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Putting a Carbon Charge on Federal Coal: Legal and Economic Issues

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RESOURCES FOR THE FUTURE

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Abstract

US policy to limit greenhouse gas emissions is currently driven, in part, by the US Environmental Protection Agency's proposed Clean Power Plan, which seeks a drop in carbon dioxide (CO_2) emissions from fossil-fueled power plants—a "downstream" approach to regulation. Here, we consider an alternative, or possibly complementary, regulatory perspective: What is the legal and economic feasibility of imposing an "upstream" CO_2 charge on coal production at its extraction site? Specifically, our focus is on leased coal from federal lands managed by the Bureau of Land Management (BLM). Such a carbon charge is designed, in principle, to embody the cumulative "lifecycle" externalities from coal mining to combustion (or other "downstream" utilization). Our legal analysis concludes that BLM has the statutory and regulatory authority to impose such a charge and that it would be best to add it to the royalty rate. But a large fee that would dramatically reduce revenues could invite judicial concern. The economic case is weaker than the legal case because production on state, private, and tribal lands (60 percent of total production) would not be subject to the charge and so could ramp up in response to the economic disadvantage the charge would cause for coal on federal lands, among other reasons. Best would be a comprehensive set of charges on royalties for all fossil fuels, irrespective of ownership.

Key Words: carbon taxes, coal, climate change, pollution strategies, emissions reductions

JEL Classification Numbers: Q30, Q52, Q54

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Introduction and Overview

There are many ways to internalize the climate-related damages from CO_2 (termed the social cost of carbon, or SCC) and other greenhouse gases (GHG) that result from fossil fuels. Most approaches tend to fall into two categories: downstream (focusing on the uses of fossil fuels) or upstream (focusing on the sources of fossil fuels).

Some current federal policies in the United States intervene downstream. For example, the US Environmental Protection Agency (EPA) has proposed to partially internalize power plant CO_2 emissions through its Clean Power Plan (CPP).[1] EPA and the National Highway Traffic Safety Administration (NHTSA) have issued rulemakings significantly increasing fuel economy standards (and therefore reducing CO_2 emissions) for light- and heavy-duty vehicles. Before that, another attempt to use a downstream approach—a cap- and- trade program introduced by Congressmen Waxman and Markey—failed in Congress (H.R. 2454).

At the same time, there have been calls, particularly from the environmental community, to internalize externalities upstream, at the wellhead or the mine, or even farther upstream, applied to the oil, gas, and coal resources in the ground.[2] These calls have joined a series of

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[1] Currently a proposed rulemaking, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Proposed Rulemaking, 79 FR 34829 (18 June 2014) (amending 40 CFR 60).

[2] Greenpeace USA (2014) uses the social cost of carbon (SCC) to calculate potential emissions from all federal coal leased during the Obama administration and argues that the program is incompatible with stated administration climate goals. The Center for American Progress has alternately called for a carbon charge at the bonus bid (Thakar 2014) or royalty (Moser et al. 2015) stage. 350.org argues for a carbon charge large enough to keep most company-held fossil fuel resources in the ground (McKibben 2012).

lawsuits by environmental groups regarding US Bureau of Land Management's (BLM) handling of a Colorado coal lease (which included concerns about methane emissions upstream at the mine)[3] and the need for BLM to develop programmatic planning documents and include climate change considerations within them.[4] Furthermore, the Obama administration has shaped this issue by releasing new draft guidance (CEQ 2014) on how federal agencies and departments should consider climate change impacts in their National Environmental Policy Act (NEPA) reviews.

The most significant upstream regulatory effort was a Clinton-era BTU tax, which failed in Congress (see, e.g., Erlandson 1994; Milne 2008; Royden 2002). More recently, Representative McDermott has introduced a bill that would require producers to purchase emission permits at the coal mine and oil refinery level (H.R. 972), and Senators Whitehouse and Schatz previously had released the draft of a proposed bill calling for an upstream carbon tax.[5] Senator Markey has announced plans to draft legislation halting new federal coal leases until the program has been reviewed, although this review is not necessarily tied to its failure to internalize climate externalities (Office of Senator Markey 2014).

With prospects for the CPP uncertain, and given the need to find a way to internalize global warming externalities, it is worth taking a closer look at an upstream approach that would target fossil fuels as they come out of the ground. Coal is the most CO_2-intensive energy sector. With coal on federal lands accounting for 40 percent of US coal production in 2013 (EIA 2014e), imposing an upstream carbon charge on federal coal production seems like a logical target for launching a federal carbon pricing policy.

This report explores the legal and economic questions raised by implementing a carbon charge on federal coal that takes into account GHGs over the entire coal life cycle. The goal of such a policy would be to internalize the social cost of greenhouse gases at the coal leasing and

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3 *High Country Conservation Advocates, et al. v. US Forest Service, et al.* (Civil Action No. 13-cv-01723, D.C. Colorado, 2014) and *Western Organization Resource Councils, et al. v. Jewell, et al.* (Case No. 1:2014cv01993, D.C. DC, filed 2014).

4 Paul G. Allen, whose grant made this RFF work possible, is underwriting this lawsuit. RFF is in no way connected to the suit or the opinions expressed therein.

113th Congress, American Opportunity Carbon Fee Act. The bill was never formally introduced, but the full text can be downloaded from the following press release on Senator. Whitehouse's website: http://www.whitehouse.senate.gov/news/release/sens-whitehouse-and-schatz-introduce-carbon-fee-legislation.

production (i.e., the upstream) stages through terms and conditions established by BLM as part of its federal coal leasing program.

This approach would be only a partial policy solution. While coal on federal lands accounts for a significant portion of US production; the remainder of coal on private (possibly tribal) and state lands would not be subject to added regulation. This limitation in scope has significant economic costs and could even eliminate any beneficial effects of such a program. Moreover, a policy aimed at climate externalities of coal alone does not address emissions from other fuels and activities, which in total amount to greater CO_2 emissions than the coal sector.

On the positive side, addressing climate externalities of coal on federal lands would be consistent with the federal government's duties to protect the public interest and its stated commitment to leadership on climate change. Such a step would also establish precedent for a more substantive, and broadly applied, upstream carbon charges in the future. If BLM can address these carbon externalities under existing law, this would be an important advantage given political gridlock in Congress.

We have several major findings. We offer these after a review of both the BLM's statutory and regulatory authority, the social cost of carbon estimates developed by the federal government's Interagency Working Group (IWG) and economic considerations arising from instituting a carbon charge upstream for the BLM coal leasing program:

1. The statutory case for a BLM coal pricing initiative appears to be stronger than the case against it since BLM is required to consider the environment when making multiple use decisions for public land. BLM's leasing statutes also appear to afford the agency a significant amount of discretion to set the financial terms of coal leases.
2. Combining a carbon charge with existing coal royalties offers the administratively simplest, most effective, and least legally problematic strategy. The BLM generally doesn't have the authority to change the terms of leases within a contract period, so adding charges to new or renewed leases would stagger the charge's introduction and allow for a gradual internalization of costs.
3. Legal arguments against a carbon charge would be strongest if such a charge were to instigate a large and abrupt reduction in coal extraction on federal lands, a move that would challenge BLM's mandate to balance multiple uses (including mining and associated generation of federal revenue). Litigation is likely no matter what the charge is. While the courts will generally defer to BLM's balancing of uses, climate-

driven policy that would stop new federal coal mining (or nearly so) would invite tough judicial scrutiny.

4. While the legal case for an upstream BLM carbon pricing program seems fairly strong, the economic case appears noticeably weaker. Since most government coal leases only have one bidder, bid prices for the land might be dropped to account for the greater royalty rate. At the same time, depending on the competitiveness of the coal market, operators on federal land might have to absorb the charge in lower profits. Both cases would result in no change in the coal price (and therefore no internalization of the climate externalities). The effectiveness of intervention upstream is further weakened because 60 percent of US coal is *not* produced on federal lands and this percentage is not expected to change much under current policies. That said, market demand for non-federal coal would likely rise if a significant federal coal-based carbon charge were implemented, partially mitigating any price increases. Further research is needed to determine how much production would potentially shift away from federal lands to private, state, and tribal lands and what the impact would be on coal prices.

5. The appropriate size of any carbon charge is outside the scope of this research, but a starting point could be the official federal social cost of carbon estimates. In this case, and using the midrange of these estimates for 2020 of about $46 per ton of $CO_{2,}$ the carbon charge would be over $90/ton of coal, far above the current price of federal Powder River Basin coal ($12/ton).

6. Policy interactions with downstream policies must be carefully considered. For instance, double-counting must be avoided. Two prominent policies are the Clean Power Plan (CPP) and the Mercury and Air Toxics Standards (MATS) program. A rise in the coal price might make the goal of the CPP easier to attain. But for reasons explained below, reducing mercury emissions could become more expensive.

7. Policymakers could achieve the most efficient approach for managing emissions by applying a carbon charge as broadly as possible -- to all fossil fuels extracted from all federal, state, tribal and private lands. Such a step of course would require Congressional approval.

The remainder of the paper is organized as follows. Section 1 is a primer on the coal sector to make it easier to understand the legal and economic arguments to come. Section 2 considers existing US legal authority to set terms and conditions (such as an additional charge or fee) applied to the lease sale, the annual lease rental, or the royalty payments tied to production (with Box 1 looking at some of these issues for Alberta, Canada, to provide a different perspective). Although a carbon charge could be applied farther upstream of this point when BLM makes land use planning decisions, or farther downstream after coal lease terms and conditions are set, the focus of this paper is the authority of BLM at the leasing stage (we do address the planning issue in Box 2, however). Section 3 discusses the SCC and its suitability for use in internalizing carbon costs in federal coal leasing (a more detailed discussion of the SCC appears in the Appendix). Section 4 examines economic and other implications of applying a carbon charge to coal mining. Section 5 provides a summary of key findings and uncertainties and outlines needs for further study.

1. Background on the Coal Sector

This section is a short primer on the US coal sector, emphasizing key features of the sector relevant to the question of placing an upstream carbon charge on federally leased coal. The United States has the largest coal reserves in the world and produces around 1 billion tons of coal annually.[6] The federal government is the largest single holder of coal reserves, with 87 billion short tons, almost one-third of domestic reserves (Humphries and Sherlock 2013, 6). Production of federal coal accounted for 40% of total US production in 2013 (EIA 2014e, Table 1) and has hovered around this number over the last decade (EIA 2014e). This trend is likely to continue in the future, as the US Energy Information Administration (EIA) projects stagnant growth (0.3%) in production levels for the Western region out to 2040, with stagnant growth in the Appalachian region (-0.6%) and slight growth (1.7%) in the Interior region (EIA 2014a).

1.1. Emissions

Considering all fuel stocks and energy uses (including transportation), coal is the third-largest source of energy consumed in the United States at 18.2%, with petroleum supplying 36.4% and natural gas supplying 27.4% (EPA 2014c, Figure 3-3). Again considering all fuel stocks and energy uses, coal is the second largest source of CO_2 emissions from fossil fuel combustion behind petroleum (ibid., Table 3-5) and has the highest carbon intensity (in CO_2 emissions per BTU). Although coal used to generate electricity has been declining in the United

[6] US coal production fell below 1 billion tons for the first time since 1993 in 2013, with total production of 984.8 million short tons (EIA 2013a).

States, it still accounts for 39% of US electricity generation, and electric power generation remains the primary use (93%) of coal consumed in the United States (EIA 2014c). Even though coal supplies 39% of electricity generation, it accounts for 75% of CO_2 emissions from electricity generation (EPA 2014c, Table 3-5). A small fraction of coal's energy-related GHG emissions are produced upstream at the mining stage itself (see Table 1).[7]

Table 1. Domestic Greenhouse Gas Emissions from Coal from Energy (Tg CO_2e), 2012

Greenhouse gas	Sector	2012 emissions (Tg CO_2e)
CO_2		
Stationary combustion[a]	Electricity generation	1,511.2
	Industrial	74.3
	Commercial	4.1
CH_4		
Stationary combustion[b]	Electricity generation	0.1
	Industrial	0.2
Mining[c]	Coal mining	55.8
	Abandoned underground mines	4.7
N_2O		
Stationary combustion[d]	Electricity generation	9.1
	Industrial	0.4
Total combustion		**1,599.4**
Total mining		**60.5**

Source: EPA (2014c).
Note: In teragrams, or million metric tons, of CO_2 equivalent emissions.
[a] EPA (2014c, Table 3-9).
[b] EPA (2014c, Table 3-10).
[c] EPA (2014c, Table 3-1).
[d] EPA (2014c, Table 3-11).

The above numbers are a snapshot of energy-related greenhouse gas emissions from all US coal, and make it clear that when discussing coal associated emissions, CO_2 is the primary pollutant, electricity generation the primary sector, and that upstream emissions from mining are

[7] Note, however, that emissions associated with certain end uses (e.g., metallurgical coke production) and emissions from transportation (e.g., midstream CO_2 emissions transporting coal from mine to consumer) are not captured here. A review of life-cycle assessments for different electricity fuel sources conducted by the National Renewable Energy Laboratory (NREL) confirms that coal emits the most greenhouse gases per kWh, with a median estimate of around 1,000 grams per kWh (Whitaker et al. 2012).

likely a relatively small share.[8] For the policy question at hand, we would like to know the emissions associated only with federal coal. One group of researchers estimates that the greenhouse gas emissions from federally leased coal in 2012 was 769 million metric tons of CO_2e, or approximately 14% of all greenhouse gas emissions from energy in 2012 (Stratus Consulting 2014).

1.2. Federal Coal Characteristics

Production on federal lands[9] totaled 401 million short tons in 2013 (EIA 2014e, Table 1). Nine states had coal production from federal and tribal lands in 2013, and five states accounted for 96% of all federal coal production: Wyoming (80%), Montana (6%), Colorado (4%), Utah (3%), and New Mexico (3%) (EIA 2014e, Table 10). In 2013, 474,025 acres were under lease for coal mining through 309 active leases, 42% of which were in Wyoming, 18% in Colorado, 18% in Utah, 9% in Montana, and 2% in eastern states (BLM 2014c). Both the number of active leases and the acreage under lease have declined since 1990,[10] although 107 lease sales have taken place during this period, and federal coal production has moderately increased both in absolute terms and as a share of total US production (GAO 2013, Figure 5). As we discuss later, the timing of lease sales and renewals has important implications for the coverage of a carbon charge policy.

