THE ECONOMICS OF COAL LEASING ON FEDERAL LANDS:

ENSURING A FAIR RETURN TO TAXPAYERS

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Contents

Executive Summary

The Federal coal leasing program accounted for nearly 40 percent of coal production in the United States in 2015, including some of the lowest-cost coal available. While the program brings in hundreds of millions of dollars of government revenue per year, it has been widely criticized in recent years by economic and environmental experts for providing a poor return to the taxpayer and for not adequately addressing the environmental costs of coal extraction, processing, and combustion. In January 2016, U.S. Department of the Interior began the first programmatic review of the Federal coal leasing program in 30 years in order to address a range of issues, including the return to the taxpayer and coal leasing impacts on the environment.

This report focuses on the issue of whether the Federal coal leasing program *provides a fair return to the taxpayer* and draws upon relevant academic research to provide an economic perspective. A review of the coal leasing program indicates that the program has been structured in a way that misaligns incentives going back decades, resulting in a distorted coal market with an artificially low price for most Federal coal and unnecessarily low government revenue from the leasing program.

Typically when the government owns a resource, whether it is timber, electromagnetic spectrum, or coal, a common objective is to ensure that the government maximizes revenue to the extent feasible, while also taking into consideration positive or negative externalities associated with the use of that resource. When it is impractical or inefficient for the government to use the resource itself, then the key task is designing an arrangement that aligns the incentives of the agent who harvests or produces the resource with the public interest.

The coal leasing program offers companies 20-year leases on Federal lands, and brings in revenue to Federal and State governments through three channels: (1) bonus bids from an auction for the right to lease land with coal resources, (2) land rental fee payments, and (3) production royalty payments as a percentage of the sale price of the coal produced. A review of these features finds that they have not fostered an efficient, competitive system that provides a fair return to taxpayers. For example, although intended to be competitive, the bonus bid auctions appear to be less and less competitive, typically with only one to two bids submitted at prices very near the lowest selling price possible, or reserve price, set by the government. Similarly, by assessing royalty payments through a royalty rate, there is an incentive for companies to reduce reported coal sales prices in order to minimize the royalty payments owed and companies have employed several tactics to lower the selling price of coal without losing revenue.

All of these factors lead to lower returns to the taxpayer from the coal leasing program. They have been exacerbated over the past few decades as Federal coal has considerably expanded its share of the overall coal market by offering coal at a much lower price on average than non-Federal coal, bringing down the equilibrium price of coal on the market. Because of these documented inefficiencies and other concerns related to the Federal coal leasing program, the

U.S. Department of the Interior (DOI) announced in early 2016 the first comprehensive programmatic review of the Federal coal leasing program since the 1980s.

This report examines the market implications of changing royalty rates based on three potential approaches motivated by the current structure of the coal market. Specifically, we consider basing royalty payments on nearby regional coal prices, nationwide coal prices, and the price of natural gas, which is a close substitute for coal in the electricity market. All three prices are in terms of dollars per one million British Thermal Units (MMBtu) to account for differences in heat rates of different types of coal (and natural gas). Further, we consider a fourth approach that establishes royalty payments based on the objective of maximizing government revenues, consistent with how the government manages many other resources.

A critical question that arises in any discussion of changing royalty rates is whether an increase will actually increase government revenue or if it will lower auction revenues sufficiently, thus decreasing government revenues. Using results from the well-known Integrated Planning Model (IPM), we find that the answer to this is unambiguous: increasing coal royalty payments for Federal leases could bring in substantially greater revenue for States and the Federal government. Modestly increasing coal royalty payments, such as basing the payments on the price of nearby regional coal, would lead to a slight decline in Federal coal production and a very slight increase in non-Federal coal production. On net, it would lead to a slight reduction in aggregate coal production across the United States that leads to subsequent emissions reductions from coal combustion. The results for the other scenarios mirror these, with larger decreases in Federal coal production, but considerable increases in government revenue. These findings highlight the potential of royalty reform to provide a fair return to taxpayers while simultaneously reducing the environmental effects of coal extraction and combustion. Finally, it is important to note that this report does not analyze the full range of considerations relevant to potential changes to the Federal coal leasing program, ranging from development benefits and employment effects to impacts on natural resources such as water and wildlife habitat.

An economic perspective on the Federal coal program highlights the need for reform.

- From an economic perspective, important objectives for the Federal coal leasing program would include maximizing return to taxpayers from the use of the public resources and addressing unpriced environmental externalities. There is growing evidence that the current structure of the Federal coal leasing program does not provide a fair return to the taxpayer due to misaligned incentives inherent in the structure and administration of the program.

The U.S. coal market has become increasingly dominated by Federal coal.

- Over 40 percent of the U.S. coal market is supplied by Federal coal and this share has increased substantially over the past several decades. On average, Federal coal is substantially less expensive than non-Federal coal, and the ratio of non-Federal to Federal prices has diverged from 3.3 in 1990 to 5.0 in 2014.

Increasing royalty payments is one approach to ensuring that the Federal coal program provides a fair return to the taxpayer.

- There is strong economic support for setting coal lease royalty terms based on the final delivered price of coal, less adjustments for the heat content, quality, and location of the coal. These adjustments are crucial to make sure coal is being assessed on its true economic value.
- Similarly, establishing lease royalty terms based on relevant (adjusted) market prices for comparable coal or coal substitutes is important to ensure a fair return to the taxpayer. The relevant market price could be the average price of nearby regional coal, the price of nationwide coal, or the price of a substitute in the electricity dispatch order: natural gas. By basing royalties on such market price comparisons, only Federal coal that is underpriced (relative to comparable direct substitutes) would have a change in the royalties paid.
- Alternatively, another option would be increasing royalty payments to maximize royalty revenues. Many government resources are managed with the goal of maximizing the return to the taxpayer. This would imply a substantial increase in the royalty rate.

Modeling results indicate that increasing royalty rates would increase government revenues while only modestly reducing Federal coal production.

- All approaches examined for assessing higher royalties can lead to higher government revenues. If royalty payments are based on the price of nearby regional coal on a per-Btu basis, after it is fully phased-in, this would add up to $290 million more to State and Federal coffers annually. Maximizing royalty payments would bring in as much as $3 billion more to State and Federal coffers annually once fully phased-in.
- Since Federal coal is so much less expensive on average to extract than other coal on the market, increasing royalty payments based on market prices for comparable substitutes (and thus increasing the price of that coal), would only result in a modest reduction in Federal coal production. For example, assessing royalty payments based on the price of nearby regional coal would reduce Federal coal production by roughly 3 percent annually once fully phased-in.
- Increasing the royalty payments on Federal coal would modestly increase production of non-Federal coal in the Appalachians and Illinois Basin through the slightly higher nationwide market price for coal. For example, assessing royalty payments based on the price of nearby regional coal would increase non-Federal production just over 1 percent annually once fully phased-in.

Environmental externalities are another important consideration.

- On net, increasing royalty payments to ensure a fair return to the taxpayer would decrease total coal production in the United States and also decrease total nationwide emissions. For example, assessing royalties on the price of nearby regional coal would reduce emissions by an estimated 12 million metric tons of carbon dioxide annually while utilizing prices for either non-Federal coal nationwide or for natural gas yields emission reductions of approximately 32 million metric tons annually. (For comparison, total U.S. carbon dioxide emissions from coal combustion for electricity in 2015 was 1,364 million metric tons).

- Although the focus of this report is on ensuring a fair return to the taxpayer, there is strong economic evidence of large external costs from coal production, transportation, and consumption. For example, incorporating the social cost of carbon in coal royalties would imply a royalty rate greater than 100 percent, implying that an increase in royalty rates could improve economic efficiency both due to fair return to the taxpayer and environmental externality considerations.

Introduction

Coal resources on Federal lands are a significant energy source for the production of electricity throughout the United States. In 2015, roughly 40 percent of coal produced in the United States was extracted from Federal lands, amounting to approximately 450 million tons per year and generating over $700 million in Federal and State revenue per year (EIA 2015a).[1] The regulations and administrative processes governing leasing of Federal coal were largely put in place in the late 1970s and early 1980s and have seen little change since that time. On January 15, 2016, Secretary of the Interior Sally Jewell issued Secretarial Order Number 3338, directing "the BLM to prepare a discretionary Programmatic Environmental Impact Statement (PEIS) that analyzes the potential leasing and management reforms to the current Federal coal program." During the pendency of the PEIS, the Secretary directed the BLM to place a pause on the issuance of coal leases subject to limited, enumerated exemptions and exclusions. This announcement was preceded by President Obama's 2016 State of the Union Address, which clearly stated the priorities of the Administration:

> "Rather than subsidize the past, we should invest in the future–especially in communities that rely on fossil fuels. We do them no favor when we don't show them where the trends are going. That's why I'm going to push to change the way we manage our oil and coal resources, so that they better reflect the costs they impose on taxpayers and our planet."

