NBER WORKING PAPER SERIES

CLIMATE ROYALTY SURCHARGES

Brian C. Prest
James H. Stock

Working Paper 28564
http://www.nber.org/papers/w28564

NATIONAL BUREAU OF ECONOMIC RESEARCH
1050 Massachusetts Avenue
Cambridge, MA 02138
March 2021

We thank Gib Metcalf for helpful discussions. The views expressed herein are those of the authors and do not necessarily reflect the views of the National Bureau of Economic Research.

Climate Royalty Surcharges
Brian C. Prest and James H. Stock
NBER Working Paper No. 28564
March 2021
JEL No. H23,Q35,Q38,Q54,Q58

ABSTRACT

In 2019, production on federal lands comprised 40% of domestic coal, 22% of domestic oil, and 12% of domestic natural gas production. Currently, the federal fossil fuel leasing program does not consider the climate costs of burning federal fossil fuels. One way to do so is through a climate royalty surcharge in addition to the current royalty rate, set in 1920, of 12.5% (18.75% offshore). We consider determining this surcharge by maximizing revenue, maximizing welfare, or setting royalties to achieve 80% of the emissions reductions of an outright leasing ban. Using the model in Prest (2021), we calculate the resulting surcharges and their implications. We estimate that all three approaches would lead to meaningful declines in global emissions, and the first two would substantially increase royalty receipts, which are split with the state of production. For example, we estimate that choosing a common royalty rate to maximize revenues yields a climate royalty surcharge of 39%, increases annual royalty receipts by $6.2B, and reduces global emissions by 37 to 63 MMton CO2e/year.

Brian C. Prest
Resources for the Future
1616 P Street NW, Suite 600
Washington, DC 20036
prest@rff.org

James H. Stock
Department of Economics
Harvard University
Littauer Center M26
Cambridge, MA 02138
and NBER
James_Stock@harvard.edu

Starting in the 19th century for coal, and in the 20th century for oil and gas, the US government promoted fossil fuel extraction from federal lands. Fossil fuel production on federal lands helped drive settlement of the American West, provided a secure domestic supply of energy to a growing nation, and created jobs and wealth. In 2019, production on federal lands comprised 40% of domestic coal production, 22% of domestic oil production, and 12% of domestic natural gas. Now, however, we understand that CO_2 emissions from burning fossil fuels is the primary driver of climate change. As a result, there have been calls to rethink the federal government's role in fossil fuel leasing in the context of the broader energy transition to a decarbonized economy.

A week after entering office, President Biden issued Executive Order 14008, which paused new oil and natural gas leases on public lands and offshore waters; federal coal leasing was, in effect, already on pause because of the lack of demand for new leases. The Executive Order instructs the Secretary of the Interior to examine the climate and other environmental consequences of the federal mineral leasing program, including considering "whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs."

This note addresses three issues raised by this EO. First, to the immediate point, we lay out general economic considerations why it may or may not be appropriate to adjust royalties based on climate considerations. In brief, while CO_2 emissions from burning federal fossil fuels contributes to climate damages, whether those emissions can be mitigated by programmatic reforms depends on several factors. One such factor is the extent to which foregone federal production is simply replaced by nonfederal production; another is any interaction with other climate policies that in effect place a price on CO_2 emissions, although at the moment there are no such policies in the United States. The question of spillovers, or leakage, into nonfederal production is an empirical one. Consistent with estimates in the literature, our modeling indicates that leakage is incomplete, so raising federal fossil fuel royalties would in fact produce climate benefits.

Second, we estimate how large those benefits would be as a function of a royalty adjustment to account for climate costs. We examine two key metrics: total royalty receipts and (net) abated carbon. Because there is essentially no demand for new coal leases, we focus on federal oil and gas and find that total royalties follow a "Laffer curve": at low values of the climate royalty surcharge, total receipts increase, but at some point they plateau then decline. A subtlety is that carbon damages are typically measured in dollars per ton of CO_2, but federal royalties are assessed as a percentage of extraction revenue. Because the prices and carbon intensities of oil and gas differ, the same carbon fee ($/ton CO_2) implies different percentages of price for oil and for gas. We therefore consider three options for a climate cost assessment: applying the same carbon fee ($/ton CO_2) to both oil and gas; applying the same climate royalty surcharge (percentage points); or applying different carbon fees to oil and gas. All carbon fees or royalty surcharges are in addition to the current federal royalty rate.

Third, we address the question of how one might choose the carbon fee or, alternatively, the climate royalty surcharge.

One principle is to maximize royalty revenue. This principle has three justifications, two of which pertain to climate change. First, because royalty revenues are split equally between the federal government and the state of extraction, the revenue-maximizing rate maximizes the funds going to states to address the challenges that fossil-fuel extraction communities will face as a result of the broader energy transition, with or without a change in royalties. Second, we find that the revenue-maximizing rate significantly reduces emissions without shutting down fossil fuel leasing altogether. Third, putting climate concerns aside, the revenue-maximizing rate achieves a long-standing goal of obtaining value for the taxpayer from selling federally owned resources.[1]

A second principle for choosing the royalty surcharge is to maximize social welfare. Welfare maximization is a standard principle of optimal taxation theory (e.g., in the context of Pigovian taxation, Sandmo (1975)). Hein (2018) argues that the welfare maximization principle, applied to fossil fuel royalties, is consistent with the statutory mandate for the federal fossil fuel leasing program.

The third principle is that a royalty rate schedule be chosen to phase out new federal fossil fuel leasing by a specified date. This approach could, for example, be motivated by achieving a carbon budget for emissions from federal fossil fuels. As we discuss, there are legal questions about whether existing authorities authorize shutting down the program administratively, and in any event we do not have available a downstream carbon budget for the federal leasing program. We therefore approximate these ideas by considering a fee, or surcharge, that achieves 80% of the emissions reductions that would be achieved by a total cessation of new fossil fuel leases.

We address these issues using a model of federal and nonfederal oil and gas production developed by Prest (2021). We find that, if a single climate royalty surcharge is applied to both oil and gas, revenues are maximized by a surcharge of approximately 39%. Currently, oil and gas royalties are 12.5% onshore (18.75% offshore), values meant to compensate the taxpayer for the value of the extracted fuels. Adding the climate royalty surcharge to the 12.5% onshore taxpayer compensation rate yields a total federal royalty rate of 51.5%. We estimate that this would generate approximately $6 billion of additional royalty revenues annually on average from 2020-2050. We estimate that, under the revenue-maximizing rate, global emissions would fall by roughly 37 MMT CO_2e/year, approximately 40% of the reductions achieved by a leasing ban.

[1] CEA (2016) provides additional discussion of setting royalty rates to maximize revenue and estimates the revenue-maximizing royalty rate for new federal coal leases.

Further reducing emissions from the revenue-maximizing rate to the level arising from a leasing ban, reduces total royalty revenues by approximately $140-$240 per ton of additional CO_2e abated.

This revenue-maximizing common royalty surcharge is bracketed by welfare-maximizing common royalty surcharges of 19% and 44%, respectively computed using a $50/mt$CO_2$ Social Cost of Carbon (SCC; the interim Biden administration central value is $51) and a $125/mt$CO_2$ SCC (the New York State value, which uses a 2% discount rate instead of the 3% rate used for the interim Biden value). Also, we estimate that a common royalty surcharge of approximately 70% would lead to a reduction of emissions of 80% of what would be achieved by a cessation of all new leasing. There is considerable uncertainty around this 80%-reduction estimate, however, because it extrapolates well outside the range of the data on which our estimates rely.

1. The Federal Fossil Fuel Leasing Program

Federal fossil fuel leasing is governed by the Mineral Leasing Act of 1920 (MLA) and the Federal Land Policy Management Act of 1976 (FLPMA). The fossil fuel leasing program is administered by the Department of the Interior, with the Bureau of Land Management (BLM) managing onshore leasing and the Bureau of Ocean Energy Management (BOEM) managing offshore leasing. In 2019, fossil fuel production on federal lands comprised 40% of domestic coal production, 22% of domestic oil production, and 12% of domestic gas production.

Since the 1920s, the federal royalty rate for surface-mined coal and onshore oil and gas has been at the 12.5% floor established by the MLA; for underground coal, the royalty rate is 8%.[2] In 2008, deepwater offshore rates for new drilling leases were increased from 12.5% to 16.67%, then raised further in 2009 to 18.75%,[3] where they currently stand for drilling in depths exceeding 200 meters. Royalty rates are one of the terms of a lease. Federal coal leases have an initial term of 20 years, with 10-year renewals; federal oil and gas leases have a primary lease period of 10 years, with 2-year extensions. Once producing, a federal oil and gas lease is extended indefinitely so long as wells on it can produce oil or gas.