One particular basin, the Powder River Basin (PRB) in Wyoming and Montana, dominates federal coal production. The Powder River Basin is the source of 86% of all federally leased coal and has an estimated 25 billion tons of economic coal resources (Scott and Luppens 2013). Coal from the Powder River Basin is surface-mined subbituminous, low-sulfur coal used for electric power generation and sells for lower prices than coal from other basins. Irrespective of ownership status (i.e., not just federally leased coal), in 2013, all of the domestic subbituminous coal shipped to electric power plants came from the western states of Wyoming, Montana, New Mexico, Colorado, and Utah; additionally, approximately 12% of the domestic bituminous coal shipped to electric power plants came from these same states (EIA 2015b[11]).

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[8] Note again that Table 1 does not include all upstream or midstream emissions.

[9] Not including Indian lands, which totaled 19 million short tons in 2013, or 1.9% of total coal production for that year (EIA 2014e, Table 2).

[10] From 489 leases covering 730,247 acres in 1990.

[11] Data set: “Shipments of coal to the electric power sector (EIA-923 schedule 2): quantity, by mine state” (filters: subbituminous, bituminous).

Across all coal ranks and ownership statuses, Wyoming and Montana constituted 51% of the total coal shipments to electric power plants in 2013. These statistics lead to the conclusion that PRB coal dominates federal coal and that the PRB also dominates production of low-sulfur subbituminous coal; indeed, Wyoming PRB lands accounted for 93% of low-sulfur subbituminous production in 2012 (EIA 2014b, Table 12.5).

In the Western region, where most federal leases are located, coal production is highly concentrated (EIA 2013c). In 2012, the top four coal companies accounted for 51.6% of total US production (EIA 2013a, Table 10). Furthermore, the top 11 coal mines—mostly in the PRB—accounted for 39.4% of total US production in 2012 (EIA 2013a, Table 9).

There is some heterogeneity in coal characteristics that any carbon charge policy must account for. For instance, underground mining of bituminous coal characterizes the Uinta Basin, a coal basin in Colorado and Utah with federal leases. Important differences across coal ranks and basins—including heat content, mining method, and various emissions factors[12]—have important implications for the market price of coal and the emissions profile once the coal is combusted. Summaries of coal production and quality for 3 of the 14 coal supply regions from EIA's Coal Market Module are presented in Table 2 as an illustration.[13] Looking at these 3 regions permits a comparison among basins with dominant federal ownership (PRB), mixed ownership (Rocky Mountain), and non–federal dominance (Central Appalachia), as well as among different ranks of coal.

[12] The heterogeneity in content of two other pollutants, sulfur dioxide and mercury, across coal is important to consider for the regulatory design and market implications of a carbon charge.

[13] For an illustration of the rank and characteristics of coal produced by region, consult the EIA Annual Coal Report (EIA 2013a), the International Energy Agency Coal Information report (IEA 2014), or the Coal Market Module in the Assumptions to the Annual Energy Outlook (EIA 2014b). The Coal Market Module classifies 14 coal supply regions according to state, coal rank, heat content, and various emissions factors.

Table 2. Coal Production and Characteristics for Three Regions

Coal supply region	States	Coal rank and sulfur level	Mine type	2012 production (million short tons)	Heat content (million BTU/ short ton)	Sulfur content (lbs/ million BTU)	Mercury content (lbs/ trillion BTU)	CO_2 (lbs/ million BTU)
Central Appalachia	KY (east), WV (south), VA, TN (north)	Metallurgical	UG	54.9	26.3	0.62	N/A	206.4
		Low-sulfur bituminous	All	10.2	24.72	0.54	5.61	206.4
		Mid-sulfur bituminous	All	82.8	24.66	0.95	7.58	206.4
Wyoming, Southern PRB	WY (Southern PRB)	Low-sulfur subbituminous	Surface	235	17.63	0.28	5.22	214.3
Rocky Mountain	CO, UT	Metallurgical	UG	0.1	26.3	0.43	N/A	209.6
		Low-sulfur bituminous	UG	40	22.74	0.51	3.82	209.6
		Low-sulfur subbituminous	Surface	5.5	19.93	0.51	2.04	212.8

Source: EIA (2014b, Table 12.5).

As seen in the table, there is significant heterogeneity in coal quality and characteristics across basins. The coal from the Southern PRB region has low sulfur and heat content, which allows for easier compliance downstream with SO_2 regulations but also requires greater consumption to achieve the same thermal output as coal with a higher heat content on a per-ton basis. Low-sulfur subbituminous coal from the Rocky Mountain region, in comparison, has a higher heat and sulfur content but lower mercury content.

Below we provide a number of prices and other relevant statistics to compare the value of different types of coal. First is the mine-mouth price, or the spot price before transportation charges are added; this is listed in Table 3. The second is the delivered end use price, or price paid by the consumer; this is listed in Table 4. One can also consider a heat rate-based price comparison, or price per energy generated as measured in Btus; this is shown in Table 5. Finally, one can consider the CO_2 emissions factor of coal, as this is the embodied CO_2 for application of a carbon charge; this is shown in Table 6.

Table 3. Average Coal Commodity Spot Prices ($/short ton)

Central Appalachia 12,500 Btus 1.2 SO_2	Northern Appalachia 13,000 Btus < 3.0 SO_2	Illinois Basin 11,800 Btus 5.0 SO_2	Powder River Basin 8,800 Btus 0.8 SO_2	Uinta Basin 11,700 Btus 0.8 SO_2
53.06	63.15	45.32	11.55	38.13

Source: EIA (2015a).
Note: For the week ending January 9, 2015

Table 4. Delivered End Use Price to Electric Power Sector

Average subbituminous	Average bituminous	Average Wyoming subbituminous
34.97	64.27	34.86

Source: EIA (2015b; data set: “Shipments of coal to the electric power sector [EIA-923 schedule 2]: price, by mine state” [filters: subbituminous, bituminous]).

Table 5. Weighted Average Cost ($/mmBtu) of Fossil Fuels for the Electric Power Industry, 2012

Bituminous[a]	Subbituminous	Lignite	All coal ranks
2.89	1.97	1.80	2.38

Source: EIA (2013b, Table 7.4).
[a] Includes anthracite coal and coal-derived synthesis gas

Table 6. CO_2 per mmBTU and per Ton of Coal

Rank	Lbs CO_2 per million Btus	Million Btus per short ton coal	Lbs CO_2 per short ton coal
Bituminous	205.6	24.93	5,125.7
Subbituminous	214.2	17.25	3,694.9
Lignite	215.4	14.21	3,062.2

Source: EPA (2014b).
Note: Originally reported in kilograms rather than pounds; slight rounding differences account for small differences from EIA reported pounds of CO_2 per million Btu. See http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11.

From these metrics, we can see that the coal that dominates federal production, PRB subbituminous, generally receives lower market prices than the others and has lower CO_2 emissions on a per-ton basis. However, on average subbituminous coal emits more pounds of CO_2 per kilowatt hour as compared to bituminous coal.[14] Thus, there is a difference in whether subbituminous coal is considered more polluting than bituminous coal based on whether it is on a per ton of coal basis or per kilowatt hour basis. Additionally, it is important to note that these numbers and those in Table 2 are averages across a rank or region. Average CO_2 emissions factors, by definition, do not capture the variation across specific coal deposits, and findings that there is greater variation within rather than among coal ranks may challenge the viability of regulating CO_2 emissions by coal rank (Quick 2010; Quick and Glick 2000; Mastalerz and Drobniak 2013). For simplicity in this paper, [15] we use average carbon content for ranks and EPA's average calculation of 2.05 tons of CO_2 emissions per metric ton of coal burned.[16]

One final issue of the market is how frequently federal coal leases turn over. This is important to the extent that BLM can account for a carbon charge only in new or renewed leases. Leases are subject to renewal only after expiration of their initial 20-year period and every 10 years thereafter. Therefore, it is important to know the ages of current leases and the current and future coal production from proposed leases, leases within their initial 20-year period, and leases within a 10-year added term.

Unfortunately, no easily accessible data are available to answer this question.[17] We do know that the amount of coal that has been proposed for leasing is significant. For instance, Wyoming's Buffalo Field Office in its 2013 Draft Resource Management Plan expects to award 28 leases (mostly extending the life of existing leases) with expected production of 10.2 billion tons of coal over the course of the next 20 years (BLM Buffalo Field Office 2013). Historically, from GAO (2013, Appendix II), estimated coal resources at the time of leasing from 1990 to 2010 were 9,010,500,000 tons. Production in 2010 was 478,000,000 tons, approximately 1/20 of existing leases. Additionally, we can see from BLM's annual Public Land Statistics report the

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14 See http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11 for calculation methodology.

15 However, this variation in CO_2 emissions within and across coal rank could be used to argue that a company is being overcharged by an average carbon charge.

16 Converted to metric tons of coal from the 'Pounds of coal burned' calculation on the EPA reference sheet, available at http://www.epa.gov/cleanenergy/energy-resources/refs.html.

17 Going to the mine-specific scale would allow for better tracking of final destination of federally leased coal and lease turnover, and is an area for further research.

production status of the 309 active leases. For 2013, only 173 of these 309 leases met continued operation requirements, producing commercial quantities of coal through either the lease or a logical mining unit (LMU); 88 report that all recoverable coal has been mined, and 19 have not yet produced in commercial quantities (BLM 2014b, Table 3-35). Thus, the amount of lease holdings that could be subject to a royalty adjustment per year appears to be quite small, although this important point needs further research.

With this background, we can now turn to the legal and economic implications of establishing a carbon charge upstream for federally leased coal.

2. Legal Issues

This section details legal arguments for and against statutory authority to impose charges on coal leases related to the climate change impacts of combustion of extracted coal. The arguments in favor are discussed first, followed by the arguments against. For two of the three lease-related payments—rents and royalties—federal authority appears sufficient to impose at least some additional carbon charge, at least for new leases. The reverse appears to be true for the third lease-related payment, bonus bids. But even where these arguments are strong, they are far from certain. In any case, litigation is likely in the event of such a policy change. There are, therefore, legal risks—courts might reject imposition of carbon or other environmental charges on the grounds that they exceed statutory authority or are inconsistent with explicit or implied principles embodied in the statute, regardless of their form and location within the leasing process.

2.1.Federal Land Management Principles

The vast majority of federally owned land, including most BLM land, is administered under the policy of "multiple use," as set forth in the Federal Land Policy and Management Act (FLPMA) of 1976.[18] This policy requires BLM to balance competing uses, including mineral extraction, on federal lands. Federal law also gives BLM broad authority to structure the coal leasing process. The Mineral Leasing Act of 1920, as amended by the Federal Coal Leasing Amendments Act of 1976,[19] provides that BLM will designate which lands are open for leasing,

[18] Codified at 43 USC §1701 et seq.

[19] Codified at 30 USC §201 et seq.

conduct a competitive bidding process, and set and collect royalties for coal extracted from federal land.

Federal law sets out background principles for mineral development on federal lands as "the development of economically sound and stable domestic mining . . . industries" and "the orderly and economic development of domestic mineral resources . . . to help assure satisfaction of industrial, security and environmental needs" (among other factors not relevant here).[20] As noted above, BLM is charged generally with administration of federal lands consistent with "multiple use"[21] and "sustained yield,"[22] "in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and agricultural values," "in a manner which recognizes the Nation's need for domestic sources of minerals," and such that the federal government receives "fair market value" for uses and extracted resources.[23] Balancing these competing values is a complex task left almost entirely to BLM's discretion.

2.2. Local and Global Impacts

BLM, like all federal agencies, has long considered local environmental impacts (such as effects on endangered species) in determining which lands will be made available for leasing and in developing land use plans for those areas which are made available (though there is debate over whether BLM has given adequate weight and attention to these local impacts).[24] Both BLM land use plans and documents prepared pursuant to NEPA—i.e., environmental assessments, environmental impact statements, and findings of no significant impact—detail consideration of such impacts.

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[20] 30 USC §21(a).

[21] "Multiple use" is defined at 43 USC §1702(c) and envisions a balance between extractive and nonextractive use and between the needs of current and future generations. The definition also explicitly declares that "the greatest economic return" is "not necessarily" the dominant consideration in use decisions.

[22] "Sustained yield" might be interpreted as barring BLM policies that prevent or even substantially impede extractive uses. The term is defined, however, as applying only to *renewable* resources on federal lands (e.g., forests). See 43 USC 1702(h). There thus appears to be no explicit commitment to "sustained yield" of coal or other minerals.

[23] 43 USC §1701(a).

[24] BLM land use plans have been the subject of frequent litigation, often on the grounds that local environmental impacts were not addressed or were not adequately addressed in leasing-related NEPA review processes. See, e.g., *New Mexico ex rel. Richardson v. Bureau of Land Management*, 565 F.3d 683 (2013) (ruling that BLM failed to adequately consider site-specific impacts of an oil and gas lease).

Could BLM consider broader climate-related impacts in addition to these local impacts? Recent challenges to BLM environmental reviews under NEPA have attempted to force the agency to consider broader climate-related impacts in these reviews.[25] To some extent, federal agencies have resisted pressure to consider broad climate impacts, but BLM almost certainly could consider such impacts in NEPA environmental assessments and/or environmental impact statements associated with individual leases or broad land use plans. In at least one instance, a federal court has ruled that BLM's current treatment of climate impacts in NEPA analyses is inadequate, specifically referencing the SCC.[26] Most of the statutory language (referenced above) directing BLM to consider environmental impacts does not distinguish between local and widespread environmental impacts of extraction.[27] Our focus here, however, is not on BLM authority under NEPA to generally consider climate impacts in its leasing decisions, but on the agency's authority to consider those impacts in setting lease-related fees.

2.3. The Leasing Process

BLM is given specific statutory authority over the leasing process but retains broad discretion in implementing that authority. The agency is authorized to "divide [federal] lands . . . into leasing tracts," offer these tracts for leasing by competitive bidding, and accept bids that exceed the "fair market value" of the lease. These leases are set by statute and BLM regulation at

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[25] For example, a ruling in the US District Court of Colorado found that "the treatment of the costs associated with GHG emissions from the mine was arbitrary and capricious" and pointed to the SCC developed by the IWG as an appropriate tool to quantify such greenhouse gas emissions (*High Country Conservation Advocates, et al. v. US Forest Service, et al.*, 16). Agency approval of the exploration plan and lease modifications was vacated in a subsequent ruling, preventing the lease expansion at hand from moving forward. The rulings did not focus on global versus local impacts, but rather the appropriateness and scientific certainty of an SCC to quantify climate impacts. See *High Country Conservation Advocates, et al. v. US Forest Service, et al.*, Case 1:13-cv-01723-RBJ (US DC Colorado, 2014).

