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Re: Comments to Proposed Rule, *Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform*, Docket No. ONRR-2012-0004

This letter provides comments on behalf of the Center for American Progress (CAP) on the proposed rule issued by the U.S. Department of the Interior's (DOI) Office of Natural Resources Revenue (ONRR) to amend regulations governing how federal coal is valued for purposes of assessing royalties, among other changes.

CAP is an independent nonpartisan policy institute that is dedicated to improving the lives of all Americans, through bold, progressive ideas, as well as strong leadership and concerted action.

CAP commends ONRR's efforts to reform the federal coal royalty system to close existing regulatory gaps through which companies are manipulating loopholes to evade paying royalties.[1] An outdated royalty system for federal coal is at the root of the problem, with the last reforms to this program occurring over 25 years ago. Additionally, DOI continues to provide generous subsidies to the industry in the form of royalty rate reductions, transportation and washing allowances and most importantly a royalty system that assesses royalties on a price of coal too early in the process that does not reflect its true market value.

ONRR's rulemaking presents a unique opportunity to reform the federal coal royalty system, cut subsidies and close loopholes. In fact, the public supports reforming the royalty system for coal production on public lands. Nearly two-thirds of Americans

[1] Press Release, U.S. Department of the Interior, Interior Announces Initial Steps to Strengthen Federal Energy Valuation Rules, Expand Guidance on Federal Coal Program (Dec. 19, 2014) http://www.doi.gov/news/pressreleases/interior-department-announces-initial-steps-to-strengthen-federal-energy-valuation-rules-expand-guidance-on-federal-coal-program.cfm

oppose providing federal subsidies to companies that mine coal on America's public lands, including 67% of Democrats, 66% of independents, and 62% of Republicans.[2] By a nearly two-to-one margin, voters want these subsidies ended.[3]

ONRR's proposed rule amends how non-arm's-length transactions are valued for purposes of assessing royalties. Specifically, the proposed rule eliminates the benchmarks currently used to value these transactions and instead requires that non-arm's-length transactions be valued at the first arm's-length transaction for assessing royalties. We believe the proposed rule is a step in the right direction, but does not go far enough to ensure royalties are paid on the true value of coal that is mined irrespective of whether the transaction is arm's-length or non-arm's-length. For the reasons discussed in these comments, CAP recommends that ONRR expand its proposed rule to use a netback model, which reflects the gross price of coal at its final point of sale, to value coal for purposes of assessing royalties. Under this model, ONRR would assess royalties based on the net delivered price of coal, while providing companies a transportation allowance not to exceed 50 percent of the net delivered price of the coal.[4] Coal washing deductions would not be allowed since washing, a process similar to refining oil or processing gas, is a cost of marketing coal that should not be borne by the federal government.

I. The Need for Royalty Reform

ONRR's current regulations for coal royalties have been in effect for more than 25 years. During this time, the coal industry and market have changed significantly, as has the U.S. energy landscape. ONRR has recognized the need to modernize its regulations, stating "in the years since we wrote these regulations, the Secretary of the Interior's (Secretary) responsibility to determine the royalty value of minerals produced has not changed, but the industry and marketplace have changed dramatically."[5] As currently written, ONRR's regulations provide regulatory and legal mechanisms by which companies are able to evade royalties by cloaking sales to their network of subsidiaries and affiliates as arm's-length transactions when they are in fact non-arm's-length, or "captive" transactions, which are sales between an affiliate and parent company.

[2] Hart Research Associates, "Public Opinion on Coal Mining Reforms on Public Lands," 2015, available at http://www.themountainpact.org/public-opinion-on-coal-mining-reforms-on-public-lands.).
[3] *Id.*
[4] "Net delivered price" is the net delivered price as the gross value of coal for royalty assessment.
[5] Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, 80 Fed. Reg. 608, 608 (Jan. 6, 2015) (to be codified at 30 C.F.R. pt. 1202 and 1206).

The current regulatory framework also provides agency officials the power to reduce the royalty rate that coal companies pay, thereby subsidizing coal production at a loss to taxpayers and the states. These flaws with the federal coal program distort the coal market and disadvantage other coal producing regions. Reform is urgently needed to fix this outdated program to ensure taxpayers and states are receiving a fair return on federal coal, and that coal companies are paying every dollar owed in royalties.

a. The Federal Coal Royalty System Is Outdated

Although DOI collects more than $1 billion annually in bonus bids and royalty revenues from coal-mining operations on federal lands, the government is not collecting the full value of this coal owed to U.S. taxpayers. Reports by the DOI Inspector General and the Government Accountability Office assessing the federal coal-leasing program have unearthed evidence of a lease sale process that is largely noncompetitive and reliant on a valuation system that is not transparent and vulnerable to industry manipulation. The basis for this problem is an outdated program governed by regulations that have not been updated in more than 25 years, including ONRR's regulations to assess royalties on federal coal, which were last updated in 1989.

President Obama's Extractive Industries Transparency Initiative (EITI) – a global initiative to improve the transparency of natural resource governance, including revenues — highlights why the coal royalty system is an important next chapter in the administration's energy reform agenda.[6] The President stated that the United States joined the EITI to ensure that "industries, governments and civil society, all work together for greater transparency so that taxpayers receive every dollar they're due from the extraction of natural resources."[7]

Today, however, DOI's outdated federal coal program can hardly be held up as a model of American leadership in transparency or efficiency. U.S. taxpayers and the states that share in these royalty collections are receiving far less than the royalty rate that is required to be collected from both surface and underground-mined coal.

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[6] U.S. Department of the Interior, U.S. Extractives Industries Transparency Initiative, http://www.doi.gov/EITI/index.cfm (last visited Dec. 2014).
[7] Press Release, Extractive Industries Transparency Initiative, President Obama: The US will implement the EITI (Sept. 20, 2011), https://eiti.org/news-events/president-obama-us-will-implement-eiti.

b. Coal Companies Are Abusing the Existing Royalty System and Evading Royalties through Non Arm's-Length Transactions

A growing body of evidence suggests that major coal companies mining coal on federal lands, particularly in the Powder River Basin, have been using their elaborate network of subsidiaries and affiliates to exploit loopholes in federal royalty regulations to maximize subsidies and avoid royalties. Most notably, companies are allegedly cloaking sales to their network of subsidiaries and affiliates as arm's-length transactions (when these sales are in fact captive, non-arm's-length transactions) to keep the price of coal artificially low for royalty, tax, and other valuation purposes.

A 2012 investigation by Reuters revealed that companies were engaging in non-arm's-length transactions by which they were selling federal coal at depressed prices to affiliates to pay a lower royalty on the coal sold; these affiliated companies were then selling the same coal on the export market for almost ten times its domestic value.[8] Republican and Democratic members of Congress and independent reviewers called on DOI to investigate these allegations, raising concerns that taxpayers are missing out on millions of dollars of revenue and emphasizing that "coal royalties were put in place so that 'people … receive a fair return on their coal, particularly when coal values are increasing rapidly.'"[9]

The captive transactions loophole has proven to be particularly lucrative for coal companies that are exporting PRB coal to foreign buyers. The Reuters investigation estimated that this loophole has allowed companies to pocket at least an additional $40 million on coal exports from Wyoming and Montana alone in 2011.[10] Cloud Peak Energy has itself stated publicly that in 2013 the company made $50 million on 3 to 4 million tons of exports, and "would like to do it again. It will happen. It's just a question of when."[11]

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[8] Patrick Rucker, *Asia Coal Export Boom Brings No Bonus for U.S. Taxpayers*, REUTERS, Dec. 4, 2012, http://www.reuters.com/article/2012/12/04/us-usa-coal-royalty-idUSBRE8B30IL20121204.
[9] Letter from Sen. Ron Wyden and Sen. Lisa Murkowski to Ken Salazar (Jan. 3, 2013), http://www.wyden.senate.gov/download/?id=ac99b7ed-8190-473f-9551-f8bb7d480999&download=1; SUBCOMMITTEE ON ROYALTY MANAGEMENT, REPORT TO THE ROYALTY POLICY COMMITTEE: MINERAL REVENUE COLLECTION FROM FEDERAL AND INDIAN LANDS AND THE OUTER CONTINENTAL SHELF (2007), http://www.onrr.gov/laws_r_d/RoyPC/PDFDocs/RPCRMS1207.pdf.
[10] Rucker, *supra* note 8.
[11] Darren Epps, *In Interview, Cloud Peak CEO Makes Case for Coal Export Business Strategy*, SNL ENERGY, Feb. 10, 2015, https://www.snl.com/InteractiveX/Article.aspx?cdid=A-31093971-12844.

Corporate filings for coal companies suggest that disguising sales to subsidiaries and affiliates as arm's-length to reduce federal royalty payments is a common practice and an integral part of these companies' business model. In a 2013 filing to the Securities and Exchange Commission, for example, Cloud Peak Energy says that the company's finances would be adversely affected if there is a change to how the federal government assesses royalty payments on non-arm's-length sales: "If the federal government were to materially alter the method for valuing royalty payments for our non-arms' length sales, our profitability and cash flows could be materially adversely affected."[12] Similarly, in a contract dispute filed in the U.S. District Court of Montana, *Western Minerals v. KCP*, Western Minerals alleged that Ambre Energy had engaged in "self-dealing transactions, by selling to itself coal from the Decker Coal Company through either Ambre Limited directly or an affiliated subsidiary and then reselling such coal at a higher price."[13]

A review of government data and the records of the largest coal companies operating in the PRB—such as Alpha Natural Resources, Ambre Energy, Arch Coal, Cloud Peak Energy, and Peabody Energy—further reveals that the major coal companies operating in the PRB have built an extensive network of subsidiaries and affiliates through which they sell and distribute their coal, which appears to help maximize their subsidies. In total, these five companies have built a network of *566 domestic and foreign affiliates and subsidiaries* through which they market and sell coal.[14]

[12] Cloud Peak Energy, 2013 10-K, http://hsprod.investis.com/shared/v2/irwizard/sec_item_new.jsp?epic=cloud-peak-energy&ipage=8721998&DSEQ=1&SEQ=45&SQDESC=SECTION_PAGE (last visited Dec. 2014).

[13] *Western Minerals v. KCP*, No. 1:12-cv-00085 (D. Mont. filed July 9, 2012), http://media.oregonlive.com/environment_impact/other/CloudPeakSuit.pdf.

[14] Alpha Natural Resources, operator of the Belle Ayr and Eagle Butte mines in Wyoming, has built a network of 184 domestic and foreign subsidiaries. Alpha Natural Resources, 2013 Wyoming Operations, http://www.alphanr.com/about/Quick Facts/Wyoming Facts.pdf (last visited Dec. 2014). Ambre Energy, which operates the Decker Mine in Montana that has produced more than 300 million tons of coal, has built a network of 26 domestic and foreign subsidiaries. Ambre Energy, Decker mine, http://www.ambreenergy.com/decker-mine (last visited Dec. 2014). Arch Coal—which controls more than 3.3 billion tons of coal reserves in the PRB and operates the Black Thunder Mine, one of the globe's largest coal mines and the first in the world to ship 1 billion tons of coal – has built a network of 83 domestic and foreign subsidiaries. Arch Coal, Our Mines, http://www.archcoal.com/aboutus/coalsupplyregions.aspx (last visited Dec. 2014); Arch Coal, Our Mines: Black Thunder, http://www.archcoal.com/aboutus/blackthunder.aspx (last visited Dec. 2014). Cloud Peak Energy, which operates the Antelope, Spring Creek, and Cordero Rojo mines in the PRB that produced more than 86 million tons of coal in 2013 alone, has built a network of at least 31 domestic subsidiaries.

Captive transaction sales through this network have skyrocketed in the past decade. According to the U.S. Energy Information Administration (EIA) almost half of all coal produced in Wyoming in 2012 – 42 percent – was sold through a captive transaction, up from just 4 percent in 2004.[15] This sharp increase appears to have begun in 2004, with captive transactions in Wyoming rising 105 percent between 2004 and 2005 alone.[16] Further, in 2013, all coal exported from Montana was sold through a broker or trader in a captive transaction.[17]

The states of Wyoming and Montana, in which the Powder River Basin is located, have raised concerns about coal company efforts to disguise transactions as arm's-length to reduce state royalty obligations. In 2012, the Montana Department of Revenue filed suit against Cloud Peak Energy, alleging that Cloud Peak Energy intentionally undervalued federal coal sold to two affiliates between 2005 and 2007 to pay reduced state taxes.[18] Likewise, the Wyoming Department of Audit has formally asked ONRR to change current regulations to better prevent coal companies from using their networks of subsidiaries to dodge royalties.[19] "Non-arm's-length transactions are highly susceptible to manipulation," wrote Michael Geesey, director of the Wyoming Department of Audit, to ONRR in 2011.[20] According to Geesey, ONRR should change current regulation to prevent coal company sales to "affiliates, partners, marketing

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Cloud Peak Energy, Operations, http://cloudpeakenergy.com/operations (last visited Dec. 2014). Peabody Energy—which operates the North Antelope Rochelle Mine in Wyoming, the largest coal mine in the United States—has built a network of 141 domestic subsidiaries and 101 foreign subsidiaries. Peabody Energy, North Antelope Rochelle Mine, http://www.peabodyenergy.com/mm/files/factsheets/narm.pdf (last visited Dec. 2014).

[15] ENERGY INFORMATION ADMINISTRATION, COAL DISPOSITION BY STATE (2012), http://www.eia.gov/coal/annual/pdf/table8.pdf; ENERGY INFORMATION ADMINISTRATION, ANNUAL COAL REPORT: 2004 (2005), http://www.eia.gov/coal/annual/archive/05842004.pdf.

[16] ENERGY INFORMATION ADMINISTRATION, ANNUAL COAL REPORT: 2004 (2005); ENERGY INFORMATION ADMINISTRATION, ANNUAL COAL REPORT: 2005 (2006), http://www.eia.gov/coal/annual/archive/05842005.pdf.

[17] ENERGY INFORMATION ADMINISTRATION, U.S. DOMESTIC AND FOREIGN COAL DISTRIBUTION BY STATE OF ORIGIN (2013), http://www.eia.gov/coal/distribution/annual/pdf/o_13foreign.pdf.

[18] *Cloud Peak Energy v. Montana Dep't of Revenue*, No. 14-0057 (Mont. filed Jan. 24, 2014), http://supremecourtdocket.mt.gov/search/case?case=16755.

[19] Letter from Michael Geesey, Director of Wyoming Department of Audit, to Hyla Hurst, Regulatory Specialist, Office of Natural Resources Revenue (July 26, 2011), http://www.onrr.gov/laws_R_D/PubComm/PDFDocs/AA00/AA00%20Wyo%20%20Dept%20of%20Audit.pdf.

[20] *Id*.

agents, and trade and export associations" from qualifying as arm's-length transactions.[21]

c. Subsidies Provided by the Department of the Interior Enable Coal Companies to Pay an Effective Royalty Rate that is Substantially Lower than the Minimum Royalty Rate Set By Law

A recent review by Headwaters Economics, an independent, non-profit research group, found that the effective royalty rate that coal companies pay when mining on federal lands is substantially lower than the rate required by law. The Mineral Leasing Act of 1920 and its amendments requires that coal companies pay a royalty of *at least 12.5 percent* on surface-mined coal and that the royalty rate for underground coal be set by regulation.[22] Under this authority, the Department of the Interior's leases for surface coal mines require that companies pay a 12.5 percent royalty rate. The Department of the Interior has promulgated a regulation setting the royalty rate for coal from underground mines at 8 percent.[23] The review by Headwaters Economics found, however, that because of royalty rate reductions, cost deductions, and other subsidies, coal companies are actually paying an average effective royalty of 4.9 percent for both surface and underground-mined coal.[24]

The Department of the Interior currently offers subsidies to coal companies in three forms. First, royalties are currently assessed on the so-called "first arm's-length sale" price of coal instead of the true market value of coal when it is sold to a power plant or exporter.[25] This means coal companies pay royalties on the price received at the first sale to another party, whether that party is non-affiliated and has opposing financial interests, or closely linked to the seller as an affiliated company. Frequently, the sale of

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[21] *Id.*

[22] 30 U.S.C. § 207(a).