Royalties are the primary, but not sole, source of US government revenues from federal fossil fuel leasing. For onshore leases, tracts for potential mineral leasing are either identified by the BLM or nominated by private parties. Mineral rights to those tracts are first auctioned competitively to the highest bidder. If BLM receives at least one bid above $2 per acre, a value specified in nominal terms in 1920 in the MLA, then BLM awards the bid to the highest bidder. If no bid of $2 per acre is received, BLM makes the tract available on a first-come, first-serve

[2] https://www.blm.gov/programs/energy-and-minerals/coal/lease-management
[3] Congressional Research Service (2015)

basis. The bids in excess of the $2 minimum are called bonus bids. In addition, the BLM receives rents on the land of $1.50 per acre for the first five years of the lease and $2 per acre thereafter.[4]

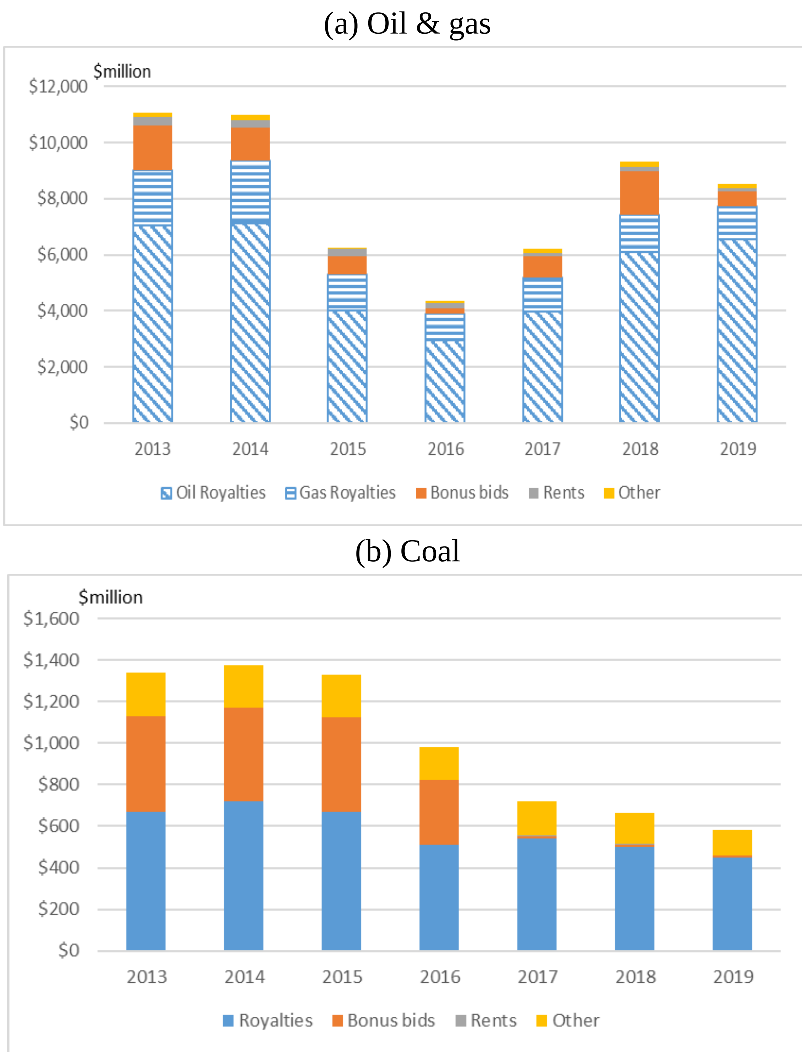
Receipts under the federal fossil fuel leasing program are shown in Figure 1. Of the three primary components of revenue – royalties, bonus bids, and rents – royalties comprised between 83% and 93% annually. In fiscal year 2019, the oil and gas program received $7.745 billion in royalties, of which 85% was from oil, $496 million in bonus bids, and $130 million in rents. Total receipts from the coal program are an order of magnitude less than for the oil & gas program. Since FY 2017, coal bonus bid receipts have been less than $15 million annually, down from $460 million in FY 2013, indicating the drying up of demand for new federal coal leases.[5]

The basis for current federal fossil fuel leasing royalties is ensuring a fair return to the taxpayer for the right to extract the minerals from federal lands. Under FLPMA, the concept of fair return is linked to "fair market value".[6] Because burning federal fossil fuels imposes costs on others, absent a price on carbon the market value does not account for the damages imposed by using federal fossil fuels. This suggests, as indicated in the Biden EO, adjusting royalty rates to reflect the costs of those climate damages.

There are various legal considerations regarding incorporating climate costs into royalty rates, or ceasing fossil fuel leasing altogether, through administrative actions. The MLA specifies a royalty rate "of not less than 12.5 percent" but does not specify a ceiling.[7] Statutory language and historical practice establishes the basis for considering environmental impacts in leasing decisions. At the same time, BLM manages federal lands under FLPMA, with a "multiple use" policy. Specifically, FLPMA states that oil, gas, and other minerals extraction programs should support "the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security and environmental needs".[8]

[4] See GAO (2020) for details.
[5] Coal leasing rules are different than oil and gas. BLM sets but does not disclose a minimum bonus bid based on its assessment of the value of a tract, and if no bid is received above that floor, the auction fails. GAO (2013) found that, of the 107 coal tracts leased from 1990 to 2013, 96 had a single bidder. A tract with a failed auction can be, and frequently is, nominated again, providing the (typically sole) bidder with multiple opportunities to bid above the floor. Our focus is on oil and gas leasing, so we do not pursue these issues further, see however CEA (2016), Hein and Howard (2016), and Gerarden, Reeder, and Stock (2016) for additional discussion.
[6] FLPMA states as policy that "the United States receive fair market value of the use of the public lands and their resources unless otherwise provided for by statute." (43 U.S.C. § 1701(a)(9)).
[7] US Code Title 30, Section 226(b)(1)(A).
[8] US Code Title 30, Section 21a.

Figure 1. Federal fossil fuel program revenues, FY 2013-2019



Notes: "Other" includes inspection and permit fees, audits and late charges, and miscellaneous revenues.
Source: US Department of the Interior at https://revenuedata.doi.gov/downloads/federal-revenue-by-company/

In 2016, the Department of the Interior issued a moratorium on new leases while it conducted a programmatic environmental review of the coal leasing program (DOI 2017). The DOI explicitly suggested a royalty surcharge, or adder, as one way to account for climate damages from burning the fossil fuels. Krupnick et al. (2016) analyze the legal basis for changing federal coal royalties administratively and conclude that DOI has the statutory and regulatory authority to impose a carbon charge via the royalty rate. Hein (2018) reaches a similar conclusion for federal oil and gas leasing as well as coal. At the same time, the multiple use mandate under FLPMA could be interpreted as limiting administrative authority to permanently end leasing or to set a royalty rate tantamount to permanently ending leasing. We take no stand on the legal issues, other than to note that a climate royalty surcharge at some value less than a value tantamount to a leasing ban might be attractive from a legal perspective.

2. The Economics of Fossil Fuel Leasing Reform[9,10]

A climate royalty surcharge adjusts the price of the extracted fossil fuel so that it reflects the damages caused by burning it, that is, it partially or completely internalizes the carbon externality. Because the fair return principle does not incorporate climate considerations, any adjustments to the royalty rate to account for climate costs would be in addition to the current rate.

A climate royalty surcharge would increase the cost of production on federal lands and waters. As a result, some drilling projects might become unprofitable, so the demand for federal drilling leases would fall. The resulting decline in new leasing would reduce production on federal lands, which would decrease total (federal plus nonfederal) production. Because the decrease in production would tighten total supply, the market price of oil and gas would rise. This increase in price would pull in additional nonfederal production, partially offsetting the decrease in production on federal lands.

In general, nonfederal production will increase by less than the decline in federal production because, at the higher price, consumer demand falls, so the total quantity of oil and gas used declines. From the perspective of reducing CO_2 emissions, the policy of incorporating climate considerations into the federal royalty rate results in "leakage," because a fraction of the decline in federal production is offset. The leakage rate λ is the fraction of the reduction in emissions from federally produced oil and gas that is offset by emissions from non-federally produced oil and gas. The leakage rate is determined by supply and demand. On the supply side, if the lost

[9] The economics literature on incorporating climate considerations into fossil fuel leasing reform consists of Gerarden, Reeder, and Stock (2020), Erickson and Lazarus (2018), and Prest (2021). Gerarden, Reeder, and Stock (2020) (the published version of Gerarden, Reeder, and Stock (2016)) consider climate royalty surcharges in the federal coal program and their interaction with demand-side CO_2 regulation. Erikson and Lazarus (2018) estimate potential reductions from the cessation of coal and oil (but not gas) leasing by 2030, using a static constant-elasticity model that drew from estimates from the literature. Prest (2021) developed an eight-component combined model oil and gas leasing, where each component is separately econometrically parameterized, to estimate the effect of percentage-based and SCC-based royalty surcharges on emissions, production, and royalties annually through 2050. This research fits into a growing body of research on supply-side climate policies, see Lazarus and van Asselt (2018) for a survey.

