in California (Assembly Bill 32) and in the Northeast (the Regional Greenhouse Gas Initiative). As part of the UN Climate Change Conference Paris 2015 Agreement (2015 Paris Agreement), the Obama administration committed the United States to achieving further reductions, so that by 2025 U.S. emissions would be 26–28 percent below 2005 levels.

BOX 1.

The Clean Power Plan

The Clean Power Plan (CPP) was proposed by the Obama administration in June 2014, and the final rule was issued on August 3, 2015. The CPP is the first federal regulation to limit carbon pollution from power plants, setting in motion a long-term strategy to address climate change. The CPP uses the legal authority of the Clean Air Act to regulate CO_2 emissions. The goal of the CPP is to reduce carbon pollution from power plants to 32 percent below 2005 levels by the year 2030. To achieve this goal, the CPP establishes state-by-state targets of CO_2 emissions, where states have the flexibility to select their measure of emissions (Environmental Protection Agency [EPA] n.d.).

Some states and industries argue that the EPA overreached its authority under the Clean Air Act in how it set these regulations, and five stay applications were filed to the Supreme Court by two dozen states, led by West Virginia, and multiple industry groups. On February 9, 2016, the Supreme Court issued the stay in a five-to-four decision, blocking the implementation and enforcement of the CPP until the case is resolved in court. Oral arguments were heard at the D.C. Circuit Court of Appeals in late September, but a decision is not expected still for months, with many saying it will be appealed to the Supreme Court (Adler 2016). The incoming Trump administration has stated its intention to dismantle the CPP, but it is unclear at this point exactly how that intention would be implemented.

These climate policies over the past 20 years have focused on reducing the demand for fossil fuels, either through direct regulation or by promoting substitutes and energy efficiency, and have not taken into account the government's role in the supply of fossil fuels. However, the tension between the federal government selling massive quantities of fossil fuels on the one hand and undertaking regulatory actions to limit CO_2 emissions on the other raises the question of whether climate considerations should be incorporated into decisions about leasing federal fossil fuel and—if so—how. The case of coal is particularly striking: combustion of federal coal accounts for 13 percent of U.S. energy-related emissions of CO_2.

Climate issues aside, federal leasing policy plays a large role in the U.S. coal market. Federal coal from the Powder River Basin (PRB) sells for much less than nonfederal Eastern or Midwestern coal. From 2006 to 2015 the share of PRB coal in U.S. production was between 40 and 45 percent, while the share of Appalachian coal declined from 33.6 percent to 24.6 percent (EIA n.d.). Over this period, which predates the introduction of the EPA's Mercury and Air Toxics Standards for power plants and the CPP, Appalachian coal production fell by 124 million tons, or 32 percent. Moreover, federal lands have vast reserves that can be mined profitably at or around current prices.

There is a wide range of views on how best to resolve these tensions. Some environmental groups and members of the scientific community have called on the federal government to "keep it in the ground" by ending fossil fuel leasing on federal lands.[1] Those groups point to the need to keep total future CO_2 emissions within a carbon budget if the world is to limit warming to 2 degrees Celsius (the international target reaffirmed in the 2015 Paris Agreement). Extracting fossil fuels will lead to their combustion so, by this argument, extraction itself must be capped.

Others have argued that although climate considerations are important, they should be addressed not through federal leasing policy but instead through downstream regulation—such as the CAFE standards and the CPP—that focuses on restricting GHGs closer to the point of emission. There are two economic arguments for favoring downstream regulation. First, reducing or halting production on federal lands could be ineffective: although fuels on federal lands would be kept in the ground, the market for fossil fuels might simply substitute nonfederal for federal production. Second, because there are already downstream regulations in place (with more pending), imposing upstream restrictions at the point of coal extraction could lead to double-counting the climate costs that have already been used to justify the downstream regulations. Both these arguments suggest that restricting federal fossil fuel production could entail costs (forgone employment, profits, and government revenue) without providing commensurate climate benefits.

In addition to the climate concerns, the federal coal program has come under widespread criticism for lack of transparency and failure to obtain a fair return for the taxpayer. For government critiques of the coal program, see Council of Economic Advisers (CEA; 2016); Government Accountability Office (GAO; 2013); and U.S. Department of the Interior Office of the Inspector General (2013). For example, one independent study has suggested that the effective royalty rate (i.e., the rate calculated based on the royalties paid and the delivered market value of coal) on federal coal is as low as 5 percent, well below the statutory minimum of 12.5 percent for surface mines (Haggerty and Haggerty 2015).

Finally, the federal coal mining program is controversial because of the environmental impacts of production itself, which include water use, the release of methane (a potent GHG) from the coal bed, possibly inadequate mine reclamation plans, and in some cases mining impacts on sensitive environmental areas (Hein and Howard 2015).

In response to three sets of concerns—obtaining a fair value for the taxpayer, the environmental impact of production, and the climate impact from combustion—the Department of the Interior announced in January 2016 that it is undertaking a comprehensive review of the federal coal program in the form of a Programmatic Environmental Impact Statement (PEIS). This is the first programmatic review of federal coal leasing since the 1980s. As it did in its review 30 years ago, the department imposed a moratorium on new and renewed federal coal leases while the review is under way.

The PEIS process is the most recent step in a history of reevaluations of the federal minerals program. The Mineral Leasing Act of 1920 emerged in part as a response to low royalties received by the government on oil production. Additional reviews, such as administrative and legislative reviews in the 1970s and 1980s, focused on speculation, inadequate production on leased lands, and failure to pay royalties. The current PEIS follows these previous reviews, but also adds climate considerations to the list of issues to be examined (Government Publishing Office [GPO] 2016).[2] The PEIS process is currently scheduled to continue into the Trump administration, but as of this writing it is unclear how that administration will handle it.

Chapter 2. The Challenge

The large footprint of the U.S. government encouraging the production of fossil fuels contrasts with its efforts over two decades to curb downstream emissions from using those fuels. Addressing this tension requires the development and implementation of upstream policies that recognize the possibility of substitution of nonfederal for federal fossil fuels and that are tailored to work alongside existing downstream policies to achieve broader climate policy goals.

PRODUCTION OF FOSSIL FUELS UNDER FEDERAL LEASES

Federal shares of domestic oil and gas production have been declining, in part because of declining production at conventional legacy wells and in part because the rise of unconventional oil and gas production has largely occurred on private land. Most federal oil production occurs offshore and on the Alaskan North Slope. Federal gas production largely occurs in the Gulf of Mexico, Wyoming, New Mexico, Colorado, and Utah. In contrast, the share of federal coal production has held steady over the past 15 years. Moreover, federal lands contain vast reserves that are economically recoverable under current conditions.[3]

In fiscal year 2014 oil production on federal land was 1.8 million barrels per day (21 percent of domestic production), down from a peak of 2 million barrels per day in 2010 (36 percent of domestic production; EIA 2015c). Federal gas production, both onshore and offshore, has been declining steadily for more than a decade: in 2003 federal gas was 36 percent of domestic gas production, but by 2014 the federal share had fallen to 14 percent. The advent of unconventional oil and gas recovery (horizontal drilling and hydraulic fracturing, or fracking), combined with the high costs of developing remaining federal offshore fields, has focused oil and gas investment on onshore, private reserves including those in Pennsylvania, West Texas, and the Bakken.

In contrast, federal coal has made up around 40 percent of domestic coal consumption for the past 15 years. Approximately 94 percent of federal coal is produced in Wyoming, Montana, Utah, and Colorado, with the bulk of that being produced from the PRB in Wyoming and Montana (EIA 2015c).[4] Although total coal production has declined since the early 2000s, PRB production has held relatively steady and its share of total domestic production rose from 35 percent in 2001 to 42 percent in 2014. According to the U.S. Geological Survey (USGS), the PRB alone has 162 billion tons of recoverable coal, including 25 billion tons that it is currently profitable to extract (USGS 2015). By comparison, total U.S. coal production in 2015 was only 897 million tons.

These trends in federal fossil fuel production, combined with the different physical properties of the fuels and the relative difficulty of transporting coal, suggest that the ability to substitute nonfederal production for federal production differs substantially across fuels. In the case of crude oil, transportation costs are relatively small compared to its market value, refined products are homogeneous, and the world market is highly integrated. In 2015 Congress lifted the 40-year-old ban on U.S. exports of crude oil, allowing domestic oil producers to sell crude oil internationally. At 1.8 million barrels per day, federal oil amounts to only 9 percent of domestic consumption and less than 2 percent of global consumption. Because federal oil production is a very small share of the global market and new domestic production sources are largely on nonfederal lands, there is considerable ability to substitute nonfederal (including non-U.S.) oil for federal oil. Although the domestic market for natural gas is currently disconnected from international markets, the declining federal share of gas production coupled with the largely nonfederal expansion of unconventional gas production suggests that there is also considerable ability to substitute nonfederal gas for federal gas.[5]

Coal, however, is different. Coal is a bulk product that is expensive to transport relative to its production cost. Although the United States both imports and exports coal, the export and import shares of total steam coal consumption are small, respectively being 3 percent and 1 percent of domestic production in 2015 (excluding metallurgical coal). Moreover, both federal and nonfederal coal compete against natural gas in their predominant market: electricity generation. These factors limit the potential for substitution of nonfederal for federal coal.