[23] *Id*. § 207(a); 43 C.F.R. § 3473.3-2(a)(1)-(2); 43 C.F.R. § 3473.3-2(e). The FCLAA specifically provides that surface mine leases will be charged a minimum royalty of 12.5 percent and that the secretary of the interior sets by regulation the royalty rate for underground mine leases. "A lease shall require payment of a royalty in such amount as the Secretary shall determine of not less than 12 1/2 per centum of the value of coal as defined by regulation, except the Secretary may determine a lesser amount in the case of coal recovered by underground mining operations." 30 U.S.C. § 207(a).

[24] MARK HAGGERTY, HEADWATERS ECONOMICS, AN ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES: CURRENT ROYALTY STRUCTURE, EFFECTIVE ROYALTY RATES, AND REFORM OPTIONS (hereinafter "ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES") 1 (2015), http://headwaterseconomics.org/wphw/wp-content/uploads/Report-Coal-Royalty-Valuation.pdf.

[25] 30 C.F.R. § 1206.257.

federal coal occurs near the point of production, meaning that taxpayers typically receive royalties on the mine-mouth price of coal instead of the true market price at which the coal is sold to a power plant or other end user, such as a broker who exports the coal. Consequently, royalties are assessed too early in the sale process on a price that is not reflective of the true value of coal.

Second, the Department of the Interior provides royalty rate reductions for non-economically viable coal production or financial hardship. Through these reductions, coal companies can pay a royalty as low as two percent of the sale price if a mine becomes unprofitable due to adverse conditions, such as limited access to coal, a decrease in its quality, or circumstances when a company can make the case for financial hardship.[26]

Finally, coal companies qualify for generous transportation and washing allowances for coal produced from federal lands. Under the current system, lessees can deduct unlimited transportation and washing costs from the total sale price upon which royalties are due.[27] In comparison, similar transportation deductions for oil and gas are capped at 50 percent of the value of oil and gas and processing allowances for certain gas products are not permitted.[28] In the case of federal coal, this translates into an allowance for the full cost of transporting federal coal from the mine mouth to a remote point of sale or to transport the coal to a distant wash plant, and washing coal to remove impurities.[29]

These subsidies provide coal companies operating on federal lands a clear advantage over the oil and gas sectors. The review by Headwaters Economics found that the average effective royalty rate for oil and gas produced on federal lands is 12.4 percent, only one-tenth of one percent below the 12.5 percent royalty rate set by regulation.[30] Because natural gas and coal are paying a higher effective royalty rate, coal from federal

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[26] U.S. DEPARTMENT OF THE INTERIOR, OFFICE OF INSPECTOR GENERAL, COAL MANAGEMENT PROGRAM 14 (2013).
[27] 30 C.F.R. § 1206.257; 30 C.F.R. § 1206.261.
[28] *Id.* at § 1206.109.
[29] TAXPAYERS FOR COMMON SENSE, FEDERAL COAL LEASING: FAIR MARKET VALUE AND A FAIR RETURN FOR THE AMERICAN TAXPAYER 19 (2013), http://www.taxpayer.net/images/uploads/downloads/TCS_Federal_Coal_Leasing_Report_-_Final_-_Updated_10.4.13.pdf.
[30] ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES at 21.

lands has a competitive advantage over oil and gas when competing as sources of electric energy. These differences in policy distort U.S. energy markets.[31]

It is noteworthy that some of the United States' biggest coal competitors in Pacific markets, including Indonesia and Australia, do not allow many of the subsidies currently offered under the U.S. system. For example, the royalty rate for exported coal in Indonesia is based on the true market value of coal received at the export terminal, not necessarily the price at the mine mouth, which is a price determined from the benchmark price or actual sales price – whichever is higher.[32] Further, Indonesia does not allow transportation costs to be deducted from the price of coal upon which a royalty is levied.[33] Similarly, states in Australia do not allow transportation deductions for domestic shipments of coal.[34]

II. ONRR's Proposed Rule

a. ONRR's Proposed Rule Ensures Royalties are Paid on the First Arm's-Length Transaction of a Coal Sale, Streamlines the Valuation Process and Reduces Administrative Burden

Among other changes to existing regulations, ONRR is proposing to change the way non-arm's-length coal sales are valued for purposes of assessing royalties. Specifically, ONRR is proposing to eliminate the benchmarks currently used to value coal in non-arm's-length transactions and instead "value coal on the gross proceeds received for the first arm's-length transaction," which is how coal is currently valued for arm's-length sales.[35] In other words, ONRR's proposed rule is revising its regulations to apply the same method for valuing coal for both arm's length and non-arm's-length transactions. This would mean that royalties would be assessed on the gross proceeds of the first arm's-length sale irrespective of how far down the transaction chain this sale occurs, effectively closing the arm's-length sale, or captive transaction, loophole. In a recent poll conducted by Hart Research Associates, 80 percent of those polled had a "strong

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[31] *Id*.
[32] PRICEWATERHOUSECOOPERS, CORPORATE INCOME TAXES, MINING ROYALTIES AND OTHER MINING TAXES (2012), http://www.pwc.com/en_GX/gx/energy-utilities-mining/publications/pdf/pwc-gx-miining-taxes-and-royalties.pdf.
[33] *Id*.
[34] QUEENSLAND GOVERNMENT, DETERMINATION OF COAL ROYALTY (2012), https://www.osr.qld.gov.au/royalties/royalty-policy-min-140-coal-royalty.pdf.
[35] 80 Fed. Reg. at 609

negative reaction to coal companies' paying less in royalties by selling to their own subsidiaries at lower prices" and supported reforms to close this loophole.[36]

For non-arm's-length sales, ONRR currently assesses the value of coal based on comparable arm's-length sales of like-quality coal in the area.[37] In evaluating the comparability of other sales, ONRR applies additional valuation criteria: including price; time of execution; duration; market served; terms; quantity of coal; prices reported to a public utility commission, the EIA, or the Department of Energy for similar coal; publicly available spot market prices; or information submitted by the lessee regarding unique circumstances to its lease operation or sale.[38] ONRR is required to complete this labor intensive and complicated valuation assessment for each and every non-arm's-length sale, making this process unwieldy and administratively burdensome.

CAP commends ONRR for proposing this very important rule to close the captive transactions loophole. This rule change is a step in the right direction toward reducing the risk of royalty evasion and increasing clarity and simplicity in valuing coal for royalties. The rule further reduces the administrative burden to ONRR by eliminating benchmarks for valuing coal and applying a straightforward approach of using the gross proceeds from the first-arm's-length sale as the indicator for the value of coal.

III. CAP's Reform Proposal: Netback Pricing with Caps on Deductions

While ONRR's proposed rule closes one regulatory gap by eliminating the arm's-length transaction loophole, more significant reforms are needed to improve efficiency and transparency in the federal royalty-collection process. As written, the proposed rule only applies to non-arm's-length transactions and does not go far enough to ensure royalties are paid on the price that reflects the true market value of coal. ONRR explicitly states in its proposed rule that "at this time, ONRR is proposing no changes to the valuation of arm's length coal sales."[39] Nevertheless, royalties from arm's-length coal sales comprise the majority of royalties collected on annual coal sales, playing an equally, if not more significant role in revenues collected by ONRR for sales of federal coal.[40] For this reason, ONRR should revise its proposed rule to use a netback pricing model, which reflects the gross price of coal at its final point of sale, with a cap on

[36] Hart Research Associates, *supra* note 2.
[37] 30 C.F.R. § 1206.257(5)(c)(2)(i).
[38] *Id*. at § 1206.257(5)(c)(2)(ii)-(iv).
[39] 80 Fed. Reg. at 609.
[40] *Id.* at 639.

transportation deductions and no washing deductions. ONRR should move the valuation point of coal for royalties from the first arm's length sale to the net delivered price to ensure both arm's-length and non-arm's-length coal sales are assessed a royalty on the true value of the coal mined.

a. Royalties Should Be Assessed on the Market Price of Federal Coal, which Reflects the Commodities' True Value

ONRR is seeking additional comments "that elaborate on specific situations where further valuation changes should be considered" to "further streamline the valuation process, while also bringing added transparency to the system."[41] To that end, CAP is proposing that ONRR take a major step toward eliminating subsidies for coal by modernizing regulations to apply the federal royalty on the commodity's true market price, which is at the final point of sale to an end user, such as a utility or power plant, for both domestic and export sales.

For purposes of assessing a royalty on federal coal, the proposed rule states that ONRR is reaffirming that the value of coal produced from federal leases will be determined at or near the lease.[42] However, in a competitive marketplace, a product's value on the market is the price that maximizes profit for the seller based on what a buyer is willing to pay.[43] In the case of federal coal that is mined for combustion in power plants, power plants are the buyers in the market, and the price they are willing to pay is the market value for this coal. In theory, royalties should be paid on the market value of coal, which would mean the net delivered price away from the lease.

There is strong public support for reforming the federal coal royalty system so royalties are paid on the true market value of coal. According to the January 2105 public opinion poll conducted by Hart Research on coal subsidies, 69 percent of respondents believes royalties should be assessed on the true market price of coal, rather than the price when it is sold to a broker or a middleman.[44] In the case of Powder River Basin coal, in particular, the net delivery price for this coal is frequently much higher than the mine-mouth price, or the market price for the coal at its point of origin. For example, the average mine-mouth price of PRB coal is $11.55 per ton, but it is sold for more than

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[41] *Id*. at 609.
[42] *Id*.
[43] N. Gregory Mankiw, Principles of Microeconomics 67 (7th ed. 2014), http://www.cengage.com/economics/mankiw/samplechapter/Mankiw6e_Econ_Ch04.pdf.
[44] Hart Research Associates, *supra* note 2.

triple that price—roughly $37 per ton—when it ultimately reaches market downstream in the Midwest.[45] Under ONRR's proposed rule, royalties would only be paid on the low price of $11.55 and not the price of $37, which reflects the real value of this resource.

By collecting federal coal royalties on these artificially low mine-mouth prices rather than the net delivery price at the final point of sale, the federal government and states are losing out on significant revenue. For example, a 12.5 percent royalty rate for a ton of coal priced at $60 per ton yields a royalty of as much as $7.50 per ton, assuming that the coal company does not receive additional transportation and processing subsidies. In contrast, a ton of coal sold at $13 per ton yields a royalty of only $1.63 per ton. These royalty losses are magnified when applied to the millions of tons of federal coal sold annually.

Through this rulemaking, ONRR has the authority to revise its regulations to change the royalty measurement point for federal coal to the net delivered price. This rulemaking presents a unique opportunity for ONRR to amend its regulations to ensure taxpayers are receiving royalties reflective of the commodities' true value and every dollar due in royalties for this publicly-owned resource.

b. ONRR Should Limit Transportation Allowances to Match those Currently Provided to the Oil and Gas Industry

The proposed rule should establish a cap on transportation deductions for federal coal. These deductions should be limited to a maximum of 50 percent of the net delivered price of coal to limit the subsidies currently provided by DOI and to level the playing field with the oil and gas industry. ONRR's proposed rule explicitly solicits comment on whether the transportation deduction for federal coal should be capped at 50 percent of the value of the coal.[46] Public opinion shows that taxpayers by nearly two to one support ending subsidies to coal companies that are mining on public lands.[47] The Director for the Wyoming Department of Audit has also expressed support for limiting transportation and washing deductions so they are in line with the oil and gas industry, stating "[transportation and washing allowances] should be the same as oil and gas."[48]

[45] Energy Information Administration, *Coal News and Markets, Week ending December 12, 2014*. Average Midwest market price is based on authors' analysis of data obtained from Energy Information Administration, "Form EIA-923 detailed data."
[46] 80 Fed. Reg. at 629.
[47] Hart Research Associates, *supra* note 2.
[48] ENERGY INFORMATION ADMINISTRATION, *supra* note 17.

ONRR's regulations currently provide unlimited deductions for reasonable, actual costs incurred for the transportation of federal coal to a sales point remote from the mine and lease or to a washing plant, so long as the royalty paid is not reduced to zero by these deductions.[49] The transportation deduction is akin to a tax deduction and provides coal companies a deduction on the value of coal upon which royalties are assessed, thereby reducing their royalty obligation.

If the point of valuation for coal were based on the true market price when coal is delivered, and if transportation deductions were capped at a maximum of 50 percent of the net delivered price, the proposed reforms would result in an average increase of $0.85 per ton in royalty payments.[50] Based on royalty collections between 2008 and 2013, these reforms would have generated an additional $2.6 billion in revenue over a five-year period, or $512 million annually (a 73 percent increase in revenue) – for a total of roughly $7.6 billion in royalty collections during this time.[51]

In addition to the revenue benefits for state governments and U.S. taxpayers, limiting transportation deductions for federal coal would help level the playing field with other fossil fuels subject to royalties, including oil and gas. Under current regulations, the transportation allowance for the oil and gas industry is capped at 50 percent of the value of the commodity.[52] However, the coal industry has had the benefit of unlimited transportation deductions for decades now, giving the industry a competitive advantage over the oil and gas sector.

c. ONRR Should Eliminate Washing Allowances for Coal Because They are a Cost of Marketing the Commodity

ONRR should eliminate all washing allowances for federal coal because, similar to refining oil or processing gas, washing is a process necessary to make coal marketable and thus a cost that should be borne by the lessee. The Mineral Leasing Act has been interpreted as obligating lessees to place mineral resources they extract in "marketable

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[49] 30 C.F.R. § 1206.257; 30 C.F.R. § 1206.258.
[50] ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES at 25.
[51] MARK HAGGERTY, HEADWATERS ECONOMICS, THE IMPACT OF FEDERAL COAL ROYALTY REFORM ON PRICES, PRODUCTION, AND STATE REVENUE (hereinafter "THE IMPACT OF FEDERAL COAL ROYALTY REFORM") 2 (2015), http://headwaterseconomics.org/wphw/wp-content/uploads/Report-Coal-Royalty-Reform-Impacts.pdf; CAP's calculations are based on the assumption that the current royalty system in place generated $4.8 billion in revenue from 2008 to 2012; ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES at 3.
[52] 30 C.F.R. § 1206.109(c); 30 C.F.R. § 1206.156(c).

condition" at no cost to the federal lessor (or government).[53] "Marketable condition" under ONRR's regulations means "coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area."[54] Coal washing is a process used to remove impurities of the coal.[55] As a result, washing costs are costs associated with making federal coal marketable, which is an obligation the lessee bears.

The Director for the Wyoming Department of Audit has also recognized that coal washing is a process required to place coal in marketable condition and for which no allowance should be permitted.[56] Further, ONRR's regulations do not permit lessees of natural gas to deduct the cost of placing residue gas and plant products in marketable condition.[57] ONRR should treat federal coal on the same footing and eliminate all washing deductions, because washing is a used to place coal in marketable condition and these expenses associated with making coal marketable are the responsibility of the lessee.

d. Benefits of CAP Proposal

Reforming the federal coal royalty system to apply a netback pricing method, which reflects the gross price of coal at its final point of sale, with caps on transportation deductions fulfills the goals of ONRR's rulemaking. The rulemaking is intended to "provide regulations that (1) offer greater simplicity, certainty, clarity and consistency in product valuation…; (2) are more understandable; (3) decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) provide early certainty to industry and ONRR that companies have paid every dollar due."[58] CAP's straightforward and simple reform would alleviate burdensome royalty assessments for ONRR while also ensuring that taxpayers are receiving a royalty on the true market value of coal. Currently, the EIA provides publicly available information with the final sales price for federal coal.[59] ONRR auditors could use this information to calculate and verify royalty obligations, eliminating the need for complicated and time-consuming

[53] *Devon Energy Corp. v. Norton*, 2007 U.S. Dist. LEXIS 61709 (D.D.C. 2007) (citing to *California Co. v. Udall*, 296 F.2d 384, 387-88 (D.C. Cir. 1961) (upholding marketable condition requirement)).
[54] *Id.* § 1206.251.
[55] *Id*.
[56] ENERGY INFORMATION ADMINISTRATION*, supra* note 17.
[57] 30 C.F.R. § 1206.158.
[58] 80 Fed. Reg. at 608.
[59] ENERGY INFORMATION ADMINISTRATION, ANNUAL COAL REPORT (2013), http://www.eia.gov/coal/annual/.

closed-door valuation assessements by federal regulators. Using publicly available data also means there is no additional reporting obligation placed on the industry.