This report covers the basic economics of coal leasing on Federal lands, with a focus on *ensuring a fair return to taxpayers* from extraction of the coal resource on public lands. To be sure, there are other economic justifications for reforming coal leasing. Most importantly, there is an economic justification based on un-internalized environmental externalities, such as carbon dioxide emissions from coal combustion, methane emissions from coal extraction, and water pollution from coal extraction and processing. The full programmatic review being launched by DOI is expected to address both the fair return to the taxpayer and coal leasing impacts on the environment, as stated by Secretary Sally Jewell on January 15, 2016:

> "We haven't undertaken a comprehensive review of the program in more than 30 years, and we have an obligation to current and future generations to ensure the Federal coal program delivers a fair return to American taxpayers and takes into account its impacts on climate change."

In her announcement, Secretary Jewell also emphasized that DOI is committed to openness and improved transparency in the Federal coal leasing program while the programmatic review, which is expected to take approximately three years, is underway. While these additional considerations are unquestionably important for understanding the economics of coal leasing on Federal lands, and will be discussed briefly, this report will retain a focus on government revenues and the return to the taxpayer.

[1] The federal government typically shares the coal leasing program revenue roughly equally with State governments.

There is an extensive legal history underpinning the current structure of the coal leasing program. The following discusses a few of the key highlights relevant to understanding the program. The Mineral Leasing Act (MLA) provides the Secretary of the Interior with substantial discretion in managing Federal coal leasing and setting the terms of leases. The Secretary "is authorized to divide any lands subject to this Act which have been classified for coal leasing into leasing tracts of such size as he finds appropriate and in the public interests and which will permit the mining of all coal which can be economically extracted" and "shall, in his discretion, upon the request of any qualified applicant or on his own motion, from time to time, offer such lands for leasing and shall award leases thereon by competitive bidding." 30 U.S.C. § 201(a)(1). The Act also directs the Secretary to set surface coal royalties at a minimum of 12.5 percent "of the value of coal as defined by regulation" and provides that the Secretary may establish a lesser royalty for coal recovered by underground mining operations 30 U.S.C. § 207(a). In 1990, the underground mining rate was set at 8 percent by regulation. The MLA also provides the Secretary discretion to suspend, waiver, or reduce royalty fees "whenever in his judgment it is necessary to do so in order to promote development, or whenever in his judgment the lease cannot be successfully operated under the terms provided therein." 30 U.S.C. § 209. Finally, the Federal Coal Leasing Amendments Act of 1976 amended the MLA to generally require that all Federal coal leases be offered competitively.

These laws formed the foundation for today's Federal coal leasing process. The current procedures were most significantly last revised in the 1980s, resulting from allegations that the Federal government did not receive fair market value from a large lease sale in the Powder River Basin due to leaked confidential information. In response, Congress directed the Secretary of the Interior to appoint members to the "Linowes Commission" to review the Federal coal leasing program's fair market value processes. The Linowes Commission's report, along with other reports from the Government Accountability Office and the Office of Technology Assessment, recommended major updates to the Federal coal leasing program procedures.

Under the current structure of the Federal coal leasing program, the Federal government receives revenue in three major ways:

1. Bonus Bids – for any new tract of land available for lease, there is a first-price sealed-bid auction (i.e., bidders submit sealed bids, the bidder with the highest bid wins the auction, and the winning bidder pays the amount they bid). DOI also establishes a confidential minimum bid based on a valuation of the coal tract. The winning bid must be above this minimum bid. The minimum bid is set as the greater of the agency's estimate of the fair market value of the tract and $100 per acre. The winner must pay the bonus bid upon issuance of the lease.
2. Rental Fees – there is a minimum $3/acre per year rental fee for use of the land.
3. Production Royalties – these are paid at the first point of sale of the coal after it is removed from the ground as a percentage of the revenues at the sale price. The royalty rates are set by regulation at a fixed 8 percent for underground mines and not less than 12.5 percent for surface mines. Lessees may request royalty waivers, suspensions, or reductions by demonstrating that the change is necessary to promote development or

that operations would not be financially successful under the lease terms. In addition, lessees may claim deductions against royalty payments for certain costs, such as washing (i.e., cleaning the coal for impurities) and transportation of coal (e.g., if the first point of sale is not at the mine mouth).

Tracts are leased for an initial 20-year primary term, contingent on continued operations and production of the coal in commercial quantities within the first 10 years. Leases may be renewed for 10-year terms. All leasing revenues (bonus bids, rental fees, and production royalties) are split roughly evenly between the Federal government and the State in which the lease is located.

The Federal coal leasing program has recently been widely criticized for failing to provide a fair return to taxpayers.[2] This criticism highlights concerns with the incentive structure of the current program and points out characteristics consistent with an uncompetitive lease bidding process and effective royalty rates that are much below the statutory minimum levels. For example, GAO (2013) reports that between 1990 and 2013 DOI leased 107 coal tracts, and 96 of them (about 90 percent) involved only a single bidder in the bonus bid leasing auction. The primary reason for this is that more than 90 percent of the lease applications were for maintenance tracts used to expand an existing mine's annual production or extend the life of the mine. GAO notes that "there is limited competition for coal leases because of the significant capital investment and time required to establish new supporting infrastructure to start a new mine or to extend operations of an existing mine to a tract that is not directly adjacent to it." GAO also points out that over time royalties provide a larger fraction of the revenue from coal leasing than bonus bids, due to greater production on existing leases. GAO calculates that bonus bid revenues have averaged $335 million per year from 2003 to 2012 (although varying significantly by year, with no clear trend), while royalty revenues have increased over time to amount to $796 million in fiscal year 2012. Rental fee payments are largely insignificant, totaling only $1.2 million in fiscal year 2012.

Haggerty and Haggerty (2015) calculate an average *effective* royalty rate, defined in that study as the final royalties paid per ton of coal divided by the average delivered market price that sellers ultimately receive for the coal sold from Federal leases. Using this approach, they divide the average royalty collections of $1.70 per ton of coal from 2008 to 2012 by the gross market price during that time period of $34.43 per ton. The result is an effective royalty rate of only 4.9 percent. Although allowable deductions are clearly a significant contributor to the difference between 4.9 percent and the statutory rate of 12.5 percent, recent reports have argued that several other factors may also help explain the difference between the effective royalty rate and the statutory minimum rate.

Lee-Ashley and Thakar (2015) point out that in 2012, 42 percent of all Federal coal produced in Wyoming was sold through a "captive transaction," which refers to a sale between a parent and affiliate company. The authors reason that these captive transactions, along with allowed

[2] The coal leasing program has also been criticized for not internalizing externalities. For example, see Krupnick et al. (2015), Hein and Howard (2015), and Gerarden et al. (2016).

deductions for transportation and washing, are an important part of the reason why the price used to determine royalties is so much below the market price of coal. Haggerty and Haggerty (2015), Lee-Ashley and Thakar (2015), and Taxpayers for Common Sense (2013) argue that coal companies have an incentive to use captive transactions and inflate the transportation and washing deductions in order to reduce the market value of coal used for calculating royalty payments.

Peterson (2015) notes these issues, but also emphasizes another particular concern: the current structure of the Federal coal leasing program provides coal companies with incentives to structure contracts to price coal as low as possible. The author argues that companies employ "take-or-pay" contracts, in which final purchasers (e.g., electricity generating units) agree to purchase very large quantities of coal at a low price and if they fail to "take" the required amount, they are required to make a "penalty payment." These penalty payments do not have royalties assessed on them, so there is an incentive for contracts to be designed with very low coal transaction prices and larger penalty payments in order to reduce royalty payments.