FEDERAL ROYALTY RATES THROUGH THE LENS OF CLIMATE COSTS

Federal royalties on fossil fuels are assessed as a percent of the selling price of the fuel (after deducting certain expenses). However, the market price of the fuel on which royalties are assessed does not reflect the climate damages caused to current and future generations by burning that fuel. That is, burning a fossil fuel generates a negative externality that is not reflected in the price of the fuel.

In climate economics, the value of this externality is called the social cost of carbon (SCC). The SCC is the net present value of the damages resulting from the emission of an additional ton of CO_2 in a specified year. The U.S. government's current estimate of the SCC for emissions in 2016 is $44 per metric ton of CO_2.[6]

The textbook solution to an externality is to adjust the price so that it reflects both the private cost of producing the good and the damages inflicted on others—that is, to internalize the externality. It is thus an open question how the conventionally determined fair return to the taxpayer compares to the adjusted price that would internalize the climate costs borne by current and future generations.

This comparison is made in figure 2, using current market prices for natural gas, crude oil, and PRB coal. The chart shows the current federal royalty and monetized externality (climate cost) of each of the fuels, converted to the same energy units (2016 dollars per 1 million British thermal units [$/MMBtu]). On a per energy unit basis, natural gas has the lowest CO_2 emissions and coal has the highest. For all three fuels, the federal royalty received is less than the cost of the climate externality. This disparity is, however, most pronounced for coal: the federal royalty (approximately $0.06/MMBtu for PRB coal) is two orders of magnitude less than the monetized climate costs (approximately $4.30/MMBtu).

Because the federal share of coal production is larger than for oil or gas, because the scope for substitution of nonfederal for federal fuels is likely to be less for coal than for oil or gas, and because current royalties are most sharply misaligned with climate costs of combustion, this policy paper focuses on the federal coal program. However, the general principles laid out here apply to federal oil and gas production as well.

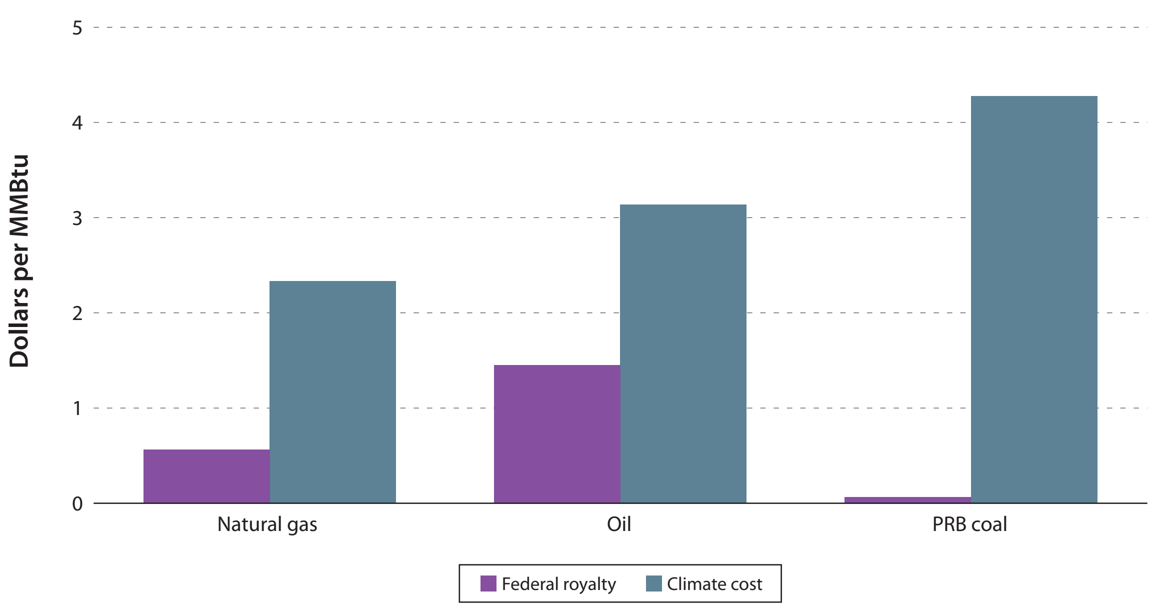
COAL MARKETS AND EMPLOYMENT

In 2015 U.S. coal production was 897 million short tons, down from an average of between 1.0 and 1.2 billion tons produced annually over the past decade. A small percentage, primarily from private lands in the East, is metallurgical coal used to make coke for iron and steel production. Of the 897 million tons mined in 2015, 74 million tons were exported, of which 46 million tons were metallurgical coal; because of some offsetting imports, net exports were 63 million tons. Lower worldwide demand for coal, particularly from China, has meant that coal exports have declined from about 125 million tons in 2012 (EIA 2016a, 2016b).

Since the late 2000s more-abundant natural gas (and declining natural gas prices) has led to lower coal demand through lower utilization of existing coal-fired power plants, retirements of

FIGURE 2.

Federal Royalty Compared to Monetized Climate Cost of Natural Gas, Oil, and PRB Coal

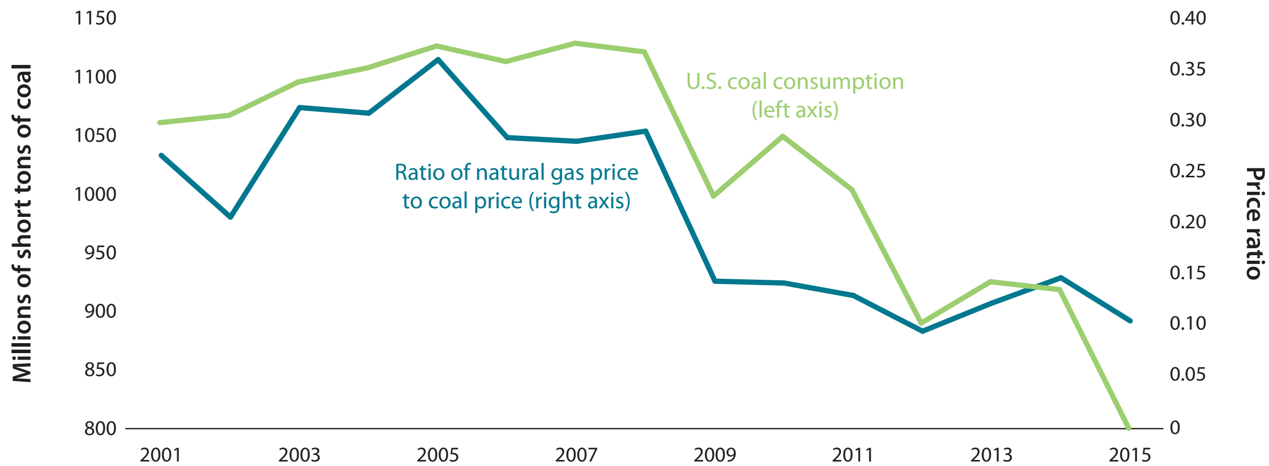


Source: Authors' calculations based on data from EIA.

Note: MMBtu = 1 million British thermal units. Assumed market prices: gas, $3/MMBtu; crude oil, $45/barrel; coal, $9/short ton. Oil and gas royalties are computed at the offshore rate of 18.75%, coal royalty is computed at the surface mining rate of 12.5%. Assumed value of the SCC is $44/metric ton CO_2.

FIGURE 3.

Thermal Coal Consumption and Ratio of Natural Gas to Coal Prices, 2001–2015



Source: Authors' calculations based on data from EIA.

aging coal plants, and very few replacement coal plants being built. Figure 3 illustrates thermal coal consumption and the ratio of the natural gas price to the coal price over the past decade.

Looking ahead, the EIA projects that although coal consumption and production will continue to decline slightly over the next decade, coal will remain a major electricity source for decades to come. In the EIA forecasts, the decline in coal is steeper if the CPP is in place; even with the CPP, however, there will be substantial coal production and consumption over the next decade (EIA 2015b).

A key feature of the U.S. coal market is the difference in production, price, and type of coal by coal-producing region. The difference in prices between Western surface coal (especially PRB coal, much of which is mined on federal lands) and most other coal resources is substantial.

Spot prices of coal from various basins are given in table 1. These large price differences have persisted for more than a decade and in fact were even slightly larger around 2011 when the demand for thermal coal was nearing a peak. PRB mines are surface mines that enjoy substantial economies of scale and tend to use the most advanced technology, both of which contribute to lower costs (Gerking and Hamilton 2008). These large persistent price differences also stem from a variety of factors including different characteristics of the coal (PRB coal is subbituminous coal with a low heat rate, high moisture content, and lower sulfur content than most Appalachian subbituminous and bituminous coal), transportation costs, and differences in contractual arrangements.[7] As can be seen in the final column of table 1, however, the differences are so great that even after adjusting for its lower heat rate, PRB coal is still a fraction of the price of coal elsewhere in

TABLE 1.