[10] At a conceptual level, royalty rate determination under the concept of maximizing taxpayer return is part of the theory of contracting and regulation with asymmetric information. A textbook treatment of this material is Laffont and Tirole (1994), which makes the connection between auctions and regulation in a setting of asymmetric information and moral hazard. For a review of the theoretical literature on royalty auctions, see Skrzypacz (2013). Evidence on the relation between auction structure and government revenues is summarized in Haile, Hendricks, and Porter (2010). For additional references to auction theory in the context of US oil and gas lease auctions (a bonus bid auction not a royalty auction), see Compiani, Haile, and Sant'Anna (2020).

federal production is readily replaced by nonfederal production at nearly the same cost (that is, if supply is elastic), then leakage will tend to be high. On the demand side, if the demand for oil and gas is insensitive to price (that is, if demand is inelastic), then leakage will tend to be high.

There are two ways to quantify an adjustment that reflects the climate costs of federal fossil fuels. The first, which we refer to as a carbon fee, is by a fee assessed per unit of production (e.g., dollars per barrel of oil), where the fee is based on the monetized damages from burning that fuel, which is in turn based on the carbon content of that fuel. The second, which we term a climate royalty surcharge, is an *ad valorem* assessment, so that payments are a percentage of sales. The carbon fee framework aligns with conventional applications of carbon pricing, whereas the climate royalty surcharge aligns with the current *ad-valorem* percentage assessment of federal royalties. Given a base price, a carbon fee can be recast as a climate royalty surcharge and vice versa.

2.1 Carbon fees

Basic economic principles provide some guidance about setting carbon fees in the presence of a carbon externality. Absent leakage – for example, if a fee (or tax) could be applied to all fossil fuels, federal and nonfederal – the optimal policy in a standard model of welfare maximization is to set the carbon fee equal to the marginal value of the avoided climate damage (e.g., Nordhaus (1982)). The marginal damage is the net present value of current and future monetized climate damages, that is, the Social Cost of Carbon (SCC). The units of this carbon fee are dollars per ton CO_2. We will refer to this as the welfare-maximizing carbon fee, although it should be kept in mind that the model in which this maximizes welfare is a simple one that abstracts from other externalities in the energy sector, such as research and network externalities, technology growth, and from multiple real-world frictions and constraints.

With leakage, the optimal carbon fee no longer equals the SCC. Instead, the marginal damages avoided are those from the *net* emissions avoided. These net climate damages avoided are $(1-\lambda)$SCC for each ton of direct (or gross) emissions reductions, where λ is the leakage rate. Thus, the carbon fee τ, in dollars per ton CO_2e, to apply to the covered fuel is $\tau = (1-\lambda)$SCC (Holland 2012).

The situation is more complicated when there are interactions in the supply of fuels, as is the case for oil and gas because some wells produce both oil and gas. Because of co-production, a change in market circumstances in one fuel will affect production of the other fuel. Thus, the welfare-maximizing carbon fee for oil and gas takes into account the cross-effects resulting from co-production. The resulting pair of welfare-maximizing per-ton carbon fees, τ_{oil} and τ_{gas}, are given in the appendix.

Note that the carbon fee τ is measured in units of dollars per ton of CO_2e. One way to incorporate climate considerations into payments for federal oil and gas production would be to have a two-part payment, with one part being the current 12.5% (or 18.75% offshore) royalty payment and a second part for the carbon fee. The first part is an *ad valorem* royalty, the second part an assessment per quantity unit (e.g., dollars per barrel) of oil or gas produced.[11] In native quantity units, the fee would be $e\tau$, where e is the carbon intensity of the fuel (e.g., tons CO_2e per barrel).

2.2. Implied climate royalty surcharge

Historically, federal fossil fuel royalties have been a percentage of sales, and there might be legal or administrative reasons to continue an *ad valorem* assessment. A per-ton CO_2e carbon fee τ can be converted to an *ad-valorem* climate royalty surcharge r using the emissions intensity and price. For example, for oil, let P_{oil} denote a benchmark price. Then the climate royalty surcharge, r_{oil}, corresponding to a carbon fee τ_{oil}. is $r_{oil} = \tau e_{oil}/P_{oil}$, where e_{oil} is the emissions intensity of oil (tons CO_2e per barrel). In practice, the benchmark price P could be a per-dollar wholesale price of the fuel at the date of issuance of the lease. The total royalty rate is the taxpayer compensation portion (12.5%) plus the climate royalty surcharge

Because oil and gas have different carbon intensities and prices, a single carbon fee implies different values of the carbon royalty surcharge for oil and gas. Historically, however, royalty rates have been the same for oil and gas for 100 years, and there might be legal or administrative reasons to have the same *ad-valorem* climate royalty surcharge for both oil and gas. Whether the royalty surcharges differ across fuels or are the same, at the welfare-maximizing climate royalty surcharge, its marginal cost, in terms of royalty revenue, equals its marginal climate benefit. The formula for the optimal common climate royalty surcharge when there is coproduction of oil and gas and leakage across fuels is given in the Appendix.

2.3. Determining the climate royalty surcharge

The effect of federal leasing reform on emissions is one important consideration, but so is the effect of that reform on communities traditionally supported by fossil fuel extraction on federal lands. Half of federal onshore royalty revenues is shared with the states (less a 2% administrative charge; 90% for Alaska and special arrangements for Gulf of Mexico drilling), and those states also receive revenues from separate state severance taxes, royalties, and/or other fees. As the energy transition progresses, states and communities reliant on federal extraction will face fiscal and related challenges. Although federal resources could be provided to support state transition through legislation, adding a climate royalty surcharge would automatically do so administratively.

---

[11] Sandmo (1975) shows that that, absent cross elasticities, the optimal tax is a linear combination of the Ramsey revenue raising component ("taxpayer compensation") and the marginal damage component.

With these observations in mind, we consider four principles for setting the climate royalty surcharge.

The first is to choose the climate royalty surcharge to maximize royalty revenues. This approach maximizes extraction revenues returned to states. Setting the climate royalty surcharge to maximize revenues also results in large emissions reductions. This principle also achieves the traditional goal of fully compensating the taxpayer for private extraction of public resources.[12]

The second is to choose the climate royalty surcharge to maximize social welfare. In general, this entails choosing the policy instrument so that the marginal cost equals its marginal benefit in avoided climate damages. This approach has the virtue of being grounded in the classic theory of optimal taxation. That framework, however, abstracts from many real-world complications, such as externalities other than the carbon externality, which are important in climate applications.

Third, much of the world has adopted a net-zero targeting approach to guiding climate policy, with target dates of 2050 (EU) or 2060 (China). Under a net-zero targeting approach, the royalty surcharge should be set on a path to phase out (non-offset) federal fossil fuel leasing. Cognizant of the legal question of whether fossil fuel leasing can be ended administratively under FLPMA, we implement this approach by considering a royalty surcharge that does not entirely shut down the program but instead achieves 80% of the global emissions reductions achieved by a ban on new leasing.

Fourth, the climate royalty surcharge could be chosen so that total emissions from federal fossil fuels were constrained by a carbon budget. To achieve this budget, the carbon surcharge would rise over time so that at some point federal production would end. Implementing this approach requires a carbon budget for federal fossil fuels, however developing such a budget goes beyond the scope of this paper so we do not pursue this principle further.

2.4. Interaction with lease auctions

An increase in the federal royalty rate would interact with the federal competitive auction process, plausibly leading to lower bonus bids at auction. The *ad-valorem* royalty and the bonus bid have different risk properties, in particular the royalty is a risk-sharing arrangement in which the government bears the risk that the tract might not be productive, whereas under the bonus bid the bidder bears that risk; in addition, the bonus bid is paid up front, whereas royalties are paid

[12] CEA (2016) interprets the fair return mandate as maximizing value of the least to the taxpayer. This is consistent with requirements for competitive auctions, for example of the infrared spectrum. CEA (2020) calculates a revenue-maximizing royalty adjustment for federal Powder River Basin coal.

later, when the lease is producing. As a result, an expected increase in royalty payments from a royalty surcharge would lead to a partial, but not necessarily complete, decrease in bonus bids.