[26] Ibid.

[27] The White House Council on Environmental Quality has recently released and solicited comment on a new draft guidance for agencies (including BLM) on how climate impacts should be considered in agency decisions and NEPA reviews. See CEQ (2014).

20-year terms (though they may be terminated early for nonproduction).[28] Lease terms may be readjusted, however, at the end of the 20-year period and every 10 years thereafter.[29]

The statute also directs BLM to collect three types of payment from leaseholders: the initial lease bid (or "bonus bid"), annual rent, and royalties on extracted coal.[30] BLM has broad authority to set these payments. Bonus bids are set by the auction market, though BLM must reject any bid that does not reach its assessment of fair market value. Rental rates are left entirely to BLM discretion. The statute sets a general royalty floor of 12.5% for surface mines, but BLM is authorized to "waive, suspend, or reduce" royalties "for the purpose of encouraging the greatest ultimate recovery of coal." The statute sets no ceiling on royalties. Royalties are to be charged "in such amount as [BLM] shall determine," subject only to the soft 12.5% floor.[31]

Finally, and separate from its directive to collect these three payments, BLM is given broad authority to impose lease terms. 30 USC §207(a) states that "[t]he lease shall include such other terms and conditions as the Secretary shall determine."

2.4. The Case for BLM Authority to Impose Environmental Charges in the Leasing Process

As an initial matter, statutory law does not preclude BLM from considering environmental impacts in coal leasing decisions. The specific statutory text detailing the leasing process itself gives little guidance on what factors may be considered in any of the three payments (aside from "fair market value" in bonus bids). But BLM's general statutory directives

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28 See 30 USC §207(a) ("A coal lease shall be for a term of twenty years and for so long thereafter as coal is produced annually in commercial quantities from that lease"). See also 43 CFR 3475.2 ("Leases shall be issued for a period of 20 years and so long thereafter as the condition of continued operation is met. If the condition of continued operation is not met the lease shall be cancelled as provided in § 3452.2 of this title").

29 See BLM Form 3400-12, *Coal Lease* (BLM's standard coal lease form contract), which states, "[This lease] is effective . . . for a period of 20 years and for so long thereafter as coal is produced in commercial quantities from the leased lands, *subject to readjustment of lease terms at the end of the 20th lease year and each 10-year period thereafter*" (emphasis added).

30 A bonus bid is the amount that an operator bids to obtain a lease. This is revenue the government (i.e., the public) gets even if the lease is not developed. It is risk-free. Annual rent is the payment by an operator to maintain the lease. Royalty is the payment the operator makes on the value of produced coal. It is the payment to the government (i.e., the public) for giving up its resource and represents risk sharing in that the government benefits if revenues are higher than expected and the operator doesn't lose as much if revenues are lower than expected.

31 30 USC §207(a).

not only permit consideration of environmental impacts in land use decisions, they require it. For example, 30 USC §201(a)(3)(C) states:

> Prior to issuance of any coal lease, the Secretary shall consider effects which mining of the proposed lease might have on an impacted community or area, including, but not limited to, impacts on the environment, on agricultural and other economic activities, and on public services.

Other statutory language also requires BLM to consider environmental impacts. For example, 30 USC §201(a)(3)(E) requires all leases to include provisions requiring compliance with the Clean Air Act and Clean Water Act, and 30 USC §207(c) requires leaseholders, as a condition of their leases, to submit an "operation and reclamation plan" to BLM for approval before taking any action that may "cause a significant disturbance to the environment." And as noted above, the general principle of BLM management for multiple use is defined so as to encompass environmental values.

To be sure, none of these provisions directly states that BLM must, should, or even may consider environmental impacts in its determinations of lease-related bid payments, rents, and royalties. What is probably the strongest statutory directive to BLM regarding environmental impacts, 30 USC §201(a)(3)(C), applies specifically to the agency's threshold leasing decisions, not its fee-setting powers.

But neither does the statute limit BLM's authority to consider relevant factors, including environmental impacts, in setting fees. 30 USC §207(a) states that "[t]he Secretary shall by regulation prescribe annual rentals on leases" and that "[a] lease shall require payment of a royalty in such amount as the Secretary [BLM] shall determine." These provisions impose no restrictions on rental fees and none on royalties other than the above-noted 12.5% floor. Nothing in 30 USC §207 appears to limit agency authority to increase rents or royalties on environmental grounds, at least for new leases. Even if authority to increase rents or royalties to include environmental charges cannot be found in the statute's delegation of authority to set these rates, the statute's *general* delegation of authority to "include such other terms and conditions" as BLM determines necessary may provide that authority. There are, however, some arguments (discussed in Section 2.1.5 below) that other statutory provisions limit BLM discretion in this regard.

Similarly, 30 USC §201 does not provide specific direction to BLM regarding the factors it may or may not consider in determining the "fair market value" (FMV) floor for auction bids. However, in this case the lack of such direction may not be sufficient to implicitly grant BLM authority to consider environmental impacts in the initial bidding process. Whatever "market" is being referenced, the term "fair market value" does not currently reflect the carbon externality associated with coal use. Therefore, to the extent that FMV is interpreted to mean an approximation of the minimum value of a lease if it were offered in a competitive market (i.e., to many well-informed bidders), adding an environmental charge distorts that approximation. This remains true even though textbook environmental economics says that a well-functioning market for coal and coal leases depends on internalizing the associated environmental externality. Under this view, inserting a carbon charge into the calculation of FMV is an attempt to achieve the desired policy outcome with a tool designed to reflect current market conditions. Nevertheless, current FMV calculations already reflect some environmental costs of coal since they depend on the market value of coal, which depends in part on fluctuations in demand as a result of a host of federal laws and regulations affecting coal mining.

Moreover, to the extent FMV reflects the effect on market value of considering additional regulations, it arguably should go down, not up. A charge reflecting some or all of the carbon externality associated with coal (whether imposed via greater royalties or a general carbon price) would depress the value of coal mining assets on federal lands. Nevertheless, what we term the external fair market value—that is, the minimum bid the agency would accept for these resources accounting for the carbon externality—would go up.

To be sure, 30 USC §201 simply states that BLM must auction leases via a "competitive bidding process," with no restriction on agency authority to structure that process other than the requirement that winning bids meet FMV. BLM therefore might be able to impose a carbon-based minimum bid requirement over and above a current market-based FMV. However, there is no statutory basis for imposition of such a floor or for rejection of bids that meet an unadjusted FMV. Applying an SCC at the bidding stage requires either an addition to the elements that enter into FMV calculation (what we term the external FMV) or the introduction of a new charge beyond FMV, neither of which the statute contemplates. This stands in contrast to rent and royalty payments, which BLM is directed by statute to collect and is given broad discretion to set.

Even for rents and royalties, where its authority to set payment amounts seems to be broad, BLM's decisions are, of course, still constrained by the Administrative Procedure Act (APA) requirement that agency action not be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[32] Increased lease fees based on environmental impacts would indeed be unprecedented—in fact, rental rates are set at a uniformly low level, and royalties rarely if ever exceed the statutory floor of 12.5%. But that alone is not strong evidence that new environmental charges would exceed BLM's authority. Given the clear directives to the agency in the statute to consider environmental impacts in the leasing decision and the explicit inclusion of environmental values in the general "multiple use" land management policy, it would likely be difficult to successfully argue that such a move would violate the APA standard (though see the next section for some more detailed counterarguments).

In other words, statutory law does not initially appear to restrict BLM from considering environmental impacts in the leasing process, including setting of rental and royalty rates. In fact, doing so is consistent with the general statutory directive that BLM manage lands "in a manner that will protect the quality of . . . environmental, air[,] and atmospheric . . . values."[33]

2.5. Counterarguments and Legal Risks

It is important to confront some counterarguments to the above conclusion that BLM's governing statutes broadly grant it the authority to include environmental charges in coal leases. Litigation is certain if BLM were to adopt such a policy. Courts therefore will have to decide whether BLM has adequate statutory authority to support the actions it takes and, relatedly, whether those actions will survive scrutiny under the APA standard of review. Any attempt to impose environmental charges carries legal risk.

As we argue later, applying a carbon charge equal to the SCC estimated by the Interagency Working Group to BLM coal leasing would make coal extraction uneconomic on some or all unleased federal lands and possibly some or all leased lands, as those leases are subject to regular readjustment (20 years to start and 10 years thereafter). One argument against BLM authority is that this result is inconsistent with the "multiple use" and "sustained yield" land management principles set out in the statute. Multiple use, however, does not require BLM to allow *all* uses. The agency has authority to ban uses incompatible with competing uses or with the other principles (including environmental values) laid out in the statute.[34] If the authority to

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[32] 5 USC §706(2)(A).

[33] 43 USC §1701(a)(8).

[34] BLM could in fact argue that, even setting aside broader climate impacts on public health and welfare, GHG emissions from mined coal and resulting climate change are a sufficient threat to BLM lands that coal extraction is

ban uses is consistent with "multiple use," imposition of fees for such uses almost certainly is as well. This does not mean that the multiple use policy directive grants agency authority to impose fees, but rather that such fees, including additional environmental charges, are *not inconsistent* with multiple use. As detailed above, Congress has granted BLM authority to impose (indeed, required it to impose) lease-related fees, and the provisions granting that authority arguably are sufficiently broad to give the agency authority to consider environmental impacts in setting those fees.

Moreover, "sustained yield" (which might otherwise be interpreted as requiring some level of extraction) is defined by the statute to apply only to renewable resources (e.g., forest products) on federal lands, not nonrenewable resources such as coal.[35]

A stronger counterargument is that the statute's directive to manage public lands "in a manner which recognizes the Nation's need for domestic sources of minerals" precludes a policy that would eliminate or substantially reduce coal extraction on those lands. Such an argument might resonate with a reviewing court (reviewing BLM action under the "arbitrary and capricious" standard mentioned above) if a policy involving environmental charges were, in effect, to completely eliminate coal extraction or reduce it to a *de minimis* level. Short of such a step, however, a court likely would leave the interpretation and weighing of this directive to agency discretion.

Another argument is that the stated goals in federal minerals policy of "development of economically sound and stable domestic mining" and "orderly and economic development of domestic mineral resources . . . to help assure satisfaction of industrial, security and environmental needs" supersede or at least must be weighed against any BLM policy that would substantially limit economic extraction of coal. However, the meaning of this language depends on the interpretation of "economically sound and stable," "orderly," and "economic." Coal production that would occur only if the negative impacts (externalities) of coal on public health and welfare were not taken into account is arguably not "economic" at all. "Economic" considerations need not be interpreted so as to exclude environmental impacts and values, whether measurable or not. Most environmental economists would argue that economic analysis

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an incompatible use. Since our object here is to assess the merits of carbon charges, not a command-and-control ban on extraction, we do not address the legal merits (much less the wisdom) of such a policy justification.

35 See 43 USC 1702(h).

of a project or action is incomplete to the extent that it fails to account for environmental impacts.

Even if "economic" in this context is interpreted to indicate congressional intent that BLM balance "traditional" economic interests (that is, economic interests exclusive of environmental externalities) with environmental impacts, these provisions constitute a broad policy pronouncement that arguably creates no discernible or enforceable limit on agency authority. Even if they are interpreted to limit BLM authority, all they do is require the agency to balance these "economic" considerations with other concerns, including environmental impacts. It would likely be difficult to persuade a court to overturn the agency's judgment on this balancing outside of the boundary case noted above, in which coal extraction on federal lands is abruptly eliminated or reduced to extremely low levels.

Finally, 30 USC §201(a)(3)(C) might require the agency to consider economic impacts in its threshold lease decisions. In addition to the consideration of environmental impacts noted above, this section of the statute instructs BLM to

> . . . evaluate and compare the effects of recovering coal by deep mining, by surface mining, and by any other method to determine which method or methods or sequence of methods achieves the maximum economic recovery of the coal within the proposed leasing tract. This evaluation and comparison by the Secretary shall be in writing but shall not prohibit the issuance of a lease; however, no mining operating plan shall be approved which is not found to achieve the maximum economic recovery of the coal within the tract.

This language, however, is probably best interpreted as requiring BLM to consider "maximum economic recovery" in its approval of mining operation plans, with specific reference to the method of mining (deep or surface), rather than as a counterweight to the previously stated consideration of environmental impacts. In other words, the statute directs BLM to consider environmental impacts when deciding whether to grant a lease, and then consider "maximum economic recovery" in reviewing the lessee's plan for getting the coal out of the ground and to market.

Similarly, the statute gives the agency the authority to reduce royalty rates below 12.5% "for the purpose of encouraging the greatest ultimate recovery of coal . . . whenever in [its]judgment it is necessary to do so in order to promote development, or whenever . . . leases cannot be successfully operated under [their terms]."[36] This provision does clearly set maximization of extraction as a goal for the agency, but only in a limited context—the setting of royalty rates. In other words, BLM may decide not to make land available for coal leasing, to impose various restrictive lease terms, and/or perhaps to impose environmental charges, but if *royalty rates* make recovery uneconomic, then the agency *may* reduce those rates below the 12.5% floor. This language, therefore, does not necessarily indicate that the agency must consider "greatest ultimate recovery of coal" at any other point in its leasing policy process.

However, this narrowly targeted discretion falls at just the right point to perhaps undercut a policy aimed at internalizing coal's carbon externality. If BLM were to generally increase royalty rates so as to reflect a social cost of carbon, but then liberally grant waivers reducing those royalties in cases in which that new, higher royalty impaired "greatest ultimate recovery," then the exception could swallow the rule, leading to little or no change in coal extraction.[37]

Finally, as the above examples illustrate, although BLM's authorizing statute contains no general directive to maximize recovery of coal or, arguably, to even balance extraction (or "sustained yield") with environmental or other considerations, there is substantial language in various statutory provisions directing the agency to consider extraction in specific contexts. A court might therefore conclude that the statute implicitly if not explicitly indicates congressional intent that the agency, indeed, balance environmental concerns with extractive uses. A court, moreover, need not go to such great interpretive lengths to reach such a conclusion—"multiple use" is defined so as to mean such balancing.