Spot Market Prices for Coal, November 11, 2016

Source	Characteristics	Price per short ton	Price per MMBtu
Central Appalachia	12,500 Btu/lb, 1.2 SO_2	$45.05	$1.80
Northern Appalachia	13,000 Btu/lb, < 3.0 SO_2	$42.25	$1.63
Illinois Basin	11,800 Btu/lb, 5.0 SO_2	$33.25	$1.41
Powder River Basin	8,800 Btu/lb, 0.8 SO_2	$9.00	$0.51
Uinta Basin	11,700 Btu/lb, 0.8 SO_2	$39.40	$1.68

Source: EIA 2016c.

Note: SO_2 is sulfur dioxide, a byproduct of coal combustion.

TABLE 2.

Coal Employment and Coal Mine Productivity in the Seven Largest States by Employment, 2014

	Employment	Productivity (tons per hour)
West Virginia	18,330	2.69
Kentucky	11,834	2.80
Pennsylvania	7,938	3.52
Wyoming	6,624	28.62
Illinois	4,218	5.99
Indiana	3,810	4.21
Alabama	3,694	1.88
All other states	18,483	–

Source: EIA 2016d, n.d.

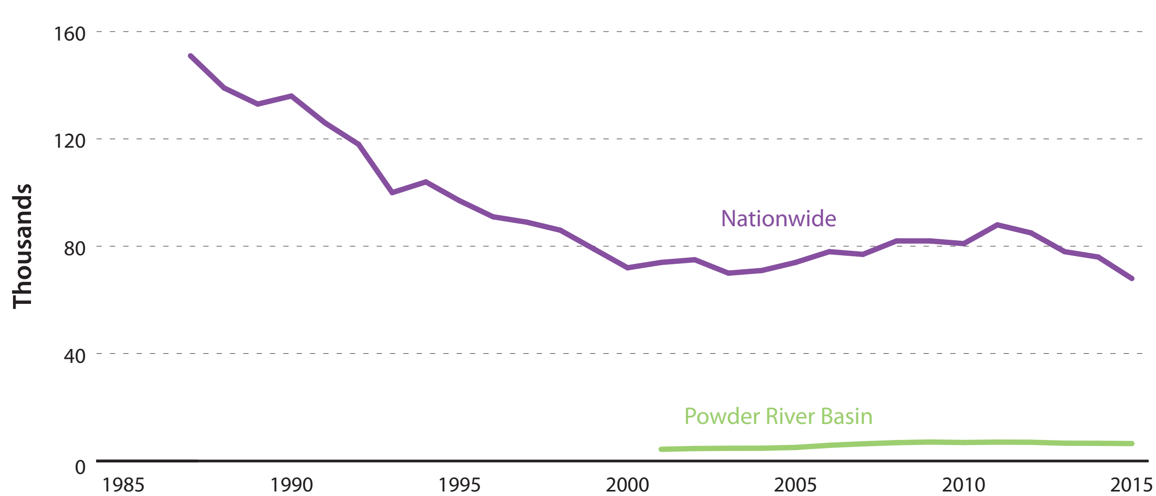
the United States. Some analysts have pointed out that federal PRB coal could be exerting downward pressure on coal prices nationwide (Sanzillo 2012).

Surface mines such as those operated in the PRB are much more efficient than underground mines: labor productivity in Wyoming is 10 times that in West Virginia and Kentucky. Table 2 summarizes employment and productivity in the top seven states by 2014 employment levels. In 2014, 74,931 workers were employed throughout the United States in coal production. Of these, only 6,592 (9 percent) were employed extracting coal in the PRB.

After falling through the 1980s and 1990s, coal employment increased slightly from 2000 to 2011. It then resumed its downward trend as low natural gas prices and coal-fired plant retirements began taking a toll on coal production (figure 4). As is evident from figure 4, the decline in coal employment through 2014 occurred largely outside the PRB, on nonfederal lands. Wyoming employment dropped slightly to 6,560 in the fourth quarter of 2015 (*Casper Star Tribune* 2016). There have been additional layoffs in the PRB in 2016, with announcements of layoffs of 235 employees by Peabody Energy in the North Antelope Rochelle Mine and layoffs of 230 employees at the Black Thunder Mine (Morris 2016). Further declines in coal

FIGURE 4.

Employment in Coal Mining, 1987–2015



Sources: Bureau of Labor Statistics 2016; EIA 2016a.

demand might reduce coal employment on federal lands, but the high productivity of PRB mines relative to others is likely to lessen the relative impact on employees of these mines.

Declining coal production reduces state government revenues in affected states. States differ substantially in their tax structures and a decline in coal production would have a different effect depending on the state. For example, Wyoming has no income tax or corporate tax, but a sales tax of 4 percent, a property tax, a 7 percent severance tax for surface coal, and a 3.75 percent severance tax for underground coal, with some limited exemptions (Tax Foundation n.d.; Wyoming Taxpayers Association n.d.).[8] Wyoming also receives half of the proceeds of the federal coal leasing program. The greatest loss in state revenues from declining coal production in Wyoming would be from the loss of ad valorem production taxes, severance taxes, and its share of the federal coal leasing revenues.

The total Wyoming state revenue directly from all federal and nonfederal coal mining was estimated at $1.3 billion (11.2 percent of total government revenues collected in the state) for fiscal year 2012. This funding is used for general state government revenues (53 percent), education (38 percent), and local government (9 percent). Looking at the historical picture, these revenues have tended to scale proportionally with coal production (Godby et al. 2015).

Declining state revenues and declining employment due to decreased coal production present fiscal challenges to states. Coal company bankruptcies suggest that states could also confront unfunded liabilities related to mine remediation. EIA projects that even without the CPP, coal consumption will decline by 12 percent by 2025, and with the CPP consumption will decline by twice that.

Morris (2016) reviews a set of different options to help the economic transition for coal communities and states heavily reliant on coal revenues, although most will require additional revenue. Reforming the federal coal program could provide such needed revenue.

BOX 2.

A Brief History of the Federal Coal Program

The basic structure of federal mineral leases dates to the Mineral Leasing Act of 1920. Under the current law, the secretary of the interior has considerable discretion in how federal coal leasing is managed. The Mineral Leasing Act sets a surface coal royalty rate at a minimum of 12.5 percent "of the value of coal as defined by regulation" (GPO 2011, 30 U.S.C. § 207(a)). The secretary is permitted to set a lower royalty rate for underground coal (currently set at 8 percent; Bureau of Land Management [BLM] 2016). Under the existing legal framework, the secretary has substantial discretion to adjust the royalty rate for new leases and lease renewals, and otherwise modify the terms of the federal coal leasing program.

Prior attempts to reform the federal coal program have focused on ensuring a fair return to the taxpayer. In 1976 the Mineral Leasing Act was amended by the Federal Coal Leasing Amendments Act of 1975 (1976) to generally require that all federal coal leases in coal-production regions be offered competitively on tracts designated by BLM. The PRB was originally certified as a coal production region, but in 1990 the BLM decertified the PRB, which permitted BLM to allow coal companies to propose tracts for leasing. The standard practice for leasing in the decertified PRB is thus "lease by application" on tracts proposed by a coal company. Under this arrangement, there is very little competition for leasing rights: since 1990, 90 percent of lease sales in the PRB have had only one bidder (GAO 2013). For more discussion, see Nelson (1983); Squillace (2013); and Hein and Cocot (2016).

THE FEDERAL COAL PROGRAM AND CALLS FOR REFORM

Federal coal leases raise revenue from three distinct components: (1) bonus bids from an auction for the right to lease, (2) royalties on production, and (3) land rental fees. In fiscal year 2012, rental fees were only $1.2 million, whereas total leasing revenues were more than $1 billion: $796 million in royalty revenues and $300 million plus in bonus bid payments (GAO 2013). Leases are for an initial 20-year term, contingent on continued operations and production within the first 10 years. Subsequently, leases can be renewed for additional 10-year terms and the secretary of the interior has discretion to change the terms of the leases at the time of lease renewal. Revenues from the federal leasing program are split evenly between the federal government and the state where the lease is located.

Bonus bids are determined by a first-price sealed-bid auction (i.e., an auction where bidders send in sealed bids, the highest bid wins, and the winning bidder pays the amount she bids), with a confidential minimum bid set by the BLM. The confidential minimum bid is established as the larger of the estimated fair market value and $100 per acre. If the highest bid is below the minimum bid, then the tract is not leased and a new auction will be held at a later time.

Production royalties are paid as a percentage of the revenues at the first point of sale after the coal is extracted. Lessees can request a royalty waiver, suspension, or reduction by demonstrating to the Department of the Interior that without the change development would not happen or that the operations would be financially unsuccessful. If the first point of sale is after the coal has been processed and transported, lessees are permitted to claim deductions that reduce the royalty payments by the cost of transporting and/or washing the coal (i.e., processing the coal by cleaning it of some impurities).

Annual land rental fees are a negligible portion of the revenue. They are set at a minimum of $3/acre per year, which must be paid regardless of whether any production occurs.