Empirically, these interactions are likely to have a limited effect on projected total revenues. As shown in Figure 1, from 2013 to 2019, oil and gas royalty revenues averaged 7.5 times bonus bids; in FY 2019, oil and gas royalty receipts were $7.745 billion, whereas bonus bids were only $496 million. Thus, the scope for a decline in bonus bids offsetting an increase in royalties is limited.

3. Estimated Effects of an Oil and Gas Climate Royalty Surcharge on Production, Emissions, and Revenue

We now turn to a quantitative assessment of the effect of a climate royalty surcharge on production, emissions, and revenue for new oil and gas leases; we exclude coal because of the absence of current and anticipated future demand for new coal leases.

Our calculations are based on Prest's (2021) model of oil and gas production on federal lands. The model has three stages of production (drilling, well completion, and production) for wells differentiated by federal/nonfederal, oil-directed/gas-directed, and onshore/offshore, for a total of eight well types. An important parameter in assessing the effect of the royalty surcharge is the elasticity of demand. Historically, the demand for oil has been inelastic because there are few alternatives to gasoline, diesel, or jet fuel. Looking ahead, as alternatives like electric vehicles become more common, oil demand could become more elastic. Similarly, in 2019, 36% of natural gas was used for electricity, and as renewable generation increases the electricity demand for gas could become more elastic. For these reasons, we use low demand elasticities as our base case, but also consider a scenario with more elastic demand.[13] The demand elasticities are the same as in Prest (2021). For the base case, we use demand elasticities of -0.2 for both oil and gas, based on several empirical estimates and surveys of the literature (Erickson and Lazarus 2018, Hamilton 2009, Bordoff and Houser 2015, Arora 2014, and Auffhammer and Rubin 2018). For the high elasticity case, we use estimates from the higher end of the literature; these are -0.51 for oil (Balke and Brown 2018, Metcalf 2018, Allaire and Brown 2012) and -0.42 for gas (Hausman and Kellogg 2015, Metcalf 2018).

[13] The model in Prest (2021) combines a detailed, econometrically calibrated simulation model of US supply with a rest of world (ROW) module with responsive supply based on the IEA 2019 World Energy Outlook. This accounts for cross-price effects on US supply (e.g., how oil prices affect both oil production and gas co-production, and vice versa), dynamics (how changes to prices or policies today affect drilling and production over time), and leakage (e.g., how changes in production on federal lands if offset by increases from nonfederal and foreign suppliers). For details, see Prest (2021).

3.1. Common carbon fee

We first consider assessing production on new leases a carbon fee expressed in 2020 dollars per metric ton of CO_2, where the per-ton CO_2 fee is the same for oil and gas.

Table 1 translates selected per-ton fees into assessments expressed in the native price units of the fuel ($/barrel for oil, $/thousand cubic feet, or mcf, for gas). For comparison purposes, these rates are also provided for coal, although coal is not included in subsequent calculations.

Table 1. Bulk fuel prices and carbon fees in fuel price units

	Oil ($/barrel)	Natural gas ($/thousand cubic feet)	Coal ($/short ton)
2019 wholesale price	$57	$2.56	$12.5
12.5% royalty rate	$7.13	$0.32	$1.56
18.75% royalty rate	$10.69	$0.48	$2.34
$25 carbon fee	$10.75	$1.65	$42.41
$50 carbon fee	$21.50	$3.30	$84.42
$75 carbon fee	$32.25	$4.95	$127.23

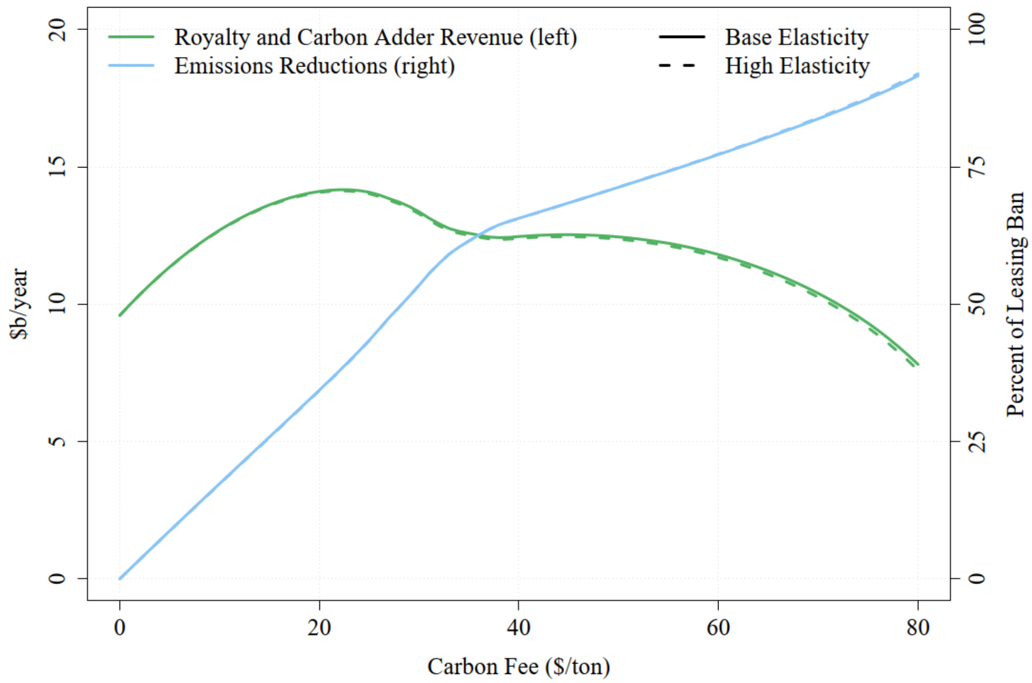
Notes: Oil price is West Texas Intermediate spot price; natural gas is Henry Hub spot price; and coal is 8800 Btu/lb Powder River Basin subbituminous spot price. Prices are 2019 averages from the Energy Information Administration. Royalty rates are 12.5% for surface-mined coal and for onshore oil and gas and are 18.75% for deepwater offshore oil and gas. These rates are converted to native price units using the 2019 price in the first line and the carbon intensities for the relevant fossil fuel.

Figure 2 summarizes the effect of a carbon fee on total royalty revenues (base royalty rate plus carbon fee) and CO_2e emissions, for both base (low) and high elasticities. The business-as-usual (BAU; no new policy) scenario corresponds to the carbon fee equaling zero; under this assumption, average oil and gas royalties are projected to be $9.6 billion/year on average from 2020-2050. The figure also shows annual average revenues under a leasing ban. Under the new leasing ban, production continues under existing leases, which generates royalties, and the 30-year average royalties are $4.1 billion/year. Emissions are shown as reductions from BAU, as a percentage of the reductions under a leasing ban.

Total revenues follow a Laffer curve: as the carbon fee increases from zero, total royalty revenues increase, then peak, then decline to below BAU levels, as the decline in production offsets the revenues generated by a higher carbon fee. Total revenues are maximized at a carbon fee of $22 per metric ton CO_2e, above which revenues drop off sharply. At a sufficiently high price, new production drops to zero, so royalties fall below BAU royalties. At their peak, increasing the carbon fee increases average annual royalties by about $4.6 billion compared with

BAU. Under current law, about half of this would be distributed to the states and half would be retained by the federal government.[14]

Figure 2. 2020-2050 average royalty revenues (left axis) and emissions reduction relative to those achieved by a leasing ban (right) under a common per-ton carbon fee



Note: Annual average emissions reductions under a leasing ban are estimated to be 85 MMton CO_2e/year in the low-elasticity base case and 147 MMton CO_2e/year in the high-elasticity case.

A nuance in this revenue Laffer curve is that it has two peaks, a global maximum at approximately $22/ton CO_2e, in addition to a local maximum at $45. The peak around $22/ton is associated with gas production declining more rapidly than oil in response to the per-ton carbon fee: as seen in Table 1, a $25 carbon fee is 64% of the price of gas, but only 19% of the price of oil. Because the two fuels have Laffer curve peaks at different values of the carbon fee, the composite Laffer curve has two peaks.

Total emissions fall as the carbon fee increases. For lower values of the carbon fee, the reduction in emissions is steeper than for higher values. The reason for this nonlinear behavior is the same as for the double peak in the revenue Laffer curves: at low levels, the carbon fee reduces both oil and gas production, but at higher levels, gas-directed leasing largely stops so the only gas production is coproduction from oil-directed wells.