However, this alone does not limit agency authority to regulate uses, including the authority to impose fees on some uses. Courts are reluctant to interfere with agency decisions requiring exercise of the agency's expertise, such as balancing multiple uses on federal lands. As noted above, however, a reviewing court would likely be more willing to intervene if BLM's chosen policy ends coal extraction or restricts it so greatly that the court can conclude the policy contradicts Congress' multiple use directive as a matter of law.

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[36] 30 USC §209.

[37] Indeed, the waiver provision seems to contradict itself. Any royalty payment impairs the "greatest ultimate recovery of coal," since production would almost always be greater if royalties were lower or zero.

2.6. Statutory Conclusions

In our view, the arguments against BLM authority to adjust coal leasing charges based on environmental impacts are somewhat weaker than arguments that BLM does have such authority under current statutory law. More broadly, it is likely that the political limits on BLM's ability to exercise this authority are more significant than the legal limits. The legal arguments against BLM environmental charges are strongest if such charges result in a complete or at least a very large, abrupt reduction in coal extraction from federal lands. Even if BLM were to consider such an action, there are arguably no legal restrictions on its authority to do so in the statutory provisions governing coal leasing. The strongest legal arguments for limitations on BLM authority derive from the statute's general requirement that the agency balance "multiple uses" on federal lands. For a court to overturn agency action on these grounds requires it to conclude that the agency has exceeded its delegated discretion and violated APA standards—a high bar.

2.7. BLM's Regulatory Authority

As discussed above, BLM has broad authority to structure the coal leasing process on federal lands. Its regulations control the initial bidding process along with rates and payment of rents and royalties. In principle, an environmental charge could be incorporated into any of these three payments (see Section 4.3, below, for a discussion of the relative merits of each as a vehicle for such charges). In this section, we consider BLM's relevant regulations for each payment in turn and identify changes that could be made to incorporate environmental impact charges. Any of these changes to BLM's implementing regulations would be subject to the standard notice-and-comment rulemaking process.

Our assumption in this section is that BLM would impose any carbon charge via a uniform policy applied to all new and renewed leases, codified in BLM's regulations. It might instead be legally permissible for BLM to adopt environmental charges in individual lease contracts (via adjustments made after 10- or 20-year contract periods), rather than its general regulations, but doing so would not create a uniform, consistent policy that addresses widespread climate externalities from coal extraction. Doing so might also increase legal risk insofar as litigants might argue that BLM was evading the rulemaking process.

2.7.1. The Bidding Process

Both statutory law and BLM's implementing regulations generally require federal coal leases to be offered on a competitive basis. Since 1990, leasing by application, in which companies nominate tracts of land to be leased, has been the predominant method of coal leasing.

Once a particular parcel has been nominated for leasing, BLM first determines whether the land should in fact be leased (this determination is part of BLM's planning process and is discussed in Box 2). If the land is to be made available for leasing, BLM then computes an FMV for the lease, based in part on production estimates provided in the leasing application. This FMV calculation is kept secret. Bidding parties submit bids to BLM, and the lease is awarded to the "qualified company" with the highest bid that exceeds the FMV. This bid or "bonus" is paid over the first five years of the lease. In practice, most lease auctions have but one bidder, putting significant pressure on the FMV calculation to ensure adequate bid amounts (GAO 2014, Figure 3).

BLM's regulations at 43 CFR § 3422.1(c)(1) implement the statutory direction that no bonus bid may be accepted for a coal lease unless it meets the FMV. If none of the bids exceed FMV, then the land is not leased (though it may be reauctioned in the future). Further, 43 CFR § 3422.1(c)(2) states that the minimum FMV for a lease is $100 per acre or its equivalent in cents per ton. BLM's detailed policies for estimating FMV for a lease are contained in Handbook H-3073-1, Coal Evaluation (BLM 2014a). This handbook incorporates the definition of FMV from another policy document, the *Uniform Appraisal Standards for Federal Land Acquisitions*:

> Fair market value means that amount in cash, or on terms reasonably equivalent to cash, for which in all probability the coal deposit would be sold or leased by a knowledgeable owner willing but not obligated to sell or lease to a knowledgeable purchaser who desires but is not obligated to buy or lease.

The handbook further outlines two methodologies for computing the FMV: the comparable sales approach (in which sale prices from similar properties in prior transactions are used to determine value) and the income approach (in which an estimate of annual costs and revenues is used to determine value) (see BLM 2014a, 4-1 et seq.). The FMV process for each tract to be leased is open to public comment.

BLM's calculation of FMV is complex, and space here permits only a general overview of how environmental charges might be integrated into that process. Moreover, as noted above, arguments in favor of BLM's statutory authority to do so are much weaker than for rent and royalty payments.

In principle, BLM would have to define a new term—the external FMV noted above—that incorporated the FMV defined in the Handbook plus the present discounted value of the

SCC embodied in an estimate of coal production from the lease in auction. While BLM does have discretion to determine how FMV is calculated, as noted above, such fundamental revision of the concept may exceed its authority.

2.7.2. Rents

BLM has set minimum rental rates for all lands leased for coal extraction at $3 per acre.[38] The result is that rental income accounts for only 0.1% of the annual revenue from federal coal leases (GAO 2014). However, as discussed above, BLM has broad statutory authority to increase rental rates.

Assuming this legal authority is sufficient to allow imposition of environmental charges, the agency could do so by modifying its regulations at 43 CFR §3473 in one of two ways. Either the agency could increase the minimum rent to reflect some average estimation of environmental impacts of extracted coal per acre, or it could create a case-by-case review process under which rental rates are set at a level that reflects impacts of extracting, processing and/or burning the coal extracted from the specific lands to be leased. As discussed below, this process could be relatively simple and easy to administer, but it would be difficult to calibrate to the specific externality associated with each lease, as it would require a good up-front estimate of total production, transportation costs, and so forth to connect the carbon charge to the actual volume of extracted coal.[39]

2.7.3. Royalties

As noted above, the royalty rate for surface-mined coal is required by statute to be at least 12.5%.[40] This floor is restated in BLM's implementing regulations at 43 CFR § 3473.3–2(a)(1). The statute and implementing regulations allow lower royalty rates for subsurface mining or "when necessary to promote development"—the floor, in other words, is not firm. The agency indicates that royalties may be reduced to as low as 2%, but regulations prohibit them from being reduced to zero.

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[38] 43 CFR § 3473.3–1(a).

[39] It might be possible to specify in lease terms that annual rental rates will be based to some extent on past year's production, rather than an initial estimate.

[40] 30 USC § 207(a) a.

The effective average royalty rate (the rate actually paid after rate reductions and allowable deductions) has been approximately 11% since 1990. The majority of the revenue from federal coal leases comes from royalties (almost two-thirds of the revenue from 2003 to 2012) (GAO 2014). In practice, BLM rarely if ever charges royalty rates above 12.5%. But as discussed above, it has broad authority to do so, arguably on environmental grounds.

The most straightforward method for imposing a charge on extracted coal aimed at partially or completely internalizing the carbon externality is to increase the royalty rate by a set social cost of carbon per ton multiplied by the carbon content of the extracted coal.[41] For example, 43 CFR §3473.3-1(a) could be amended to read:

> A lease shall require payment of a royalty of not less than 12 1/2 percent of the value of the coal removed from a surface mine plus the carbon content of the coal times the designated social cost of carbon per ton of CO_2, as defined elsewhere in these regulations, per metric ton of coal extracted.[42]

2.7.4. New and Existing Leases

Should BLM choose to incorporate a carbon-related charge into the leasing process, it would not immediately apply to all leases. Lease terms are set when the lease is initially signed and are subject to readjustment (as noted above) after 20 years and every 10 years thereafter. For areas already subject to existing leases, therefore, carbon-related charges could be applied as leases come up for readjustment. However, only for new leases would such charges apply

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[41] Since royalties are calculated as a percentage of sales, there are two ways, mathematically, to change them—either change the royalty rate or change the way in which sales themselves are calculated. For the most part, BLM uses actual market sales values as the base on which royalties are calculated, with exceptions only for certain non-arm's-length transactions, for which a hypothetical market price must be determined. We assume this practice will continue and therefore discuss a possible carbon charge at the royalty stage only in terms of an increased royalty rate. In principle, however, BLM could increase its estimated "value" of coal sold by some amount related to its environmental impact and calculate royalties using current rates applied to this larger base. This might create additional legal risk—a reviewing court might, for example, conclude that the plain meaning of "value" makes such an interpretation unreasonable, or that Congress did not intend to commit determination of value in this context to agency discretion. On the other hand, such an approach might allow BLM to impose a carbon charge on coal produced from any lease, not just new and expired leases. While the royalty rate is a term in the lease, the method for calculating value of sold coal presumably is not (though lessees could argue that it is an implied term).

[42] If the IWG's estimate is imposed, for subbituminous coal like that produced from federal lands in Wyoming, the value is approximately 1.8 times the SCC per ton of coal, since every ton of extracted subbituminous coal generates approximately 1.8 tons of CO_2. See EPA (2014b). Additionally, if BLM chose not to use the average emissions factor for coal rank due to concerns about variation within rank, it could incorporate carbon content testing for use of determining the carbon charge in its presale site evaluation process.

immediately. As noted below, new or renewed leases in any given year are a small fraction of all coal under lease.

2.7.5. Regulatory Conclusions

Assuming that BLM has the requisite legal authority to impose environmental charges on rents and/or royalties, the changes to its implementing regulations necessary to do so would be relatively minor. Just as is the case with the governing statutory text, BLM's implementing regulations are quite general, with the specifics of lease terms left to case-by-case determination. This could remain the case even if environmental charges are imposed—BLM could simply raise the floor it specifies for one of these payments or indicate that case-by-case fee determinations are to include adjustments based on estimated social cost of carbon. In contrast to rents and royalties, however, imposing environmental charges on bonus bids would likely require major changes in how BLM does business and even need statutory change.

Any of the changes (to royalty and rental rates) would likely requiring notice-and-comment rulemaking, are likely to be contentious, and are likely to be followed by litigation. But the actual changes to BLM regulations would be relatively small.

Box 1. Coal Leasing in Alberta, Canada

To add insight to the scope for addressing the social cost of carbon at the mine mouth, we investigated the coal leasing system in the province of Alberta, Canada. Unlike the United States, the provinces in Canada own most of the coal resources. Among these provinces, Alberta holds 70% of Canada's coal reserves, the Albertan government owns almost all the coal resources within its borders, and in 2013 Alberta's coal production amounted to 34.5 million tons. In Alberta, as of January 1, 2015, there were 1,232 coal leases covering over 661,403 acres (Alberta Energy 2015).

There are various legal statutes governing coal extraction and its environmental impacts in Alberta, including the Coal Conservation Rules. In addition to the considerations for prohibition and restrictions on exploration and development in Alberta, the Coal Conservation Rules, among their various mandates, require control of pollution and ensure environmental conservation in coal mining activities. As just one example, Section 3(e) of the Coal Conservation Rules states that any application to explore for coal shall include "a description of the measures the applicant takes to remedy or modify the potential impact of the proposed program on the environment, and to control pollution."[43] Lessees are required to present documentation that outlines measures to be taken to remedy or modify potential environmental

[43] Coal Conservation Rules, RRA 2014, Reg 140 ss 3(e),(i),(ii).

impacts and to control pollution. However, the Coal Conservation Rules stop short in outlining what are the required measurements to ensure environmental protection, as they focus primarily on limiting the amount of loss or reduced recovery of coal during mining operations.

Environmental protection lies under the jurisdiction of the Ministry of Environment and Sustainable Resource Development, specifically governed by the Environmental Protection and Enhancement Act and the Conservation and Reclamation Regulation. The purpose of the act is to ensure environmental protection while securing Alberta's economic growth and prosperity in a sustainable manner, and it applies to energy resource activities in the province.[44] Within the act's jurisdiction is the Environmental Protection and Enhancement Fund, a funding mechanism geared toward environmental protection and enhancement and emergencies.[45] Under the act, an environmental assessment is required depending on the type of activity and the area where mining will take place in a process that seems very similar to NEPA in the United States.

In terms of climate change, the act makes reference to the powers of the Lieutenant Governor in Council to make regulations concerning CO_2 emissions and the emissions credit system operating in Alberta. However, in terms of considering damages, the act requires only consideration of local environmental impacts, although it does require GHG emissions monitoring. Nevertheless, parameters on environmental impacts already exist and could be amended to more explicitly address climate change emissions and impacts.

Coal companies pay bonus bids, rents, and royalties, as in the United States, although there are some differences in the two systems that might be instructive in the context of applying a social cost of carbon. Some of these differences are notable but not substantial—for instance, lease terms are renewable after 15 years, whereas in the United States, the usual term is 20 years to start and 10 years thereafter.[46] A more substantial difference is royalty differentiation based on rank of coal. Unlike in the United States, under the Albertan Coal Royalty Guidelines, royalties are divided into royalties for subbituminous coal (electric power) and bituminous coal (exports for electric power generation and steel making), defined by their coal quality attributes (Alberta Energy 1993). In the United States, no such distinction is made. These royalties are CAD$0.55 per ton for subbituminous coal, and for bituminous coal, after the mine begins operation, 1% of mine-mouth revenue plus 13% of net revenue (Alberta Energy 2015b). This contrasts with the United States, which varies royalties by mining method—that is, whether the coal is surface mined (12.5% of net revenue) or deep mined (8% of net revenue).[47] The most significant implication the Canadian system has for a carbon charge policy would be the ability to set different carbon charges based on the different carbon content of coal ranks.

[44] Environmental Protection and Enhancement Act, RSA 2000, c E-12 ss 2(b), 2.1.

[45] Ibid., s 30(2).

[46] Mines and Minerals Act, RSA 1980 cM-15 s66 2(68)

[47] 30 CFR 1206.257. However, the question of arm's-length and non-arm's-length contracts between companies as a form of lowering royalty rates has been a subject of discussion in the export valuation debate in the United States. See Humphries and Sherlock (2013), 15–16.

The existing policy terrain also has some differences from the case in the United States. There are two end uses of coal that already come under a carbon charge in Alberta: a $15/ton carbon price on industrial sources emitting over 100,000 tons of CO_2 per year and federal regulation of CO_2 emissions from new coal-fired electric utility plants (similar to the proposed EPA regulation 111(b) on new stationary sources). Thus there are two partial policies in place, as even taken together these two policies do not cover all uses of coal (notably, coal use at existing power plants) or constitute an economy-wide policy on all fuels. A switch to a carbon charge upstream would fill some of these gaps but has drawbacks of its own. The primary flaw is the same faced in the United States: it covers only one fuel source. Second, ownership (and presumably the carbon charge policy) at the province rather than federal level would suggest greater leakage of coal production to other provinces, increased imports, or fuel switching. However, Alberta has an even more outsize influence on the Canadian coal market (70% of total production) than federal coal has on the United States (40% of total production), and thus these arguments are weak. As in the United States, these climate change internalization policies could be seen as at least partly redundant to an SCC applied at the coal mine.