Criticisms of the federal coal program fall into two major categories. The first category consists of good governance concerns that the federal coal leasing program is not providing a fair return to the taxpayer due to the incentives provided by its structure. The second category of criticisms is that the federal coal leasing program does not account for environmental costs, including those from climate change.

The concerns about whether the federal coal leasing program provides a fair return to the taxpayer relate to both the bonus bids and the production royalties. According to the GAO, 96 of the 107 coal tracts that the Department of the Interior leased between 1990 and 2013 had only a single bidder, and most of the remaining tracts had only two bidders. The reason for the limited competition is logistical: over 90 percent of the tracts put up for auction are adjacent to an existing mine and are used either to extend the life of the mine or to expand an existing mine's production. The large fixed cost of building new infrastructure to start a new mine adjacent to an existing one appears to have deterred nearly all bidders other than the one that operates the adjacent mine (GAO 2013). With very little competition, bidders have an incentive to bid as close as possible to the confidential minimum bid, which savvy bidders can learn through repeated interaction with the Department of the Interior. These issues leading to lower bonus bid revenue are inherent in the program and are extremely difficult to address under the current structure of the program.

The criticisms of the production royalties are at least as important, especially since the largest fraction of revenue from the federal coal leasing program comes from production royalties. Ideally, production royalties would be based on the true market value of coal, which accounts for characteristics of the coal (e.g., heat rate, sulfur content, distance from markets, etc.). Problems arise because the incentive under the current program is to reduce the sale price of coal that the royalty rate is assessed on (CEA 2016).

There are at least three ways in which these incentives play out. First, firms have an incentive to sell coal through a captive transaction to a subsidiary or affiliate company. In fact, in 2012 42 percent of all Wyoming federal coal was sold through captive transactions (GAO 2013). Since royalties are assessed based on the price at the first point of sale, firms have an incentive to sell coal to their affiliates at low prices (Haggerty and Haggerty 2015; Lee-Ashley and Thakar 2015; Taxpayers for Common Sense 2013). Second, when the coal is sold to a third party after transportation, firms have an incentive to take as many washing and transportation deductions as possible to reduce the post-deduction sales price. To the extent that firms can include any overhead or logistics costs in the self-reported cost of washing and transportation, they can reduce their royalty payments (Haggerty and Haggerty 2015). Third, the structure of the coal leasing program permits take-or-pay contracts between coal producers and utilities or other coal-consuming firms. Such contracts require that the final purchasers agree to buy large quantities of coal—higher quantities than they ever plan to use—for a low price and then pay a penalty if they do not purchase the entire amount. As was upheld in the courts, these penalty payments cannot have royalties assessed on them. Thus, there is an incentive to structure transactions to have a high penalty payment and a low transaction price in order to reduce total royalty payments (Peterson 2015).

> The federal coal leasing program does not account for environmental costs, including those from climate change.

In addition, waivers, suspensions, or reductions in royalty payments are occasionally given to coal producers to encourage development. However, although these waivers are important in some smaller-producing states, they affect a small percentage of total production. From 1990 to 2012 the average royalty rate actually paid on the transaction price at the first sale (after adjusting for both deductions and any waivers, suspensions, or reductions) was estimated to be 11 percent (averaged over both surface and underground coal). It varied substantially by state, from as high as 12.2 percent in Wyoming to as low as 5.6 percent in Colorado in fiscal year 2012 (GAO 2013).

However, these numbers do not reveal the royalty rate paid relative to market prices (instead of transaction prices). In the extreme case, if the effective royalty rate is calculated by simply taking the average royalty payment per ton of coal and dividing it by the average delivered market price for coal sold from federal leases, then a commonly cited estimate of the effective royalty rate is 4.9 percent (Haggerty and Haggerty 2015). This estimate is useful as a benchmark, but is based on only a sample of federal leases and assumes no deductions at all.

In sum, there are multiple reasons based on good governance—in addition to environmental externalities—to reform the federal coal leasing system.

Chapter 3. The Proposal

We propose that policy decisions regarding federal fossil fuel leases directly address the climate consequences of burning those fuels, while at the same time recognizing both the limitations of upstream policies (e.g., coal royalties) in the larger fossil fuel market and the interaction of leasing policy with downstream policies. This approach strikes a middle path between calling for a stop to all federal fossil fuel leases on the one hand, and relying entirely on imperfect downstream regulation on the other.

Our specific proposal has two parts. First, we propose that federal royalties be augmented by an amount equal to 20 percent of the U.S. government's estimate of the social cost of carbon. This royalty adder can be imposed under existing law. Under existing regulation, half of the additional revenues would go to the state of extraction, with the remaining half allocated to the federal government. Second, we propose that Congress direct the federal half of the additional revenues to fund transitional assistance for coal communities in states with a large private coal presence.

PRINCIPLES FOR INCORPORATING CLIMATE CONSIDERATIONS INTO FEDERAL FOSSIL FUEL LEASING DECISIONS

We begin by laying out four principles to guide leasing policy reform.

1. Federal fossil fuel leasing policy should consider the climate externality from producing and burning those fuels.

2. Consideration of climate externalities should avoid both under- and over-counting the relevant costs, which requires analyzing the interaction of a specific leasing policy with downstream regulation.

3. Consideration of climate externalities should incorporate an evidence-based assessment of the extent of substitution of nonfederal for federal fossil fuel.

4. Climate considerations should be incorporated into leasing decisions in a way that supports market efficiency while remaining consistent with climate policy goals.

Our first principle affirms the Department of the Interior's commitment to include climate considerations in its Programmatic Environmental Impact Statement, and extends that commitment so that climate considerations are incorporated into the ultimate leasing policy that emerges from the department's regulatory process. This principle recognizes that in the absence of a first-best policy that internalizes the carbon costs of burning fossil fuels, upstream regulation has the potential to improve the effectiveness of second-best climate policies. Thus, the climate consequences of burning fuels extracted on federal lands have a legitimate and economically justified role in setting federal fossil fuel leasing policy.

The remaining principles frame our view about how best to incorporate climate considerations in a way that both improves economic efficiency and achieves the broader goals of climate policy.

In particular, the fourth principle stresses the importance of implementing upstream climate-related policies in an economically efficient manner. If some federal reserves are less expensive to mine than others, then short of a complete shutdown of federal coal production, it makes sense to prioritize production from the more-efficient reserves, a decision that is best left to private producers and the market. In practice, this means that policy should provide as much scope as possible for the market to make decisions based on price signals that incorporate the full range of costs and benefits of production.

Finally, we reiterate that while our focus in this proposal is on the climate considerations of federal coal policy, there are other good reasons for reform of the federal coal program related to transparency and ensuring a fair return to the taxpayer. Both these goals and climate considerations are legitimate and important reasons to pursue coal program reform.

INCLUDE A CARBON ADDER IN COAL ROYALTIES

We propose that a carbon adder equal to 20 percent of the U.S. government estimate of the SCC be incorporated into coal royalties assessed on new leases and lease renewals. This adder—assessed per ton of coal produced—would be in addition to the standard 12.5 percent royalty payment assessed on the market price of the coal. The adder would vary by coal type to reflect the CO_2 emissions per ton of coal and could also reflect the GHG emissions in the production process.[9]

BOX 3.

Interaction of Upstream and Downstream Regulation

To illustrate those principles, it is useful to consider three extreme scenarios in which the economic role of upstream policy is clear. For concreteness, we focus on coal. First, imagine that there is no downstream regulation (no CPP or carbon tax) and that federal coal is the only fossil fuel used to generate electricity (no nonfederal coal, no gas). Then the optimal policy is a tax that exactly internalizes the externality, leading market participants to account for climate costs. Imposing that tax at the mine mouth is equivalent to incorporating a per ton carbon adder to federal royalties. Thus the ideal first-best policy is a federal royalty carbon adder assessed at the full externality value, which we take to be the SCC.

Next, suppose instead that federal coal remains the only fossil fuel for electricity generation but that there is already in place an economy-wide carbon tax, set at the SCC and implemented effectively. Arguably the most administratively efficient way to implement a carbon tax is at the mine mouth, point of collection, and port of entry of the fuel. Under this arrangement, the coal producer would already be assessed a carbon tax per ton of coal produced, so any additional climate-based royalty adder would in effect increase the carbon price beyond its efficient value. This would be double-counting, or more precisely over-counting, the climate costs of emissions, and would thus be economically inefficient. In this example, the optimal climate royalty adder is zero.

Finally, imagine that there is no downstream regulation, but only one very small mine on federal lands. Next to the small federal mine sits a much larger mine on private land with vast reserves of the same coal. In this case, climate policy that raises the price of federal coal or restricts its output would simply redirect business to the private mine. In this example, even though there is no downstream regulation, climate-based upstream regulation of federal mining is ineffectual and does not reduce the amount of coal produced or the amount of CO_2 that enters the atmosphere: it imposes private costs (on federal coal miners) while achieving no emissions reductions, so the optimal policy is again to do nothing.