[14] Much of the federal share of onshore royalties—40 percentage points of the 50% federal share—is deposited in the Reclamation Fund, which supports irrigation and hydropower projects. See https://revenuedata.doi.gov/how-revenue-works/reclamation

The results in Figure 2 are insensitive to the demand elasticity. The effect on total emissions depends strongly on the elasticity, however: under a leasing ban, global emissions are estimated to fall by 85 and 147 MMt CO_2e/year for the base and high elasticity cases respectively. At the revenue-maximizing carbon fee, emissions reductions are about 38% of the emissions reductions achieved by a leasing ban, corresponding to 32 to 56 MMt CO_2e/year in the low elasticity base case and high elasticity cases, respectively.

Figure 3 shows time paths of revenues under a revenue-maximizing carbon fee, a leasing ban, and BAU. Because the carbon fee applies to only new leases, the effects of the programs phase in over time. The effects on revenues, whether positive (under a $22/ton carbon fee) or negative (under a leasing ban) are smaller than plus or minus $1 billion per year through 2025. The gap widens significantly after 2030.[15]

Figure 3. Time path of total royalty revenues for revenue-maximizing carbon fee (billions of 2020 dollars)

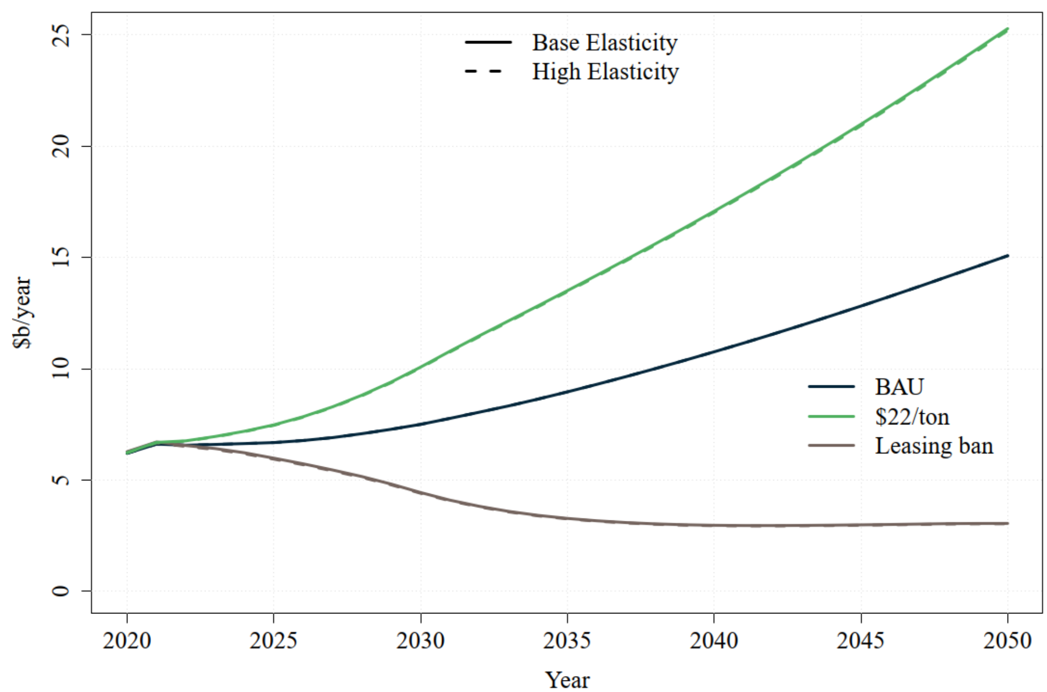


Table 2 provides the values of the revenue-maximizing and welfare-maximizing carbon fees, along with their climate and revenue effects, where the estimates are for the low elasticity base case. The welfare-maximizing fee depends on the Social Cost of Carbon. The table uses two SCC values: $50/ton, closely reflecting the interim Biden Administration central value (3%

[15] Even under a leasing ban, royalties flatten out over time as wells on existing leasing continue to produce, albeit at declining levels. Revenues under the leasing ban flatten out after 2040. This is the net result of two offsetting factors: production on existing leases declines annually as wells are exhausted, but under this price path, oil and gas prices rise at a similar rate.

discounting) for emissions in 2020 in 2020 dollars, and $125, which uses the same models and assumptions but a 2% discount rate.[16] The welfare-maximizing carbon fees are $13/ton and $33/ton for the two SCC values, bracketing the $22 revenue-maximizing value. Emissions reductions depend strongly on the fee, with the $33/ton fee yielding emissions reductions that are nearly 60% of the reductions under a leasing ban.

Table 2 also shows a case not discussed so far, which is raising the royalty rate for onshore extraction to match the 18.75% rate for offshore oil and gas. This change increases taxpayer receipts somewhat, however the gains in revenues are small compared with the revenue-maximizing rate. The decline in emissions resulting from this alignment of onshore and offshore rates is quite modest.

Table 2. Revenue-maximizing and welfare-maximizing carbon fees, under a common carbon fee across oil and gas, base elasticities

	Carbon fee ($/ton CO_2e)	Oil climate royalty surcharge	Gas climate royalty surcharge	Emissions reduction (% of leasing ban)	Emissions reduction (MMt CO_2e/yr)	Royalties ($B/year)
BAU	$0	0%	0%	0%	0	$9.6
Revenue-maximizing	$22	17%	57%	38%	32	$14.2
Raise onshore O&G to 18.75%	na	na	na	5%	4	$10.6
Welfare-maximizing SCC=$50	$13	10%	34%	22%	19	$13.3
Welfare-maximizing SCC=$125	$33	25%	86%	59%	50	$12.8
Emissions reduction 80% of ban	$64	48%	165%	80%	68	$11.3
Leasing ban	na	na	na	100%	85	$4.1

3.2. Common climate royalty surcharge

As can be seen in Table 2, imposing the same carbon fee on oil and gas implies quite different climate royalty surcharges for the two fuels. We now consider applying the same climate royalty surcharge to oil and gas, which aligns with historical practice.

Figure 4 shows total royalty revenues and emissions reductions as a function of a common royalty rate. Revenues again follow a Laffer curve, but without the double peak because the common royalty rate implies a smaller carbon charge on gas than on oil. The revenue-maximizing royalty surcharge is 39%.

[16] https://www.dec.ny.gov/press/122070.html

Figure 4. 2020-2050 average royalty revenues (left axis) and emissions (right) under a common climate royalty surcharge

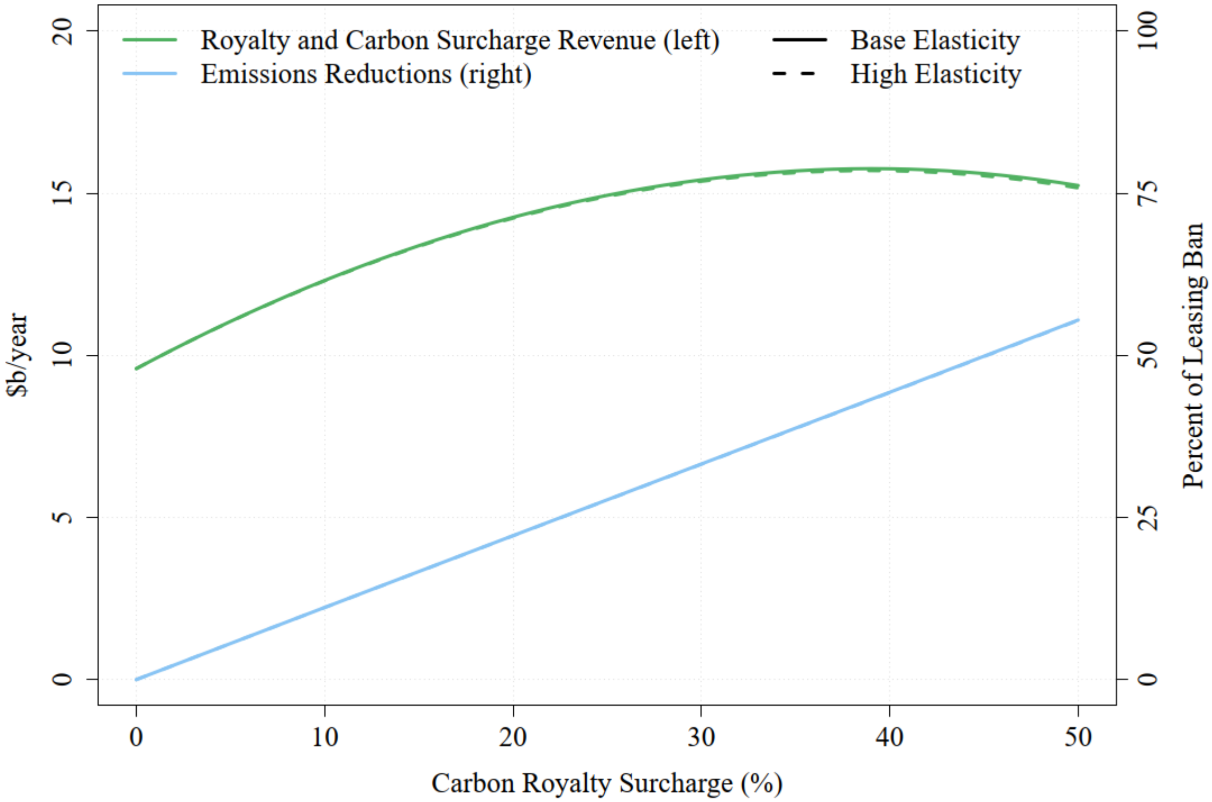


Figure 5 shows the time path of revenues for the revenue-maximizing 39% common royalty surcharge, and revenues and emissions reductions for various common royalty surcharges are summarized in Table 3.