The following sections explore lessons from economic theory relevant to ensuring a fair return to taxpayers, examine characteristics of the current coal market, and provide possible options to improve the likelihood that taxpayers will receive a fair return from the Federal coal leasing program. The remainder of the report then uses results from the well-known Integrated Planning Model (IPM) to estimate the effect of adjustments to the Federal coal leasing program on the coal market, Federal coal production, and royalty revenues. It concludes with a few key take-away findings.

I. An Economic Perspective on a Fair Return to the Taxpayer from Federal Coal Leasing

The recent criticisms of the Federal coal leasing program raise questions about the incentives provided to coal companies under different ways of structuring the program. This section takes a theoretical view of the economics of coal leasing and discusses the economic implications of different choices in program design.

The need to properly design payment for the development or use of public resources is a common one. From National Park Service auctions for concessionaire rights in Yosemite National Park, to timber auctions on National Forest Service land, electromagnetic spectrum auctions by the Federal Communications Commission, and government surplus property auctions by the General Services Administration, there are examples of mechanisms used to ensure a fair return to taxpayers throughout the Federal government. States with significant coal reserves also routinely use auctions for the right to extract coal on State land.

A common theme among all of these examples is the goal of maximizing return to the taxpayer from the use of the public resource to the extent feasible. In addition to ensuring a fair return to the taxpayer for the use of the public resource, this goal has an additional economic rationale: if revenues are raised in a non-distortionary or minimally distortionary way through the use of a government-owned resource, then revenues will not have to be raised through other, more distortionary, taxes, such as income taxes or sales taxes. In this sense, maximizing the return to the taxpayer can improve economic efficiency.

It is worth considering the infeasible, but ideal, "first-best" (in an economic efficiency sense) arrangement for ensuring maximum return to the taxpayer. In the first-best outcome, all of the economic profits (i.e., profits after excluding the standard return on capital) would go to the government, as the resource owner and steward.[3] This could in theory be accomplished by the government itself efficiently extracting the coal using the lowest-cost approaches and keeping the economic rents. Alternatively, it may be more practical for a trusted agent, with the necessary equipment, infrastructure, and expertise, to efficiently extract the coal and remit any economic profits to the government. The coal firm (or agent) would get a fair return for its investment and effort, while the public would receive any remaining or excess value from the development of the public resources. Thus, the task is designing an arrangement that aligns the incentives of the agent with those of the government.

Auctions are the most common way to align incentives. With many bidders (i.e., a thick bidding pool), auction mechanisms can be designed so that the revenues received come as close as possible to the first-best economic profits or rents. Such mechanisms have been studied extensively in economics, focusing primarily on a simple auction setting that does not include

[3] Economic profits can include the option value of a long-term lease, which accounts for the fact that coal companies who win the lease have the option to extract in the future should prices be sufficiently high, but are not required to do so until the tenth year of the lease.

royalty or other ex-post verifiable payments. In such a setting, with a first price sealed-bid auction, as the number of bidders increases, the auction revenue increases, for each bidder realizes that they must outbid the other bidders and thus bids higher. As the number of bidders approaches infinity (i.e., a perfectly competitive market), the optimal bids approach the true market valuation. So in a highly competitive auction, the revenues to the taxpayer approach the first-best outcome, which is the full value of the economic profits. The less competitive the market, the further the deviation from a first-best outcome. For example, in a first price sealed-bid auction with only two bidders, the optimal bid is only one half of the true valuation. With a single bidder, the optimal bid is as low as possible (Milgrom 2004, Laffont and Tirole 1994).

Even closer to the Federal coal leasing context, there is also significant work analyzing “auctions with contingent payments” (Haile et al. 2010, Skrzypacz 2013). Bonus bid auctions for coal leases can be considered auctions with contingent payments, for the right to lease the tract is auctioned with contingent payments (i.e., royalties) that are paid based on revenues. Auctions to determine the royalty rate paid are also possible instead of auctions for the right to lease a tract. For example, firms bid a per unit price for each species of timber in U.S. Forest Service auctions, which is equivalent to a royalty rate auction if prices are stable (Athey and Levin 2001).

Raising revenue from Federal coal leasing using bonus bid auctions along with royalty payments may deviate from the first-best outcome. For example, when there are few bidders in an auction (i.e., a thin bidding pool), then the auction is expected to generate much less revenue than the first-best outcome. As is discussed above, for practical reasons 90 percent of Federal coal lease auctions between 1990 and 2013 had a single bidder. Requiring royalty payments also raises the post-royalty marginal cost of production, thereby reducing production. This would lead to a deviation from the first-best production levels if coal production and combustion did not have external costs, but given the important externalities of coal production and combustion, the use of royalties may actually move us closer to the first-best outcome by helping to internalize some of these externalities.

In a context with perfect information, it may be possible for the government to calculate the market value of the lease to the limited number of firms bidding and impose a minimum bid (or even a price) for the lease that would be auctioned. However, coal leasing is a setting with asymmetric information where the agents (coal companies) know more than the government about their cost structure and the true market value of the lease to the entire firm, including subsidiaries. In a context with asymmetric information, it is extremely challenging to determine the true market value of the lease. In addition, while firms may not know the exact minimum bid for any given auction, there is a repeated game being played, so that the firms can roughly infer what the minimum bid might be, and thus can make sure to bid just above it. Such a repeated game may also lead to lower calculated minimum bids than the true market value of the coal if the minimum bid is determined in part based on other recent successful bids. If other recent successful bids come in low, it would appear that the market value of the new coal lease is also low, potentially leading to an equilibrium with lower minimum bids than would be needed to fully capture the economic profits from the coal leasing.

Given these challenges with the bonus bid auction (and similar challenges that would occur with a royalty auction), royalty payments assessed on the production of coal have the potential to bring the return to the taxpayer closer to the first-best outcome. These payments could be based on traditional fixed royalty rates, a fixed royalty fee or charge, or other royalty payment structure including a combination of royalty rates and fees. In principle, in a context where competitive auctions are not possible, royalty payments can provide firms an incentive to minimize costs and produce efficiently, and may partly help overcome issues of asymmetric information and costly monitoring.

There are two important questions that determine whether or not using royalty payments along with a lease auction is an attractive second-best approach. First, to what extent are the lease auctions uncompetitive? Increasing the royalty payments would be expected to reduce the remaining economic rents to the successful bidder, so the bonus bids would be expected to decrease as royalty rates rise. If lease auctions are generally uncompetitive, the additional revenues from the increased royalty payments would exceed the lost bonus bid revenue. In contrast, if lease auctions are entirely competitive and the bonus bid revenues fully capture the remaining economic profits, then increasing the royalty rate may not bring in any additional revenue (as lower bids offset royalty rate revenue), and may even bring in slightly less revenue by discouraging production (although this may be optimal if relevant externalities are otherwise un-internalized).[4] This is fundamentally an empirical question and one that is addressed in the modeling exercise later in this report.

Second, royalty payments are a more attractive approach if the royalties are assessed on the true market value of the coal.[5] From an economics perspective, the coal market is a nationwide market, but coal is not homogenous. Coal differs in characteristics such as heat content, sulfur content, mercury content, moisture, and ash content. Moreover, coal that is extracted near the location of purchasing facilities is more valuable than coal mined far from demand, since the transportation costs would be lower. This is again where considering the first-best economic outcome is useful. In the first-best, coal with higher heat content would be worth more, with higher sulfur or mercury content would be worth less, and with higher transportation costs would be worth less. Thus, from an economics perspective, the true market value of the coal adjusts for the characteristics of the final coal produced, including its location.

Due to asymmetric information, the underlying value of coal would also be gross of any unobserved or imperfectly observed costs involved in extracting or preparing the coal for consumption. For example, marketing costs, overhead, and washing costs are all necessary costs of preparing the coal for final combustion. Moreover, they are highly specific to the particular

[4] Technically this equivalence works in expectation; with risk-neutral bidders, the *expected* revenues from the bonus bids are exactly offset by the *expected* present value of the flow of royalty payments. If bidders are risk-averse, the expected revenues from the bonus bids may not be entirely offset by the flow of royalty payments, since with royalty payments, the government will be sharing in the risk of low revenue outcomes, allowing for slightly higher bonus bids.