3. The Role of a Social Cost of Carbon

Section 2 reviewed the regulatory and rulemaking authority that would allow BLM's coal-leasing decisions to embody the environmental externalities associated with the coal life cycle, beginning with its extraction at the leased "upstream" site and ending with its "downstream" combustion or other utilization. The externality on which we focus in this report is coal's carbon content and its CO_2 emissions, whose radiative atmospheric "forcing" is widely accepted as a major contribution to global warming and its diverse societal impact. Depending on the monetary magnitude ascribed to that impact—otherwise known as the social cost of carbon (SCC)—it provides a quantitative basis for how much the traded price of coal might need to be augmented to reflect (or "internalize") the externality hitherto missing from marketplace transactions.

It is precisely because of the consequences that the imposition of an SCC—or a charge guided by its value—would have on the economics of the coal industry (the subject of Section 4) that we provide here a brief look at key features of one version of an SCC, the federally estimated social cost of carbon. (The Appendix presents a much fuller account, including detailed references.)

The SCC is the estimated worldwide incremental damage from climatic change brought about by an additional metric ton of CO_2 emissions. Equivalently, it can be defined as the incremental benefit from avoiding such damage. Damages could take the form of impaired human health, reduced agricultural productivity, coastal flooding, ecological losses, and myriad other effects. For at least the last five years, a succession of federal interagency working groups

(IWG 2010, 2013), comprising climate researchers, economists, risk experts, policy analysts, and other professionals, have developed a range of SCC estimates, which in turn have served to inform policy deliberations by a number of federal agencies (e.g., EPA) through its appearance in Regulatory Impact Analyses of various rules. Some private firms have embraced the SCC concept to help them factor the possible stringency of future climate policy into their operations and investment decisions. Table 7 provides the most recent federal SCC estimates resulting from the efforts of the IWG.

Table 7. Social Cost per Ton of CO_2 Emitted, 2015–50, at Different Discount Rates (in 2011$)

Year	5% average	3% average	2.5% average	3% 95th percentile
2015	12	39	61	116
2020	13	46	68	137
2030	17	55	80	170
2040	22	65	92	204
2050	28	76	104	235

Notes: These numbers are EPA updates of the IWG estimates. The EPA updates are presented in 2011$, rather than 2007$ as used in both the February 2010 and May 2013 IWG reports. The updated numbers are used in EPA's Regulatory Impact Analysis for the Clean Power Plan (2014d); see ES-3. Throughout the report, we refer to the EPA estimates, particularly the $46/ton estimate representing the 3% average discount rate for the year 2020. For the EPA fact sheet with the updated estimates, see EPA (2013).

The table highlights three aspects of the SCC to which we particularly direct readers' attention: First, the value of the SCC in any given year (i.e., the present discounted value of a stream of damages from CO_2 emitted in that year) is a function of the discount rate used to estimate long-term climatic damage. A relatively risk-averse rate of 2.5% (perhaps reflecting sensitivity to the prospect of ultimately catastrophic disruption) translates into high present value figures for each of the successive years posted. The converse (a 5% rate rate) reflects a relaxed and more optimistic worldview. The 2.5% position can be loosely associated with a sense of urgency for early and substantial emission-mitigation initiatives, while the 5% posture emphasizes the extent to which large near-term mitigation expenditures would unjustifiably crowd out other pressing societal priorities. The column headed by 3% is the compromise between these two positions and is most commonly employed in policy discourse. The possibility of economic impacts more extreme than those projected in the 3% column of the table is represented in the modeling by the 95th percentile column. In that case, with a 3% discount rate in 2020, the IWG-based estimate of the SCC cited by EPA comes to about $137 in 2020—significantly higher than the $46 compromise estimate. Clearly, each of the four columns in the table should be viewed with caution. Still, the 3% column is our choice for the analysis in Section 4.

Second, prolonged delay in instituting CO_2 reduction initiatives progressively raises cumulative damages and therefore the cost of avoiding those damages. Thus, in the 3% column, mitigation delayed from 2020 to 2050 translates into an SCC cost rising from $46 to $76 per metric ton of CO_2 (calculated in constant dollars).

Third, the globally diffuse nature of atmospheric warming and its disparate geographic impacts signify, as its necessary and logical counterpart, the *global* dimension of the SCC measure. This is a marked, but inescapable, departure from more conventional, nationally circumscribed cost–benefit calculations. In other words, an SCC borne by US emitters, in our view, should be a global value, not just the value of estimated damages *inflicted on the United States.* This position is controversial, however.

In sum, the general concept of an SCC provides a conceptual setting that signals the degree to which private markets underrate the true cost to society of coal and other fossil energy sources. Its approximate character notwithstanding, the federal IWG SCC's range of estimates is the result of major exploratory research and measurement. It would nevertheless be something of a stretch to draw an immediate and prescriptive equivalence to a carbon tax or comparable policy initiative that would be reflected in an internalized energy price. But the SCC gives us a powerful basis and tool to move in that direction.

4. Economic Issues

In this section, we examine from an economic point of view the case for using the federal coal leasing program with a carbon charge as a vehicle for internalizing the climate change externalities from coal throughout its transformation from extraction to utilization. Unlike the legal analysis, in Box 2 we briefly consider implications of incorporating a carbon charge in prelease planning and decision-making.

4.1. Economic Analysis

The key concern is the need to internalize externalities of polluting activities if social welfare is to be maximized. Externalities are the costs and benefits that occur from economic activities that are not otherwise captured—that is, internalized—in market transactions. In this case, where coal externalities are not internalized, buyers and sellers of coal do not take into account the impacts of GHGs related to the coal life cycle. From an economy-wide perspective, the socially optimal level of a given polluting activity occurs when its price reflects its full social opportunity cost, which includes its marginal cost of production plus its marginal external damage (net of positive externalities). If a policy existed to tax coal at its marginal damage, then the price of coal would be much higher, and without an offsetting surge of technological progress (e.g., cheap carbon, capture and sequestration), coal would be a much less attractive fuel to use.

However, internalizing externalities at the mine is only one of many possible stages of coal production and use to do so. These stages can be described as being upstream (mine), downstream (the power plant smokestack), or midstream (e.g., pipeline, railcar) of the activity chain. For many polluting activities and types of pollutants, internalizing on the extraction of an input (such as coal mined) rather than an output (such as coal burned) is problematic, and further, internalizing on output rather than emissions from using or burning that product is also problematic. For instance, if SO_2 were the pollutant of concern, a charge on coal extraction at the mine, absent some form of rebate system, would not provide incentives for reducing SO_2 at the smokestack or at a coal washing stage. Thus in this case, regulating downstream is preferred.

For the case of CO_2 (and other GHGs, for that matter) from coal, however, these arguments are far less compelling. The CO_2 emissions factor varies only slightly in the particulars of combustion, and there are no current economical approaches to removing CO_2 from the smokestack. Thus the ultimate incentives for reducing CO_2 do not differ significantly between internalization at the mine and at the smokestack (although which producers and users along the supply and use chain are directly and indirectly affected would be different).

We can dismiss one theoretical concern, the rebound effect. While it has been shown that a rebound effect exists for coal utilization at electric generating units – that is, placing an emissions tax downstream on an electric generating unit will induce greater heat rate efficiency, thus leading to greater coal utilization – this is for a downstream approach holding coal prices fixed (Linn et al. 2014). This finding corresponds with the general understanding of rebound effects applied downstream. For instance, if the question was where CO_2 reduction policies should be placed on autos and trucks—upstream (the fuel) or downstream (the vehicle)—increasing fuel economy standards on vehicles would make it cheaper to drive, which would work against the CO_2 reduction policy. Focusing the policy on the fuel likely does not have this effect.

Another issue is administrative simplicity, or what economists call transactions costs. Transactions costs vary with the number and size of entities that need to be subject to monitoring and enforcement. The fact that a relatively small number of coal mines on federally leased land—about 300 active leases in 2013—but around 1,300 coal-fired electric generating units, would suggest an upstream approach.[48] However, the fact that regulated utilities already report fully on their operations argues that a downstream approach would not be more difficult to implement. Previous authors have recommended an upstream approach for taxing coal due to the lower transactions costs, but notes that the degree of pass through to the final consumer (electricity customers) is an issue to be considered (Metcalf and Weisbach 2009).

Another issue is coverage—that is, where should a tax be placed to provide as broad an internalization as possible? The standard answer is upstream because, as for coal, regulating at the mine has the advantage of applying, in theory, to all uses of coal, not just to coal used in particular sectors that happen to be regulated for carbon emissions, such as the power sector in the CPP. The CPP, for example, will provide no direct incentive to reduce exports or the use of coal in industrial processes, although by raising electricity prices, it would indirectly induce less coal use in, say, the steel sector.

A limitation of a charge only on federal coal is that tribal, state, and privately held coal resources (including almost all metallurgical coal) would by definition be excluded from the policy. This would be very likely to result in unintended and/or perverse consequences arising from the resulting more favorable market position of tribal, state, private, or state-owned coal, some of which are noted below.

Thus there is a key trade-off here. There are good reasons to internalize climate externalities from coal at the mine, but its limitation to federal coal provides insufficient coverage to make the policy work as intended. Of course, Congress could create a program to also put a price on the carbon content of tribal, private, and state coal. But this is outside of our scope here.

4.2. Economics of a Carbon Charge on Coal Leasing in General

In this section, we first consider the basic economics of adding a charge to new or renewed coal leases, without considering which of the three alternatives (bid price, rent and royalty) is chosen as the vehicle.

Let's assume that the carbon price being considered is the social cost of carbon developed by the IWG for 2020 using the 3% discount rate: \$46/ton CO_2. With this value and an average of

[48] For federal coal leases, see BLM (2014c), Table 3-18. For coal-fired electric generating units, see EIA (2014f).

2.05 metric tons of CO_2 produced for every metric ton of coal burned,[49] the charge per ton coal would be $94, compared with steam coal prices at the mine of $12/ton for PRB and $38/ton for Uinta, and an average price paid for coal by electric utilities of $46 domestically and $70 for exported steam coal. A tax of $94 per ton of coal mined on federal land (irrespective of where in the process it is levied) would probably drive new federal coal production to zeroor close to zero, and increasing demand for other coal (including imports)[50] to compensate. In the limit, if the supply curve of US coal were essentially flat, prices would remain unchanged, as would CO_2 emissions, although the government would lose its lease-related revenues. In the more likely event that the supply curve for coal were upward sloping, the overall price of coal would increase, putting coal at a disadvantage against other fuels and possibly leading to lower CO_2 emissions as a result. As any policy raising coal prices would do, further incentives would be created to shift to other fuels, economize on electricity use, and reduce use of electricity-rich products. The lower the carbon charge, the smaller the shift to tribal, private, or state coal and the less the rise in price.[51]

The specifics of how a carbon charge on only federal coal would raise the price of coal in the market are difficult to ascertain.[52] First, one would need to know the elasticity of substitution between federal coal and other coal (including imports). While this substitution was relatively low in older boiler designs, newer boilers are insensitive to coal type and substitution to low-sulfur coal was widely observed as a compliance strategy for SO_2 regulation under the 1990 Clean Air Act (see, e.g., Ellerman 2000; Carlson et al. 2000; Burtraw 2000). A carbon charge

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[49] The figure of 2.05 tons is the average CO_2 emissions per metric ton of coal burned as calculated by EPA. As noted previously, this will vary slightly but not drastically for different ranks of coal. See “Pounds of Coal Burned” at http://www.epa.gov/cleanenergy/energy-resources/refs.html.

[50] If such a policy were to be implemented, there would be a discussion of the “leakage” question, in this case the leakage of imported coal that does not carry a carbon price into the US market. One option for addressing such leakages is to levy an import tariff. See Fischer and Fox (2009) and Metcalf and Weisbach (2009) for more on this topic.

[51] Note that there would be changes in environmental impacts that follow from changes in the location and production of coal.

[52] However, EIA has modeled projections for the total US coal sector with a carbon charge in place in the 2014 Annual Energy Outlook. When compared with the reference case, an SCC of $34/ton in 2040 leads to 32% lower coal production, and an SCC of $85/ton in 2040 leads to 73% lower coal production (EIA 2014a, MT-32). A carbon charge could also lead to efficiency improvements at power plants; analysis of coal-fired electric generating units by Linn and colleagues finds that an increase in coal prices corresponding to a $10/ton CO_2 tax results in efficiency improvements (in heat rate reductions, or mmBTU/kWh) of 0.6%-2%, holding coal utilization constant.

only on federal coal would induce substitution in the other direction, away from low-sulfur coal.[53]

Second, one would want to know the elasticity of substitution of coal with other fuels. A 2012 EIA analysis of the elasticity of substitution among coal, natural gas, and petroleum for electricity generation found that a 10% increase in the price of coal relative to natural gas would lead to a 1.4% increase in the use of natural gas relative to coal (EIA 2012). Depending on the elasticity of substitution between federal coal and other coal, and between coal and other fuel sources, an increase in the price of federal coal could therefore lead to greater use of natural gas over federal coal (and more nonfederal coal). Indeed, EIA suggests as much in its 2014 Annual Energy Outlook, stating that "In general, assumptions that reduce the competitiveness of coal versus natural gas lead to lower coal production" (EIA 2014a, MT-32).

Third, one would want to know which types of coal are "marginal" and which are "inframarginal," or which types of coal are the most expensive types supplied (and therefore determine the market price) and which are cheaper and therefore earn rents (more than "normal" profits for operators). To the extent that the federal coal is in the Powder River Basin, which is very cheaply extracted relative to other coal supplied, the carbon charge would mainly lower profits there rather than affect the market price.

4.3. Distinguishing among the Three Options

In principle, capitalization of a carbon charge throughout the supply-and-demand chain for coal would occur regardless of where in the life cycle the charge is imposed. At whatever point in the life cycle the intervention takes place for federal coal, there will be similar repercussions in the rest of the coal market. If all federal coal were inframarginal, the carbon charge could be seen as like a profits tax, introducing very little distortion to the market. Similarly, in principle, the effect on the size of CO_2 emissions reductions would be the same regardless of where the intervention takes place in the life cycle.