Because reality lies between these extremes, policy needs to be developed allowing for both limitations and leakage in the downstream policy and for possible partial substitution of nonfederal for federal coal.

Legal basis

Separate legal analysis indicates that the secretary of the interior has the authority to make this change to federal royalty policy under existing law (Burger 2016; Hein and Cecot 2016; Krupnick et al. 2015). Under the Mineral Leasing Act (as amended), the 12.5 percent royalty rate is a floor, not a ceiling, and the statute gives the secretary of the interior the authority to determine a new royalty rate for new leases and at the time of lease renewal. As discussed in the next section, a royalty adder would reduce production from federal lands, but there would likely still be production from the most efficiently run mines, implying that this reduction would be consistent with the BLM's multiple use mandate.[10] Moreover, our proposal is within the scope of the options included for potential analysis in the Department of the Interior Notice of Intent, making it a logical outgrowth of the PEIS review.

Royalty adder versus partial or complete moratorium

There is a basic choice among ways to incorporate climate goals into upstream policy: it can be done either through quantity restrictions or through a price mechanism. Here, a quantity-based policy would be a partial or complete continuation of the current leasing moratorium or a carbon budget that amounts to a cumulative coal extraction quota. Our analysis suggests several reasons for preferring a price policy to a quantity restriction for federal coal leasing.

First, a royalty adder would tie the climate cost directly to consumption, providing a market incentive to switch to cleaner fuels—natural gas or renewables—in an efficient way. Where it is least costly for generators to switch, the switch will occur.

Second, compared with a partial moratorium or quota, a carbon royalty adder allows the market to determine which coal is most efficiently mined, thereby harnessing the efficiency of the market while achieving climate policy goals. While economists might be able to invent a complicated trading scheme that would smooth the rough edges of quantity regulation, that complication is unnecessary because the simpler, less-cumbersome, and more-transparent mechanism of a carbon royalty adder is already available under existing statutory authority. Moreover, future demand for coal is uncertain, so a partial moratorium or quota could easily turn out to be too tight or too loose, and might not be tied to climate costs.

Third, a royalty adder will induce less volatility in coal prices, and thus in electricity prices, than a comparable quantity restriction. As always, it is very difficult to project demand on a horizon of a decade or more. Under a quantity restriction, coal prices could rise sharply if demand is unexpectedly strong, or decline sharply if demand is weak. These price fluctuations would be reduced under a royalty adder because the market can supply more coal when demand is high, and less when demand is low, dampening price fluctuations. A royalty adder is thus more conducive to market stability and price predictability than would be a comparable quantity restriction.

Fourth, a carbon adder will generate considerable additional revenues (the details are discussed in the next section). These revenues can in turn be used to provide resources to the miners and regions negatively impacted by reduced coal mining. Because royalties are split between the federal government and the state of extraction, the current royalty system provides targeted support to the states that are directly affected. In contrast, a quantity policy puts miners out of work and cuts state receipts without providing an alternative source of revenues. In fact, under a quantity policy the delivered price of coal will increase for the coal that is sold, implying that the remaining coal mining firms might actually make a larger profit for each ton of coal sold.

Approximate dollar values of the adder

Table 3 reports approximate dollar values of the carbon adder, computed at 20 percent of the SCC, for two types of Western coal: PRB subbituminous (Wyoming and Montana) and Uinta Basin subbituminous (Utah and Colorado). Because they have different carbon content, these coal types would have different royalty adders on a per ton basis. In 2015 PRB coal sold for approximately $10 per short ton. For a new lease or a lease renewal in 2018, the carbon adder for that coal would be approximately $15.60/short ton, so the combined selling price would be approximately $25.60, assuming that the carbon adder was passed through to buyers. As can be seen from table 1, even with this 20 percent SCC carbon adder the mine-mouth price of PRB coal would still be less per ton than Illinois or Appalachian subbituminous, and would be the same or less than Illinois Basin and Appalachian coal on an energy-equivalent basis. The royalty adder on coal from the Uinta Basin would be higher, at $20.70 per short ton in 2018, because of the higher carbon content of that coal.

Justification for a 20 percent adder

The 20 percent SCC royalty adder would fall between the extremes of a permanent cessation of new leases and reliance only on downstream policy such as the CPP. A royalty adder of 20 percent of the SCC would more closely align coal royalties with oil royalties (currently 30–46 percent of the SCC) and natural gas royalties (currently 16–24 percent of the SCC). It would also roughly align mine-mouth energy-equivalent PRB coal prices with Eastern and Midwestern prices, as indicated in table 3.

By roughly raising the price of PRB coal on an energy-adjusted basis to approach Midwestern and Eastern coal, the 20 percent rate would reduce, but not end, production of federal coal. This is consistent with BLM's multiple use mandate. Demand for Eastern coal would increase, but considerably less than one-for-one, the specifics depending on how the CPP is implemented. With the increase in production, Eastern coal employment would be higher than without the royalty adder.

The net CO_2 emissions reduction in the power sector depends on the implementation of the CPP. With the CPP final rule in place, a 20 percent royalty adder would induce modest additional emissions reductions by reducing so-called leakage in the CPP. This leakage arises from likely differences across states in their implementation of the CPP, potential regional variations in the price of CPP allowances, and other factors. Moreover, some experts currently expect the CPP restrictions to be nonbinding in some states or regions, or to be minimally binding with a small price on carbon. If the CPP turns out to be nearly nonbinding, the 20 percent royalty adder serves as a backstop so that additional emissions reductions are obtained in pursuit of broader national climate policy and the nation's commitments made in the 2015 Paris Agreement. If the CPP fails to withstand court challenges, a 20 percent SCC adder would result in meaningful emissions reductions, and this percentage could be increased, given the absence of national CO_2 emissions regulation in the power sector.

TABLE 3.

Carbon Adder Schedule for Two Typical Western Federal Coals, 2015

	2015 dollars per short ton of coal	
	Powder River Basin	Uinta Basin
Heat content (Btu/lb)	8,800	11,700
2018	$15.60	$20.70
2025	$18.30	$24.30
2030	$20.20	$26.90

Source: Authors' calculations based on data from EIA.

Note: Based on average CO_2 emissions per Btu for U.S. subbituminous coal.

In addition, the 20 percent SCC royalty adder would generate additional revenues that could be used for transitional assistance to coal communities. Up to a point, gross royalty receipts increase as the royalty adder increases, but for further increases in the royalty adder, gross receipts eventually begin to fall because of declining production. CEA (2016) estimates that royalty receipts are maximized at a royalty adder equal to 30 percent of the SCC, implying that our proposal would likely raise revenue relative to the status quo. That estimate depends on modeling assumptions. Moreover, it is likely that total revenues related to coal production, including severance taxes and income taxes as well as the state share of royalties, would peak at a royalty of less than 30 percent of the SCC. The 20 percent SCC royalty adder strikes a conservative balance that generates large additional royalties.

Use the revenues to support coal communities

Federal mineral royalties are split roughly evenly between the U.S. government and the state of extraction. Thus, under current law and without any adjustment, half the increased royalties from a 20 percent SCC royalty adder would go to the affected states, which in turn could use the increased receipts to support transitions in the coal communities that would see a reduction in mining employment and income.

The 20 percent SCC royalty adder strikes a conservative balance that generates large additional royalties.

As highlighted in the previous section, communities that rely on the mining industry at nonfederal sites in the East and Midwest are also in decline. Those communities face additional losses in employment as the power sector transitions toward a low-carbon future. The estimates in the next section suggest that the revenues from a 20 percent SCC royalty adder would provide substantial resources over the next 10 to 20 years to fund transitional assistance to these communities as well, such as the POWER+ Plan (White House 2015) proposed in the Obama administration's fiscal year 2016 and fiscal year 2017 budgets.

In addition to any state revenues allocated to transition assistance, we propose that Congress authorize the use of the federal share of receipts from the royalty adder to fund transition and support programs for coal communities that rely on private coal reserves, such as bolstering coal worker pension and health-care benefits and supplementing underfunded mine reclamation.

EFFECTS ON EMISSIONS, EMPLOYMENT, AND REVENUES

A 20 percent SCC carbon adder to royalties on federal coal would reduce but not eliminate production of federal coal and would generate substantial federal and state revenues. The adder would also reduce total CO_2 emissions in the power sector, with the extent of the emissions reduction depending on the way the CPP ends up being implemented. The results from this section draw on simulations of the U.S. energy sector using the Integrated Planning Model (IPM), developed by the consultancy ICF Incorporated. The IPM is a proprietary model that has been widely used by the U.S. government for the analysis of regulation; for example, the EPA used the IPM for the Regulatory Impact Analysis of the CPP. It includes detailed modeling of key aspects of the energy system relevant to our analysis, including 36 coal supply regions, 14 coal grades, coal transportation and distribution, electricity generation, and production of alternative inputs to electricity generation. It models electricity generation investment, the choice of when to turn up generation, fuel switching, and regulatory compliance.