[5] One would generally call this a "fair market value," but in coal leasing this term has been co-opted and given a technical definition as the value used for choosing the minimum bid level in the bonus bid auctions.

mine and coal extracted. These costs are thus imperfectly observable to DOI, and yet are known by the firm. As mentioned above, coal washing costs currently can be deducted from the value of coal that royalties are assessed on. Not deducting these costs from the reported market value of coal would help to prevent two potential issues of perverse incentives. First, allowing these costs to be deducted reduces the incentive to minimize these costs and prepare coal for market as efficiently as possible. Second, deducting these costs provides an incentive for lessees to inflate these reported costs and thus reduce the royalties paid. In a context of imperfect information and high monitoring costs, profit-maximizing firms would have an incentive to include as many costs in the category of deducted costs as possible in order to earn the highest return for their shareholders. With larger deducted costs, fewer royalties are paid.

A useful analogy for understanding how market value may be manipulated is considering how property is taxed in the United States. If homeowners were allowed to state the value of their property instead of being required to use assessor data on the market price, then homeowners would have an incentive to systematically report lower property values and to neglect to mention home improvements that may increase the value of the property. It would also create an incentive for side payments during home sales, so that the recorded value of the home comes in below the true value of the home (similar to penalty payments in coal contracts). The primary check against these incentives is that assessors follow the property market closely and base home valuations on similar homes elsewhere in the overall housing market. This helps to ensure that the property tax base is the fair market value of the property. Property transaction records are also public records, which fosters transparency in the market, which is critical for assessing the fair market value of any property.

The logic here also extends to transportation costs. As described above, the location from which coal is extracted is an easily observed characteristic of the coal. Furthermore, rail shipping costs for different commodities are in most cases easily observed, and in principle, arms-length coal shipping costs could be observed and verified against costs of other similar commodities. If firms are permitted to self-report transportation costs, this not only reduces the incentive for efficiently transporting the coal, but it also provides an incentive for inflating the transportation costs and including other costs in with transportation costs. For instance, there could be an incentive to include logistics support costs, which are just standard overhead costs for marketing the coal.

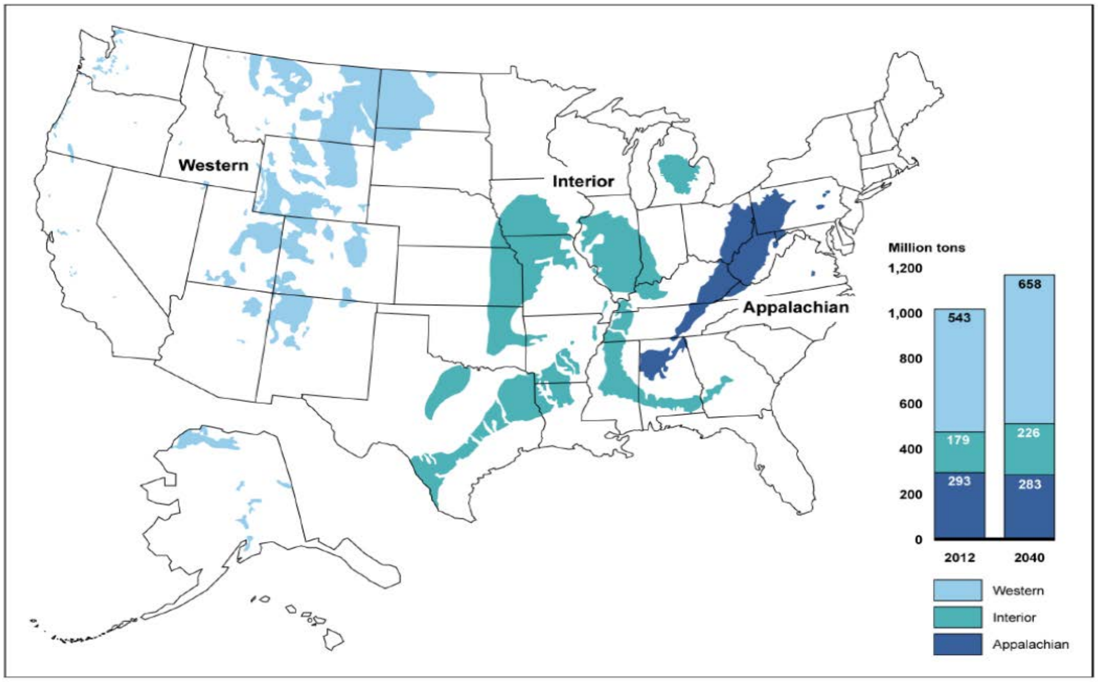
Economics delivers significant guidance on the optimal design for the Federal coal leasing program by providing a first-best benchmark and highlighting issues of asymmetric information and perverse incentives in the royalty program when there is insufficient competition in the leasing auctions. Economic logic points to the importance of transparency, adjusting the market value of coal for its characteristics, excluding deductions from the market value that are not easily observable, and basing the market value (and any deductions) on observable market prices rather than self-reported prices.

II. The Coal Market in the United States Today

Coal is a major feedstock for electricity generation, and the United States has substantial coal resources. In 2014, just over one billion tons of coal were produced in the United States, down from just under 1.2 billion tons of coal in 2006, and comparable to production levels over the past two decades (all tons in this report are short tons). Roughly 74 million tons were exported in 2015, with net exports of about 73 million tons, most of which was metallurgical coal used for industrial purposes. Gross and net exports peaked in 2012 with net exports in 2012 of about 116 million tons (EIA 2015a). With retirements of aging coal plants and low natural gas prices, coal production declined 11 percent in 2015 (by 109 million tons) and a slight decline is forecasted to continue over the next two years (EIA 2016a). Yet, despite the declines, coal is still expected to remain one of the primary feedstocks for electricity generation over the next decade (EIA 2015b).

Figure 1 shows the location of coal resources in the United States, along with 2012 estimates and 2040 forecasts of coal production by region (GAO 2013). There are substantial coal resources in the Appalachian region and interior region, but the largest resources are in the western region. Almost all coal produced on Federal lands is produced in the western region and in fiscal year 2012 nearly 80 percent of coal production in the western region was from Federal lands (GAO 2013).[6] The reliance on Federal coal in the western region for coal production is even higher today; according to EIA, the largest percentage decrease in production between 2014 and 2015 was in the Appalachian region, followed by the interior region, with the smallest decline in the western region (EIA 2016b). This shift is unsurprising as some of the largest, most productive, and lowest-cost coal mines are found on Federal lands, and in particular in the Powder River Basin (PRB) of Wyoming and Montana.

[6] Small amounts of coal are produced from federal leases in Alabama, Kentucky, New Mexico, North Dakota, and Oklahoma. In fiscal year 2012, 85 percent of federal coal was produced in Wyoming, and 97 percent produced in Wyoming, Montana, Colorado, or Utah (GAO 2013).



Sources: GAO analysis of Energy Information Administration data; copyright © Corel Corp., all rights reserved (map).

Figure 1. Coal producing regions around the United States. Source: GAO (2013)

The coal market in the United States has seen a significant shift since the current coal royalty system was established, from a market mostly reliant on production on private lands to one with a much larger share of production mined on Federal lands. In 1990, the percentage of total coal produced from Federal leases was 24 percent. This rose to roughly 40 percent in 2002 and has leveled off at just above 40 percent since then. Figure 2 illustrates this shift graphically by splitting production between the PRB and all other coal production. Over 85 percent of Federal coal has been produced in the PRB in recent years, and the vast majority of PRB coal production is on Federal lands.