Additionally, a netback pricing model would provide greater consistency in how both arm's-length and non-arm's-length sales are valued for royalties. Coal companies have raised concerns that ONRR's rule is discriminatory and disadvantages vertically integrated companies because the rule purportedly treats non-arm's-length transactions differently than arm's-length transactions.[60] By using the net delivery price to value coal for assessing royalties, all companies - whether they are vertically integrated or not - would pay a royalty on the final net delivery price of coal, minus allowable deductions. Applying this netback method alleviates any concerns of the proposed rule having a discriminatory effect.

Reforms to the federal coal royalty system to use the net delivery price for assessing royalties and capping transportation deductions would mean not only greater revenues for taxpayers for the sale of federal coal, but would also mean greater returns for states in which federal coal development takes place. Royalties and bonus bids collected on coal are an important part of both federal and state budgets, especially for Wyoming and Montana, which are home to the coal-rich Powder River Basin. The royalties received by the federal government from coal production are split roughly equally between the U.S. Treasury Department and coal-originating states.[61] As a result, there is a direct benefit to states from which federal coal is extracted. Royalty payments to states provide a significant source of funding for schools, universities, highways, and construction statewide.

Furthermore, implementing a netback pricing model with limits on transportation and washing allowances would have a minimal effect on overall federal coal prices and production, as well as state revenues. Gross delivered prices for federal coal would only rise by roughly $1.17 per ton and domestic demand for coal would only fall by one percent.[62] In the state context, increased royalty distributions to coal producing states would outweigh any decline in state tax revenues due to marginal declines in production and the offset of state severance taxes by federal royalties due.[63] Of note, Wyoming

[60] Taylor Kuykendall, *Critics of Federal Coal Leasing Program Say Reform 'Urgently Needed*,' SNL ENERGY (Jan. 6, 2015), https://www.snl.com/InteractiveX/Article.aspx?cdid=A-30471504-14128
[61] 30 U.S.C §§ 191, 191a, 355.
[62] THE IMPACT OF FEDERAL COAL ROYALTY REFORM at 2.
[63] *Id.*

could receive an additional $234 million annually in additional revenue and Montana could receive as much as an additional $8.8 million annually.[64]

IV. Conclusion

Under current royalty regulations, U.S. taxpayers and state governments are missing out on hundreds of millions of dollars in revenue that would accrue if coal companies were required to pay a royalty on the true market price of coal, rather than being able to exploit generous taxpayer-funded subsidies and regulatory loopholes.

Taxpayers and states are not the only parties that are hurt by an outdated federal coal royalty system. DOI's subsidies for coal distort U.S. energy markets, incentivize U.S. coal exports by subsidizing transportation costs, disadvantage cleaner sources of energy, and ultimately undercut the president's Climate Action Plan. DOI should level the playing field between coal operators and ensure that taxpayers are receiving a fair return on their publicly owned resources by expanding its proposed rule to apply the federal royalty rate to the true market value of coal at its final point of sale and limit transportation and washing deductions.

Respectfully,

/s/ Nidhi Thakar

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Attachments

[64] *Id*.

Center for American Progress

Cutting Subsidies and Closing Loopholes in the U.S. Department of the Interior's Coal Program

By Matt Lee-Ashley and Nidhi Thakar January 6, 2015

In 2002, the Powder River Basin, or PRB, in Wyoming and Montana surged past the Appalachian coalfields that stretch from Pennsylvania to Tennessee to become the nation's largest coal-producing region.[1] Today, the PRB occupies a 40 percent share of the U.S. coal market.[2] Although market forces, mechanization, and technological changes help explain some of the coal industry's decision to shift more production from privately owned lands in the East to federal lands in the American West, the U.S. Department of the Interior's, or DOI's, coal policies have played an equally important—though largely unnoticed—role in this transition.

Specifically, the DOI's Bureau of Land Management, or BLM, and Office of Natural Resources Revenue, or ONRR, use their royalty-collection authority to subsidize coal production on federal lands. Coal companies, in turn, have learned to maximize these subsidies by shielding themselves from royalty payments through increasingly complex financial and legal mechanisms. Reform is urgently needed to cut these subsidies and to close loopholes that disadvantage other coal producing regions and distort U.S. energy markets.

Subsidizing federal coal through royalty relief

The law governing royalty payments for coal produced on federally owned lands is straightforward. Under the Mineral Leasing Act of 1920 and its amendments, coal companies are required to pay a royalty of at least 12.5 percent of the value of surface-mined coal and 8 percent for coal from underground mines.[3] The law authorizes the secretary of the interior to set the regulations by which the value of federal coal is determined for calculating a royalty.

In a competitive marketplace, a product's value on the market is the price that maximizes profit for the seller based on what a buyer is willing to pay.[4] In the case of thermal coal—or coal that is burned to produce electricity—power plants and electric utilities are the buyers in the market. The market value of thermal coal, therefore, is the price that power plants are willing to pay for the product. In theory, royalties should be paid on this market price of coal.

In reality, however, the DOI has built a complex regulatory framework that provides agency officials the power to reduce the effective royalty rate that coal companies pay and thereby subsidizes coal production. The subsidies that DOI officials routinely provide coal companies come in three forms:

1. **The assessment of royalties on the so-called "first arm's-length sale" price of coal instead of the true market value.** Coal companies pay royalties on the price that they receive at the first sale to another entity. This transaction can be to an affiliated or nonaffiliated entity but must be valued as an arm's-length transaction irrespective of the buyer's relationship to the coal company.[5] This sale often occurs near the point of production, meaning that taxpayers typically receive royalties on the mine-mouth price of coal instead of the true market price at which the coal is sold to a power plant or other end user, such as a broker who exports the coal. As a result, the federal government assesses royalties too early in the sale process and on prices that are not reflective of the true value of coal, which in turn results in lower royalty returns to taxpayers.

2. **Royalty reductions for noneconomically viable coal production or financial hardship.** The BLM provides royalty reductions as low as 2 percent of the sale price if a mine becomes unprofitable due to unfavorable conditions—such as limited access to coal or a decrease in its quality—or if a mining company can show it is facing financial hardship.[6]

3. **Subsidies for the costs of washing and transporting coal produced on federal land.** Under the current system, coal lessees can deduct transportation and washing costs, with no cap on deductions, from the total sale price upon which federal coal royalties are due.[7] This translates into an allowance for the full cost of transporting federal coal from the mine mouth to a remote point of sale or to transport the coal to a distant wash plant.[8] Unlike coal, transportation deductions for oil and gas are capped at 50 percent of the value of the resource.[9]

Captive transactions

The coal industry staunchly defends these subsidies and is lobbying the Obama administration to preserve them. In fact, the National Mining Association told the administration in November 2014 that the royalty-collection system is working and that the coal-valuation regulations that were last updated in 1989 are still relevant and effective.[10] In their written presentation to the administration, the National Mining Association argues, "Changes to the existing regulations are not justified as there have been no significant market changes in the last 25 years and markets are even more transparent."[11]

A review of government data and the records of the largest coal companies operating in the PRB—such as Alpha Natural Resources, Ambre Energy, Arch Coal, Cloud Peak Energy, and Peabody Energy—reveals that, notwithstanding industry claims that the markets have remained stagnant, the coal market in the PRB has changed dramatically in the past decade alone. Of perhaps greatest note, the major coal companies operating in the PRB have built an extensive network of subsidiaries and affiliates through which they sell and distribute their coal, which appears to help maximize their subsidies.

A review of corporate documents from five of the biggest coal companies operating in the PRB, listed below, reveals hundreds of affiliates and subsidiaries of parent companies with names such as Excelven Pty Ltd., licensed in the British Virgin Islands, and Jacobs Ranch Holdings LLC, licensed in Delaware.[12]

- Alpha Natural Resources, operator of the Belle Ayr and Eagle Butte mines in Wyoming, has built a network of 184 domestic and foreign subsidiaries.[13]
- Ambre Energy, which operates the Decker Mine in Montana that has produced more than 300 million tons of coal, has built a network of 26 domestic and foreign subsidiaries.[14]
- Arch Coal—which controls more than 3.3 billion tons of coal reserves in the PRB and operates the Black Thunder Mine, one of the globe's largest coal mines and the first in the world to ship 1 billion tons of coal—has built a network of 83 domestic and foreign subsidiaries.[15]
- Cloud Peak Energy, which operates the Antelope, Spring Creek, and Cordero Rojo mines in the PRB that produced more than 86 million tons of coal in 2013 alone, has built a network of at least 31 domestic subsidiaries.[16]
- Peabody Energy—which operates the North Antelope Rochelle Mine in Wyoming, the largest coal mine in the United States—has built a network of 141 domestic subsidiaries and 101 foreign subsidiaries.[17]

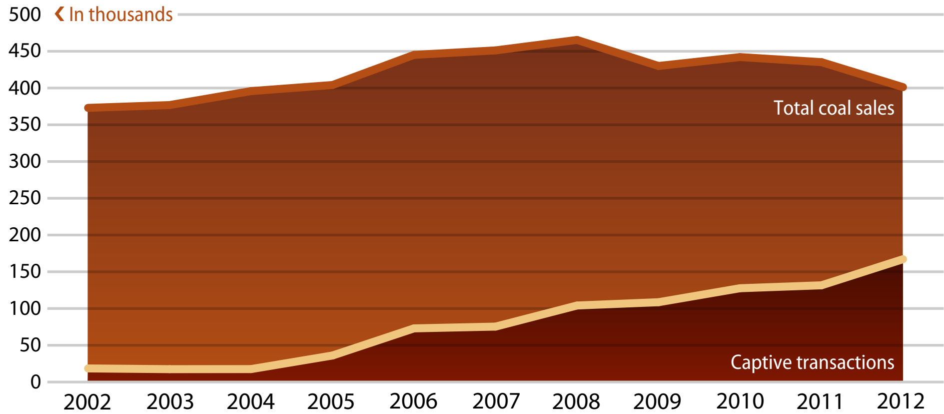
A full list of the affiliates and subsidiaries of these companies is provided in the appendix.

Sales of PRB coal through this network have skyrocketed in the past decade. According to data from the U.S. Energy Information Administration, or EIA, 42 percent of all coal produced in Wyoming in 2012 was sold through a "captive transaction"—a sale between an affiliate and parent company—up from just 4 percent in 2004.[18] This upward trend appears to have begun in 2004; captive transactions in Wyoming spiked 105 percent between 2004 and 2005 alone.[19]

FIGURE 1

Rise in captive transactions in Wyoming, 2002 to 2012

Sales of coal to affiliates and subsiaries, thousands of short tons



Source: U.S. Energy Information Administration, Annual Coal Report (U.S. Department of Energy, 2004–2012), available at http://www.eia.gov/coal/annual/.

Evading royalties

A growing body of evidence suggests that the major coal companies use their elaborate network of subsidiaries and affiliates to maximize the subsidies that can be gained through existing federal royalty regulations. To keep the price of coal artificially low for royalty, tax, and other valuation purposes, companies are allegedly cloaking sales to their network of subsidiaries and affiliates as arm's-length transactions when they are in fact captive, non-arm's-length transactions.

For example, in *Western Minerals v. KCP*—which involved a contract dispute filed in the U.S. District Court of Montana in 2012—Western Minerals alleged that Ambre Energy engaged in "self-dealing transactions, by selling to itself coal from the Decker Coal Company through either Ambre Limited directly or an affiliated subsidiary and then reselling such coal at a higher price."[20]

Similarly, in *Cloud Peak Energy v. Montana Department of Revenue*—a Montana state court case regarding a tax dispute—the state of Montana alleged that Cloud Peak Energy intentionally undervalued federal coal sold to two affiliates between 2005 and 2007 to pay reduced taxes.[21]

Coal industry records suggest that masking sales to subsidiaries and affiliates as arm's length to reduce federal royalty payments is a common practice. In a 2013 filing to the Securities and Exchange Commission, for example, Cloud Peak Energy says that the company's finances would be adversely affected if there is a change to how the federal government assesses royalty payments on non-arm's-length sales: "If the federal government were to materially alter the method for valuing royalty payments for our non-arms' length sales, our profitability and cash flows could be materially adversely affected."[22]

The arm's-length-transaction loophole is particularly lucrative for coal companies that are exporting PRB coal to foreign buyers.[23]* A 2012 Reuters investigation estimated that the loophole allowed companies to pocket at least an additional $40 million on coal exports from Wyoming and Montana alone in 2011.[24]

The state of Wyoming—which, similar to other coal producing states, receives approximately 50 percent of the royalty revenue from coal production on federal lands within its boundaries—has formally asked the Obama administration to change current regulations to better prevent coal companies from using their networks of subsidiaries to dodge royalties.[25] "Non-arm's-length transactions are highly susceptible to manipulation," wrote Michael Geesey, director of the Wyoming Department of Audit, to ONRR in 2011.[26] According to Geesey, Wyoming's chief auditor, ONRR should change current regulation to prevent coal company sales to "affiliates, partners, marketing agents, and trade and export associations" from qualifying as arm's-length transactions.[27] Republican and Democratic members of Congress and independent reviewers have also called for reforms to close this loophole.[28]

Overdue reforms and recommendations to eliminate subsidies and close loopholes

President Obama's 2011 commitments under the Extractive Industries Transparency Initiative, or EITI—a global initiative to improve the transparency of natural resource governance, including revenues—highlight why the coal royalty system should be an important next chapter in the administration's energy reform agenda.[29] The president has stated that the United States joined the EITI to ensure that "industries, governments and civil society, all work together for greater transparency so that taxpayers receive every dollar they're due from the extraction of natural resources."[30]

Today, however, the DOI's federal coal program can hardly be held up as a model of American leadership in transparency or efficiency. U.S. taxpayers and the states that share in these royalty collections are receiving far less than the 12.5 percent royalty rate that is required to be collected from surface-mined coal. Additionally, the United States' biggest coal competitors in Pacific markets, such as Indonesia and Australia, do not allow many of the subsidies currently in place under the U.S. system. In Indonesia, for example, the royalty rate for exported coal is based on the true market value of the coal received at the export terminal, which is a price determined from the benchmark price or actual sales price, whichever is higher.[31] Further, Indonesia does not allow transportation costs to be deducted from the price of coal upon which a royalty is levied.[32] Likewise, states in Australia do not allow transportation deductions for domestic shipments of coal.[33]

***Correction, February 9, 2015:** This issue brief has been corrected to remove a reference to Peabody Energy's revenues and royalty payments. Endnote 23 has also been updated.*

The DOI has acknowledged some of the deficiencies of the current royalty-collection system, recently issuing a proposed rule to remedy the arm's-length-transaction loophole.[34] While this proposed rule closes one regulatory gap by eliminating the arm's-length-transaction loophole, more significant reforms are needed to improve efficiency and transparency in the federal royalty-collection process.

The Obama administration should take a major step toward eliminating the DOI's subsidies for coal by modernizing existing regulations to apply the federal royalty on the commodity's true market price—which is at the final point of sale to an end user, such as a utility or power plant, for both domestic and export sales. This straightforward reform would alleviate burdensome royalty assessments for ONRR while also ensuring that taxpayers are receiving a royalty on the true market value of coal. Currently, the EIA provides publicly available information with the final sales price for federal coal;[35] ONRR auditors could use this information to calculate and verify royalty obligations, eliminating the need for complicated and time-consuming closed-door valuation estimates by federal regulators.

Making such a change would not come without opposition from coal companies, which have built a complex system of corporate entities to game the current system and shortchange taxpayers. Nevertheless, the administration must enact reforms. Each month, U.S. taxpayers and state governments are missing out on tens of millions of dollars in revenue that would accrue if the DOI was enforcing the minimum 12.5 percent royalty rate that is required by statute rather than effectively lowering rates through subsidies and regulatory loopholes.

Taxpayers are not the only ones hurt by an outdated coal royalty system. Federal subsidies in the PRB unfairly disadvantage coal producers in Appalachia and other regions, contributing to job losses and economic dislocation in Appalachia. More broadly, the DOI's subsidies for coal distort U.S. energy markets, incentivize U.S. coal exports by subsidizing transportation costs, disadvantage cleaner sources of energy, and ultimately undercut the president's Climate Action Plan. The DOI should level the playing field between coal operators and ensure that taxpayers are receiving a fair return on their publicly owned resources by expanding its proposed rule to apply the federal royalty rate to the true market value of coal at its final point of sale.