When considering targeting the bonus bid, rental, or royalty, the obvious point is that only the royalty payment is denominated in the appropriate unit, tons of coal produced, while the rental payment is denominated in acreage and the bonus bid is based on expected (not actual)

[53] It should be noted, however, that the literature suggests that railroads transporting low-sulfur coal out of the PRB played a non-trivial role in the market re-alignment towards low-sulfur coal, capturing much of the economic rent created by the increased demand for low-sulfur coal (Busse and Keohane 2007; Gerking and Hamilton 2010).

production and prices. Thus adding a premium to the royalty payment makes the most economic and administrative sense. It would internalize the climate externality with less ambiguity about coal production than an adjustment to the bonus bid or rental payment. For each ton of carbon mined, the operator would pay a charge for that ton's calculated emissions potential in addition to BLM's conventional royalty fee. This charge would make it less profitable to mine the coal and ultimately lower the amount of federal coal mined. The operator, knowing the royalty payment would be larger with the carbon charge, would make a correspondingly lower initial lease bid. Considered in the context of the present value of revenues from the lease, revenues could increase or decrease.

In contrast, a charge on the bonus bid (or lease rental) would apply to coal not yet mined—possibly the amount of the recoverable coal in the lease that the operator is required to state. Bidders would also be likely to simply reduce their bonus bids in response to the additional fees. However, this stated amount of recoverable coal may not be equal to the amount of coal that would eventually be mined and therefore the bid reduction by bidders may not be equal to the full social costs of mining, transporting, and burning the coal. Once paid as part of the bonus or rental bid, there would be no incentive to limit mining the coal. In fact, with the charge on the bonus bid, the incentives to limit coal mining would appear earlier in the process, but they would be less directly calibrated to damage from actual production than with the charge on the royalty.

4.4. Policy Interactions

A policy to internalize GHG externalities at the mine would not exist in a vacuum. The coal industry itself is subject to a host of regulations to internalize other externalities that might contribute to lower CO_2 or methane emissions as ancillary benefits.[54] These existing regulations do not present any particular difficulties for a carbon charge policy, as they merely lower the GHG emissions baseline. Industries that use coal, mainly the electric power industry, but also the chemical industry, and others, also are subject to regulations that might make coal less likely to be used or lead to economizing on coal use, which would lead to lower GHG emissions. Again, these types of regulations present no particular difficulties.

Possible problems arise when a coal-using sector is confronted with multiple policies whose purpose is to reduce CO_2 or other greenhouse gas emissions. In the limit, a policy such as

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[54] For example, the mercury rule for electric utilities. See EPA's Mercury and Air Toxics Standards for New Power Plants, 78 FR 24073 (24 April 2013) (amending 40 CFR 60 and 63).

carbon cap and trade could apply to an entire sector or many sectors. In this case, as noted below in the export discussion about the EU Emissions Trading System (ETS), a carbon charge at the mine would be largely redundant, as CO_2 emissions from burning coal would be capped, so an additional ton burned would have to be offset by reductions in CO_2 elsewhere. A possible middle case is the Clean Power Plan (CPP). Since the plan targets CO_2 emissions from the electric power sector, it would to some degree internalize the externalities from coal (and other fossil fuels). This internalization would be particularly obvious and potentially complete if the states adopted a cap-and-trade program to implement the CPP.[55] Even if they did not, we can see some degree of internalization through regulation, as power plants would become more efficient, lower-carbon fuels would be switched in to replace coal, and other impacts would occur to lower CO_2 emissions, with a goal of 30% reductions from 2005 levels by 2030 (EPA 2014a). Whether a carbon charge at the mine would be partly, fully, or not at all redundant in this case would require further study, although administrative simplicity would argue for locating the policy intervention either upstream or downstream rather than in both places.[56]

Another area of possible problems is related to the interaction of existing policies affecting SO_2 emissions with a carbon charge on coal produced from federal lands. This interaction arises if, as we suspect, most low-sulfur subbituminous coal is from the PRB. Thus if this low-sulfur supply is reduced by a carbon charge, there may be economic consequences to meeting SO_2 reduction goals or goals of other related policies.

If the cap established by the SO2 trading program were binding, then the shift to higher-sulfur coal as a result of a carbon charge on federal (mostly PRB – low sulfur) coal, would raise costs to meet the cap (although SO_2 emissions would not increase). Actually, the cap is nonbinding because of another policy{ The Mercury and Air Toxics Standard (MATS) to be met by power plants.

55 Potentially complete because if each coal-producing state adopted a carbon cap-and-trade system and states could trade with one another, this would be like a national cap-and-trade system. In that case, any additional CO_2 emissions would need to be offset by reductions somewhere else, so the added externality from producing and burning an additional ton of coal would be zero. These assumptions about what policies will look like under the CPP, needless to say, are rather extreme.

56 One gauge of the degree of internalization from the CPP would be to examine the marginal cost of meeting these CO_2 reduction targets. An optimal target would be set to equalize marginal benefits and costs. Thus if the marginal benefits are \$46/ton CO_2 reduction (from the IWG report), marginal costs of the CPP at \$46/ton CO_2 (in 2020) would be an indicator of optimality. In fact, the marginal costs as taken from EPA (2014d) are \$14/ton CO_2. Thus this inequality implies “headroom” for a carbon charge at the mine coexisting with the CPP.

The cost of the MATS policy is also affected by a coal charge because low sulfur coal permits the use of the cheapest technology to reduce mercury emissions To meet the mercury standard coal plants will have to either operate flue gas desulfurization (FGD) technology, which takes out mercury as well as SO_2, or install much cheaper dry sorbent injection (DSI) technology, which works only with low-sulfur coal. If little low-sulfur coal is available, plants that are already investing in DSI will see their investments become worthless or will have to obtain more expensive low-sulfur coal elsewhere or install FGD, which is far more expensive than DSI. Plants yet to make a decision would probably need to opt for the expensive FGD option.

Box 2. The SCC and BLM Planning

There are a number of points in the BLM planning process prior to lease sales where the agency could consider a social cost of carbon in making decisions about what lands to lease for coal. BLM's planning must comply with NEPA, for which the White House Council on Environmental Quality (CEQ) has just released new draft guidance on accounting for greenhouse gas emissions and climate change impacts. Among a number of revisions, this new guidance extends its previous 2010 draft guidance to cover federal land and resource management decisions, including oil, gas, and mineral extraction.

BLM's coal management program has been tiered for NEPA compliance since its original programmatic review in 1979. That Final Environmental Statement: Federal Coal Management Program, amended by an FEIS Supplement released in 1985, remains in force today. It informs all BLM coal decisions, including Resource Management Plans that designate multiple-use lands suitable for coal development and lease sale plans that support decisions to offer specific tracts for coal mining.

The new draft guidance further details the manner in which climate impacts should be considered:

> When assessing direct and indirect climate change effects, agencies should take account of the proposed action—including "connected" actions. . . . In addition, emissions from activities that have a reasonably close causal relationship to the Federal action, such as those that may occur as a predicate for the agency action (often referred to as upstream emissions) and as a consequence of the agency action (often referred to as downstream emissions) should be accounted for in the NEPA analysis.

Even before the new guidance, BLM had already begun to consider carbon externalities in some of its prelease planning activities. For example, in its environmental assessments of oil and gas lease sales, it applies the SCC from the Interagency Working Group to an estimate of greenhouse gas emissions "associated with potential development on lease sale parcels." It does not look beyond the lease boundaries to take into account ensuing emissions from transportation, refining, or burning of oil and gas downstream. The draft CEQ guidance instructs BLM to consider whether it is appropriate to look downstream and reasserts its long-standing directive that "as called for under NEPA, the CEQ Regulations, and CEQ guidance, the NEPA review process should be integrated with planning at the earliest possible time."

Accordingly, in the event BLM considers future changes to its coal leasing program, the agency may choose to undertake a new programmatic NEPA statement to support the coal program going forward. This would be the earliest possible time to consider the SCC in shaping overall federal coal activity. Applying the SCC to federal coal could also be done systematically when BLM prepares Resource Management Plans, its basic multiple-use planning activity under the Federal Land Policy and Management Act (FLPMA). This multiple-use planning is a particularly promising place to incorporate full-cost accounting for coal—that is, the full costs and benefits of coal across its complete life cycle. It is early in the coal decision sequence, it includes all BLM lands for coverage and consistency, it creates planning areas of similar resources and recognizes differences among them, it has extensive public engagement, and it is where BLM explicitly applies its mandate to consider multiple-use and environmental trade-offs. Such incorporation gives BLM the opportunity to decide whether given federal lands are suitable for coal leasing, considering (among many other factors) the climate impacts of extracted coal.

4.5. Fugitive Methane and Exported Coal

Even if the CPP and a royalty premium on coal at the mine are regulating the same emissions from coal use, there are at least two categories of emissions from mining and using that would remain uninternalized by the CPP: (1) all of the GHG emissions related to the coal life cycle other than those related to power plant coal burning, particularly fugitive methane emissions at the mine, and (2) emissions from exported coal (as well as nonutility uses of coal).

While the methane and CO_2 emissions from these early stages in the coal life cycle are small relative to the CO_2 emitted from burning the coal (see Table 1), they are not inconsequential. In *High Country Conservation Advocates, et al. v. US Forest Service, et al.*, a district court judge pointed to these fugitive methane emissions at the mine mouth, as well as emissions from coal combustion downstream, as worthy of monetization in agency cost–benefit analysis using the IWG SCC. The challenge was brought against a lease modification to add 1,721 acres to existing leases for the underground West Elk coal mine, an action the EIS estimated would result in production of 5.6 million tons of coal from private lands and 3.3 million tons from federal lands. Annual fugitive methane emissions at West Elk mine for 2010–11 were estimated at 1.23 million annual tons of carbon dioxide equivalent emissions, which, depending on the carbon charge, could range from $6 million to $984 million per year if based on the SCC.[57] Methane emissions of this amount would qualify as worthy of quantitative disclosure under the new draft guidance on consideration of climate change impacts in NEPA documents, which establishes a disclosure threshold of 25,000 tons of carbon dioxide emissions (CEQ 2014). Note, however, that most methane emissions from coal mining are from underground, not surface mines, whereas most federal coal (with some exceptions, such as the West Elk mine in question) is surface mined.

The leakage from coal exports is potentially much larger. The CPP would effectively price carbon from burning coal in power plants but miss coal used by other domestic sectors, whether for power, heat, or product manufacturing, as well as for export. Thus the CPP, by lowering the demand utilities have for coal, and therefore lowering its domestic price, would create incentives for other countries to import our coal. To the extent that other countries lack regulations to internalize the CO_2-related damages from using coal, this creates a socially undesirable "leakage" from that policy.[58] In this context, what would be the effect of a carbon charge applied to federal coal at the mine?

The United States has been a net exporting country since 1949, but the share of total production that has been exported has risen dramatically in the last few years and now surpasses 10% of aggregate production, as seen in Figure 1.

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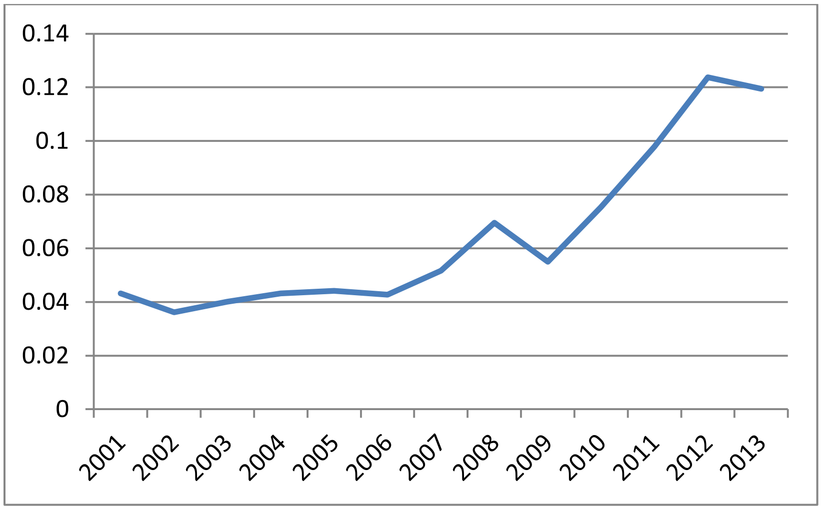
57 *High* C*ountry Conservation Advocates, et al. v. US Forest Service, et al*. Order of June 27, 2014.

58 A similar form of leakage is described by Harstad (2012), in which reduced demand for fossil fuel deposits by an agent (in this case a coalition of countries) leads to increased consumption of these deposits by another agent. He advocates for purchase and non-utilization, rather than reduced demand, of the deposits by the first actor to avoid this scenario.

Figure 1. Share of US Production Exported by Year



Source: EIA (2015b; data sets: "Coal Mine Production [MSHA]: Aggregate coal mine production" and "Imports & Exports of Coal [US Census Bureau]: Quantity & price of coal imports & exports").

The US exports more metallurgical (56% total exports) than steam coal, although metallurgical coal production only made up 8% of total US production in 2013 (EIA 2014g). However, the importance of steam coal exports to domestic producers is expected to increase in future years as the demand for steam coal imports rises worldwide (IEA 2014; Humphries and Sherlock 2013).

While we know that approximately 10% of total US coal is exported, we do not know how much federal coal is exported (GAO 2013). We can, however, see how much total (federal and other) coal individual states export. Table 8 shows the 2011 coal exports for the five states that produce 96% of all federal coal.

Table 8. Coal Exports by State, 2011

State	Total production (million short tons)	Coal exports (million short tons)	Share of total production that is exported	Share of exports that are steam coal
Wyoming	437.8	4.5	1%	76%
Montana	38.5	13.2	34%	72%
Utah	19.0	1.1	6%	100%
Colorado	25.9	3.0	12%	39%
New Mexico	24.9	—	—	—

Source: Ernst & Young (2013, Appendix B).

The table illustrates that, with the exception of Montana, the states that make up virtually all federal coal production export a very small share of this production (and one state, New Mexico, reportedly exported no coal in 2011). While Montana has experienced a sharp increase in coal exports, going from about 2 million to 13 million short tons of exported coal from 2009 to 2011, the other states have not experienced similar levels of growth (Ernst and Young 2013). Wyoming, for instance, which is responsible for 80% of all federal coal production, exports only 1% of its total coal production.