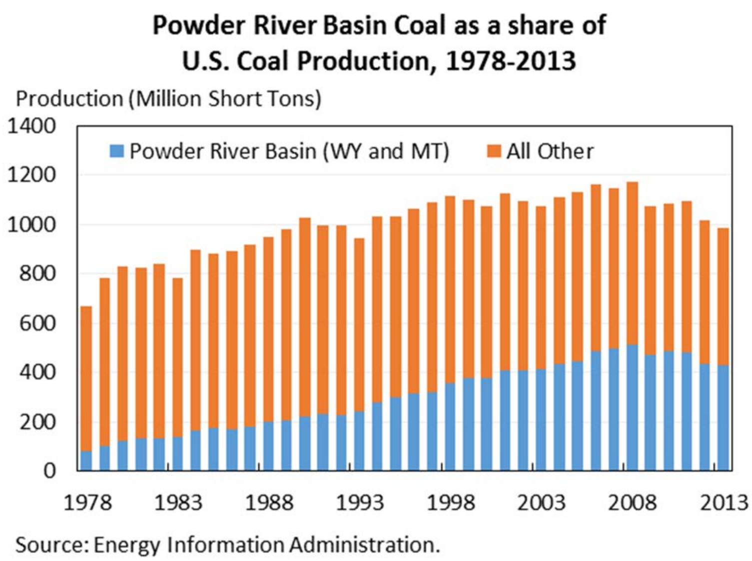


Figure 2. U.S. Coal Production from 1979 to 2013, showing the share of PRB coal. Source: EIA (2015a)

Another major shift over the past two decades is a divergence in dollars per ton coal prices at the mine mouth by State, as is shown in Figure 3.[7] In the 1990s, mine-mouth prices (i.e., prices at the time of first sale, just before transportation) were generally less than $30 per ton (in 2014$), with Appalachian and interior region coal bunching between $15 per ton and $30 per ton. In contrast, Federal PRB coal prices were around or less than $10 per ton. In the past several years, that gap between Federal PRB coal and private coal prices has widened, with private coal from Appalachian and interior States ranging from $30 per ton to as high as $100 per ton (in Virginia), while Federal PRB coal still remains close to $10 per ton. Another way to see this divergence is to consider that the ratio of the price of Southern West Virginia coal (a common benchmark for Appalachian coal) to the price of Wyoming PRB coal increased from 3.3 in 1990 to 5.0 in 2014.

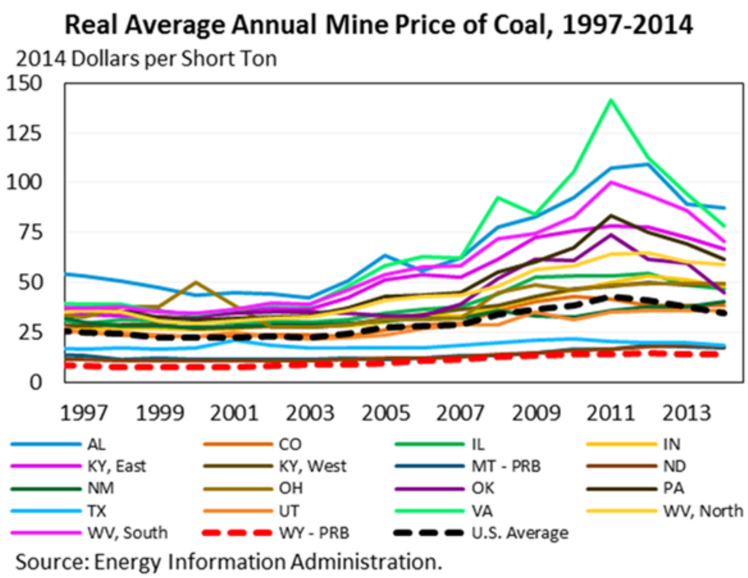


Figure 3. Average coal prices ($/ton) by State and basin from 1997 to 2014. Source: EIA (2016b)

The prices of coal from different locations can vary for a number of reasons. Federal PRB mines are all surface mines, while some of the other Federal leases are for underground mines, such as in Utah and Colorado. Surface mines tend to have lower costs. But, there are surface mines in the Appalachian and interior regions as well. Gerking and Hamilton (2008) argue that technological innovation and economies of scale help explain the lower prices of PRB coal, but these factors alone are unlikely to fully explain the cost difference, since surface mines elsewhere in the United States use similar technology (although not usually at quite the same scale).

Another explanation for the differences in price is that the coal itself is different. PRB coal is sub-bituminous coal with a low heat rate (i.e., low Btu content per ton) and low sulfur content. The low heat rate means that more coal must be burned to generate the same amount of electricity, which is a major disadvantage. However, the low sulfur content is advantageous for it can reduce

[7] The estimates in Figure 3 are simple arithmetic averages including all grades of coal. Non-metallurgical coal has continued to make up only a small percentage of coal, so most of the coal produced is thermal (steam) coal used for electricity generation.

the need for scrubbers to remove sulfur dioxide from the emissions (Considine and Larson 2006). Many coal electricity generating units can switch between coal of different grades based on relative prices. For reference, the Appendix presents average coal prices by State and basin over time only in terms of dollars per millions of Btu (MMBtu) of coal, rather than in terms of dollars per short ton of coal.

A further major difference is that Federal PRB coal is generally farther from markets and thus tends to have higher transportation costs. Another significant difference is that Federal PRB coal tends to be sold at low prices to subsidiaries, as is described in several recent reports, including Lee-Ashley and Thakar (2015). The coal is then sold for higher prices in a final transaction. This vertically-integrated arrangement may lower transaction costs (Joskow 1985), but it provides a perverse incentive by allowing firms to self-report deductions, as discussed above. Some final transactions may also have lower reported prices, but utilize take-or-pay contracts with high penalty payments.

Since the lower-cost Federal PRB coal makes up roughly 40 percent of the market, it clearly exerts a strong downward pressure on the national average coal price, as was noted in Sanzillo (2012). This downward pressure is a likely contributor to the sharper decline in production in the Appalachian and interior coal-producing regions over the past few years, especially as mines in those regions have moved into higher-cost coal deposits. Moving forward, EIA forecasts suggest that this trend will continue, further increasing the influence of Federal coal in setting lower market prices for coal in the United States (EIA 2015b). This is important in providing a motivation for approaches to ensure a fair return to taxpayers.

III. Approaches to Ensure a Fair Return to the Taxpayer from Federal Coal Leasing

Ensuring a fair return to the taxpayer and approaching the first-best outcome is challenging in light of the current legal framework of the Federal coal royalty program. Issues of asymmetric information and imperfect monitoring imply that DOI's Office of Natural Resources Revenue (ONRR) must expend significant resources in auditing coal contracts to prevent gaming and other abuses. DOI is undertaking efforts towards increasing transparency and further improving the Federal coal leasing process within the current framework.

The following are two possible approaches to help ensure a fair return to the taxpayer that are rooted in the economic perspective and observations about the current coal market described above. These approaches do not explicitly address changes that could improve transparency or improve the lease bidding process (GAO 2013), but rather they are premised on the fact that bonus bid auctions are structurally uncompetitive, and thus the royalty payments are the primary mechanism that can be used to move revenues from coal leasing closer to the first-best outcome.

Approach 1. Assess Royalties Based on the Full Market Value of Coal

The effective royalty rate is often much below the minimum level of 12.5 percent for surface coal mines or 8 percent for underground coal mines. This is only in part due to the granting of royalty waivers, suspensions, and reductions to encourage development. Due to these royalty reductions, GAO calculates that the effective royalty rate charged on revenues from all Federal leases in fiscal year 2012 was 11 percent.[8] This royalty rate varied significantly across States. In Wyoming, the effective rate was 12.2 percent and in Montana it was 11.6 percent. The rate was much lower in Utah and Colorado, coming in at 6.9 and 5.6 percent respectively. In more minor coal-producing States, such as North Dakota, it is even lower. As Wyoming and Montana are the largest coal-producing regions, the waivers do not appear to be the root of the issue.

There are additional important reasons why the true effective royalty rate is often much lower than the statutory minimum levels. By using the first sale for determining the market value of the coal that the royalties are assessed on, several issues may arise. For example, asymmetric information and costly monitoring may allow for reporting of artificially low prices at the first sale. Similarly, artificially high deductions for washing and transportation may also reduce the post-deduction reported price. In either case, the royalties would not be assessed on the full market value of the coal.

Under a framework analogous to property taxes, the market value for coal should be based on sale prices of coal with similar characteristics, from both Federal lands and non-Federal lands. Under such a framework, the most appropriate price to use would be the market price for coal with similar characteristics in the region of coal extraction. This market price would already be

[8] In contrast to Haggerty and Haggerty (2015), GAO defines the "effective royalty rate" as the rate after accounting for waivers. So, the rate would be the royalty revenue divided by the reported revenue from the first sale.

adjusted in large part for transportation costs. However, it may also be constructive to instead look to nation-wide market average coal prices. This could be particularly useful in locations where Federal coal dominates the regional market, potentially depressing the prices in that regional market. Under this approach, nation-wide market prices would be used to determine the starting royalty payment, although deductions for transportation costs might still be applied to reflect the different value of coal in different locations. However, deductions for poorly observable costs, such as washing costs, could be removed. Deductions for transportation costs are more easily observed and can be based on easily observable indices of coal transportation costs per rail mile, rather than on self-reported cost numbers. These changes would reduce the incentive for penalty payments, improve incentives for efficient transportation and washing, and help increase the likelihood that the company-reported market value of the coal is close to the true market value.