Matt Lee-Ashley is Director of the Public Lands Project and a Senior Fellow at the Center for American Progress. Nidhi Thakar is the Deputy Director of the Public Lands Project at the Center.

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Appendix: Network of Powder River Basin coal companies

Alpha Natural Resources, Inc.: Subsidiaries

T. Massey Coal Company, Inc.

Alex Energy, Inc.

Alpha American Coal Company, LLC

Alpha American Coal Holding, LLC

Alpha Appalachia Holdings, Inc.

Alpha Appalachia Services, Inc.

Alpha Australia, LLC

Alpha Australia Services, LLC

Alpha Coal India Private Limited

Alpha Coal Resources Company, LLC

Alpha Coal Sales Co., LLC

Alpha Coal Sales International Limited

Alpha Coal West, Inc.

Alpha European Sales, Inc.

Alpha Gas and Oil Company

Alpha India, LLC

Alpha Land and Reserves, LLC

Alpha Midwest Holding Company

Alpha Natural Resources, Inc.

Alpha Natural Resources, LLC

Alpha Natural Resources International, LLC

Alpha Natural Resources Services, LLC

Alpha Natural Resources Singapore Private Limited

Alpha PA Coal Terminal, LLC

Alpha Shipping and Chartering, LLC

Alpha Sub One, LLC

Alpha Sub Two, LLC

Alpha Terminal Company, LLC

Alpha Wyoming Land Company, LLC

AMFIRE, LLC

AMFIRE Holdings, LLC

AMFIRE Mining Company, LLC

AMFIRE WV, L.P.

ANR Receivables Funding, LLC

Appalachia Coal Sales Company, Inc.

Appalachia Holding Company

Aracoma Coal Company, Inc.

Austin Rubber Company LLC

Axiom Excavating and Grading Services, LLC

Bandmill Coal Corporation

Bandytown Coal Company

Barbara Holdings Inc.

Barnabus Land Company

Belfry Coal Corporation

Ben Creek Coal Company

Big Bear Mining Company

Black Castle Mining Company, Inc.

Black Dog Coal, LLC

Black King Mine Development Co.

Black Mountain Cumberland Resources, Inc.

Black Mountain Resources LLC

Boone East Development Co.

Brooks Run Mining Company, LLC

Brooks Run South Mining, LLC

Buchanan Energy Company, LLC

Castle Gate Holding Company

Central Penn Energy Company, Inc.

Ceratech, Inc.

Ceratech USA Holdings, LLC

Clear Fork Coal Company

Coal Gas Recovery II, LLC

Coal Handling Solutions LLC

Coral Energy Services, LLC

Covington Handling LLC

Crystal Fuels Company

Cumberland Coal Resources, LP

Dehue Coal Company
Delbarton Mining Company
Delta Mine Holding Company
Dickenson-Russell Coal Company, LLC
Dickenson-Russell Land and Reserves, LLC
Dominion Terminal Associates
DRIH Corporation
Dry Systems Technologies, Inc.
Duchess Coal Company
Eagle Energy, Inc.
Elk Run Coal Company, Inc.
Emerald Coal Resources, LP
Enterprise Mining Company, LLC
Esperanza Coal Co., LLC
Excelven Pty Ltd.
Foundation Mining, LLC
Foundation PA Coal Company, LLC
Foundation Royalty Company
Freeport Mining, LLC
Freeport Resources Company, LLC
Green Source Holdings LLC
Goals Coal Company
Gray Hawk Insurance Company
Green Valley Coal Company
Greyeagle Coal Company
Harlan Reclamation Services LLC
Herndon Processing Company, LLC
Highland Mining Company
Hopkins Creek Coal Company
Independence Coal Company, Inc.
Jacks Branch Coal Company
Jay Creek Holding, LLC
Joboner Coal Company
Kanawha Energy Company
Kepler Processing Company, LLC
Kingsport Handling LLC
Kingsport Services LLC
Kingston Mining, Inc.
Kingwood Mining Company, LLC
Knox Creek Coal Corporation
Lauren Land Company
Laxare, Inc.
Litwar Processing Company, LLC
Logan County Mine Services, Inc.
Long Fork Coal Company
Lynn Branch Coal Company, Inc.
Mahatamil Mining and Thermal Energy Limited
Maple Meadow Mining Company
Marfork Coal Company, Inc.
Marshall Land LLC
Martin County Coal Corporation
Maxxim Rebuild Co., LLC
Maxxim Shared Services, LLC
Maxxum Carbon Resources, LLC
Maysville Handling LLC
McDowell-Wyoming Coal Company, LLC
Mill Branch Coal Corporation
Mountaineer Capital, LP
Neweagle Industries, Inc.
New Ridge Mining Company
New River Energy Corporation
Nicewonder Contracting, Inc.
North Fork Coal Corporation
Omar Mining Company
Paramont Coal Company Virginia, LLC
Paynter Branch Mining, Inc.
Peerless Eagle Coal Co.
Pennsylvania Land Holdings Company, LLC
Pennsylvania Land Resources Holding Company, LLC
Pennsylvania Land Resources, LLC
Pennsylvania Services Corporation
Performance Coal Company
Peter Cave Mining Company
Pigeon Creek Processing Corporation
Pilgrim Mining Company, Inc.
Pioneer Fuel Corporation

Plateau Mining Corporation

Power Mountain Coal Company

Premium Energy, LLC

Rawl Sales & Processing Co.

Republic Energy, Inc.

Resource Development LLC

Resource Land Company LLC

River Processing Corporation

Riverside Energy Company, LLC

Riverton Coal Production Inc.

Road Fork Development Company, Inc.

Robinson-Phillips Coal Company

Rockspring Development, Inc.

Rostraver Energy Company

Rum Creek Coal Sales, Inc.

Russell Fork Coal Company

Scarlet Development Company

Shannon-Pocahontas Coal Corporation

Shannon-Pocahontas Mining Company

Sidney Coal Company, Inc.

Simmons Fork Mining, Inc.

Solomons Mining Company

Spartan Mining Company

Stirrat Coal Company

Sycamore Fuels, Inc.

T. C. H. Coal Co.

Tennessee Consolidated Coal Company

Tennessee Energy Corp.

Town Creek Coal Company

Trace Creek Coal Company

Tucson Limited Liability Company

Twin Star Mining, Inc.

Twisted Gun, LLC

Vantage Mining Company

Wabash Mine Holding Company

Warrick Holding Company

West Kentucky Energy Company

West Virginia Media Partners, LP

White Buck Coal Company

Williams Mountain Coal Company

Wyomac Coal Company, Inc.

Wyoming Quality Healthcare Coalition, LLC

Source: Edgar Online, "Alpha Natural Resources, Inc. Form 10-K" (2014), available at http://cleanenergyaction.org/wp-content/uploads/2014/06/Alpha-Natural-Resources-ANR-2013-10-K-Annual-Report.pdf.

Ambre Energy Limited: Subsidiaries

Subsidiary	Country of incorporation	Ownership interest
Ambre Energy (Felton) Pty Ltd	Australia	100%
Ambre Energy Exploration Pty Ltd	Australia	100%
Ambre Fuels Limited (formerly Ambre CTL Limited)	Australia	100%
Ambre EOR Pty Ltd	Australia	100%
Ambre Pipelines Pty Ltd	Australia	100%
AE Minerals Pty Ltd	Australia	100%
AE Oil Shale, Inc.	United States	100%
Ambre Energy Partners, Inc.	United States	100%
Ambre Energy Technology, LLC	United States	100%
AE Alternative Fuels, LLC	United States	100%
AE Fuels North America, LLC	United States	100%
Ambre Energy North America, Inc.	United States	100%
AE Coal, LLC	United States	100%
AE Infrastructure, LLC	United States	100%
Millennium Bulk Terminals-Longview, LLC	United States	62%
AE Coal Marketing, LLC	United States	100%
Coyote Island Terminal, LLC	United States	100%
Gulf States Bulk Terminal, LLC	United States	100%
Barlow Point Land Company, LLC	United States	62%
Pacific Transloading, LLC	United States	100%
AE Wind River, LLC	United States	100%
Eldorado Coal, Inc.	United States	100%
KCP, Inc.	United States	100%
KCP Properties, Inc.	United States	100%
Big Horn Coal Company	United States	100%
Rosebud Coal Sales Company USA	United States	100%

Source: Ambre Energy, "Annual Report" (2012), available at http://www.ambreenergy.com/FileLibrary/ambre_energy_limited_annual_report_30_june_2012_lr.pdf.

Arch Coal, Inc.: Subsidiaries

Subsidiary	Country or state of incorporation	Ownership interest
Arch Coal Asia-Pacific PTE. LTD.	Singapore	100%
Arch of Australia PTY LTD	Australia	100%
Arch Coal Australia PTY LTD	Australia	100%
Arch Coal Australia Holdings PTY LTD	Australia	100%
Arch Coal Europe Limited	United Kingdom	100%
Arch Reclamation Services, Inc.	Delaware	100%
Arch Western Acquisition Corporation	Delaware	100%
Arch Western Acquisition, LLC	Delaware	100%
Arch Western Resources, LLC	Delaware	0.5%
Arch Western Resources, LLC	Delaware	99.5%
Arch of Wyoming, LLC	Delaware	100%
Arch Western Finance, LLC	Delaware	100%
Arch Western Bituminous Group, LLC	Delaware	100%
Mountain Coal Company, L.L.C.	Delaware	100%
Thunder Basin Coal Company, L.L.C.	Delaware	100%
Triton Coal Company, LLC	Delaware	100%
ACI Terminal, LLC	Delaware	100%
Ark Land Company	Delaware	100%
Western Energy Resources, Inc.	Delaware	100%
Ark Land KH, Inc.	Delaware	100%
Ark Land LT, Inc.	Delaware	100%
Ark Land WR, Inc.	Delaware	100%
Allegheny Land Company	Delaware	100%
Apogee Holdco, Inc.	Delaware	100%
Arch Coal Sales Company, Inc.	Delaware	100%
Arch Energy Resources, LLC	Delaware	100%
Arch Coal Terminal, Inc.	Delaware	100%
Arch Coal West, LLC	Delaware	100%
Arch Development, LLC	Delaware	100%
Arch Receivable Company, LLC	Delaware	100%
Ashland Terminal, Inc.	Delaware	100%
Catenary Coal Holdings, Inc.	Delaware	100%
Cumberland River Coal Company	Delaware	100%
Lone Mountain Processing, Inc.	Delaware	100%
Powell Mountain Energy, LLC	Delaware	100%
Catenary Holdco, Inc.	Delaware	100%
Coal-Mac, Inc.	Kentucky	100%

Subsidiary	Country or state of incorporation	Ownership interest
Energy Development Co.	Iowa	100%
Hobet Holdco, Inc.	Delaware	100%
International Coal Group, Inc.	Delaware	100%
ICG, LLC	Delaware	100%
ICG, Inc.	Delaware	100%
Arch Flint Ridge, LLC	Delaware	100%
ICG Beckley, LLC	Delaware	100%
ICG Natural Resources, LLC	Delaware	100%
ICG East Kentucky, LLC	Delaware	100%
ICG Illinois, LLC	Delaware	100%
ICG Knott County, LLC	Delaware	100%
ICG Tygart Valley, LLC	Delaware	100%
Shelby Run Mining Company, LLC	Delaware	100%
ICG Eastern, LLC	Delaware	100%
ICG Eastern Land, LLC	Delaware	100%
ICG Hazard, LLC	Delaware	100%
ICG Hazard Land, LLC	Delaware	100%
CoalQuest Development LLC	Delaware	100%
Hunter Ridge Holdings, Inc.	Delaware	100%
Hunter Ridge, Inc. (Delaware)	Delaware	100%
Hunter Ridge Coal Company	Delaware	100%
White Wolf Energy, Inc.	Virginia	100%
Bronco Mining Company, Inc.	West Virginia	100%
Juliana Mining Company, Inc.	West Virginia	100%
Hawthorne Coal Company, Inc.	West Virginia	100%
Marine Coal Sales Company	Delaware	100%
Upshur Property, Inc.	Delaware	100%
King Knob Coal Co., Inc.	West Virginia	100%
Vindex Energy Corporation	West Virginia	100%
Patriot Mining Company, Inc.	West Virginia	100%
Melrose Coal Company, Inc.	West Virginia	100%
Wolf Run Mining Company	West Virginia	100%
The Sycamore Group, LLC	West Virginia	50%**
Simba Group, Inc.	Delaware	
Jacobs Ranch Holdings I LLC	Delaware	
Jacobs Ranch Holdings II LLC	Delaware	
Jacobs Ranch Coal LLC	Delaware	
Mingo Logan Coal Company	Delaware	

Subsidiary	Country or state of incorporation	Ownership interest
Mountain Gem Land, Inc.	West Virginia	100%
Mountain Mining, Inc.	Delaware	100%
Mountaineer Land Company	Delaware	100%
Otter Creek Coal, LLC	Delaware	100%
P.C. Holding, Inc.	Delaware	100%
Prairie Holdings, Inc.	Delaware	100%
Prairie Coal Company, LLC	Delaware	100%
Saddleback Hills Coal Company	Delaware	100%

Source: Arch Coal, Inc., "Form 10-K" (2014), available at http://cleanenergyaction.org/wp-content/uploads/2014/06/Arch-Coal-Inc-ACI-2013-10-K-Annual-Report.pdf.

Note: The Sycamore Group is 50 percent owned by Wolf Run Mining Company and 50 percent owned by Emily Gibson Coal Co., Inc.

Cloud Peak Energy, Inc.: Subsidiaries

Domestic subsidiary	State of incorporation	Ownership interest
Antelope Coal LLC	Delaware	100%
Arrowhead I LLC	Delaware	100%
Arrowhead II LLC	Delaware	100%
Arrowhead III LLC	Delaware	100%
Big Metal Coal Co. LLC	Delaware	100%
Caballo Rojo Holdings LLC	Delaware	100%
Caballo Rojo LLC	Delaware	100%
Cloud Peak Energy Finance Corp.	Delaware	100%
Cloud Peak Energy Logistics LLC	Oregon	100%
Cloud Peak Energy Receivables LLC	Delaware	100%
Cloud Peak Energy Services Company	Delaware	100%
Cordero Mining Holdings LLC	Delaware	100%
Cordero Mining LLC	Delaware	100%
Cordero Oil and Gas LLC	Delaware	100%
Decker Coal Company	Unincorporated	50%
Kennecott Coal Sales LLC	Oregon	100%
Montana Royalty Company Ltd.	Unincorporated	50%
NERCO Coal Sales LLC	Tennessee	100%
NERCO Coal LLC	Delaware	100%
NERCO LLC	Delaware	100%
Prospect Land and Development LLC	Oregon	100%
Resource Development LLC	Washington state	100%
Sequatchie Valley Coal Corporation	Tennessee	100%
Spring Creek Coal LLC	Delaware	100%
The Interstate Ditch Company	Wyoming	59.68%
Venture Fuels Partnership	Colorado	50%
Western Minerals LLC	Oregon	100%
Wyoming Quality Healthcare Coalition, LLC	Delaware	33.30%
Youngs Creek Holdings I LLC	Delaware	100%
Youngs Creek Holdings II LLC	Delaware	100%
Youngs Creek Mining Company, LLC	Delaware	100%

Source: Morningstar Document Research, "Cloud Peak Energy, Inc., Form 10-K" (2014), available at http://cleanenergyaction.org/wp-content/uploads/2014/06/Cloud-Peak-CLD-2013-10-K-Annual-Report.pdf.