The revenue-maximizing climate royalty surcharge, 39%, is slightly less than the welfare-maximizing surcharge of 44% when using an SCC of $125/ton CO_2e. The emissions reductions at the welfare-maximizing surcharge is half that of a leasing ban. Compared to a common carbon fee, a common royalty surcharge implies a relatively higher tax on higher-emissions and higher-value oil than on gas. As a result, the revenue-maximizing climate surcharge results in higher revenues and slightly more emissions reductions than the revenue-maximizing carbon fee.

Figure 5. Time path of total royalty revenues for 39% climate royalty surcharge (billions of 2020 dollars)

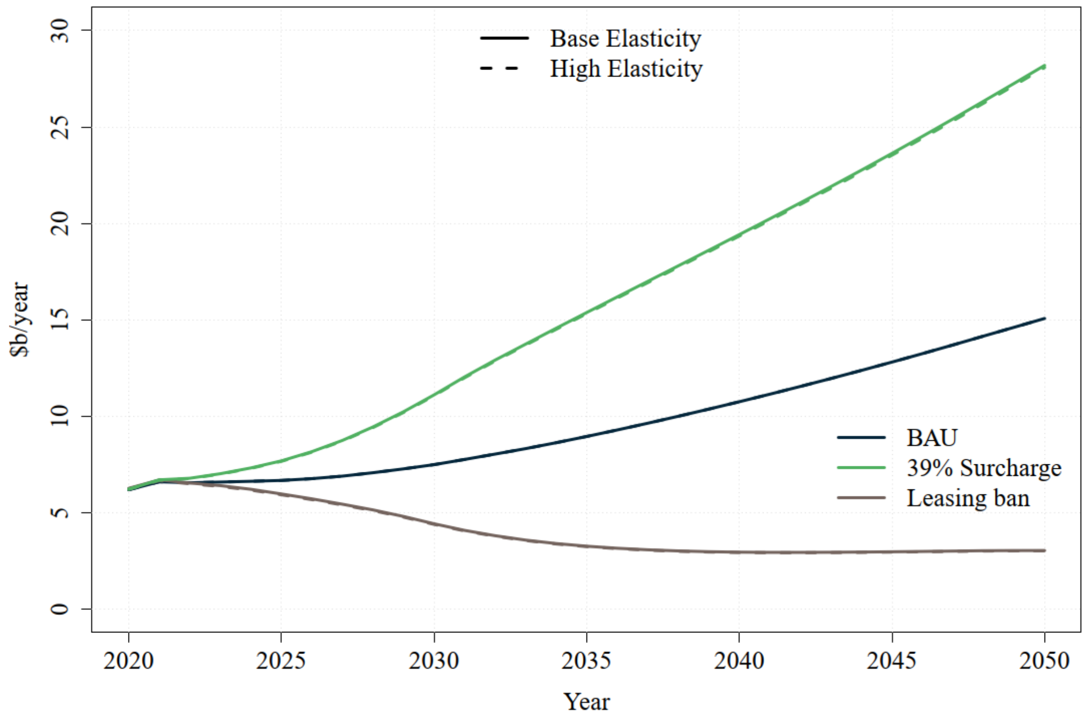


Table 3. Revenue-maximizing and welfare-maximizing climate royalty surcharge, under a common surcharge across oil and gas

	Climate Royalty Surcharge	Oil: Equivalent carbon fee ($/ton CO2e)	Gas: Equivalent carbon fee ($/ton CO2e)	Emissions reduction (% of leasing ban)	Emissions reduction, (MMt CO_2e/yr)	Royalties ($B/year)
BAU	0%	$0	0%	0%	0	$9.6
Revenue-maximizing	39%	$52	$15	43%	37	$15.8
Welfare-maximizing SCC=$50	19%	$25	$7	21%	18	$14.1
Welfare-maximizing SCC=$125	44%	$58	$17	49%	42	$15.7
Emissions reduction 80% of ban	71%	$94	$28	80%	68	$9.4
Leasing ban	na	na	na	100%	85	$4.1

3.3. Different carbon fees for oil and gas

The calculations so far assume either the same carbon fee (dollars per ton CO_2e) or the same climate royalty surcharge (in percent) for oil and gas. In principle, however, the fees or surcharges could be calculated separately for the two fuels. Because of coproduction of oil and gas, the effects of the two separate surcharges interact. For example, a surcharge on oil only, but not on gas, would reduce gas production because of reduced drilling of wells that produce both oil and gas. As a result, the effects of a different surcharge on each fuel needs to be analyzed jointly.

Table 4 presents the effect of distinct oil and gas carbon fees on additional royalty revenues for the base case elasticity. Because of the interactions and the different types and locations of wells, the interaction between the two carbon fees is complex. For a given value of the oil fee, as the gas fee increases, total royalties initially increase, then decline as gas-directed drilling diminishes. However, because of gas co-production at oil-directed wells, total revenues revive as the gas carbon fee further increases, for a double peak along almost every row of Table 4. With a single common fee, total royalties were maximized at \$22/ton CO_2e, yielding royalty revenues of \$14.2 B/year. According to Table 4, total revenues could be further increased by imposing higher fee on oil of \$50/ton and reducing the gas surcharge to \$5/ton to \$16.2 B/year.

Table 5 presents the effect of distinct oil and gas carbon fees on emissions, both for the base case elasticities. The revenue-maximizing carbon fee of \$50 for oil and \$5 for gas yields similar emissions reduction to the single-fee maximum of \$22 in Table 2, 37 MMT/yr compared to 32 MMT/yr. However, the composition of these emissions reductions differs, with a high oil fee and low gas fee placing greater emphasis on reducing oil production, rather than gas.

Table 4. Effect of distinct oil and gas carbon fees on total revenues (change relative to BAU)

		Gas carbon fee ($/ton)										
		$0	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50
Oil carbon fee ($/ton)	$0	$0.0	$0.6	$1.0	$1.2	$1.3	$1.1	$0.7	$0.3	$0.5	$0.8	$1.2
	$10	$2.4	$2.8	$3.1	$3.2	$3.1	$2.8	$2.1	$1.6	$1.6	$1.9	$2.3
	$20	$4.3	$4.6	$4.7	$4.7	$4.5	$4.0	$3.1	$2.4	$2.4	$2.7	$3.0
	$30	$5.6	$5.8	$5.9	$5.7	$5.4	$4.8	$3.8	$2.9	$2.8	$3.1	$3.3
	$40	$6.4	$6.5	$6.5	$6.2	$5.8	$5.1	$4.0	$3.0	$2.9	$3.1	$3.3
	$50	$6.6	$6.6	$6.4	$6.1	$5.7	$4.9	$3.7	$2.6	$2.5	$2.7	$2.9
	$60	$6.0	$5.9	$5.7	$5.3	$4.8	$4.1	$2.8	$1.8	$1.6	$1.8	$1.9
	$70	$4.4	$4.2	$4.0	$3.6	$3.1	$2.4	$1.3	$0.3	$0.2	$0.3	$0.4
	$80	$0.9	$0.7	$0.5	$0.2	-$0.2	-$0.8	-$1.5	-$2.1	-$2.2	-$2.2	-$2.1
	$90	-$3.5	-$3.6	-$3.8	-$4.0	-$4.2	-$4.4	-$4.7	-$4.9	-$4.9	-$4.9	-$4.9

Table 5. Effect of distinct oil and gas carbon fees on emissions.