There may be cases where no non-Federal mines produce coal of exactly the same characteristics. This may be even be partly true with PRB coal. In this case, the royalty rate can be adjusted for the particular characteristics of the coal. For example, the true price of coal can be thought of on an energy-equivalent basis to reflect the fact that the heat rate of the coal is a determinant of its value in the coal power plant. Pricing on an energy-equivalent basis would imply pricing in units of dollars per Btu, rather than dollars per ton. Pricing this way also facilitates comparisons to the royalties collected from Federal leases for natural gas and oil on public lands. For example, after adjusting for the heat content of coal, the royalty rate being paid by surface PRB coal is roughly one third of the royalty rate paid for natural gas on Federal lands (on an energy-equivalent basis), even though they are both subject to a 12.5 percent royalty rate on their respective reported sales prices (before deductions).

It could be appropriate to adjust the royalty rate directly to reflect an adjustment for heat content, or to include a Btu-adjusted royalty "adder" on top of the base royalty rate. In other words, the royalty owed would be 12.5 percent of the revenues plus an additional payment in dollars per Btu. Similar adjustments would be possible for sulfur content and other characteristics, but the heat content adjustment is likely to be among the most important.

Approach 2. Increase the Royalty Rate to Maximize Revenues to the Taxpayer

If bonus bids are truly uncompetitive, then increasing the royalty rate to simply maximize the return to the taxpayer is another option for bringing revenues closer to the first-best outcome. For surface coal, the 12.5 percent royalty rate is a minimum royalty rate, and the Secretary of the Interior has discretion to increase this rate to ensure a fair return to the taxpayer. If externalities had been internalized and the leasing program was perfectly competitive, there would be a trade-off in that this approach would conceptually reduce coal production below the economically efficient level. Given that there are un-internalized externalities and the leasing program does not appear to be perfectly competitive, this trade-off is likely to be less of a concern.

The net results in terms of revenue to the public would depend on how production, and hence revenues, change with respect to changes in the royalty rate, and the degree to which the additional royalty revenues exceed any lost bonus bid revenue (due to fewer new leases as well as due to smaller economic profits to be bid on). But it is quite possible that this approach could substantially increase revenues and the return to the taxpayer. Whether it does is an empirical question, and the next section presents the results of a modeling exercise to explore this question and flesh out the implications of possible approaches for improving the return to the taxpayer. Whether this approach is the preferred approach overall may depend on whether there are other considerations regarding the Federal coal leasing program, ranging from development benefits and employment effects to environmental concerns.

IV. The Effects of Possible Reforms on Revenues and the Coal Market

Background

This section explores the effects of possible reforms to the Federal coal leasing program that are intended to ensure a fair return to the taxpayer. These effects depend on the economic environment that coal producers face going forward. For example, coal will be more economic if natural gas prices rise, less economic if utilities decide not to recommission coal plants for any number of reasons, and more economic if demand for coal increases in China or elsewhere. Any modeling analysis of the effects of a policy into the future should be taken as illustrative. One of the key factors that could influence the effects of possible reforms to the Federal coal leasing program is the Clean Power Plan, which is set to reduce emissions from the electric power sector by 32 percent by 2030. Many compliance approaches are possible under the Clean Power Plan, including fuel switching from coal and other carbon intensive fuels to less carbon intensive ways to produce electricity.

The analysis presented here is based on publicly available detailed spreadsheets with model results from IPM model runs also used in Vulcan (2016) and Gerarden et al. (2016). IPM is a well-established energy and electricity system model of the United States that is developed and run by the consulting firm ICF International. IPM has been used extensively for many years by the U.S. government in support of rulemakings. For example, the U.S. Environmental Protection Agency (EPA) Clean Power Plan technical analysis uses IPM for estimating the effects of the policy. The model has multiple regions, and in each region there are endogenously determined unit dispatch, capacity expansion, fuel switching, and environmental compliance decisions based on power market fundamentals. IPM also models coal resources (location and grade of the supply) and demand sources (electric generating units and other industrial users). In addition, IPM models coal imports and exports based on EIA Annual Energy Outlook 2015 projections.

Vulcan Philanthropy contracted with ICF to perform a set of IPM runs examining the effect of several different increases in royalties on all new Federal coal leases. The royalty payment increases are modeled as phasing in over 10 years, to roughly model the phasing in of the change in royalty rates as old leases expire and new or renewed leases are signed at the higher royalty rate. In performing the runs, ICF made every effort to use the same assumptions as the EPA and EIA have recently used. This includes the assumptions in the v5.15 Base and Final Clean Power Plan runs, as well as the EIA Annual Energy Outlook 2015. States have several options to comply with the Clean Power Plan, including mass-based plans (i.e., an emissions limit) and rate-based plans (i.e., an emissions intensity target). Vulcan (2016) uses IPM to model an all-mass-based plan and all-rate-based plan, just as is in the EPA Regulatory Impact Analysis of the Clean Power Plan. See Vulcan (2016) for further details on the cases run.

The effect of an increase in coal royalty payments may be different depending on whether States choose mass-based plans or rate-base plans.[9] It is also possible that some States choose mass-based plans and others choose rate-based plans. Such an intermediate case is likely bounded by the all-mass-based or all-rate-based cases. Under a rate-based regulation, an increase in royalty rates would change relative prices of fuels, which would impact both capacity investment and dispatch decisions, thus influencing costs and emissions. Under a mass-based plan, an increase in royalty rates may change the dispatch order in some States due to transportation costs and the location of Federal coal.[10] It is also possible that a sufficiently large increase in royalty rates could effectively accomplish the Clean Power Plan goals without further adjustments. Lower coal usage could make the emissions limit non-binding and lead to allowance prices that approach zero in some States.

The IPM is particularly well-suited for analyzing policy cases that capture all of these complicated dynamics of the electricity system. It also has a reasonably detailed characterization of the coal market with supply curves at a fairly disaggregated regional level, allowing for a careful modeling of the production of coal (and coal royalty revenues) after an increase in royalty rates. The Vulcan (2016) scenarios involved a dollars per ton royalty charge, which can be easily converted into actual increases in royalty rates given the price at the time. The royalty charges were applied to both surface and underground mines, but the results are driven by the surface mines, which account for over 80 percent of coal production on Federal leases. The royalty charges were also applied to the western States that produce nearly all coal from Federal lands: Colorado, Montana, Utah, and Wyoming.[11] However, it is important to note that the results are nearly identical if the focus is shifted to only PRB coal in Wyoming and Montana, given the dominance of these States in western Federal coal production.

Methodology and Scenarios Examined

For this analysis, CEA used the model results from the Vulcan runs at different values of per ton royalty charges. There were four values of royalty charges used in the Vulcan analysis (the current royalties and three cases with higher royalty payments). The first step in the CEA analysis was to linearly interpolate the results from these four runs in order to have a complete set of results for all values of the royalty charges.[12] This provides a set of estimated results (e.g., coal production, coal prices, royalty payments) for any value of royalty charges within the range of the original Vulcan runs.

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[9] Mass-based plans put a limit on the amount of emissions in the State in that year and can allow trading between sources. Rate-based plans put a limit on the average emissions rate in the State. Again, trading can be allowed.

[10] In a classic textbook mass-based regulation, if the emissions limit is binding, then the increased royalty rate would be exactly offset by lower allowance prices for coal-fired generation. In this textbook case, there would be no impact on capacity investment and dispatch decisions.

[11] Since the coal supply curves in the IPM do not differentiate federal from non-federal coal within sub-basins ("logical mining units") the increased royalties are applied to the supply curves on a weighted basis, based on the mix of federal and non-federal coal included in the supply curve. This is likely to be a very close approximation given how high a percentage of federal coal is mined in the Powder River Basin, which is almost entirely federal leases.

[12] There may be some interpolation error from this approach, so these results should be taken as illustrative. That said, the scaling appears to be quite linear, so it is very likely that the interpolation error is small.

The second step in the CEA analysis was to develop a set of four scenarios designed with the economic issues and approaches in mind. Each scenario is based on a different argument for improving the return to taxpayers from the coal leasing program. The CEA analysis is completed with a set of calculations based on the interpolated results.