Peabody Energy Corp.: Subsidiaries

Foreign subsidiary	Country of incorporation
Bowen Basin Coal Joint Venture	Australia
Conexcel 1 Pty Ltd.	Australia
Coppabella and Moorvale Joint Venture	Australia
Excel Equities International Pty Ltd.	Australia
Helensburgh Coal Pty Ltd.	Australia
Metropolitan Collieries Pty Ltd.	Australia
Middlemount Coal Pty Ltd	Australia
Middlemount Mine Management Pty Ltd	Australia
Burton Coal Pty Ltd.	Australia
Capricorn Joint Venture	Australia
Millennium Coal Pty Ltd.	Australia
Monto Coal 2 Pty Ltd	Australia
Monto Coal Joint Venture	Australia
Moorvale West Joint Venture	Australia
North Goonyella Coal Mines Pty Ltd.	Australia
North Wambo Pty Ltd.	Australia
Olive Downs South Joint Venture	Australia
Peabody (Bowen) Pty Ltd.	Australia
Peabody (Burton Coal) Pty Ltd.	Australia
Peabody (Horse Creek) Pty Ltd.	Australia
Peabody (Kogan Creek) Pty Ltd.	Australia
Peabody (Wilkie Creek) Pty Ltd. South	Australia
Peabody Acquisition Co. No. 2 Pty Ltd.	Australia
Peabody Acquisition Co. No. 5 Pty Ltd	Australia
Peabody Australia Holdco Pty Ltd.	Australia
Peabody Australia Intermediate Pty Ltd	Australia
Peabody Australia Mining Pty Ltd.	Australia
Peabody BB Interests Pty Ltd	Australia
Peabody Bistrotel Pty Ltd	Australia
Peabody Budjero Holdings Pty Ltd	Australia
Peabody Budjero Pty Ltd	Australia
Peabody Capricorn Pty Ltd	Australia
Peabody Coalsales Australia Pty Ltd.	Australia
Peabody Coaltrade Australia Pty Ltd.	Australia
Peabody Coppabella Coal Pty Ltd	Australia
Peabody Custom Mining Ltd	Australia
Peabody Energy Australia Coal Pty Ltd.	Australia

Foreign subsidiary	Country of incorporation
Peabody Energy Australia PCI (C&M Equipment) Pty Ltd	Australia
Peabody Energy Australia PCI (C&M Management) Pty Ltd	Australia
Peabody Energy Australia PCI Berrigurra Pty Ltd	Australia
Peabody Energy Australia PCI Equipment Pty Ltd	Australia
Peabody Energy Australia PCI Exporation Pty Ltd	Australia
Peabody Energy Australia PCI Financing Pty Ltd	Australia
Peabody Energy Australia PCI Management Pty Ltd	Australia
Peabody Energy Australia PCI Mine Management Pty Ltd	Australia
Peabody Energy Australia PCI Pty Ltd	Australia
Peabody Energy Australia PCI Rush Pty Ltd	Australia
Peabody Energy Australia Pty Ltd	Australia
Peabody Energy Finance Pty Ltd.	Australia
Peabody MCC Holdco Pty Ltd.	Australia
Peabody Monto Coal Pty Ltd	Australia
Peabody Moorvale Pty Ltd.	Australia
Peabody Moorvale West Pty Ltd	Australia
Peabody Olive Downs Pty Ltd	Australia
Peabody Pastoral Holdings Pty Ltd.	Australia
Peabody Queensland Coke & Energy Pty Ltd	Australia
Peabody West Burton Pty Ltd	Australia
Peabody West Rolleston Pty Ltd	Australia
Peabody West Walker Pty Ltd	Australia
PEAMCoal Holdings Pty Ltd.	Australia
PEAMCoal Pty Ltd.	Australia
Ribfield Pty Ltd	Australia
Wambo Coal Pty Ltd.	Australia
Wambo Coal Terminal Pty Ltd.	Australia
Wambo Open Cut Pty Ltd.	Australia
West/North Burton Joint Venture	Australia
West Rolleston Joint Venture	Australia
West Walker Joint Venture	Australia
Wilpinjong Coal Pty Ltd.	Australia
Excelven Pty Ltd.	British Virgin Islands
Peabody Coal Venezuela Ltd.	Bermuda
Peabody Energy (Botswana) (Proprietary) Limited	Botswana
Peabody Investment & Development Business Services Beijing Co., Ltd.	China
Peabody Bear Run Mining, LLC	Delaware
Peabody Coaltrade GmbH	Germany

Foreign subsidiary	Country of incorporation
Peabody Energy (Gibraltar) Limited	Gibraltar
Peabody Holdings (Gibraltar) Limited	Gibraltar
Peabody International (Gibraltar) Limited	Gibraltar
Peabody Investments (Gibraltar) Limited	Gibraltar
Peabody MCC (Gibraltar) Limited	Gibraltar
Peabody Mining (Gibraltar) Limited	Gibraltar
Peabody Coaltrade India Private Ltd	India
PT Peabody Coaltrade Indonesia	Indonesia
PT Peabody Mining Services	Indonesia
Peabody Energy (Gibraltar) Limited and S.C.S.	Luxembourg
Peabody Gobi LLC	Mongolia
Peabody Mozambique, Limitada	Mozambique
BTU International BV	Netherlands
Peabody Acquisition Cooperative U.A.	Netherlands
Peabody AMBV2 B.V.	Netherlands
Peabody Holland BV	Netherlands
Peabody Netherlands Holding B.V.	Netherlands
9 East Shipping (Asia) Pte Ltd.	Singapore
Peabody Coaltrade Asia Private Ltd.	Singapore
Peabody Global Services Pte Ltd.	Singapore
9 East Shipping Limited	United Kingdom
Peabody Coaltrade International Limited	United Kingdom
Carbones Peabody de Venezuela S.A.	Venezuela
Complejo Siderurgico Del Lago, CA	Venezuela
Desarrollos Venshelf IV, CA	Venezuela
Transportes Coal Sea de Venezuela, CA	Venezuela

Domestic subsidiary: Peabody	State of incorporation
American Land Development, LLC	Delaware
American Land Holdings of Colorado, LLC	Delaware
American Land Holdings of Illinois, LLC	Delaware
American Land Holdings of Indiana, LLC	Delaware
American Land Holdings of Kentucky, LLC	Delaware
American Land Holdings of West Virginia, LLC	Delaware
Arid Operations, Inc.	Delaware
Big Sky Coal Company	Delaware
BTU Western Resources, Inc.	Delaware
Caballo Grande, LLC	Delaware
Caseyville Dock Company, LLC	Delaware
Central States Coal Reserves of Illinois, LLC	Delaware
Central States Coal Reserves of Indiana, LLC	Delaware
Coal Reserve Holding LLC No. 1	Delaware
Coalsales II, LLC	Delaware
Colorado Yampa Coal Company	Delaware
Conservancy Resources, LLC	Delaware
Cottonwood Land Company	Delaware
Cyprus Creek Land Company	Delaware
Cyprus Creek Land Resources LLC	Delaware
Dyson Creek Coal Company, LLC	Delaware
Dyson Creek Mining Company, LLC	Delaware
El Segundo Coal Company, LLC	Delaware
Elkland Holdings, LLC	Delaware
Gallo Finance Company	Delaware
Gold Fields Chile, LLC	Delaware
Gold Fields Mining, LLC	Delaware
Gold Fields Ortiz, LLC	Delaware
Hayden Gulch Terminal, LLC	Delaware
Highwall Mining Service Company	Delaware
Hillside Recreational Lands, LLC	Delaware
HMC Mining LLC	Delaware
Independence Material Handling, LLC	Delaware
James River Coal Terminal, LLC	Delaware
Juniper Coal Company	Delaware
Kayenta Mobile Home Park, Inc.	Delaware
Kentucky Syngas, LLC	Delaware
Lively Grove Energy Partners, LLC	Delaware

Domestic subsidiary: Peabody	State of incorporation
Lively Grove Energy, LLC	Delaware
Marigold Electricity, LLC	Delaware
Midwest Coal Acquisition Corp.	Delaware
Midwest Coal Reserves of Illinois, LLC	Delaware
Midwest Coal Reserves of Indiana, LLC	Delaware
Midwest Coal Reserves of Kentucky, LLC	Delaware
Moffat County Mining, LLC	Delaware
Mustang Clean Energy, LLC	Delaware
Mustang Energy Company, LLC	Delaware
New Mexico Coal Resources, LLC	Delaware
P&L Receivables Company LLC	Delaware
Pacific Export Resources, LLC	Delaware
Peabody America, Inc.	Delaware
Peabody Archveyor, LLC	Delaware
Peabody Arclar Mining, LLC	Delaware
Peabody Bear Run Services, LLC	Delaware
Peabody Bear Run Mining, LLC	Delaware
Peabody Caballo Mining, LLC	Delaware
Peabody Cardinal Gasification, LLC	Delaware
Peabody China, LLC	Delaware
Peabody Coalsales, LLC	Delaware
Peabody Coaltrade International (CTI), LLC	Delaware
Peabody Coaltrade, LLC	Delaware
Peabody Colorado Operations, LLC	Delaware
Peabody Colorado Services, LLC	Delaware
Peabody Coulterville Mining, LLC	Delaware
Peabody Development Company, LLC	Delaware
Peabody Electricity, LLC	Delaware
Peabody Employment Services, LLC	Delaware
Peabody Energy Generation Holding Company	Delaware
Peabody Energy Investments, Inc.	Delaware
Peabody Energy Solutions, Inc.	Delaware
Peabody Gateway North Mining, LLC	Delaware
Peabody Gateway Services, LLC	Delaware
Peabody Holding Company, LLC	Delaware
Peabody Illinois Services, LLC	Delaware
Peabody Indiana Services, LLC	Delaware
Peabody International Investments, Inc.	Delaware

Domestic subsidiary: Peabody	State of incorporation
Peabody International Services, Inc.	Delaware
Peabody Investments Corp.	Delaware
Peabody Magnolia Grove Holdings, LLC	Delaware
Peabody Midwest Management Services, LLC	Delaware
Peabody Midwest Operations, LLC	Delaware
Peabody Midwest Services, LLC	Delaware
Peabody Mongolia, LLC	Delaware
Peabody Natural Gas, LLC	Delaware
Peabody Natural Resources Company	Delaware
Peabody New Mexico Services, LLC	Delaware
Peabody Operations Holding, LLC	Delaware
Peabody Powder River Mining, LLC	Delaware
Peabody Powder River Operations, LLC	Delaware
Peabody Powder River Services, LLC	Delaware
Peabody PowerTree Investments LLC	Delaware
Peabody Recreational Lands LLC	Delaware
Peabody Rocky Mountain Management Services, LLC	Delaware
Peabody Rocky Mountain Services, LLC	Delaware
Peabody Sage Creek Mining, LLC	Delaware
Peabody School Creek Mining, LLC	Delaware
Peabody Services Holding, LLC	Delaware
Peabody Southwest, LLC	Delaware
Peabody Southwestern Coal Company	Delaware
Peabody Terminal Holding Company, Inc.	Delaware
Peabody Terminals, LLC	Delaware
Peabody Trout Creek Reservoir LLC	Delaware
Peabody Twentymile Mining, LLC	Delaware
Peabody Venezuela Coal Corporation	Delaware
Peabody Venture Fund, LLC	Delaware
Peabody Western Coal Company	Delaware
Peabody Wild Boar Mining, LLC	Delaware
Peabody Wild Boar Services, LLC	Delaware
Peabody Williams Fork Mining, LLC	Delaware
Peabody Wyoming Gas, LLC	Delaware
Peabody Wyoming Services, LLC	Delaware
Peabody-Waterside Development LLC	Delaware
PEC Equipment Company, LLC	Delaware
PG Investments Six LLC	Delaware

Domestic subsidiary: Peabody	State of incorporation
Point Pleasant Dock Company LLC	Delaware
Pond River Land Company	Delaware
Porcupine Production LLC	Delaware
Porcupine Transportation LLC	Delaware
Riverview Terminal Company	Delaware
Sage Creek Holdings, LLC	Delaware
School Creek Coal Resources, LLC	Delaware
Seneca Coal Company, LLC	Delaware
Shoshone Coal Corporation	Delaware
Star Lake Energy Company LLC	Delaware
Thoroughbred Generating Company LLC	Delaware
Thoroughbred Mining Company LLC	Delaware
Twentymile Coal LLC	Delaware
West Roundup Resources, LLC	Delaware
Big Ridge, Inc.	Illinois
Black Hills Mining Company, LLC	Illinois
Century Mineral Resources, Inc.	Illinois
Illinois Land Holdings, LLC	Illinois
Midco Supply and Equipment Corporation	Illinois
Falcon Coal Company, LLC	Indiana
Kentucky United Coal LLC	Indiana
Peabody Midwest Mining, LLC	Indiana
Sugar Camp Properties, LLC	Indiana
United Minerals Company LLC	Indiana
Newhall Funding Company (MBT)	Massachusetts
Sterling Centennial Missouri Insurance Corporation	Missouri
Sterling Centennial Insurance Corp.	Vermont

Source: Morningstar Document Research, "Peabody Energy Corp. Form 10-K" (2014), available at http://cleanenergyaction.org/wp-content/uploads/2014/06/Peabody-BTU-2013-10-K-Annual-Report.pdf.

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A Research Paper by

HEADWATERS ECONOMICS

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Current Royalty Structure, Effective Royalty Rates, and Reform Options

January 2015

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ABOUT HEADWATERS ECONOMICS

Headwaters Economics is an independent, nonprofit research group whose mission is to improve community development and land management decisions in the West.

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I. EXECUTIVE SUMMARY

Coal extracted from federal land is an important source of energy and revenue in the United States. The U.S. government owns roughly one-third of total coal reserves. Bonus payments and royalty revenue from minerals extracted from public lands and waters represent the largest non-tax source of income for the federal government. Despite the importance of this revenue stream, little information is available to describe accurately the return to the public from taxation of federal coal resources. This paper analyzes how revenues from federal coal are obtained, estimates current effective royalty rates, reviews problems with the current system, and assesses policy reform options.

Challenges with Royalty Structure

The Bureau of Land Management (BLM) and the Office of Natural Resources Revenue (ONRR) administer the federal coal leasing program and have multiple and diverse objectives: a fair return for U.S. taxpayers, economic development and jobs, energy costs and security, and environmental protection. Royalties are the owner's share of the resource value, but the ONRR often accepts less than full value—the effective royalty rate is 4.9 percent of the gross market value of coal extracted between 2008 and 2012 (compared to the average statutory rate of 12.3 percent). Evaluating the effective returns earned by the ONRR under the current royalty structure reveals several problems:

- The first problem is transparency. The royalty rates applied to each lease, prices used to determine royalties due, and allowable cost deductions are all considered proprietary and data are withheld. As a result, there is little outside oversight of the royalty structure, engendering uncertainty about how the government is balancing competing interests.
- Second, the cost of administering the current royalty structure is high. Royalties are often based on non-market transactions where prices are uncertain and the ONRR uses complex valuation methods that are expensive to administer.
- Third, coal valuation procedures raise questions about fair returns to the U.S. government. The ONRR values coal for royalties at the first point of sale at or near the mine, limiting royalty collections when the coal is remarketed at significantly higher prices, including for export.