Nevertheless, there are signals that the potential leakage could grow in the future.[59] While exports have traditionally been dominated by metallurgical coal, a 2013 Congressional Research Service report on US coal production predicts both that steam coal exports will become increasingly important and that "if trends continue, the US coal industry will likely become more concentrated and produce more on federal lands" (Humphries and Sherlock 2013, 20). Finally, EIA projects that total world steam coal import demand will rise from 757.7 million metric tons in 2012 to 844.4 million metric tons in 2020 and 1,054.5 million metric tons in 2040, driven by an increase in import demand of 35% from Asia (EIA 2014b, Table 12.3).

A carbon charge on federal coal may reduce this source of carbon leakage by raising the price of coal. That is, even if state or private coal could take up the slack, the diversion of demand to these sources of coal would drive up prices for foreign buyers.

In addition, there is a legitimate question about whether the externalities from coal exports are already being internalized, at least in some countries. Table 9 includes a list of leading importers of US coal and the quantities of both total and steam coal for 2013. Most prominently, given that Europe is the largest importer of US coal, the EU's Emissions Trading System (ETS) caps carbon emissions from the countries in the EU. Thus the carbon emissions from coal imports from the United States must be offset by reductions in CO_2 emissions elsewhere in the EU economy (in theory). In this case, there would be no additional emissions from coal imports to the EU, and the climate damages are therefore near zero,[60] unless the cap is not binding, and implicitly internalized.

Several other countries or smaller jurisdictions have carbon policies in place that are at least partially internalizing climate damages from using coal. Of the top 10 destination countries

[59] Sightline Institute (2014) presents evidence that federal coal is already going abroad.

[60] Or nearly zero, as there would be emissions from coal transport and mining.

for US coal, 6 can be said to have a price on carbon currently; these include European countries in the EU ETS (Netherlands, UK, Italy, Germany), Mexico, and Japan (Kossoy et al. 2014). Emerging carbon pricing schemes are developing in South Korea, which intends to launch its cap-and-trade system in 2015, and China, which has announced a cap on total amount of coal consumed and has seven cap-and-trade pilot markets prior to the roll-out of a larger cap-and-trade system in 2016 (Kossoy et al. 2014; Munnings et al. 2014).

Table 9. Top US Coal Export Destination Countries 2013, Total Coal and Steam Coal

Total exports		Steam coal exports	
Country	**Quantity** (short tons)	**Country**	**Quantity** (short tons)
United Kingdom	13,511,213	United Kingdom	9,825,874
Netherlands	12,708,786	Netherlands	8,357,121
Brazil	8,610,418	South Korea	4,433,748
South Korea	8,430,182	Italy	4,210,329
China	8,229,531	Germany	3,407,892
Canada	7,110,055	Canada	3,403,003
Italy	6,593,622	Mexico	2,522,030
Mexico	5632,789	Morocco	2,381,520
Germany	5,475,367	Chile	2,258,531
Japan	5,360,260	China	1,489,773

Source: EIA (2015b; data set: "Imports & Exports of Coal [US Census Bureau]: Quantity & price of coal imports & exports").

Overall, therefore, a carbon charge on federal coal, with or without domestic downstream policies in place, would serve to only partially close CO_2 leakages through exports to importing countries. Leakages could still occur as other supplying countries take the place of US coal supply. Presumably, importing countries were buying US coal because it was cheaper than some other sources. Without this coal, the world price of coal would likely rise, acting as a partial mechanism for internalizing climate damages.

4.6. Factors Increasing the Competitiveness of Federal Coal

If the carbon charge on federal coal is high enough, federal production and leasing activity could come to an end. How high this charge would have to be for this outcome requires further study, but clearly at higher and higher carbon charges, the competitiveness of federal coal would fall. What conditions could work to increase competitiveness of federal coal in the face of any given charge?

One way would be for the demand for coal to rise, raising its price enough to make mining federal coal profitable even with a carbon charge. EIA's forecast for the Northern Great Plains (which includes the PRB) shows coal prices rising a modest 2.5% per year from 2012 to 2040, and a more limited 1.1% for other western areas (which include the Uinta Basin); by 2040 the EIA projects the mine mouth price of Northern Great Plains coal to be $29.43 per short ton.[61] What about export demand rising to push up coal prices? After a banner year for coal exports in 2012, exports have fallen off slightly since then. Moreover, reduced prices for natural gas are already disadvantaging coal, and new climate agreements and any new plans coming out of the Paris climate meetings will put downward pressure on demand.

More significant is the possibility of new technology being developed to cost-effectively reduce CO_2 emissions. The big question here is the future path of carbon capture and sequestration (CCS) for coal-burning utilities: how effective and costly this new technology is in removing CO_2 from the waste stream, and how quickly coal-fired facilities install it. Starting with new coal plants, even without EPA's CPP proposal, no new coal plants are expected to be built for at least the next 20 years. The CPP would make this outcome even more likely. Retrofitting existing plants with CCS is a possibility, and this is occurring on a pilot basis. For example, the Boundary Dam Carbon Capture Project in Saskatchewan will extract up to 90% of CO_2 for underground enhanced oil recovery injection.[62] Nevertheless, widespread adoption of

[61] See EIA (2014a), Coal Production and Minemouth Prices by Region, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=3-AEO2014&table=94-AEO2014&region=0-0&cases=ref2014-d102413a.

[62] For more information, see the project website at http://www.saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/.

CCS is far from certain because of its cost and the lack of secure storage sites. Moreover, renewable power technologies and natural gas extraction technologies are not standing still either, increasing their competitiveness against coal. Finally, economic deployment of CCS technology would affect not just federal coal but all coal, and thus a carbon charge only on federal coal would still leave federal coal at reduced competitiveness, all else equal.

Another option that would not harm coal competitiveness much, if at all, would be to adopt a carbon charge for its symbolic or precedential value. Some analysts justify a relatively low carbon charge on the grounds that the domestic damages from global warming are the only relevant climate externalities. The IWG estimates domestic damages at 7% to 23% of global damages, using a 3% discount rate and alternative approaches to determining a US share within the global total. At the lower end of this range, the domestic-only SCC per ton of coal would be $6.60 (0.07*$46*2.05), a large fraction of the current PRB coal price ($12/ton) but a smaller fraction of the Uinta coal price ($42/ton).

Moreover, many experts acknowledge that the estimates of the SCC are likely to increase over time as the underlying models are refined and extended to include impacts recognized in the climate change literature but not yet known precisely enough to enter the models. Further, the SCC, as estimated by the IWG (and reported in Table 7) already rises over time. These trends do not preclude use of a very low carbon charge, but arguments for a higher one will likely become even more compelling over time.

5. Conclusions

This report explores the legal and economic questions raised by implementing a policy on federal coal lands that seeks to consider GHGs over the entire coal life cycle. It focuses on internalizing the climate-related damages from CO_2 (and to a lesser extent other GHGs) at the coal leasing (or upstream) stage through BLM planning and analyses or through changes to the terms and conditions established for tracts of land being offered for lease.

Our legal analysis supports the view that the arguments in favor of BLM authority under current law to incorporate a carbon charge reflecting the external costs of coal over its life cycle in coal lease terms and conditions are stronger than the arguments that such authority is lacking.

- BLM is required by statute to consider the environment in making multiple use decisions for the public lands it administers, and its coal leasing statutes give it broad discretion to set financial terms of leases—rents, royalties, and to a lesser extent, bonus bid minimums.

- Legal arguments against a carbon charge would be strongest if such a charge were to instigate a large and abrupt reduction in coal extraction on federal lands, a move that would challenge BLM's mandate to balance multiple uses (including mining and associated generation of federal revenue). While the courts will generally defer to BLM's balancing of uses, climate-driven policy that would stop new federal coal mining (or nearly so) would invite tough judicial scrutiny.
- Probably the simplest, most rational, and least legally problematic point of action would be for BLM to add a carbon charge on top of the existing royalty. The royalty for surface-mined coal has a floor of 12.5% of production value but no ceiling.
- It would be most problematic legally to incorporate an SCC on the bonus bid.
- Any carbon charge policy would have a delay in coming into effect as new leases are proposed and existing leases come up for renewal. The only exception to this would be if BLM were to change the estimated value on which it calculates royalties, a move that would face substantial legal risk.
- BLM can establish procedures for incorporating CO_2 charges in lease terms through standard notice-and-comment rulemaking.

Of course, litigation is likely no matter what the charge is or where the charge is placed. So, the courts would have the final say on what BLM is allowed to do. Internalizing CO_2 costs in coal leasing is not anticipated by the relevant leasing statutes, which are more oriented toward making coal available, getting value for the resource, and maximizing recovery. Thus, it may turn out that BLM's best opportunity to recognize the external costs of CO_2 in coal leasing will occur prior to the leasing stage, when the agency makes decisions on which lands will be open for coal development. This opportunity has recently been bolstered by the issuance of draft guidance on including climate change impacts in documents produced to satisfy requirements under the NEPA. We note the potential role of BLM's planning activity in Box 2, but it is not the main subject of this report.

The effectiveness of an economic case for a carbon charge on federal coal to manage GHGs is weaker than the case about whether the statute allows such a charge. The point of incorporating a carbon charge is to raise the price of coal to internalize its climate change externalities. But there are at least four arguments why such a charge is unlikely to reduce the externality.

1. The first is that coal production on BLM lands at present is only 40% of total coal production and is not expected to be growing in the future. Although exports may rise they are expected to be more or less balanced by falling generation demand. Therefore, any increase in prices of federal coal driven by increased royalties will be diluted by the lack of any equivalent price hike on coal mined on state, tribal or private lands (although such prices will likely increase over time through increased demand for nonfederal coal and as old leases are renewed).
2. Second, federal coal lease auctions are not competitive—more than 90% have only one bidder. Thus, at least for new leases, if BLM raises royalty rates, firms will lower their lease bids in reaction to the lower profitability of that coal, eliminating some or possibly all upward pressure on coal prices. Operators might also be forced to take lower profits to the extent there is competition from non-federal coal. At the same time, to the extent that the additional fee is large or BLM's Fair Market Value calculation does not adjust downward accordingly, bidders may move off federal land, thereby bidding up the prices of state and private coal and hence raising national coal prices (a good result if the goal is to increase coal costs so as to better reflect coal externalities).
3. The third argument is that BLM does not appear to have the authority, or if it has the authority rarely uses it, to change lease terms within a contract period (20 years to start and 10 years thereafter). Therefore, existing leases would not come under a carbon internalization policy until they were renewed, dramatically limiting the short-term impact of the policy on coal prices.
4. The fourth argument is that if the Clean Power Plan (CPP) is implemented, it may well at least partly internalize the coal-related damages, possibly making internalization at the mine at least partly redundant. One mechanism to address any duplication would be a rebate program, which could also be used for coal exported abroad into a market with a carbon charge. However, this option would impose administrative costs associated with tracking exports of federally leased coal.

Our research has also unconvered a possible area of very high transactions costs to implementing a carbon charge system at the mine. Average CO_2 emissions factors, by definition, do not capture the variation across specific coal deposits, and findings that there is greater variation within rather than among coal ranks may challenge the viability of regulating CO_2 emissions by coal rank.

Nevertheless, the current administration has signaled some willingness to make changes to the coal leasing program. In response to the GAO report and others, BLM has released a new Coal Evaluation handbook (BLM 2014a), which, among other things, requires more consideration of export prices in fair market value calculations. More significantly, in December 2014, the Council on Environmental Quality released updated draft guidance on consideration of climate change impacts in NEPA (CEQ 2014). While the draft guidance is still preliminary—indeed, the original draft guidance on the subject released in 2010 was never finalized—it addresses the potential for incorporating climate change impacts in the land management and planning stage rather than during leasing.

Our report describes, but takes no position on, the appropriate size of the carbon charge. However, we note four issues with applying the SCC as developed by the IWG to BLM coal leasing decisions (see the Appendix). These issues transcend the BLM context and include uncertainty in the estimates, the question of whether a global or domestic damage estimate should be used, the exclusion of damages from non-CO_2 gases in the SCC, and the original development of the SCC for use in supporting documents (i.e., RIAs) rather than in operational decisions (e.g., sale of a particular lease tract).

We find that the global damages per ton of coal are currently about $94 (given the administration's estimate of around $46/ton CO_2; see Table 1) and the slightly greater than two tons of CO_2 created for every ton of average coal burned, whereas the price of the most prevalent type of federal coal used by power plants is PRB coal currently sold at $12 per ton of coal. While modeling would be needed to discern the specific impacts of putting such a large carbon charge on federal coal, the effects would surely be significant. We note only that private, tribal and state lands and even imports could possibly take up much of the demand pressure. Indeed, cheap natural gas could help alleviate such pressure as well.

However, the upstream policy would require consideration of interactions with downstream policies (including those on other pollutants) through the use of rebates, tax offsets, and so forth. The possibility for interaction with existing SO_2 and mercury emissions policies merits particular consideration. A carbon charge only on federal coal would essentially take out a large part of the supply curve of low-sulfur subbituminous coal. To the extent to which companies are complying with SO_2 or mercury regulations by using low-sulfur coal, such a policy would lead to higher-priced compliance mechanisms, including scrubbers. However, to the extent to which most companies already have adopted these technologies, the effect would be reduced.

With emerging policy decisions raising understandable concerns about the scale of disruptive economic consequences, there is an argument for an extended transition of adjustment to full internalization of climate externalities. One can imagine a small charge that tests the principle of increasing royalty rates for this purpose, while minimizing any economic fallout. One additional caution: a small charge to begin this transition should not discriminate between federal coal for domestic use and exports, although companies selling into the EU and other places where carbon caps or taxes are in place could get a rebate. Such a rebate could also be an appropriate offset to whatever restriction (in terms of its carbon tax equivalent) is imposed under EPA's CPP.

The economic efficiency case for an upstream carbon charge is much stronger if charges are applied comprehensively, that is to all fossil fuels extracted from all lands -- federal, state, tribal and private. In this way, perverse substitutions from federal coal to other coal and other fossil fuels will be avoided, as incentives may strengthen to switch to renewables or nuclear power or carbon storage and sequestration. But before major policy action of this type or even just for federal coal are taken, studies like ours are needed on other fossil fuels and quantitative analyses are needed to help design the most efficient and least disruptive policies.