One of the ways discussed above to improve the return to taxpayers is to assess the royalties on a value of produced coal that more closely approximates the true market value of coal. Three of the four scenarios are based on recalculating the market value of the coal based on a per-Btu market price, rather than the per-ton self-reported price that is currently used (Approach #1 from above).

- The first uses the market price for nearby regional coal;
- The second uses the market price for non-Federal coal nationwide;
- The third uses the price of natural gas because marginal dispatch decisions tradeoff between coal and gas.

Basing the market value of coal on the market price for nearby regional coal would by construction account for the fact that coal in different locations has a different value. One challenge with this approach is that in some regions there may be very little non-Federal coal produced. In this case, it may make sense to use the market price for non-Federal coal nationwide or the market price for a close substitute for coal in electricity dispatch decisions, such as natural gas. In using these other comparison market prices, the second and third scenarios do not account for the differing value of coal by location. Thus, in principle, the royalty payments for these scenarios should be adjusted downward for transportation costs, perhaps through a deduction for observable transportation costs.

For each of these three scenarios, the royalty charges can be calculated by determining what 12.5 percent of the scenario's price (in per-Btu terms) would be. The per-Btu values are then converted back to the dollars per ton royalty charge.[13] As an illustrative example for how these charges for each scenario are calculated, consider a scenario that bases the market value of coal on the market price of nearby regional coal. For concreteness, consider Federal PRB coal in 2016. Recent EIA coal market reports indicate the market spot price (pre-royalty) of nearby regional coal in Colorado and Utah is roughly $37 per ton, while the market spot price (pre-royalty) for PRB coal is roughly $9 per ton.[14] Converting these prices to per-Btu prices based on the different heat rates implies a market spot price of $1.62 per MMBtu for nearby regional coal and $0.53 per MMBtu for PRB coal. Taking 12.5 percent of the PRB coal price of $9 per ton is equivalent to a royalty charge of $1.13 per ton, which is roughly the current royalties being paid per ton on PRB coal. In contrast, taking 12.5 percent of the per-Btu price of nearby regional coal of $1.62 per MMBtu implies a royalty charge of $0.20 per MMBtu (i.e., $1.78 per ton) for PRB coal, a 58 percent increase in the royalty charge that would raise the post-royalty price by less than 12.5 percent.

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[13] Further refinement could adjust the market value for sulfur content, ash content, moisture content, etc.

[14] For example, see http://www.eia.gov/coal/markets/#tabs-prices-1.

A royalty charge based on the three scenarios could be applied in several different ways. One direct approach would be to simply apply a fee per ton on coal. This could be in addition to the current royalty rate as a per MMBtu "adder" or it could be an alternative to the existing Federal coal leasing structure. Another approach would work within the existing structure by increasing the royalty rate and keeping all other facets of the Federal leasing program the same. A third approach would be to retain the existing royalty rate, but apply the royalty rate on the market price of coal (as designated by the scenario), rather than the reported transaction price as in the current system. This would imply that the total royalties would be calculated as a percentage of the market value of coal based on the market price of coal (or substitute natural gas), rather than the market value based on the typically lower transaction prices currently reported.

The fourth scenario would maximize return to the taxpayer from the Federal coal leasing program (Approach #2 from above). In other words, the royalty payments would be increased until royalty revenues peak, after which they begin to decrease (due to reduced production). Increasing the royalty payments to this level is illustrative for providing a sense of how high the royalty payments could go while still increasing revenues. This may maximize return to the taxpayer from royalties, but it is possible that tax revenue on income and business profits would correspondingly decrease. These countervailing effects on tax receipts are not modeled here, but could be considered in further refinements of this analysis.

The Vulcan IPM model runs provide results for several years, but for clarity, this report focuses only on 2025. Note that the royalty charges tend to be larger in 2025 than they would be today because the overall coal price is expected to be higher than it is today. This report also focuses on results that include the mass-based Clean Power Plan in the baseline for illustrative purposes. Of course, the quantitative results would change under different Clean Power Plan configurations.

The analysis proceeds as follows. For each of the four scenarios, CEA began with the interpolated suite of results from the IPM runs based on different values of dollars per ton royalty charges. These are converted to dollar per MMBtu royalty charges. For the first three scenarios, we then calculate the dollar per MMBtu 2025 coal prices for each scenario (e.g., the regional coal price, nationwide coal price or natural gas price). For the regional average scenario, this is $40.71 per ton or $3.48 per MMBtu, implying a royalty payment of $0.32 per MMBtu in 2025 following the 9.3 percent average royalty collections on all Federal lands (all in 2012$).[15] For the national coal price, the production-weighted average price is $69.07 per ton or $5.76 per MMBtu, implying a royalty payment of $0.54 per MMBtu (all 2012$). It turns out that the natural gas price scenario is almost identical to the nationwide coal price scenario. This makes sense because coal and natural gas are substitute feedstocks in the dispatch order in the nationwide electricity generation market. Matching up these calculated per-Btu royalty payments with the per-Btu payments in the suite of results from the IPM runs yields a full set of results for each of these

[15] The 9.3 percent is calculated based on a production weighted average of the royalty rates by region in GAO (2013) based on production in the year 2025, which is the royalty rate after accounting for waivers, suspensions, or reductions.

scenarios. The maximizing revenue scenario simply finds the royalty charge that maximizes total government revenue.

Royalties Resulting from Each Scenario

Table 1 provides an overview of the four scenarios in 2025 based on the interpolated Vulcan IPM results. For each scenario, Table 1 shows the total royalty charge per ton of coal in 2025. It also shows the 2025 royalty rate that corresponds to this charge (if the increased royalty payments are achieved by increasing the rate rather than using a per ton or per Btu charge). Note that the current royalty structure is equivalent to roughly a $2 per ton royalty charge or a 9.3 percent weighted average royalty rate in 2025, so all of the estimates in the table can be compared to these values. The high royalty charge in the scenario that maximizes return to the taxpayer indicates that royalties can be increased dramatically before royalty revenue begins to decline. The extremely high royalty rate in that scenario is because the pre-royalty price is reduced to roughly $10 per ton (from roughly $19 per ton with the current royalty structure and rate).

Table 1. Four scenarios of different rationales for changing coal royalties to ensure a fair return to the taxpayer.

Scenario	2025 Royalty Charge (2012$/ton)	2025 Royalty Rate (percentage)
1. Prices based on nearby regional coal prices	3	17
2. Prices based on non-Federal nationwide coal prices	5	29
3. Prices based on natural gas prices	5	29
4. Maximize return to the taxpayer	30	304

Notes: The royalty charge in 2025 under the existing structure is just under $2/ton, which corresponds to a 9.3 percent royalty rate. The charges shown here can be compared to this current charge. The royalty rate is calculated as the royalty payment per ton of coal divided by the pre-royalty equilibrium average price per ton for Federal coal.

The findings in Table 1 indicate that under scenario 1 (regional prices), the current royalty rate could be replaced by a $3 per ton (or $0.32 per MMBtu) charge. If the current royalty rate is retained and an adder is included on top of the current rate, then the adder would be approximately $1 per ton (or $0.13 per MMBtu). Similarly, under scenarios 2 and 3 (national prices or natural gas prices), the adder on top of the current rate would be approximately $3 per ton (or $0.35 per MMBtu). Under scenario 4 (maximizing return), the adder on top of the current rate would be approximately $28 per ton (or $3.01 per MMBtu). The next section provides more detailed 2025 results for each of the four scenarios.

Illustrative Impacts on Production, Emissions, and Revenue

Before moving to the impacts for each of the options, there are some key findings common to all of the scenarios worth noting. The increased royalty payments for all scenarios lead to the following:

- The increase in royalty revenues is vastly larger than the loss in bonus bid revenue.

- Non-Federal coal production becomes slightly more competitive relative to Federal coal.
- The phase in of the policy (it is applied only to new lease sales, new lease modifications, and lease renewals) leads to a very minor impact on existing operations.
- There is reduced demand for new Federal leases, and a modestly higher price for coal, thereby improving margins for existing operations.
- For all but the maximize revenues approach, there is a modest reduction in net U.S. coal production and associated greenhouse gases, and a modest increase in market share for renewables. In the maximize revenues approach, there is a more substantial reduction in production and emissions.