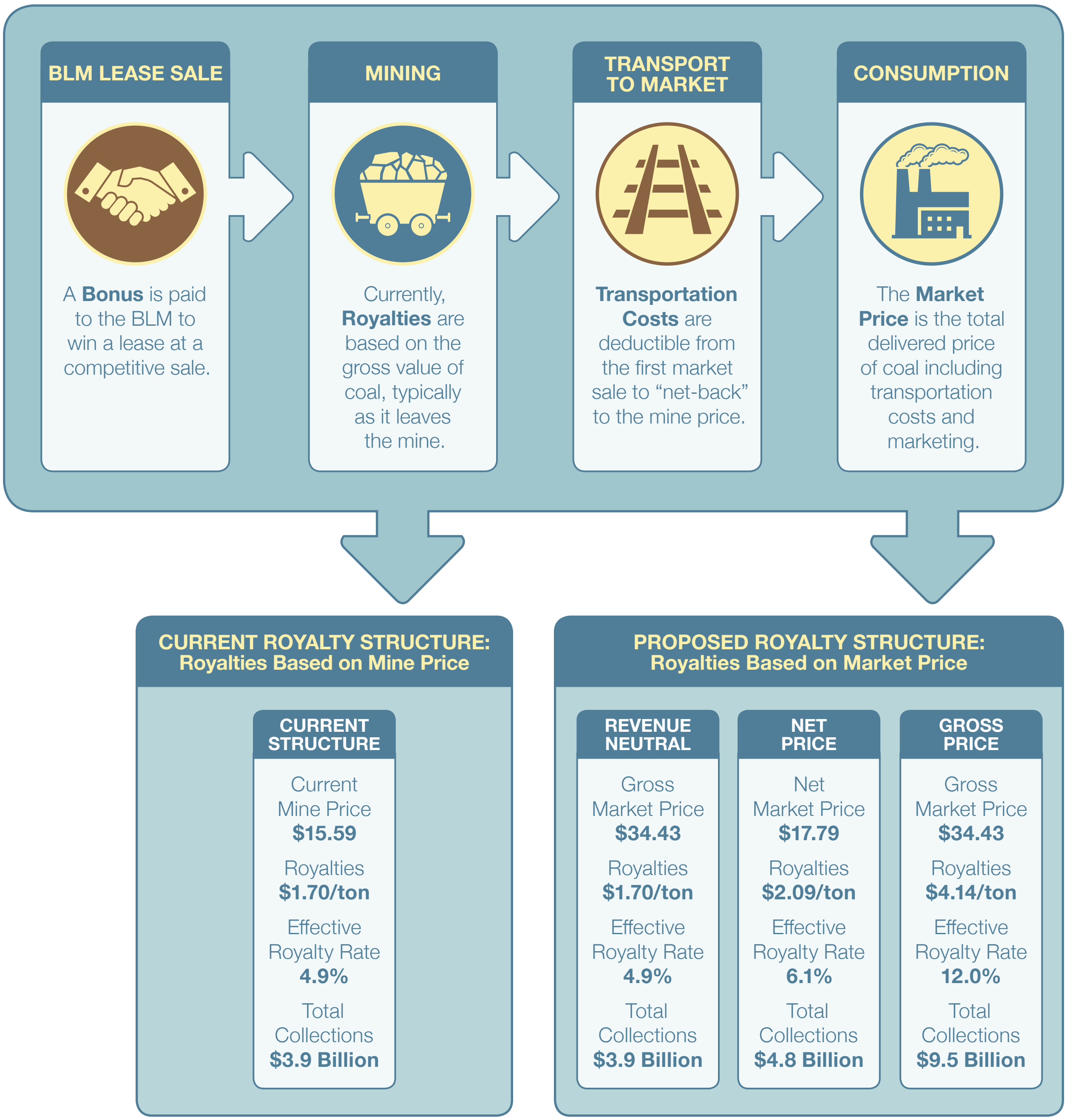
Royalty Reform Options

A range of alternative policy options would remedy problems with the current system and offer benefits to the U.S. public. The figure on the next page illustrates the current coal royalty structure, valuation policy, and returns, and illustrates the projected outcomes of reforms that would value coal for royalties using market prices. Changing the point of valuation would achieve several benefits:

- Moving the point of valuation would improve transparency. Market prices of coal are known. The BLM and the public would have easy access to coal valuation data.
- Reform would greatly simplify the valuation process and reduce administrative costs.
- Reforming the royalty structure also makes it easier to assess what a fair return is, and balance these returns against other competing interests.

The figure compares the current royalty structure to three reform options. For current policy, the analysis uses actual coal sales and royalty collections between 2008 and 2012. The figure shows that the effective royalty rate over this period was 4.9 percent, and royalty collections averaged about $1.70 per ton. The price used to determine royalties averaged $15.59 for all federal coal sales.

Current U.S. Coal Royalty Structure, Valuation Policy, and Reform Options



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The first reform option would be revenue neutral, achieving transparency and administrative cost reductions without changing royalty collections.

The second reform option shows that had coal valuation been based on net market prices during the same period, the effective royalty rate would have been 6.1 percent, royalty collections would have averaged $2.09 per ton, and total collections more than $850 million higher ($4.8 billion in total revenue compared to $3.9 billion in revenue under the current system). Royalty collections would have been higher because the average net market price paid for coal delivered from states with federal leases between 2008 and 2012 was $17.72, about two dollars per ton higher than the current reported sales price. The difference is an estimate of the margins (or profits) earned by affiliated and non-affiliated brokers that paid a low price at the mine for federal coal, and then remarketed this coal at higher domestic and export market prices.

The third reform option shows that had coal been valued for royalties using the gross market value—meaning transportation costs would no longer be deductible expenses—the effective royalty rate would have been 12 percent and average collections per ton would have been about $4.14 per ton. Total royalty collections would have been about $5.5 billion higher than actual royalties.

Interpreting Results

The Office of Natural Resources Revenue (ONRR) is currently proposing to change the regulations governing valuation of coal for royalty purposes. While this paper does not specifically address the rulemaking process, the results can inform the public comment and ultimately the rule that ONRR adopts.

The ONRR proposes to retain royalty valuation at or near the lease, using gross proceeds from the first arm's-length transaction (or market sale) as the basis for royalties. The rule is specifically designed to address situations where the first sale is to an affiliate broker—in other words, it is not at arm's-length and may be structured only to avoid paying royalties on the higher market value of federal coal. In making this change, ONRR would use the first market sale to determine royalty valuation.

One way to interpret our results is that the rule would effectively change royalty valuation to the net market price of coal (if transportation costs are still deductible). However, non-affiliated brokers may still play an important role in the coal market, and the rulemaking would do little to affect royalty collections. Our results define the upper end of the possible outcomes that could range from very little change up to an increased royalty payment per ton averaging about $0.18 for federal coal in Montana and Wyoming (after accounting for state severance tax and corporate income tax interactions).

If the rulemaking additionally limits transportation costs deductions to 50 percent of actual costs, the effect of the rulemaking could be an average increase in royalty payments per ton of about $0.85 per ton (after accounting for state severance tax and corporate income tax interactions). Again, this estimate should be considered the upper end of costs that would accrue only if closing the affiliate broker loophole results in mines in Montana and Wyoming marketing all federal coal directly to consumers. If, however, brokers remain an important player in the market structure (and they still retain a cost advantage over a mine marketing coal directly by avoiding royalty payments), then changing royalty valuation and transportation deductions will have little, if any, effect on collections.

Data Withholdings and Error

Throughout this report we endeavor to use publically available data. We do this for two reasons: so that our methods and data can be easily assessed and replicated; and to document the challenges created by federal data withholdings. Understanding the current coal royalty structure is limited primarily by data availability. Detailed descriptions of data, methods, and results are presented in three appendices. In Wyoming, coal sales from federal leases account for 93 percent of all coal sales in the state. As a result, we are more confident in estimates of effective tax rates in Wyoming compared to results in states where sales from federal leases account for a small share of all coal sales in the state.

II. INTRODUCTION

This report presents data and analysis to help decision makers evaluate possible updates to the federal coal leasing and royalty valuation program. It is intended to contribute to a growing body of literature evaluating the federal coal program that includes recent reports from the U.S. Government Accountability Office (GAO)[1] and the Department of Interior (DOI) Inspector General.[2]

Coal extracted from federal land is an important source of energy and revenue in the U.S. The U.S. government owns roughly one-third of total coal reserves. Production from federal leases has increased steadily from a low of about three percent of all mining in 1960 to 43 percent of total domestic coal production today. The increase in federal coal production was ushered in by a shift toward large western surface mines—80 percent of federal production now comes from the Powder River Basin in Wyoming and Montana.[3]

Coal extracted from federal land generates revenue for the United States through bonus payments, annual royalties, and taxes paid by private companies that negotiate for rights to mine the public resource. Bonus payments and royalty revenue from minerals extracted from public lands and waters represent the largest non-tax source of income for the federal government. Royalties are paid to the U.S. Treasury, and roughly half (49%) are returned to the states where the production activity takes place.[4]

Despite the importance of this revenue stream, little information is available to accurately describe the return to the public from taxation of federal coal resources. The topic has gained currency lately because of recent reports and press suggesting the BLM now is not receiving fair compensation for federal coal resources,[5] and because the Office of Natural Resources Revenue (ONRR) is undertaking a rulemaking process to reform aspects of the royalty and leasing structure.[6] In addition to this agency-led reform process, members of the Senate and Energy Natural Resources Committee have called for a larger review.[7] The BLM also is facing a lawsuit intended to force a review of the agency's coal leasing program in light of concerns about coal's role as a major source of greenhouse gas emissions.[8]

This report evaluates royalties on federal coal. One important step in the report is estimating the effective royalty rates under the current royalty structure and coal valuation policy. Our study discusses why effective rates fall below statutory rates and the potential outcomes of reforms that move the point of royalty valuation from the price received by the lessee at the first point of sale, typically as it leaves the mine (the mine price), to the delivered price, or market price of coal. The benefits of moving the point of valuation include increased transparency, lower administrative costs, and flexibility to consider higher royalty returns.

This report begins with a brief review of findings followed by documentation of data and methods. The first section of the report surveys the current federal royalty structure for federally owned coal. The second section presents findings on the effective royalty rate on federal coal with comparisons to reported rates and rates on other energy resources extracted from federal lands. Finally, the report defines several reform options and describes the outcomes of these potential reforms on effective rates, royalty revenue, and costs on the extraction of federal coal. An appendix at the end of this report describes data sources and methods.

III. U.S. FEDERAL ROYALTY STRUCTURE: HOW IT WORKS CURRENTLY

Bonus payments and royalties are part of a broader fiscal regime that collects revenue at the local, state, and federal level from the value of resources extracted from public lands. Internationally, countries generate revenue from state-owned resources in a variety of ways, including state-owned corporations, production agreements, and variations on the tax and royalty structure. Resource owners commonly structure leases, bonus payments, royalties, and taxes to ensure a fair and predictable return to the public and to share in windfall profits. In the U.S. the bonus and royalty structure provides a minimum return, and corporate income taxes are typically used to share in the profits and risks of mineral extraction and to incentivize exploration, new technologies, and production.

The U.S. is unique in that private individuals and companies own the majority of natural resources, and where the public does own resources, these resources are leased to private developers. The government uses the corporate income tax to tax profits as well as to provide subsidies and create incentives including cost recovery for exploration and mining activities that are not deductible from royalties. Subsidies in the corporate tax structure can be significant.[9] The sidebar *"Revenues from Oil, Natural Gas, and Coal Production on Federal Lands"* on the next page defines the several bonuses, royalties, and taxes coal companies pay.

Figure 1 focuses on the bonus and royalty structure, particularly the point of valuation for royalty determination. It shows that the federal coal royalty structure begins when a bonus payment is made to the BLM to win the right to extract coal through a competitive lease sale. Once mining is underway, the lease can be renewed and companies pay an annual royalty on the gross value of the coal extracted.[10] The valuation of coal for royalty purposes typically takes place as the coal leaves the mine. "Downstream" from the mine, the coal is transported primarily by railroad, but also by truck, waterway, and conveyor belt to a domestic power plant, or exported to foreign markets. At the end of this process, the coal is resold at the market rate depending on its energy content and other qualities.

In addition to lease bonus payments and royalties on extraction, companies pay state and federal corporate income taxes, state severance taxes, and a variety of sales and property taxes to state and local governments. Royalties often influence other aspects of the producer's tax liability. For example, the royalty interest in coal extracted from public land, including federal, state, tribal, and local government ownership, is exempt from state severance taxation. Royalties are also deductible from corporate income tax liability. If the federal rate (or share of production) increases, or if actual collections change, severance taxes and income taxes will rise and fall accordingly. An implication of these tax interactions is that companies do not pay the full cost of higher royalties. These will be offset by lower corporate income taxes and state severance taxes.

Recent government audits have considered coal lease sale and bonus payment processes extensively.[11] In separate reports, the GAO and the Inspector General of the DOI arrived at the conclusion that lease sales undervalue public coal. Specifically, the reports observe that nearly every lease sale since 1990 had only a single bidder, that the fair market valuation process was not transparent, and that overall it is difficult to determine if the BLM and ONRR is receiving full consideration for the public's coal.[12]

Revenues from Oil, Natural Gas, and Coal Production on Federal Lands

Bonus Payments and Rents: Companies pay bonuses (a premium paid to the BLM to win a leasing contract to mine in a specific area) through the competitive leasing process, and fees or rents to maintain a lease. Bonuses are one-time payments generally calculated on a price per ton basis. Rental payments are charged on a per acre basis and are paid annually to maintain the lease.

Royalties: Royalties are production taxes paid on the volume or value of coal extracted annually to the owner of the resource, including federal, tribal, state, and private landowners. Federal royalties are paid to the U.S. Treasury, and roughly half are returned to the states where drilling takes place. Federal royalties are 12.5 percent for surface coal, oil and natural gas; 18.75 percent for offshore oil and natural gas; and 8 percent for coal extracted from underground mines. Most states charge higher royalties of 16.67 to 25 percent on oil and natural gas while state coal royalty rates tend to mirror federal coal royalty rates.

Production Taxes: A production tax is any tax levied against the production value or volume of coal, oil, and natural gas extracted or "severed" from the earth. Production value is equal to the volume of the resource produced times the sales price. Wyoming and Montana's severance taxes are examples of state production taxes. In Colorado and Wyoming, local governments also levy ad valorem (property) taxes on the production value of fossil fuels, including coal, oil, and natural gas at the local level. The federal black lung excise tax and abandoned mine fees also are production taxes that are levied at a fixed rate on each ton of coal mined.

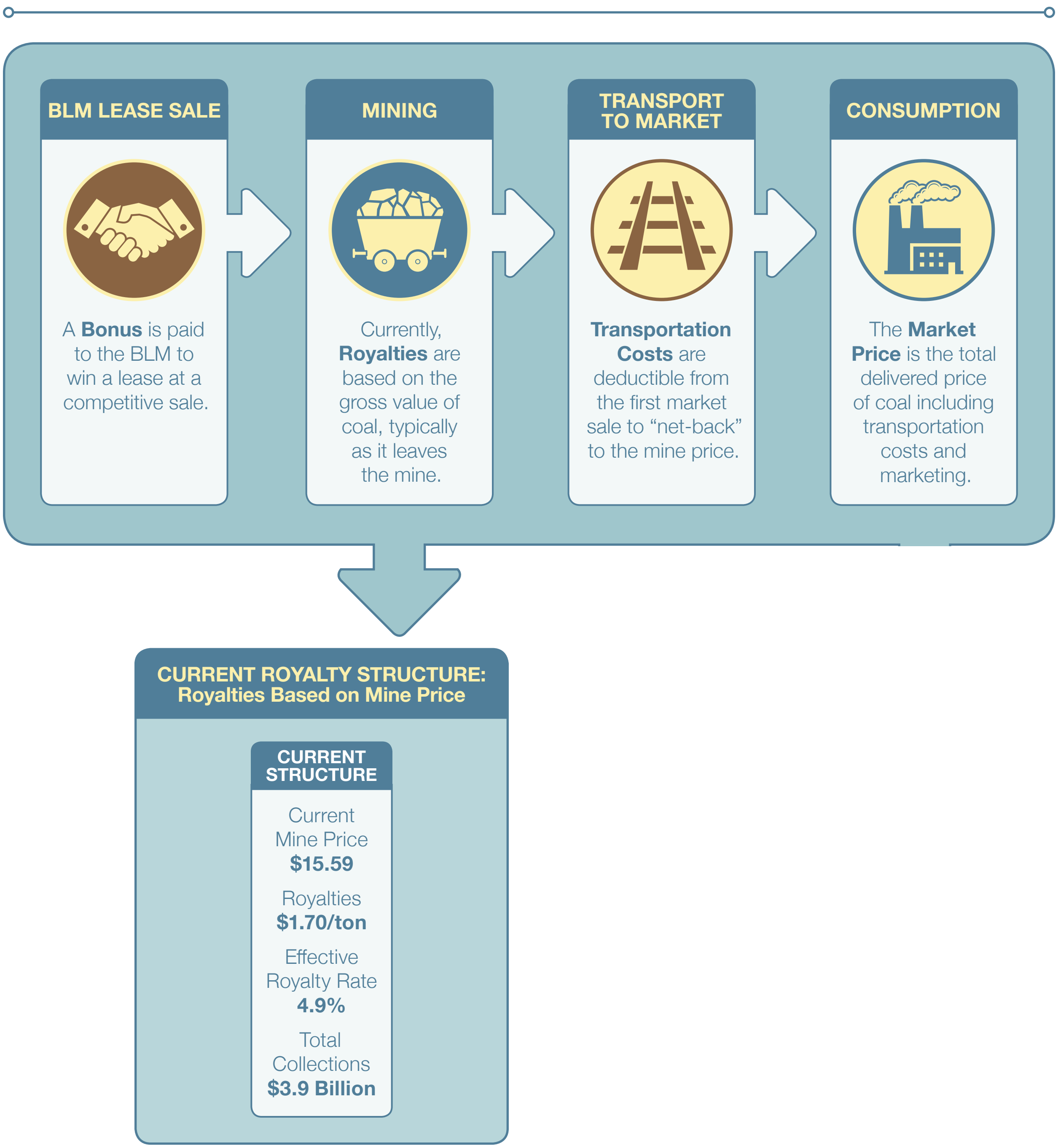
Corporate Income Taxes: Production taxes and royalties are distinct from corporate income taxes levied on net profits. Corporate income tax rates vary widely at the state level, ranging from zero (in Wyoming) up to about 10 percent for the highest tax brackets in several states, and 35 percent at the federal level. Compared to production taxes, bonus payments, and royalties, corporate income tax is paid on a smaller tax base (net profit compared to gross production value), and generates relatively less revenue for the federal and state governments.