The baseline assumptions used in this analysis are based on the assumptions used in the Regulatory Impact Analysis for the CPP. The estimates vary somewhat depending on how states choose to comply with the CPP. Just as in the Regulatory Impact Analysis, we present the bounding cases of all states choosing a mass-based plan (i.e., a set mass of emissions is permitted for the state and a tradable permit program or other policy is used to meet the target) or all states choosing a rate-based plan (i.e., states meet a carbon intensity target). We also model a no-CPP scenario. For each of these baseline scenarios, our results assume phase-in of the carbon adder as a linearly increasing royalty schedule for all leases, ramping up over a 10-year period from 2016 to 2026. Some mines include both federal and nonfederal coal. For these mines, the adder was assessed at each step of the mine's supply curve in proportion to the current fraction of federal coal in the mine. This is consistent with the current logical mining unit approach for mining regions—such as the PRB—that commonly contain inholdings of nonfederal coal.

Table 4 summarizes the estimated effects on coal production, mining employment, and power sector emissions of a 20 percent SCC royalty adder on federal coal, relative to a scenario with no royalty adder. Estimates are reported for 2025 and 2030. Like all estimates, the specific numerical values depend on the underlying assumptions, which are (other than the carbon adder) the assumptions in the EPA's Regulatory Impact Analysis for the CPP. The results discussed here are taken from CEA (2016); Gerarden, Reeder, and Stock (2016); and Vulcan (2016). Under the 20 percent SCC royalty adder, federal coal production declines. In the PRB, production declines in 2025 by between 82 and 107 million short tons, depending on the CPP implementation; for comparison, PRB production in 2015 was 399 million short tons.

Table 4 provides estimates of the degree of substitution of nonfederal for federal coal. Under a mass-based CPP, the royalty adder reduces PRB production by 82 million tons in 2025, while non-Western coal production increases by 49 million tons, corresponding to a substitution ratio (49/82) of roughly 60 percent. The substitution ratio is less in 2025 under a rate standard—only 35 percent—as electric power generation shifts to new natural gas and renewables.[11] The largest increase in nonfederal coal is in the Illinois Basin. Northern Appalachia sees an increase, relative to the no-adder case, of approximately 8 million tons (approximately 12 percent) in each of the CPP scenarios.[12]

TABLE 4.

Estimated Effect of 20 Percent SCC Royalty Adder on Production, Emissions, and Employment

	CPP Implementation					
	Mass-based		Rate-based		No CPP	
	2025	2030	2025	2030	2025	2030
Coal production by basin (million short tons)						
Powder River Basin	–82	–92	–107	–107	–86	–76
Rocky Mountains	0	1	–4	–1	–14	–15
Central Appalachia	4	1	2	2	5	1
Northern Appalachia	8	7	9	11	8	12
Illinois Basin	18	23	20	22	16	15
All other U.S. Regions	18	26	9	19	15	10
Total	**–33**	**–34**	**–70**	**–53**	**–56**	**–54**
Power sector emissions (million metric tons CO_2)	–28	–10	–81	–39	–66	–54
Direct mining employment						
Powder River Basin	–1,400	–1,500	–1,800	–1800	–1,400	–1,300
Rocky Mountains	0	100	–300	0	–1,000	–1,000
Central Appalachia	1,100	200	500	500	1,200	200
Northern Appalachia	1,300	1,100	1,500	1,800	1,300	1,800
Illinois Basin	2,000	2,500	2,200	2,400	1,700	1,600
All other U.S. Regions	2,200	3,300	1,100	2,400	1,900	1,300
Total	**5,200**	**5,700**	**3,200**	**5,300**	**3,700**	**2,600**

Note: All entries are changes relative to the no-adder base case under the indicated CPP implementation. Estimates are based on IPM simulations in Vulcan (2016). Direct mining employment is estimated from coal production and average coal productivity by basin. The mass-based CPP scenario includes new source complements and regional trading. The rate-based CPP scenario includes new sources covered by Section 111(b) of the Clean Air Act, with regional trading. The royalty adder is phased in, consistent with its application only to the federal component of coal mined in new and renewed leases. For details, see Gerarden, Reeder, and Stock (2016); and Vulcan (2016).

Despite this partial switching to nonfederal coal, total power sector emissions decline under the 20 percent carbon adder. The size of this decline depends on the year and on the way the CPP is implemented. The smallest reductions occur under the mass-based CPP, in which case the royalty adder induces emissions reductions in 2025 of 33 million metric tons.

Table 4 also provides preliminary estimates of the direct employment effects of the 20 percent SCC adder for the major coal-producing states. Employment falls in the regions with a preponderance of federal coal, but increases in the East and Midwest. On average, nonfederal mines have lower productivity than federal mines, and national mining employment is estimated to increase under the 20 percent SCC carbon adder even though there is only partial substitution of nonfederal for federal coal.

The 20 percent SCC royalty adder would result in substantial additional royalty revenue, on the order of $3 billion additional total revenues annually in the mid-2020s. Through 2030 cumulative additional revenues (undiscounted) could exceed $35 billion. These revenues would be split with the state of extraction. For example, in the mid-2020s Wyoming's share of the royalty revenues would increase by roughly $1.3 billion, relative to the no-adder case.[13]

It is worth noting that the increases in royalty revenues could be partly offset by decreased severance tax (levied on extraction of certain natural resources) as well as income, sales, and property taxes in some states (Headwaters Economics 2015).[14] However, even in the extreme case that all of the severance tax payments, sales taxes, and bonus bid payments were lost, our modeling suggests that the increased revenue from the royalty payments with a 20 percent SCC adder would exceed the lost revenue.

It is also notable that the estimates discussed here scale nonlinearly with the adder. For substantially smaller values of the adder, for example at 5 percent of the SCC, the substitution ratio of nonfederal to federal coal is greater (approximately two-thirds replacement), and emissions reduction is relatively small. For a 50 percent SCC royalty adder, there is substantially less substitution, and consequently more emissions reduction.

Chapter 4. Questions and Concerns

Why a royalty adder rather than auction reform?

In principle, changes to the bidding process could complement or substitute for an increase in the royalty adder. Good governance considerations should support transparency and competition in bidding along with other reforms, such as increasing the minimum bidding price, so that the taxpayer gets a fair return. However, we see reforms to the bidding process as less effective than a royalty adder from the perspective of climate policy. Most importantly, a bid provides the right to mine reserves, whereas the royalty adder applies to coal actually mined. Because combustion of the coal produces the externality, the price should be tied to its production and sale, and not to the right to produce. Given that bonus bids are sunk costs, production will occur as long as the price exceeds the marginal cost of production, in which case the price to the user will not reflect any climate externality. In addition, process reforms must confront the fact that the tracts nominated by the mining companies for leasing typically are adjacent to existing mines, which intrinsically limits competition. A royalty adder is thus more practical and more directly targeted than changing the bidding process to achieve climate policy goals.

What should the value of the adder be if the CPP is not in place, or is substantially weakened?

Absent meaningful downstream policy, the main tool to internalize the externality value would be the carbon adder. In this case, a larger carbon adder would be appropriate. Because of substitution with nonfederal coal, the appropriate carbon adder would still be less than 100 percent of the SCC, but it would exceed 20 percent of the SCC.

What is the role of upstream policy if the U.S. adopts a carbon tax?

A carbon tax at a rate that fully internalizes the climate costs of CO_2 emissions is the first-best policy. With such a policy in place, there is no economic justification for additional upstream policy, and the market should be free to choose between coal or other energy sources based on their after-tax cost. To the extent that the carbon tax does not fully internalize the externality (i.e., is too low), then there would be a role for an upstream carbon adder.

Wouldn't cutting back on federal coal production simply spur exports?

This would not occur if the cutback resulted from a royalty carbon adder. The adder drives up the price of U.S. coal, which makes it less, not more, competitive on the export market. With the higher domestic price, producers will want to sell the coal domestically.

Isn't it more direct just to stop issuing coal mining leases on federal lands?

Simply stopping all new and renewed leases misses many of the benefits of a royalty adder. Using a 20 percent royalty adder recognizes that the CPP could provide a powerful downstream tool to limit emissions, and simply ceasing federal leases in effect double-counts by placing too high a carbon price on federal coal. Using royalties allows markets to direct coal mining in the most economically efficient way. And simply halting federal mining would reduce economic activity and severance receipts in directly affected states without generating additional revenues to support their transition.

Won't we see climate benefits from reforming the current royalty system to ensure that the taxpayer receives a fair return, but without a carbon adder?

Doubling the amount received for federal coal under the current system would result in an increase in royalties of roughly \$1.50 per ton of PRB coal. This is an order of magnitude less than the 20 percent SCC carbon adder. The emissions benefits are even less than proportional because the greater the royalty increase, the less substitution there is of nonfederal for federal coal: a larger royalty adder increases the demand for, and price of, nonfederal coal, making gas and renewables increasingly attractive on the margin. Royalty reform focused solely on the taxpayer receiving a fair return would have to substantially increase payments in order to provide comparable climate benefits.

Won't this proposal exacerbate the squeeze on coal states and coal communities?