The extent of each of these forces scales with the royalty charge. For example, the reduction in net U.S. coal production is much greater in scenario 4 than scenario 1. The results for each of the four scenarios are given in Table 2.

Table 2. IPM results for the scenarios once the changes are fully phased in (post-2025).

Scenario	Percent Change in Federal Coal Production	Emissions Reduction (MMtCO2/year)	Government Revenue Increase (millions 2012$)
1. Prices based on nearby regional coal prices	-3	12	0-290
2. Prices based on non-Federal national coal prices	-7	32	330-730
3. Prices based on natural gas prices	-7	32	330-730
4. Maximize return to the taxpayer	-53	319	2,700-3,110

Notes: These results are based on IPM runs. The government revenue is split between the States and the Federal government, following current practice. The ranges in the change in government revenue account for the possibility that bonus bid revenue is lost entirely; the lower bound should be considered extremely conservative, and is zeroed out in scenario 1. Emissions reduction calculates the direct reduction from reduced coal use nationwide.

A major finding from this modeling exercise is that the potential to bring in additional revenue to the public is quite substantial. While the past year may have been difficult for certain coal companies, in general, the analysis indicates there are large economic rents being earned on Federal coal, and only a small fraction of these rents are currently going to the States and the U.S. Treasury. Even the more modest increases in the royalty charge in scenarios 2 or 3 would bring in on the order of $0.7 billion in revenue annually (once fully phased in), would lead to fairly small decreases in western Federal coal production, and would have the offsetting effect of making non-Federal coal slightly more competitive in the nationwide market by leveling the playing field between the two.

The small, but positive, impact on non-Federal coal production is due simply to the changes in relative prices of coal. The IPM baseline results show eastern (Appalachian and Illinois basin) coal production in 2025 at 168.8 million tons of coal. Under scenario 1 (nearby regional prices), eastern coal production increases by just over 1 percent to 171.0 million tons of coal. Under scenarios 2 and 3 (nationwide or natural gas prices), eastern coal production increases by just over 3 percent to 174.5 million tons. Under the maximizing royalties scenario, eastern coal production increases by just over 25 percent to 211.6 million tons. At the same time, coal prices also slightly rise, suggesting that reform of the Federal coal leasing program could increase profits for eastern coal producers.

V. Environmental Externality Considerations

Although the focus of this report is on ensuring a fair return to the taxpayer from the Federal coal leasing program, there are other relevant economic considerations. The most important of these are un-internalized externalities from coal production, transportation, and consumption. On the production side, coal mining involves emissions of methane, which is a potent greenhouse gas. Coal extraction and processing also may lead to external costs from water pollution and land degradation. Transportation of coal is often energy and emissions intensive. Coal combustion releases carbon dioxide, mercury, and other harmful air pollutants. Impoundments and coal combustion waste can also lead to severe water pollution (Epstein et al. 2011).

The resulting climate and health impacts are either not internalized in the price of coal at all, or are imperfectly internalized. For example, coal-bed methane emissions and the social cost of carbon dioxide emissions are not currently internalized in the price of coal at all. Gerarden et al. (2016) model the coal market with the IPM to find that including a Federal coal royalty charge equal to the U.S. government social cost of carbon (IWG 2015) in the presence of the Clean Power Plan would reduce the price of tradeable emissions allowances (reducing the cost of the Clean Power Plan) and lead to additional emissions reductions by reducing leakage. In addition, Gerarden et al. (2016) find that in the absence of the Clean Power Plan, the same Federal coal royalty charge could achieve roughly three quarters of the emissions reductions that the Clean Power Plan is expected to achieve. Hein and Howard (2015) point out that even if the external costs from the carbon dioxide emissions from the combustion of coal are completely internalized through downstream regulation, there would still be an economic case for ensuring that royalties are sufficiently high to internalize the externalities caused by coal-bed methane emissions that are released during mining.

Many estimates of the external costs from the coal supply chain are large. Incorporating the social cost of carbon in coal royalties would imply a royalty rate of well-over 100 percent. Thus, there is an economic rationale for increasing royalty rates both to ensure a fair return to the taxpayers and to internalize environmental externalities. Under either rationale, an increase in royalty rates would improve economic efficiency.[16]

[16] Note that the National Environmental Policy Act (NEPA) environmental review process can also provide for the consideration of environmental externalities.

VI. Conclusion

This report examines the economics of the current coal leasing program in the United States, with a focus on ensuring a fair return to the taxpayer from the Federal coal leasing program. From an economic perspective, the current structure of the program faces issues of uncompetitive bidding, asymmetric information, and costly monitoring. These issues all have the potential to reduce the likelihood that taxpayers are receiving a fair return on coal production on Federal lands, and present DOI with a difficult challenge in best managing the program for the taxpayer. There are strong arguments from an economic perspective for basing the market value of coal on observable market prices, rather than self-reported prices, and only allowing easily verified deductions, such as for transportation costs.

These economic issues interact with the structure of the coal market in the United States today. The artificially low price of PRB coal exerts downward pressure on nationwide coal prices as the gap between PRB coal prices and coal prices elsewhere in the nation has increased. This gap has even put downward pressure on production of Appalachian and other non-Federal coal. The production of PRB coal, nearly all of it on Federal leases, has also increased to roughly 40 percent of the nationwide market. Exports remain small, largely due to transportation constraints, but the prices earned on exported coal are often much higher (EIA 2016b).

Using an economic lens and considering the current structure of the coal market, this report lays out two possible approaches to help ensure a fair return to the taxpayer. The first would assess royalties on the true observable market value of coal. Using observable market prices (rather than self-reported prices), limiting and standardizing deductions, and adjusting for the heat content (and possibly other characteristics) of coal would significantly help ensure that the market value of coal used to assess royalties is as close as possible to the true market value. The second option would be to increase the royalty rate to maximize return to the taxpayer. Since the bonus bid auctions are widely considered uncompetitive (GAO 2013), increasing royalty rates has the potential to increase the return to the taxpayer.

An analysis based on IPM modeling indicates that several different approaches to adjusting royalty rates could help address the economic issues in the current structure of the program. This analysis indicates that increasing royalty payments—either to approximate the effect of using market prices to determine the market value of coal, or to simply attempt to maximize the return to the taxpayer—serves to greatly increase Federal lease revenue collections, which benefit both States and the U.S. Treasury. It also has the consequence of raising the nationwide equilibrium price of coal, which improves the competitiveness of Appalachian and interior region coal production. Furthermore, increasing the royalty rate could help address externalities, thus improving economic efficiency.

Ensuring a fair return to the taxpayer from the Federal coal leasing program is an important objective, and economics provides valuable guidance on the incentives provided by different program structures and the potential effects of changes to the program. This guidance is a useful consideration—among others not analyzed—for potential changes to the Federal coal leasing program.

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Appendix

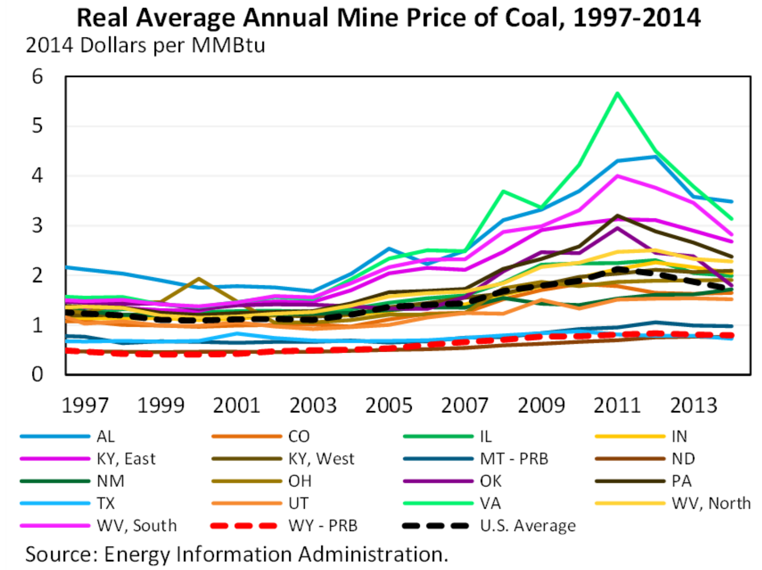

Figure A1. Average coal prices ($/MMBtu) by State and basin from 1997 to 2014. Source: EIA (2016b)