General Taxes and Fees on Drilling and Mining Activity: State and local governments also levy taxes and fees on the value of labor, purchases, land, and equipment associated with drilling and mining activities. The general tax structure can be important to local governments, but the role they play varies from state to state. For example, sales taxes generate revenue in jurisdictions where activity takes place. In some states, however, sales taxes accrue to the state government and distributions are made on a formula unrelated to local impacts. Property taxes on land and equipment value are levied at the local government level.

This report address the royalty structure, including bonus payments, but does not address production taxes, corporate income taxes or aspects of the general tax structure specifically.

Figure 1:

Current U.S. Coal Royalty Structure



http://headwaterseconomics.org

Why Are Royalties Collected?

Royalties represent the owner's negotiated share of the value created when resources are used. The purpose of royalties is to provide a minimum, fair return to the resource owner for the depletion of non-renewable fossil fuels.[13] In the case of federally owned coal, the U.S. public owns the resource. The BLM oversees the leasing of the right to extract federal coal and the lessee pays annual royalties based on a percentage of the gross value of coal extracted from the lease (the mine price). The royalties accrue back to the public through the U.S. Treasury. Royalties are also paid to state, tribal, and private resource owners that lease the rights to extract fossil fuels.

When the BLM sells coal through a lease, the lessee agrees to take on the risk of developing the resources, including exploration, extraction, and marketing costs. The royalty interest is retained by the federal government and is paid by the lessee whether or not the mining company loses money on the sale, or earns a profit.

In practice, subsidies occur through two vehicles: direct subsidies offered at the discretion of the BLM in the form of royalty rates and rate reductions, and the coal market structure where brokers play a central role in delivering coal to markets, which serves to minimize the price used to determine royalties owed.

Royalty Rates and Rate Reductions

The BLM and coal operators negotiate royalty rates on a lease-by-lease basis, but generally are set at a minimum of 12.5 percent of the gross value of coal after it is extracted from surface mines and 8 percent for coal extracted from underground mines. Coal lessees can apply for a royalty rate reduction if the current royalty rate imposes economic hardship that would otherwise result in abandoning the lease, or in less than full recovery of leased coal. Rate reductions are also granted to encourage the greatest utilization of federal coal,[14] even in instances when high-cost or low-value coal would otherwise be uncompetitive in the domestic energy market.

The BLM makes a determination and has discretion to grant royalty rate reductions if three basic requirements are met:

1. The royalty rate reduction must encourage the greatest ultimate recovery of the coal resource.
2. The royalty rate reduction must be in the interest of conservation of the coal and other resources.
3. The reduced royalty rate is necessary to promote development of the coal resource.[15]

Royalty rate reductions occurred on at least 30 out of 83 leases (36 percent of leases) offered for sale since 1990.[16] The GAO found that the reported rate that lessees pay on the mine price used for royalty valuation varies between 5.6 percent in Colorado and 12.2 percent in Wyoming.[17] The lower reported rates are largely a function of the rate reductions offered for coal extracted from federal leases in these states.

How Coal Is Valued for Royalties

The valuation of coal for royalties is based on the gross value of the coal sold from the lease (the mine price).[18] To ensure full compensation, the lessee is required to place the coal in a "marketable condition" at no cost to the government. Costs for exploration, mining, and marketing are not deductible from royalty liability.

In the case where the mining company sells the coal in a market transaction, either directly to a consumer, such as a power plant, or to an unaffiliated broker, the contract price is used to determine royalties. If instead the mine sells coal to an affiliate, or to another company that is partly or entirely owned by the mining company, no arm's-length transaction occurs. An arm's-length transaction is defined as a sale of coal in which the buyer and seller are not affiliated and have competing economic interests. In other words, the seller attempts to sell his or her coal for the highest price possible, ensuring a fair market return for the government. In cases where sales are not at arm's-length (called "captive transactions") the ONRR is responsible for certifying that the price agreed to in the transaction is a fair price—or that it will provide a fair return to the government. In 2012, 42 percent of all coal sold in Wyoming was traded via captive transactions.[19]

The ONRR applies five benchmarks to determine the value—or price—that should be used for royalties. These methods include using comparable sales, the income approach, and "netback pricing" that uses a price earned downstream (typically the sale by the marketing affiliate) and deducts any costs. The ONRR's process of determining if a sale is an arm's-length sale or not, and auditing that the contract price reported to the agency is fair when no market transactions exist, is unwieldy and costly to administer, and opens a loophole that can be exploited to limit royalty liability.

Allowable Cost Deductions

Royalty regulations allow for certain deductions that can lower the value against which royalties are assessed. These deductions are netted out of gross sales value (the mine price), and include allowable transportation and washing costs.[20]

Transportation deductions are allowed when the valuation for royalty purposes is determined at a point remote from the mine. Deductions may be allowed for the "reasonable, actual costs incurred to transport coal" that may be required in order to move the coal from the lease to a point where it can be sold.[21] Transportation costs within the mine are not eligible for deduction. Transportation costs between a mine and a power plant or export terminal can be substantial, but these costs are typically outside of the royalty valuation process as value is determined at or near the mine. Long-distance rail shipments between the Powder River Basin and power plants on the East Coast, for example, are not part of the royalty valuation as the coal is typically sold (and valued) when it is loaded into trains at the mine.

Washing is defined as any process that improves the purity of the coal if it is required by the sales contract. The BLM may "allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal" if they are considered to exceed what would normally be required to place coal in a "marketable condition."[22]

Data on coal extracted from leases sold since 1990 show that transportation cost deductions made up less than 0.3 percent of the sales value reported by mining companies for royalty valuation. In reality, transportation costs between the mine and domestic power plants average just less than half of the total delivered cost of coal (see Appendix B). The low value of allowable deductions reported by ONRR illustrate that coal is being valued for royalties at the mine in nearly every instance.

Problems with the Current Structure

Current federal policy for coal royalty payments appears to prioritize the maximum recovery of federal coal regardless of market conditions. The objective of obtaining fair return to the public is secondary both as a matter of policy and practice. Policy allows for reductions of royalty rates and taxable value; practice allows for a disparity between the valuation basis for royalties using mine prices and actual domestic and international market prices, which can be substantially higher.

To be sure, the government does not only seek to maximize return on federal resources. The BLM has multiple and diverse objectives, including a fair return, economic development and job creation, energy security, and environmental health, including climate mitigation. However, the trade-offs between these policy goals cannot be well understood in the context of the current royalty structure. Evaluating current effective returns primarily from the standpoint of ensuring a fair return to the public reveals several problems. These problems must be understood before the larger conversation about the correct balance between these competing uses can be fully informed.

The first problem is transparency. The entire valuation process is opaque with respect to public review. As a matter of practice, the BLM treats valuation methods—lease details including royalty rates, allowable cost deductions, and prices used for royalty assessment—as proprietary information. The BLM and ONRR explicitly exempt lease royalty rates and royalty valuation data from Freedom of Information Act (FOIA) requests. The timing, amount, and goals of royalty rate reductions could be important data points in understanding the competitiveness of coal as an energy commodity. With access to this information, U.S. policymakers could weigh the relative merits of subsidizing coal over other energy sources. But a thoughtful dialogue is more difficult when these important data are withheld.

Second, the ONRR's job is complicated by the regulation that values coal using the first arm's-length sale from the lease. The ONRR must determine if the first sale is in fact an arm's-length sale, and if not, if the reported mine price represents a fair return. The process for evaluating sales and valuing coal is unwieldy, expensive, and controversial.

Third, the same coal valuation process fails to ensure a fair return to the public. The ONRR's valuation policy clearly states that royalties must be assessed using the price received at the first point of sale, even when this first sale price is substantially lower than the market price for coal—meaning that the ONRR uses the lowest possible valuation of federal coal to determine royalties, reducing compensation for the extraction of public coal.

The rise of the Powder River Basin (PRB) as the main federal coal supplier has dramatically increased the role of affiliate and non-affiliate brokers. The PRB is so remote from most use, and the mines so huge, that the majority of coal is moved by rail to meet market demands, creating an opportunity for midstream exchanges through brokers. Brokers buy coal from these massive mines, and seek out the highest market price. The current structure that values coal for royalties based upon the first sale at or near the lease results in low royalty collections because this "mine price" can be substantially lower than the price coal is eventually sold for to consumers, including power plants, industrial users, and coal exports. The ONRR is investigating whether this current royalty valuation structure provides a fair return on federal coal and is proposing a rulemaking change to address valuation policies.

Often brokers are affiliates of the actual mining company, meaning that the exchange of coal does not occur under an arm's-length transaction. In these cases, the ONRR has to determine if the price agreed upon between related companies provides a fair return for the public. The ONRR's five benchmarks used to determine the appropriate "market' value are still designed around the policy of using the mine price for royalty valuation, and can be complex and costly.

IV. CALCULATING ROYALTY RATES

We describe three ways of evaluating the rate of return on federal coal: the statutory rate, the "reported" rate, and the "effective" rate. Comparing these different rates allows for a better understanding of how the current structure works and how it returns revenue from coal extraction.

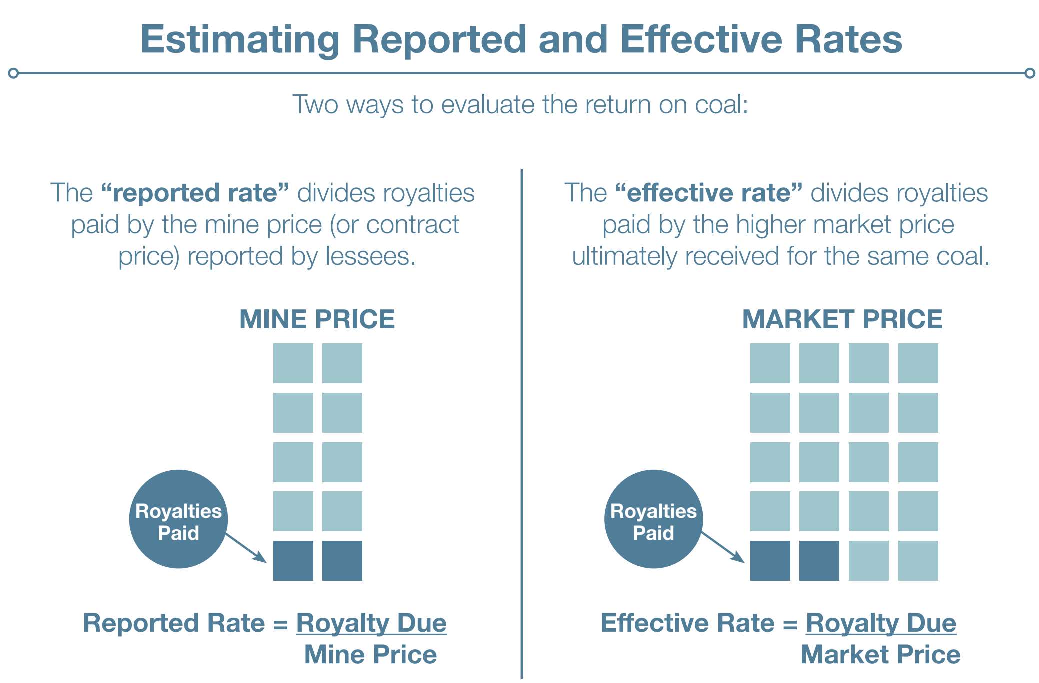
The statutory rate is set by regulation at a minimum of 12.5 percent of the gross value of coal extracted from surface mines. The regulation lowers the rate to 8 percent of the gross value of coal extracted from underground mines.

The "reported" royalty rate is calculated by dividing total royalties paid by the sales value reported by the lessee. The reported sales value is the contract price the lessee receives at the first arm's-length sale from the lease, or the "mine price."

The "effective royalty rate" is calculated by dividing total royalties paid by the market price ultimately received for the coal sold from federal leases. Figure 2 illustrates how the reported rate and effective rate are calculated.

Estimating the effective royalty rate offers significant improvements compared to the reported rate as the effective rate takes into account all incentives, deductions, and valuation policies. Kunce et al. (2003) write that "rather than itemize tax code details, effective tax rates are used to translate dynamic tax policy into a tractable form. Effective rates can be expressed as the ratio of taxes (or royalties) collected from a particular tax to the value of production. Thus, the calculation of specific effective tax rates fully account for exemptions, incentives, different tax bases, and frequent changes in tax law."[23]

Figure 2:



Importantly, we want to understand how royalty revenue would change if the tax base were redefined from the mine price to the market price. This comparison provides several outcomes: an estimate of what the BLM may be forgoing in royalty collections due to the affiliate loophole; a comparison to the return received from oil and natural gas production on federal lands; and estimates of the outcomes of reform options.

Reported Royalty Rates

Previous reports have established that royalty reductions and allowable transportation and washing cost deductions reduce the reported rate paid on federal coal downward from the statutory rate. The GAO, using 2012 data, found the actual rate lessees pay on the contract prices used for royalty valuation varies between 5.6 percent in Colorado and 12.2 percent in Wyoming.[24]

We replicated the GAO methods using additional years of sales value and royalty data[25] for all states with producing federal leases between 2008 and 2012. Figure 3 shows that North Dakota has the lowest reported royalty rate at 2.3 percent, and Wyoming the highest at 12.3 percent. The average reported rate for all federal coal produced from federal leases between fiscal years 2008 and 2012 is 10.9 percent. This compares to the average statutory rate of 12.2 percent nationally based on the share of coal extracted from surface mines and underground mines (See Appendix B).

Figure 3: Reported Royalty Rates and Size of Rate Reductions, FY 2008-2012

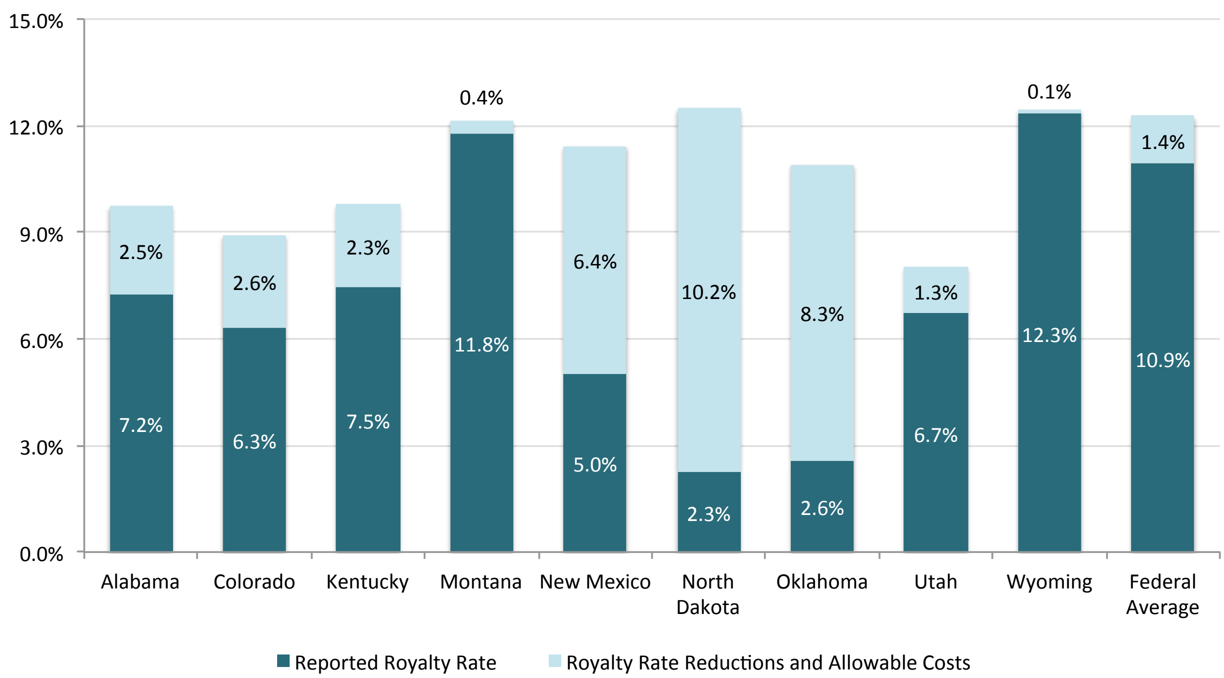


Table 1 shows that royalty collections per ton averaged $1.70 for all federal coal extracted between 2008 and 2012. The majority of federal coal extraction—and royalty value—comes from the Powder River Basin in Wyoming. Table 1 also shows that coal mined in the PRB received the lowest contract price (mine price) compared to mine prices in the other states. The five-year average mine price for coal sold from Wyoming was $13.07 compared to the national average of $15.59 and a high in Kentucky of $82.66.