Oil carbon fee ($/ton)	Gas carbon fee ($/ton): $0	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50
$0	0	-4	-9	-13	-18	-24	-31	-36	-38	-38	-38
$10	-6	-10	-15	-19	-24	-29	-36	-41	-42	-42	-42
$20	-13	-17	-21	-25	-29	-34	-40	-45	-47	-47	-47
$30	-19	-23	-27	-31	-35	-40	-45	-50	-51	-51	-51
$40	-26	-30	-34	-37	-41	-45	-51	-55	-56	-56	-56
$50	-34	-37	-41	-44	-47	-51	-56	-60	-61	-61	-61
$60	-42	-45	-48	-51	-54	-58	-62	-65	-66	-66	-66
$70	-52	-54	-57	-59	-62	-65	-68	-71	-71	-71	-71
$80	-65	-67	-68	-70	-72	-74	-76	-78	-78	-78	-78
$90	-78	-79	-80	-81	-82	-83	-83	-84	-84	-84	-84

Table 6 is the counterpart of Table 2 when there are distinct carbon fees. As derived in the appendix, the welfare-maximizing pair of carbon fees depends on the SCC, on direct and cross-price effects, for instance how a fee on oil affects gas through co-production, and on leakage rates. We solve for the optimal price numerically along the grid of oil and gas fees shown in Tables 4 and 5. At a $50/ton SCC based on a 3% discount rate, the welfare-maximizing fees are about $20/ton for oil and $15/ton for gas. These amount to about $9/barrel gas and $1/mcf of gas, which in turn are roughly equivalent to a climate surcharge of 15% for oil and 39% for gas. This achieves 29% of the emissions reductions that a leasing ban would achieve and raise $4.7 B/year in revenue above BAU. At a $125/ton SCC, the welfare-maximizing fees are twice as large at about $40/ton for oil and $30/ton per gas, corresponding to climate royalty surcharges of approximately 30% for oil and 77% for gas. This achieves about 60% of the emissions reductions that a leasing ban would and raises $4 b/year in revenue above BAU, compared to the $5.5 b/year loss in revenues under a ban.

Table 6. Revenue-maximizing and welfare-maximizing fuel-specific carbon fees

	Oil carbon fee ($/ton CO_2e)	Gas carbon fee ($/ton CO_2e)	Oil: Equivalent climate royalty surcharge (%)	Gas: Equivalent climate royalty surcharge (%)	Emissions reduction, % of ban	Emissions reduction (MMt CO_2e/yr)	Royalties ($B/year)
Revenues-maximizing	$50	$5	38%	13%	44%	37	$16.2
Welfare-maximizing, SCC = $50	$20	$15	15%	39%	29%	25	$14.3
Welfare-maximizing, SCC = $125	$40	$30	30%	77%	60%	51	$13.6
Leasing ban	na	na	na	na	100%	85	$4.1

Notes: Entries are computed using the grid of separate gas and oil climate royalty surcharges in Table 4.

4. Discussion

Looking across the multiple cases – the three principles for determining the surcharge, the low and high demand elasticities, and whether there is a common carbon fee, a common royalty surcharge, or a different carbon fee for oil and gas – suggests three main conclusions.

First, all cases imply substantial climate surcharges, typically in the 20% to 50% range. These surcharges are in addition to the current royalty rate of 12.5% (18.75% offshore). The current royalty rates, which for onshore oil and gas and surface-mined coal date to the MLA of 1920, neither take climate costs into account nor do they maximize revenue to the taxpayer. It is worth noting that any of the calculations here could have yielded a corner solution in which an increase in the royalty rate decreased royalty revenues, but that is not the case. Thus, all the royalty surcharges considered have both a traditional taxpayer return justification in addition to a climate cost justification.

Second, for surcharges based on revenue or welfare maximization, both the revenue increases and emissions reductions are substantial compared to the no-policy BAU scenario. For example, for a common royalty surcharge, the revenue-maximizing surcharge of 39% reduces emissions by more than 40% of what would be achieved by a royalty ban, while increasing annual average revenues by $6.2B, compared to BAU.

Third, although the revenue-maximizing royalty surcharges and projected revenues with a surcharge do not depend significantly on the elasticity of demand, projected emissions reductions do. For the revenue-maximizing common surcharge of 39%, we estimate emissions reductions range from 37 to 63 MMton CO_2e/year. As a point of comparison, these round to one percent of US CO_2 emissions in 2019.

The welfare-maximizing common surcharge is estimated to be 19% and 44% for $50/ton and $125/ton SCCs respectively. Welfare could be further increased by charging separate fees or surcharges by charging $20-40/ton fees for oil production and lower fees of $15-$30/ton for gas. In surcharge terms, these separate charges are equivalent to 15-30% surcharges for oil and 40-80% surcharges for gas. These would reduce emissions by 25 to 88 MMt CO2e/year and raise $4 to $5 billion/year.

References

Allaire, M., and S.P.A. Brown (2012). "Eliminating Subsidies for Fossil Fuel Production: Implications for U.S. Oil and Natural Gas Markets." Resources for the Future Issue Brief.

Arora, V. (2014). "Estimates of the Price Elasticities of Natural Gas Supply and Demand in the United States." MPRA Paper No. 54232.

Auffhammer, M. and E. Rubin (2018). "Natural Gas Price Elasticities and Optimal Cost Recovery Under Consumer Heterogeneity: Evidence from 300 Million Natural Gas Bills." Energy Institute at Haas Working Paper 287.

Balke, N.S. and S.P.A. Brown (2018). "Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model." *Energy Policy* 116: 357 - 372.

Bordoff, J. and T. Houser (2015). *Navigating the U.S. Oil Export Debate*. Manuscript, Columbia Center for Global Energy Policy.

Compiani, P., Haile, P., and Sant'Anna, M. (2020). "Common Values, Unobserved Heterogeneity, and Endogenous Entry in US Offshore Oil Lease Auction," *Journal of Political Economy* 128 (10), 3872–3912.

Council of Economic Advisers (2016). "The Economics of Coal Leasing on Federal Lands: Ensuring a Fair Return to Taxpayers" at https://obamawhitehouse.archives.gov/sites/default/files/page/files/20160622_cea_coal_leasing.pdf

Erickson, P. and M. Lazarus (2018). "Would constraining US fossil fuel production affect global CO2 emissions? A case study of US leasing policy." *Climatic Change* 150(1-2): 29-42.

Fæhn, T. et. al. (2017). "Climate Policies in a Fossil Fuel Producing Country: Demand versus Supply Side Policies," *The Energy Journal* 38(1): 77-102.

Gerarden, T., S. Reeder, and J.H. Stock (2020). "Federal Coal Program Reform, the Clean Power Plan, and the Interaction of Upstream and Downstream Climate Policies," *American Economic Journal – Economic Policy* 12(1), 167-199.

Gillingham, Kenneth, James Bushnell, Meredith Fowlie, Michael Greenstone, Charles Kolstad, Alan Krupnick, Adele Morris, Richard Schmalensee, and James H. Stock. (2016). "Reforming the US Coal Leasing Program." *Science*, 354(6316): 1096-1098.

Hamilton, J.D. (2009). "Understanding Crude Oil Prices." *Energy Journal*, 30(2): 179-206.

Hausman, C. and R. Kellogg (2015) "Welfare and Distributional Implications of Shale Gas." *Brookings Papers on Economic Activity*, Spring 2015, 71-139.

Haile, P., K. Hendricks, and R. Porter (2010). "Recent US Offshore Oil and Gas Lease Bidding: A Progress Report," *International Journal of Industrial Organization* 28(4): 390-396.

Hein, J. F. (2018). "Federal Lands and Fossil Fuels: Maximizing Social Welfare in Federal Energy Leasing." *Harvard Environmental Law Review* 42: 1-59.

Holland, Stephen P. (2012). "Emissions Taxes versus Intensity Standards: Second-Best Environmental Policies with Incomplete Regulation." *Journal of Environmental Economics and Management* 63 (3): 375–87.

J.-J. Laffont and J. Tirole (1994). *A Theory of Incentives in Procurement and Regulation*, Cambridge: MIT Press.

Krupnick, A., J. Darmstadter, N. Richardson, and K. McLaughlin (2016). "Putting a Carbon Charge on Federal Coal: Legal and Economic Issues." *Environmental Law Reporter News & Analysis*, 46: 10572.

Lazarus, M. and H. van Asselt (2018). "Fossil Fuel Supply and Climate Policy: Exploring the Road Less Taken," *Climatic Change* 150: 1-13.

Metcalf, G.E. (2019). "On the Economics of a Carbon Tax for the United States." *Brookings Papers on Economic Activity*, Spring 2019: 405-458.