Coal employment has followed its historical downward trend under pressure from low natural gas prices, and this trend is projected to continue. The proposed carbon adder would provide revenue to fund the transition of communities that have historically mined federal coal. The proposal would increase the demand for nonfederal coal and therefore increase employment in Appalachian and Midwestern coal mining states and communities; in fact, total national mining employment would increase, relative to the current policy case, because of the lower productivity in those regions. Finally, the proposal would provide a new revenue stream that Congress could direct toward supporting the transition of communities and states that have historically mined nonfederal coal.

Won't it lead to more bankruptcies of coal companies?

It is true that several prominent coal companies are in Chapter 11 bankruptcy proceedings (and some Chapter 7 liquidations). A major reason for most of these bankruptcies is the taking on of significant debt to expand or acquire operations, often internationally. These debt-financed investments were made when international coal demand was high in the early 2010s. For example, in June 2011 Alpha Natural Resources acquired Massey Energy for $7.1 billion and Arch Coal acquired International Coal Group for $3.4 billion. In December 2011, Peabody Energy bought Macarthur Coal of Australia for $5.1 billion. With the slowdown in demand on the international coal market, many of these investments turned out to be poor ones, leading to bankruptcies. This proposal will slightly increase demand for Eastern coal, raising the price of that coal and easing financial pressures on all coal companies with operations focused in the East. Many of these companies are among those in Chapter 7 or Chapter 11 bankruptcy. Coal companies producing on federal lands will see steady but declining production, and the most efficient PRB mines will remain productive assets.

Chapter 5. Conclusion

The federal coal program is in need of reform. In addition to improving transparency and providing a fair return to current taxpayers, coal program reform should also take into account the costs that burning federal coal imposes on current and future generations by exacerbating climate change. Doing so requires aligning federal coal management policies with downstream regulations aimed at stemming CO_2 emissions from burning fossil fuels. Furthermore, these policies need to recognize that there will be some substitution of nonfederal production for federal production, which has implications for the optimal federal coal policy.

Incorporating a carbon adder into federal coal royalties would reduce but not eliminate federal coal production, would reduce total power sector CO_2 emissions, and would generate substantial additional royalties. These royalties can be used to support those communities that have historically engaged in mining nonfederal coal as the U.S. economy develops a low-carbon power sector.

Endnotes

1. See, e.g., the July 2016 letter from 69 climate scientists to Secretary Jewell calling for an end to federal coal leasing (Caldeira et al. 2016). The petition to Secretary Jewell from the Center for Biological Diversity and other organizations goes one step farther and calls for an end to all federal fossil fuel leasing (Center for Biological Diversity 2016).
2. The department makes this clear in its Notice of Intent to undertake the PEIS: "With respect to the climate impacts of the Federal coal program, the Programmatic EIS [PEIS] will examine how best to measure and assess the climate impacts of continued Federal coal production, transportation, and combustion. . . . It will also consider [mitigation by] land use planning, adjustments to the scale and pace of leasing, adjustments to royalties or other means of internalizing externalities, mitigation through greenhouse gas reductions elsewhere, information disclosure, and other approaches. . . . *The Programmatic EIS will examine the climate impacts of the coal program in the context of the Nation's climate objectives, as well as the Nation's energy and security needs*" (GPO 2016, 81 FR 17720; emphasis added).
3. The federal fossil fuels leasing program encompasses extraction of oil, natural gas, and coal. Federal leasing activities occur in different entities within the Department of the Interior. The Bureau of Ocean Energy Management is responsible for offshore oil and gas leases. Onshore oil and gas leases, as well as coal leases, are managed by the Bureau of Land Management. Revenues from all mining leases (oil, natural gas, coal, and non-fossil-fuel mining) are collected by a separate entity with the Department of the Interior, the Office of Natural Resource Revenue.
4. Most of the mineral rights in the PRB are federally held. Typically, state and some private mineral rights are held in a checkerboard fashion surrounded by federal mineral rights. Coal seams cross mineral rights boundaries and as a result mining occurs in logical mining units that combine tracts with different mineral rights. In 2014 396 million tons of coal were mined in Wyoming, of which 341 million tons (86 percent) was federal.
5. Liquefied natural gas (LNG) export terminals have been permitted and are under construction. It is possible that at some future date there could be sufficient export capacity to better integrate domestic and international gas markets. However, the cost of liquefaction, transportation, and regasification are sufficiently large that domestic prices would stay well below international prices.
6. This is the central estimate based on a 3 percent discount rate and converted to 2016 dollars (Interagency Working Group on the Social Cost of Carbon [IWG] 2016).
7. The lower sulfur content of the coal tends to raise the price of the coal, since it implies that there is less need for costly scrubbers to reduce the sulfur dioxide (SO_2) emissions (Considine and Larson 2006).
8. A severance tax is defined as a tax on nonrenewable resources that are extracted within that jurisdiction.
9. The carbon content of coal varies by basin; within basin it can vary by seam and even within a seam. Coal is regularly assessed for heat content, as well as content of ash, sulfur, and other matter, as part of setting its price for ultimate sale. These regular assays could include carbon content or measure CO_2 emissions from total combustion.
10. The multiple use mandate was introduced in the Federal Land Policy and Management Act of 1976. The statutory definition is "The term 'multiple use' means the management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; making the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use to conform to changing needs and conditions; the use of some land for less than all of the resources; a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output" (GPO 1976).
11. As the royalty adder increases beyond 20 percent, the substitution ratio decreases because the higher royalty adder increases the price of nonfederal coal, which in turn makes natural gas and renewables increasingly attractive economically.
12. The royalty adders for this analysis were applied to all federal coal and coal on Indian lands in the PRB. The moratorium does not apply to Indian lands and an open policy question is whether future changes would apply to Indian lands. To the extent they do not, this would be another channel of substitution from federal to non-federal coal. It may be sizable. For example, one study estimated potential resources of 23 billion tons on the Northern Cheyenne Reservation in southeastern Montana, with perhaps 5 percent suitable for strip mining (Mapel et al. 1975).
13. This estimate assumes that the CPP is implemented by a mass-based standard; royalty revenues would be greater absent the CPP.
14. For example, Wyoming currently has a 7 percent severance tax on surface coal (3.75 percent severance tax on underground coal), although there is an exemption down to $0.60 per short ton in some cases where the state aims to encourage production. In 2012, severance taxes brought in roughly the same amount as royalty payments ($297 million). Wyoming levies no individual income tax and has a 4 percent sales tax. Conservatively assuming 2015 coal industry employment, annual earnings of $82,654 (in 2013 from Godby et al. 2015), and all earnings spent in Wyoming, would imply a roughly $20 million in revenues from the sales tax from coal workers.

Authors

Kenneth T. Gillingham

School of Forestry and Environmental Studies and Department of Economics, Yale University

Kenneth Gillingham is an Assistant Professor of Economics at Yale University, with appointments in the School of Forestry & Environmental Studies, Department of Economics, and School of Management, as well as a Faculty Research Fellow at the National Bureau of Economic Research. In 2015-2016 he served as the Senior Economist for Energy and the Environment at the White House Council of Economic Advisers. He is an energy and environmental economist drawing from the fields of applied microeconomics, behavioral economics, and industrial organization. He has published widely on consumer decisions in energy efficiency and renewable energy, as well as on climate and energy policy. He was a Fulbright Fellow in New Zealand and has also worked at Resources for the Future, the California Air Resources Board, and Pacific Northwest National Laboratory. He received a Ph.D. in Management Science & Engineering and Economics, as well as M.S. degrees in Statistics and Management Science & Engineering, from Stanford University. His undergraduate degree was an A.B. in Economics and Environmental Studies from Dartmouth College.

James H. Stock

Department of Economics and Harvard Kennedy School, Harvard University

James H. Stock is the Harold Hitchings Burbank Professor of Political Economy, Faculty of Arts and Sciences and member of the faculty at Harvard Kennedy School. He received a M.S. in statistics and a Ph.D. in economics from the University of California, Berkeley. His research includes applied macroeconomics, econometrics, and energy and environmental economics. He previously served as Chair of the Harvard Economics Department from 2007-2009 and as Co-Editor of *Econometrica* from 2009-2012. In 2013-2014 he was Member of President Obama's Council of Economic Advisers, where his portfolio included macroeconomics and energy and environmental policy. He is currently Co-Editor of *Brookings Papers on Economic Activity.*

Acknowledgments

The authors would like to acknowledge Spencer Reeder and Todd Gerarden for their contributions to the analysis performed in this policy proposal. We also thank the participants at the author's conference on the proposal at the Brookings Institution, Adele Morris, Nathan Richardson, and the staff of The Hamilton Project for their helpful input.

References

Adler, Jonathan H. 2016. "Supreme Court Puts the Brakes on the EPA'S Clean Power Plan." *Washington Post*, February 9.

Bureau of Land Management (BLM). 2016. "Coal Operations." Bureau of Land Management, U.S. Department of the Interior, Washington, DC.

Burger, Michael. 2016. "A Mitigation-Based Rationale for Incorporating a Climate Change Impacts Fee into the Federal Coal Leasing Program." Sabin Center for Climate Change Law, Columbia Law School, New York.