Appendix: The Social Cost of Carbon (SCC)

A.1. Background

The social cost of carbon (SCC) refers to global damages attributable to the effects of an *additional* unit of carbon dioxide emissions. It is thus an estimate of the monetized damages associated with an incremental increase of CO_2 emissions in a given year. The damages associated with these emissions represent important, and in some ways unique, cases of negative externalities—that is, they fail to be "internalized" in private market transactions. But they should also be seen as coexisting with a wide array of environmental and other noninternalized externalities.

The italicized term *additional* (synonymously, *marginal* or *incremental*) above must be underscored. It refers to the societal harm inflicted by one additional unit of CO_2 released into the atmosphere. To the extent that the SCC suggests economic imperfections susceptible to the imposition of a monetary penalty (sometimes labeled a Pigouvian tax or equivalent charge), it would ensure a closer fit to a socially optimum level of output.

It should also be noted that global damages are more precisely termed "net global damages." While concern over global warming is legitimately dominated by its harmful implications, one should not exclude the prospect that at least some regions of the world would benefit from rising temperatures.

As the 2010 IWG report puts it, the potential damages prominently associated with global warming may be manifested physically as reductions or degradation in agricultural productivity, the quality of environmental and ecological resources, direct and indirect effects on human health and productivity, sea-level rise and coastal flooding, and numerous other consequences. Procedurally, the estimation of the SCC involves assembling scientific information about physical damages, monetizing these physical damages using a set of integrated assessment models, and specifying net present values for the SCC. It is imperative to note that any such estimates are the result of specific assumptions (e.g., the rate of time preference), omit some important damages (e.g., ocean acidification), and as they have thus far been developed, would not accurately predict the impact of emissions of non-CO_2 gases (even once they have been converted into CO_2-equivalent units). For these and other reasons, the SCC is usually expressed as a range of values and is also expected to be updated over time as uncertainties are reduced and better analyses are conducted.

A.2. The Estimates

The dollar estimates of the SCC produced by the IWG are shown in Table A1. There are three critical determinants of the dollar magnitudes in the table. The first two—the future years selected for estimation and the rates of discount chosen to be able to express the SCC in present-value terms—are apparent from the table. The third—that they reflect global, not just US domestic, damages—is not. Box A1 covers a fourth issue—how non-CO_2 gases are treated.

Table A1. Social Cost per Ton of CO_2 Emitted, 2015—50, at Different Discount Rates in 2011$

Year	5% average	3% average	2.5% average	3% 95th percentile
2015	12	39	61	116
2020	13	46	68	137
2030	17	55	80	170
2040	22	65	92	204
2050	28	76	104	235

Note: These numbers are EPA updates of the IWG estimates, reported in 2011$ rather than 2007$. See www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf.

Box A1. Non-CO_2 Greenhouse Gases in the Social Cost of Carbon

It is important to note that the IWG numbers apply only to CO_2, not all greenhouse gases. Important differences in atmospheric lifetime and radiative forcing between, say, methane (CH_4) and carbon dioxide (CO_2) make it inappropriate to assume that the social cost of carbon (dioxide) can be used with other gases expressed in CO_2-equivalent terms, as it has been shown that this method underestimates the benefits of mitigating non-CO_2 gases (Marten and Newbold 2012; Marten et al. 2015). While this issue has been known since the 1990s (see, e.g., Schmalensee 1993 and Fankhauser 1994), and social cost estimates for non-CO_2 gases were identified as an area for further research in the 2010 IWG report, the IWG did not present any such social cost estimates in its 2013 report. As a result, how federal agencies should value the damages from non-CO_2 gases remains unclear. Thus one analysis provides social cost estimates for methane "based on assumptions similar to those used by the [IWG]" and finds that using a social cost of carbon and CO_2-equivalents, rather than developing social cost estimates for each individual GHG, can "underestimate the benefits of current CH_4 emissions by up to 35%" (Marten and Newbold 2012, 969). We present their estimates of the social cost of methane in Table A2.

The issue of applicability of the social cost of carbon to methane emissions is relevant to the policy question at hand of how best to internalize climate damages from the BLM coal leasing program. As shown in Table 1 of the main text, most of the greenhouse gas emissions from the federal coal life cycle prior to combustion are methane, not carbon dioxide, emissions. Additionally, it is these upstream methane emissions at the mine that would not be internalized by the proposed Clean Power Plan. Nevertheless, these emissions are relatively small (even corrected for their greater global warming potential) compared with CO_2 emissions from burning

Table A2. Social Cost per Ton of CH_4 Emitted, 2015–50, at Different Discount Rates in 2011$

Year	5% Average	3% Average	2.5% Average
2015	488	1,052	1,410
2020	597	1,193	1,627
2030	868	1,736	2,170
2040	1,193	2,278	2,929
2050	1,627	3,146	3,797

Source: Marten and Newbold (2012).
Note: Originally reported in 2007$.

A.2.1. How Far into the Future? At What Rates of Discount?

That annual SCC estimates shown in Table A1 increase steadily reflects the fact that, especially when coupled with projected increases in world population and GDP, a deferred onset of carbon mitigation strategies inescapably means the likelihood of worsening conditions as time goes by. Thus incremental damage associated with an added ton of CO_2 to prevailing emissions points to an estimated SCC of $39 and $46 per ton for the years 2015 and 2020, respectively, in present value terms using a 3% discount rate; those figures rise to $76 per ton in 2050.

As in commercial and financial sector transactions, where discount rates reflect the estimated time value of money and uncertainty, their use in the economics of climate change compels us to assess how the prospect of future costs to society of climate change impacts should drive anticipatory measures to manage those costs. Thus even if values close to market rates satisfy conventional business planning, the unique and highly uncertain risks associated with climate change present a far more complex challenge. Ultimately, these are among the key challenges that led the IWG to use multiple discount rates, both because the SCC calculations are very sensitive to choice of rate and because there is no consensus on the “correct” rate.

Each of the three average discount columns of Table A1 shows, a stream of corresponding damages for each of the years shown. Thus when future impacts are discounted heavily (the far-left 5% column), the estimate by mid-century is relatively low ($28); however, an only modestly discounted future (2.5%) produces a high present value ($104). Between these outer calculations, it is relatively common practice in cost–benefit analyses to select the midrange rate of 3%, which by 2020 is estimated to produce a present value of $46. The possibility of economic impacts more extreme than those projected in these three columns of the table is represented by the 95th percentile in the models. As illustrated in the table, with a 3% discount rate in 2020, the IWG-based estimate of the SCC cited by EPA comes to about $137—

significantly higher than the $46 average estimate. The IWG chose not to include a 5th percentile estimate.

A.2.2. Use of the SCC in the Federal Government

This section looks at the SCC's development and use for regulatory purposes by the US federal government. The SCC's adoption by the government owes its emergence to Executive Order 12866, a 1993 directive that obliged federal agencies to assess the estimated benefits and costs of consequential regulatory actions. In 2003, OMB's Circular A-4 fleshed out that Executive Order by assisting agencies in "defining good regulatory analysis and standardizing the way benefits of federal regulatory actions are measured and reported" (OMB 2003). Monetization was expected to be part of that process.

The SCC's prominence within that more general process dates from 2009, when OMB's Office of Information and Regulatory Affairs (OIRA) and the Council of Economic Advisers (CEA) convened an Interagency Working Group on the Social Cost of Carbon (IWG), an effort by leading economists, risk analysts, and climate experts to evaluate a set of major global economy-climate models and projections and, on the basis of such evaluation, to render a collective judgment about the range of SCC values that could be used uniformly across federal agencies in their RIAs.[63] This limited use envisioned for the SCC is important when considering its use in an operational context by BLM. Such expanded use would significantly expand its reach and the consequences to economic actors affected by BLM leasing decisions.

That said, the SCC has emerged as an increasingly referenced tool of analysis in federal RIAs. The most visible and widely discussed agency use of the SCC as a significant factor in a proposed rulemaking process is in EPA's Clean Power Plan. But an exhaustive compilation by the US GAO, covering the period 2008–14, provides additional detail on federal agency SCC reliance beyond its consideration by EPA. GAO reports the use of an SCC estimate in 58 proposed or final rules and identifies, along with EPA, the US Department of Energy (DOE), and the Department of Transportation (DOT) as the leading SCC-using agencies, with DOE making up 14 of the 16 total agency citations of the 2013 IWG estimates (GAO 2014, Appendix I). No

[63] Even so, the SCC's role in that process dates from 2007, when the Ninth Circuit Court remanded a vehicle rule to the US Department of Transportation (DOT), ruling that not monetizing the CO_2 emissions reduction benefits was arbitrary and capricious, noting that the value was certainly not zero. Subsequently, beginning in 2008, under the Bush administration, agencies started including estimates of the SCC in their RIAs, though the values used varied widely across agencies. We thank a reviewer for that more complete historical amplification.

part of this record should be read as pointing to the SCC as a core and decisive factor in proposed or adopted rules. But its growing place in agency RIAs shows that it is becoming the standard vetted referent for federal evaluation of greenhouse gas emissions policies.

A.2.3. Other Estimates of the SCC

There are several other sources of social cost of carbon estimates worth noting. The first is simply the taxes put on carbon emissions in some countries or by other government bodies (e.g., Mexico and British Columbia) or the price of a CO_2 permit determined by the permit market in a tradable permit system, such as in California's carbon market and the northeast Regional Greenhouse Gas Initiative (RGGI) market. The most recent prices in the California and RGGI markets are $12.10 and $5.41, per ton of CO_2, respectively (CARB 2015; Potomac Economics 2015). These price signals have the advantage of being determined, at least in part, by an economic process and a political process. These prices are quite low in comparison to the SCC from the IWG.

A second application of the SCC from what may be called the compliance cost approach, which would peg the SCC at the amount of costs the government is willing to impose on the economy to bring down the expected damages from greenhouse gas emissions. This type of measure has the advantage of avoiding the use of damage estimates, which are far more controversial than compliance costs. In this spirit, the costs per ton of reducing CO_2 emissions in the Clean Power Plan are about $14 (from dividing the present discounted value of compliance costs by total CO_2 reductions), against $40 and up for the damages. Nevertheless, this approach has the disadvantage of being a lower-bound estimate of damages, in the sense that a government will not want to impose compliance costs unless they are exceeded by the damages avoided.

The third is the use of the SCC by private companies for investment and more general planning purposes. Private-sector use of the SCC appears to be growing, albeit in a much more limited and less publicized fashion. This growing use should not be surprising as firms feel increasingly exposed to the risk of future climate change legislation and regulation, which in turn becomes a putative factor in investment planning as well as in evaluation of fossil fuel resource stocks. At the same time, there is no systematic tabulation of data that would indicate the number and industrial classification of firms using carbon prices, the values chosen, and their role—casual or integral—in their long-term planning and resource valuation strategies. Nor is it clear whether and to what extent firms conform in their reckoning with the marginal (rather than average) cost concept that underlies the SCC. A nongovernmental organization, the Carbon Disclosure Project (CDP), recently surveyed a sample of companies worldwide with a view to examining carbon prices used by companies (CDP 2014). For the United States, this survey lists 10 companies "that disclose an internal price on carbon," as shown in Table A3.

Table A3. Internal Carbon Price at Select US Companies

Firm	Carbon price ($/ton CO_2)
Walt Disney Company	10–20
Mars	20–30
ConocoPhillips	8–46
Encana Corporation	10–80
ExxonMobil Corporation	60–80
Devon Energy Corporation	15
Google Inc.	14
Microsoft Corporation	6–7
Ameren Corporation	30
Xcel Energy Inc.	20

Source: CDP (2014).

We also note that pressure on private companies to account for climate change in reporting is also coming from the government. The Securities and Exchange Commission has issued interpretive guidance on disclosure related to the effects of climate change and related public policy on business assets and operations, as well as legal developments, pertinent to the company.[64]

A.3. Global versus Domestic SCC

The rapid atmospheric mixing of CO_2, which respects no geopolitical boundaries, argues in some respects for an SCC reflecting global damages. Indeed, the IWG's SCC is defined to be a global SCC. As the 2010 IWG states:

> The climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would

[64] See http://www.sec.gov/rules/interp/2010/33-9106.pdf.

> be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. (IWG 2010, 10–11)

In the light of such considerations, the IWG embraced the logic justifying a global measure of the benefits from reducing US emissions and reaffirmed this position in its 2013 update.

Some who tend to question this position may have in mind guidelines from OMB that, in the past, have typically limited regulatory cost and benefit rulemaking as follows: "[Agency] analysis should focus on benefits and costs that accrue to citizens of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (OMB 2003, 8). To be sure, using only the domestic portion of the SCC rather than the global SCC makes a marked difference; the 2010 IWG report does not give specific domestic SCC values but suggests that they should be calculated at 7% to 23% of the global figure, while noting that these values are "approximate, provisional, and highly speculative" and depend on key assumptions (IWG 2010, 11).[65] Although the domestic versus global dimensions may have invited such ambiguity in earlier phases of the SCC's evolutionary path, we are satisfied that today OMB embraces the global scope of the measure.

A.4. Conclusions on the SCC

Four issues arise with respect to choosing an estimate of the SCC for use in BLM's coal leasing program. The first is the wide range of uncertainties associated with the appropriate value. These uncertainties—in discount rates, in the "routine" damages within various sectors as calculated by the integrated assessment models reviewed, and in the handling of catastrophic damages, to name a few—are addressed to a reasonable extent by the IWG report. Unavoidably, however, in successive refinements of a still novel economic construct, uncertainties—whether technical or substantive—will arise. The second issue is that the IWG effort was geared from the outset to develop an SCC for use in RIAs, the cost–benefit analyses required by OMB to be conducted for all major federal regulatory activities and that were recently proposed for use in

[65] For instance, for a 3% discount rate, IWG estimates the domestic benefit share at 10% according to the models analyzed, which would, using the $46/ton global figure in Table A1, yield an estimate of domestic effects of $4.60/ton CO_2. Alternatively, if one were assuming that the domestic benefit matched the US share of global GDP, a rate of 23% would be used, yielding an estimate of domestic effects of $10.58/ton CO_2.

NEPA planning documents. By inference, they were not developed to be used directly in agency operational decisions, such as leasing. Presumably, their use in this manner would require further discussions and analyses. The third issue is whether the SCC used for coal leasing should capture global or domestic damages. This controversial choice, with OMB and IWG at odds, could have dramatic implications for the SCC. The fourth is how the SCC should be altered to account for multiple gases, specifically, fugitive methane emissions from coal mining. Given these issues, there are serious questions about using the SCC taken from the IWG reports and used in RIAs in the context of BLM coal leasing decisions.

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