Nordhaus, W. (1982). "How Fast Should We Graze the Global Commons?" *American Economic Review – Papers and Proceedings*, 72(2): 242-246.

Prest, B. (2021). "Supply-Side Reforms to Oil and Gas Production on Federal Lands," manuscript, Resources for the Future.

Sandmo, A. (1975). "Optimal Taxation in the Presence of Externalities," *Swedish Journal of Economics* 86-98.

Skrzypacz, A. (2013). "Auctions with Contingent Payments," *International Journal of Industrial Organization* 31: 666-675.

U.S. Department of the Interior (2017). *Federal Coal Program: Programmatic Environmental Impact Statement – Scoping Report*, Volume 1. Available at http://columbiaclimatelaw.com/resources/climate-deregulation-tracker/database/blm/

Vulcan, Inc. (2016). "Vulcan Analysis of Federal Coal Leasing Program: Summary of Modeling Results" at http://www.vulcan.com/MediaLibraries/Vulcan/Documents/Federal-Coal-Lease-Model-report-Jan2016.pdf.

Appendix

This appendix derives the social welfare maximizing emissions fee or climate royalty surcharge when there are multiple fuels, some of which are covered by the fee or surcharge and some of which are not. The setup is standard, e.g. Hoel (1996), Holland (2012), and Fæhn et al. (2017), with static utility, cost, and damage functions, extended to *n* fuels, with leakage and co-production. Each fuel has covered (superscript *c*) and uncovered (*u*) production. The *n*-vector of production of covered fuels is $Q^c = (q_1^c, ..., q_n^c)'$ and uncovered fuels is $Q^u = (q_1^u, ..., q_n^u)'$; the vector of total production is $Q = Q^c + Q^u$. The representative consumer derives utility $U(Q)$ from consumption of the fuels, where consumption equals production. The cost function for producing uncovered fuels is $C^u(Q^u)$. For covered fuels, the cost function is $C^c(Q^c,.)$, where the final argument is the carbon fee or royalty surcharge; this cost function is inclusive of carbon fee/royalty payments. Burning Q_i produces emissions $E_i = e_i Q_i$, where e_i is the emissions intensity of fuel *i* (e.g., tons CO_2e/barrel), with vectors of covered, uncovered, and total emissions being E^c, E^u, and $E = E^c + E^u$. Total covered emissions $E^{tot,c} = e'Q^c$ total uncovered emissions are $E^{tot,u} = e'Q^u$, and total emissions are $E^{tot} = e'Q$, where $e = (e_1, ..., e_n)'$. External damages from emissions are $D(E^{tot})$.

Separate carbon fees. First consider the problem of setting a vector τ of carbon fees on each covered fuel, where the fees are denominated in dollars per ton CO_2e and the fees can differ across fuels. Total receipts from the fee are $\tau' E$.

The social planner chooses the vector of carbon fees τ to maximize social welfare:

$$\max_\tau W(Q) = U(Q) - C^c(Q^c, \tau) - C^u(Q^u) - D(E^{tot}) + \tau' E^c , \tag{1}$$

where receipts from the carbon fee are added back into welfare because they are subtracted off in the covered cost function. The first order conditions for τ is,

$$\begin{aligned} &\frac{\partial U}{\partial Q'}\left(\frac{\partial Q^c}{\partial \tau'} + \frac{\partial Q^u}{\partial \tau'}\right) - \frac{\partial C^c(Q^c,\tau)}{\partial Q^{c\prime}}\frac{\partial Q^c}{\partial \tau'} - \frac{\partial C^c(Q^c,\tau)}{\partial \tau'} - \frac{\partial C^u(Q^u,\tau)}{\partial Q^{u\prime}}\frac{\partial Q^u}{\partial \tau'} \\ &-\theta\frac{\partial E^{tot}}{\partial \tau'} + E^{c\prime} + \tau'\frac{\partial E^c}{\partial \tau'} = 0, \end{aligned} \tag{2}$$

where θ = dD/dE^{tot} is the marginal damage. Market clearing implies that $\frac{\partial U}{\partial Q}=\frac{\partial C^c(Q^c,\tau)}{\partial Q^c}=\frac{\partial C^u(Q^u)}{\partial Q^u}$, and the envelope theorem implies that $\partial C^c(Q^c,\tau)\big/\partial\tau = E^c$. Thus, (2) simplifies to $\tau'\frac{\partial E^c}{\partial\tau'}=\theta\frac{\partial E^{tot}}{\partial\tau'}$, so

$$\tau=\left(\frac{\partial E^{c\prime}}{\partial\tau}\right)^{-1}\frac{\partial E^{tot}}{\partial\tau}\theta\,. \tag{3}$$

Expression (3) generalizes Holland's (2012, equation (5)) expression for a single fuel with partial coverage to multiple fuels. In the case of a single fuel, (3) reduces to $\tau=(1-\lambda)\theta$, where λ is the leakage rate (that is, the increase in uncovered production for a unit decrease in covered production) and θ is the marginal monetized damages of emissions, that is, the social cost of carbon (SCC).

Another special case of (3) is when there is no substitution in production or consumption across fuels, so the markets are separate. Then the welfare-maximizing fee for each fuel is $\tau_i=(1-\lambda_i)\theta$, where λ_i is the leakage rate for covered production into uncovered production of fuel *i*.

In general, the welfare-maximizing vector of fees depends on leakage both within and across fuels.

Common royalty surcharge. Next consider the problem of setting a common *ad-valorem* climate royalty surcharge *r*, which applies equally to the value of production of each fuel. This surcharge applies above and beyond any base royalty rate set using non-climate considerations, such as taxpayer value. The market value of covered fuels is $Y^c=P'Q^c$, where *P* is the vector of prices. The royalty costs are part of the covered fuel cost function so the social planner's problem now is,

$$\max_\tau W(Q)=U(Q)-C^c(Q^c,r)-C^u(Q^u)-D(E^{tot})+rY^c\,. \tag{4}$$

The first order condition for *r* is,

$$\begin{aligned}&\frac{\partial U}{\partial Q'}\left(\frac{\partial Q^c}{\partial r}+\frac{\partial Q^u}{\partial r}\right)-\frac{\partial C^c(Q^c,r)}{\partial Q^{c\prime}}\frac{\partial Q^c}{\partial r}-\frac{\partial C^c(Q^c,r)}{\partial r}-\frac{\partial C^u(Q^u,r)}{\partial Q^{u\prime}}\frac{\partial Q^u}{\partial r}\\&-\theta\frac{\partial E}{\partial r}+Y^c+r\frac{\partial Y^c}{\partial r}=0.\end{aligned} \tag{5}$$

Using market clearing conditions and the envelope theorem as above yields,

$$r\frac{\partial Y^c}{\partial r}=\frac{\partial E}{\partial r}\theta\,. \tag{6}$$

Equation (6) has an intuitive interpretation: the marginal cost of further increasing the royalty surcharge, which is the foregone revenue (the royalty rate times the loss in the market value of covered production), should equal the marginal benefit, which is the net change in emissions valued at the SCC.

Rearranging (6) and expanding terms yields,

$$r=\frac{e'\dfrac{\partial Q}{\partial r}\theta}{P'\dfrac{\partial Q^c}{\partial r}+\dfrac{\partial P}{\partial r}'Q^c} \tag{7}$$

If the effect on the value of the covered fuel from a royalty surcharge is dominated by the effect on quantity produced, not its effect on market prices, then the second term in the denominator of (7) is small so we have the approximation,

$$r\approx\frac{e'\dfrac{\partial Q}{\partial r}\theta}{P'\dfrac{\partial Q^c}{\partial r}}\,. \tag{8}$$

In the approximation (8), the royalty rate is proportional to the SCC, scaled by the emissions-weighted average of the marginal change in production. It can be shown that the right hand side of (8) is the welfare-maximizing royalty rate computed from the welfare-maximizing distinct carbon fees on each fuel, subject to the constraint that each carbon fee is the same percentage of sales of the applicable fuel at the fixed price vector P. The difference between this optimal per-ton fee, reexpressed as a percentage of sales, and the welfare-maximizing royalty rate (7) is the that the optimal royalty rate also incorporates the effect of a change in the royalty rate on prices and thus on royalty receipts. Because prices will typically rise as the royalty rate increases, the denominator in (7) is smaller (less negative) than the denominator in (8), so the welfare-maximizing royalty rate computed using (7) will exceed the value computed using (8).

In the case of a single fuel, (8) simplifies to $r=e(1-\lambda)D'/P$, which is the optimal carbon fee with leakage $\lambda > 0$, expressed in dollars per quantity unit (barrel), then reexpressed as a fraction of the sales price of the fuel.