Caldeira, Ken, James Hansen, Stuart Pimm, Michael Soulé, Susan Solomon, Ove Hoegh-Guldberg, Aradhna Tripati, et al. 2016, July 27. "Scientists Support Ending Coal Leasing on Public Lands to Protect the Climate, Public Health, and Biodiversity." Submitted to BLM_WO_Coal_Program_PEIS_Comments@blm.gov

Casper Star Tribune. 2016. "Wyoming Coal Production Hit a 13-year Low in 2015." January 25.

Center for Biological Diversity. 2016, July 12. "Petition for a Moratorium on the Leasing of Federal Public Land Fossil Fuels Under the Mineral Leasing Act, 30 U.S.C. §§ 226, 241 Before the United States Department of the Interior." Center for Biological Diversity, Tucson, AZ.

Clean Air Act (CAA) of 1963. Pub. L. 88-206, 77 Stat. 392 (1963).

Considine, Timothy, and Donald Larson. 2006. "The Environment as a Factor of Production." *Journal of Environmental Economics & Management* 52 (3): 645–62.

Council of Economic Advisers (CEA). 2016. "The Economics of Coal Leasing on Federal Lands: Ensuring a Fair Return to Taxpayers." Council of Economic Advisers, Executive Office of the President of the United States, Washington, DC.

Energy Independence and Security Act of 2007, Pub. L. 110-140 (2007).

Energy Information Administration (EIA). 2015a. Annual Coal Report. Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. 2015b. "Annual Energy Outlook." Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. 2015c. "Sales of Fossil fuels Produced from Federal and Indian Lands, FY 2003 through FY 2014." Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. 2016a. "Short-Term Energy Outlook." Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. 2016b. "Quarterly Coal Report." Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. 2016c. "Coal Markets: Average Weekly Coal Commodity Spot Prices." Energy Information Administration, U.S. Department of Energy, Washington, DC. Accessed November 15, 2016.

———. 2016d, November. "Annual Coal Report." Energy Information Administration, U.S. Department of Energy, Washington, DC.

———. n.d. "Coal Data Browser." Energy Information Administration, U.S. Department of Energy, Washington, DC.

Environmental Protection Agency (EPA). n.d. "Fact Sheet: Overview of the Clean Power Plan." Environmental Protection Agency, Washington, DC.

Federal Coal Leasing Amendments Act of 1975, Pub.L. 94-377 (1976).

Gerarden, Todd, W. Spencer Reeder, and James Stock. 2016. "Federal Coal Program Reform, the Clean Power Plan, and the Interaction of Upstream and Downstream Climate Policies." Working Paper 22214, National Bureau of Economic Research, Cambridge, MA.

Gerking, Shelby, and Stephen Hamilton. 2008. "SO_2 Policy and Input Substitution Under Spatial Monopoly." *American Journal of Agricultural Economics* 90 (4): 933–50.

Godby, Robert, Roger Coupal, David Taylor, and Tim Considine. 2015. "The Impact of the Coal Economy on Wyoming." Center for Energy Economics and Public Policy, University of Wyoming, Laramie, WY.

Government Accountability Office (GAO). 2013. "Coal Leasing: BLM Could Enhance Appraisal Process, More Explicitly Consider Coal Exports, and Provide More Public Information." GAO Publication No. 14-140. U.S. Government Printing Office, Washington, DC.

Haggerty, Mark, and Julia Haggerty. 2015. "An Assessment of U.S. Federal Coal Royalties: Current Royalty Structure, Effective Royalty Rates, and Reform Options." Headwaters Economics, Bozeman, MT.

Headwaters Economics. 2015. "Social and Economic Context for the Federal Coal Program." Headwaters Economics, Bozeman, MT.

Hein, Jayni F., and Caroline Cecot. 2016. "Coal Royalties: Historical Uses and Justifications." Institute for Policy Integrity, New York, NY.

Hein, Jayni F., and Peter Howard. 2015. "Illuminating the Hidden Costs of Coal: How the Interior Department Can Use Economic Tools to Modernize the Federal Coal Program." Institute for Policy Integrity, New York, NY.

Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). 2016. "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866." Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, Washington, DC.

Krupnick, Alan, Joel Darmstadter, Nathan Richardson, and Katrina McLaughlin. 2015. "Putting a Carbon Charge on Federal Coal: Legal and Economic Issues." Discussion Paper 15-13, Resources for the Future, Washington, DC.

Lee-Ashley, Matt, and Nidhi Thakar. 2015. "Cutting Subsidies and Closing Loopholes in the U.S. Department of Interior's Coal Program." Center for American Progress, Washington, DC.

Mapel, W. P., B. F. Bohor, J. C. Sarnecki E. A. Magill, Michael Sokaski, and George McIntyre. 1975. "Status of Mineral Resource Information for the Northern Cheyenne Indian Reservation, Montana." Administrative Report BIA-3, Bureau of Indian Affairs, Washington, DC.

Mineral Leasing Act (MLA) of 1920, 30 U.S.C. § 181 et seq. (1920).

Morris, Adele C. 2016. "Build a Better Future for Coal Workers and Their Communities." The Climate and Energy Economics Project, Brookings Institution, Washington, DC.

Nelson, Robert H. 1983. *The Making of Federal Coal Policy.* Duke University Press: Durham, NC.

Peterson, Isaiah. 2015. "Devaluing Coal: Reasons for Restructuring How Federal Coal Is Valued." *Georgetown Journal of Law and Public Policy* 13 (1): 165–80.

Sanzillio, Tom. 2012. "The Great Giveaway: An Analysis of the Costly Failure of Federal Coal Leasing in the Powder River Basin." Institute for Energy Economics and Financial Analysis, Cleveland, OH.

Squillace, Mark. 2013. "The Tragic Story of the Federal Coal Leasing Program," *Natural Resources & Environment* 27 (3): 1–5.

Tax Foundation. n.d. "Wyoming: The facts on Wyoming's Tax Climate." Tax Foundation, Washington, DC.

Taxpayers for Common Sense. 2013. "Federal Coal Leasing: Fair Market Value and a Fair Return for the American Taxpayer." Taxpayers for Common Sense, Washington, DC.

U.S. Department of the Interior Office of the Inspector General. 2013. "Coal Management Program, U.S. Department of the Interior." Office of the Inspector General, U.S. Department of the Interior, Washington, DC.

U.S. Geological Survey (USGS). 2015. "Coal Geology and Assessment of Coal Resources and Reserves in the Powder River Basin, Wyoming and Montana." Professional Paper 1809, U.S. Geological Survey, Washington, DC.

U.S. Government Publishing Office (GPO). 1976. "43 USC 1702–Federal Land Policy and Management Act, Subchapter I–General Provisions, Definitions." U.S. Government Publishing Office, Washington, DC.

———. 2011. "30 USC 207–Conditions of lease: United States Code, 2006 Edition, Supplement 5, Title 30–Mineral Lands and Mining." U.S. Government Publishing Office, Washington, DC.

———. 2016, March. "Notice of Intent to Prepare a Programmatic Environmental Impact Statement to Review the Federal Coal Program and To Conduct Public Scoping Meetings." 81 FR 17720, U.S. Government Publishing Office, Washington, DC.

Vulcan, Inc. 2016. "Vulcan Analysis of Federal Coal Leasing Program: Summary of Modeling Results." Seattle, WA.

White House. 2008. "Energy for America's Future." White House, Washington, DC.

———. 2015. "Investing in Coal Communities, Workers, and Technology: The POWER+ Plan." The President's Budget: Fiscal Year 2016, White House, Washington, DC.

Wyoming Taxpayers Association. n.d. "Severance Taxes." Wyoming Taxpayers Association, Cheyenne, WY.

THE HAMILTON PROJECT

ADVISORY COUNCIL

Highlights

Kenneth T. Gillingham of Yale University and James H. Stock of Harvard University propose reforms to the federal minerals leasing program that both tie it to negative climate effects associated with coal mining, and improve its efficiency and benefits to the taxpayer. Specifically, they propose applying a royalty adder of 20 percent of the social cost of carbon to new and renewed federal coal leases.

The Proposal

Include a carbon adder in coal royalties. Applying a carbon adder to federal coal royalties would reduce but not eliminate federal coal production, reduce total power sector CO_2 emissions, and generate substantial additional royalties. This royalty adder would be set to 20 percent of the U.S. government's estimate of the social cost of carbon. Revenues would then be used to support communities that have historically engaged in mining nonfederal coal.

Benefits

Implementation of this proposal would benefit current and future generations by mitigating climate change costs through reduced carbon emissions from the use of federal coal. Communities reliant on nonfederal coal mining would benefit from transition support funded by the increased revenues.

THE HAMILTON PROJECT

1775 Massachusetts Ave., NW
Washington, DC 20036

(202) 797-6484

BROOKINGS

EPIC
ENERGY POLICY INSTITUTE
AT THE UNIVERSITY OF CHICAGO

Printed on recycled paper.

WWW.HAMILTONPROJECT.ORG
EPIC.UCHICAGO.EDU