Table 1: Sales Volume, Sales Value, Royalties, and Reported Royalty Rate, 2008-2012 (2013 $s)

State	Reported Sales Volume (tons)	Reported Sales Value	Reported Royalties Due	Reported Contract Price (Mine Price) ($/ton)	Reported Royalties Due ($/ton)	Reported Royalty Rate
Alabama	9,043,639	480,463,745	34,830,873	$53.13	$3.85	7.2%
Colorado	97,242,959	4,254,725,406	269,460,788	$43.75	$2.77	6.3%
Kentucky	977,116	80,768,664	6,019,775	$82.66	$6.16	7.5%
Montana	121,474,627	1,858,383,451	219,090,309	$15.30	$1.80	11.8%
New Mexico	18,418,053	913,339,362	45,911,763	$49.59	$2.49	5.0%
North Dakota	10,909,897	169,017,118	3,822,998	$15.49	$0.35	2.3%
Oklahoma	3,039,401	156,778,612	4,046,018	$51.58	$1.33	2.6%
Utah	55,144,127	1,982,399,360	132,991,300	$35.95	$2.41	6.7%
Wyoming	1,974,279,688	25,811,102,337	3,183,032,256	$13.07	$1.61	12.3%
Federal Total	**2,290,529,507**	**35,706,978,054**	**3,899,206,080**	**$15.59**	**$1.70**	**10.9%**

*Federal total reported contract price, reported royalties due and reported royalty rate are weighted averages.

The Value of Royalty Rate Reductions and Allowable Cost Deductions

The difference between the statutory rate and the reported rate in Figure 3 is the combined value of royalty rate reductions and allowable cost deductions. The majority of the difference is due to royalty rate reductions, with allowable costs making up only a small share of the difference. The BLM and Office of Natural Resources Revenue (ONRR) do not provide statistics on these costs. To estimate these values, we submitted a Freedom of Information Act (FOIA) request for a complete set of leases sold since 1990 for which we have actual production, total sales value, the value of cost deductions, and royalty payments data for coal produced.[26] These data are joined with lease statistics published by the BLM and specific data on royalty rate reductions (See Appendix A for data sources).

Data Used in This Report

Current Production, 2008 to 2012
The main findings presented in Figure 1 are based on the most current production data, including sales volume, sales value, royalties, transportation costs between the mine and consumers, and market prices between 2008 and 2012.

Lease Data, 1990 to 2013
Because of data withholdings, we requested data from ONRR for a known set of leases for which we have additional information on bonus payments, allowable transportation and processing cost deductions, and royalty rate reductions. We use these “lease data” to estimate the value of subsidies in the current royalty structure and to include statistics on the reported and effective bonus payment rates.

Using lease data since 1990, Figure 4 and Table 2 show the relative value of royalty rate reductions and allowable costs as a share of the reported royalty rate. Allowable transportation and processing costs combined to average about a third of one percent of total sales value for all coal produced from leases sold since 1990. Utah had the highest costs relative to sales value at 1.2 percent, while coal produced on federal lands in New Mexico and North Dakota had no allowable transportation or processing costs.

Table 3 shows that royalty rate reductions occurred on at least 30 out of 83 leases (36 percent of leases) offered for sale since 1990.[27] Royalty rate reductions can be applied for a fixed time period, often for a year, or can be granted for the life of the lease. In the case of Wyoming, nearly all coal is mined at the surface and only one of 21 leases sold since 1990 received a temporary royalty rate reduction. As a result, there is little difference between the estimated statutory rate and the estimated value of royalty rate reductions in Wyoming. In other states the reported rate is significantly lower than the estimated statutory rate, indicating that royalty rate reductions are more common in these states. For example, at least 11 of the 12 coal leases offered in North Dakota since 1990 have received royalty rate reductions to between 2 percent and 2.6 percent.

The value of these royalty rate reductions has lowered royalty payments by $294 million since 1990. The lease data describe about 34 percent of coal mined from all active federal leases between 1990 and 2013. The balance of total coal mined over this period is extracted from leases sold prior to 1990. If we assume royalty rate reductions are similar for leases sold prior to 1990, the total value of royalty rate reductions could be closer to $860 million from 1990 to 2013, or about $37 million annually (in 2013 dollars).

Figure 4: Allowable Cost Deductions as a Share of Sales Value, Based on Lease Data 1990-2013

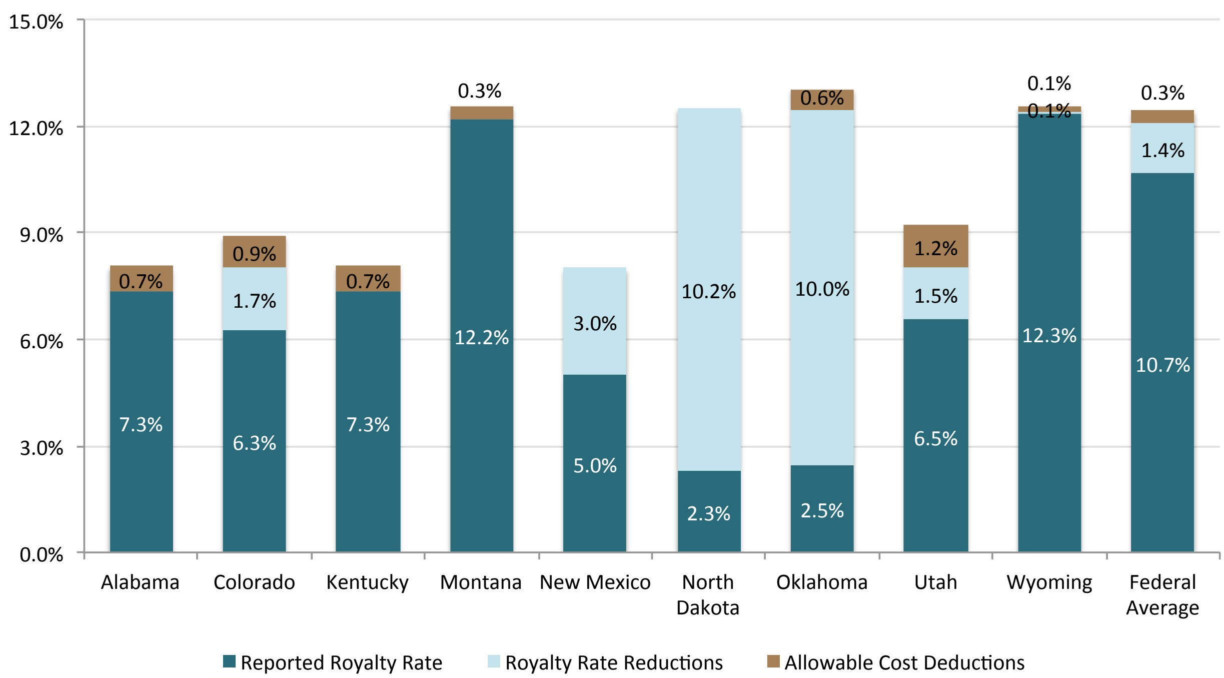


Table 2: Allowable Transportation and Processing Costs, Lease Data 1990-2013 (2013 $s)

State	Sales Value	Allowed Transportation Cost	Allowed Processing Cost	Net Taxable Value	Allowable Cost Deductions
Alabama	$648,199,202	$86,465	$4,633,541	$643,479,196	0.7%
Colorado	$5,646,464,779	$48,214,954	$3,640,680	$5,594,609,145	0.9%
Kentucky	$187,531,728	$202,056	$1,150,961	$186,178,711	0.7%
Montana	$567,928,408	$1,710,343	$154,711	$566,063,354	0.3%
New Mexico	$487,088,643	$0	$0	$487,088,643	0.0%
North Dakota	$432,262,237	$0	$0	$432,262,237	0.0%
Oklahoma	$479,159,488	$2,387,853	$359,145	$476,412,491	0.6%
Utah	$4,072,408,872	$48,143,213	$1,995,318	$4,022,270,341	1.2%
Wyoming	$32,129,773,453	$42,578,904	$0	$32,087,194,549	0.1%
Federal Total	**$44,650,816,810**	**$143,323,788**	**$11,934,355**	**$44,495,558,668**	**0.3%**

* Federal total allowable cost deductions is a weighted average.

Table 3: Estimated Value of Royalty Rate Reductions, Federal Coal Leased Since 1990

State	No. of Leases Sold Since 1990	No. of Leases Granted Royalty Rate Reductions	Share of Leases Granted Royalty Rate Reductions	Royalty Rate Reductions	Value of Royalty Rate Reductions
Alabama	3	0	0.0%	0.0%	$0
Colorado	16	9	56.3%	1.7%	$97,965,234
Kentucky	6	0	0.0%	0.0%	$0
Montana	4	0	0.0%	0.0%	$0
New Mexico	1	1	100.0%	3.0%	$14,612,659
North Dakota	12	11	91.7%	10.2%	$44,070,704
Oklahoma	6	5	83.3%	10.0%	$47,902,834
Utah	14	3	21.4%	1.5%	$59,309,705
Wyoming	21	1	4.8%	0.1%	$23,651,618
Federal Total	**83**	**30**	**36.1%**	**1.4%**	**$287,512,755**

* Federal total royalty rate reductions is a weighted average.

Total Reported Bonus and Royalty Rates

Bonus payments add an important source of revenue for the public from federal coal sales. Bonus payments total $3.7 billion for leases sold since 1990 (2013 $s), about 44 percent of revenue derived from these leases to date.[28] On a per-ton basis, bonus payments averaged $0.60 cents per ton. The highest average bids were in Wyoming at $0.66 per ton and the lowest were in North Dakota at $0.01 per ton. The per-ton bonus bid is expressed as the total bonus bid received at the time the lease is sold divided by the estimated amount of coal sold with the lease.[29]

To estimate the average reported return from bonus payments, we divide the per-ton bonus payment by the average contract price received for the same coal as it has been mined. Figure 5 and Table 4 show that the total reported return on bonus payments based on the average mine price is 3.9 percent. The highest reported return on bonus bids was in Wyoming at 5 percent, and was lowest in North Dakota and Oklahoma at less than 0.1 percent of the eventual mine price of the same coal when it was sold.

Figure 5: Total Reported Bonus Payments and Royalties, Lease Data 1990-2013 (2013 $s)

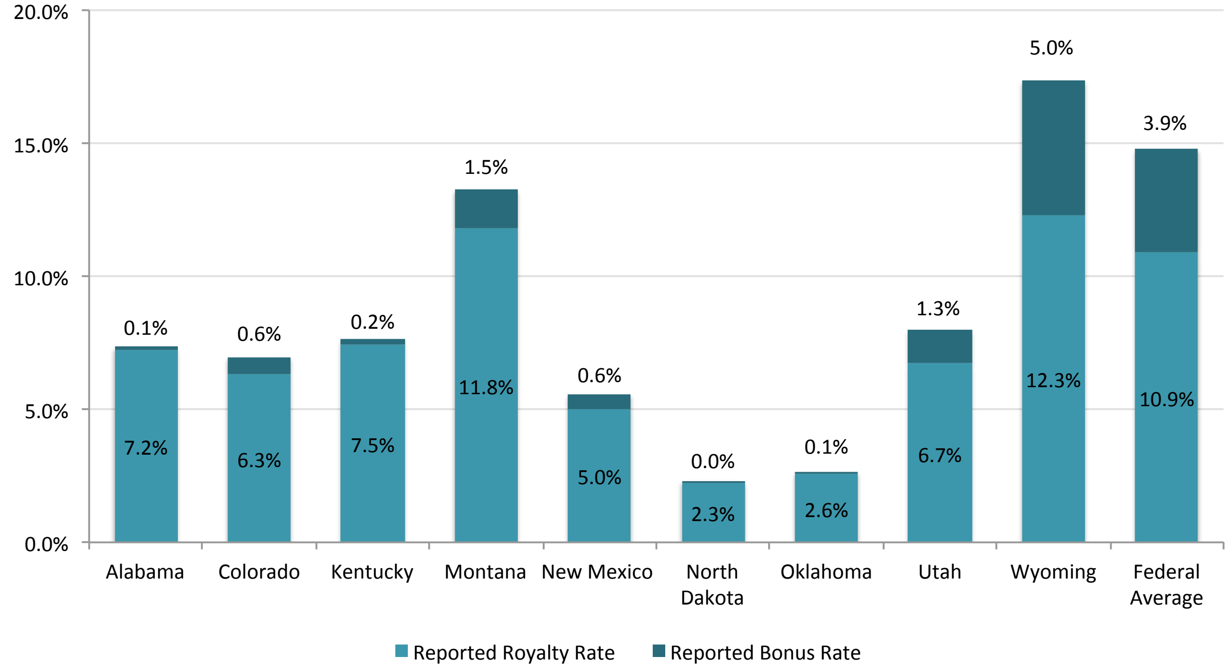


Table 4: Effective Bonus Rates, Coal Lease Data, 1990-2013 (2013 $s)

State	Estimated Amount of Coal Leased (thousand tons)	Total Accepted Bid (2013 $s)	Bonus Bid Per Acre (2013 $s)	Contract Price (2013 $s per ton)	Reported Bonus Rate	Total Reported Bonus and Royalty Rate
Alabama	19,014	955,923	$0.05	$53.13	0.1%	7.3%
Colorado	185,923	52,513,849	$0.28	$43.75	0.6%	7.0%
Kentucky	9,400	1,320,106	$0.14	$82.66	0.2%	7.6%
Montana	187,100	41,897,475	$0.22	$15.30	1.5%	13.3%
New Mexico	63,000	17,681,167	$0.28	$49.59	0.6%	5.6%
North Dakota	129,110	999,259	$0.01	$15.49	0.0%	2.3%
Oklahoma	58,409	2,432,282	$0.04	$51.58	0.1%	2.7%
Utah	198,786	91,546,365	$0.46	$35.95	1.3%	8.0%
Wyoming	5,426,092	3,568,766,373	$0.66	$13.07	5.0%	17.4%
Federal Total	**6,276,834**	**3,778,112,799**	**$0.60**	**$15.59**	**3.9%**	**14.8%**

* Federal total bonus bid per acre, contract price, reported bonus rate and total reported bonus and royalty rate are weighted averages.

Effective Royalty Rates

The effective royalty rate is calculated by dividing royalty collections by the gross market value of the same coal. Using current production data, we compared total royalties paid between 2008 and 2012 to market prices earned for coal sold by state of origin (the state where the coal is mined) to consumers including domestic power generators,[30] industrial users, coke plants,[31] and for export.[32]

Figure 6 shows that the effective royalty rate of return is lowest in North Dakota and Oklahoma at 0.7 percent and 2.2 percent respectively. The highest effective royalty rate is in Kentucky at 7.8 percent. Wyoming, which accounted for 86 percent of coal sales from federal leases between 2008 and 2012, had an effective rate of 5 percent. Montana, the second largest producer of federal coal, had an effective royalty rate of 4.6 percent over the same period. (See the sidebar on *Data Withholdings and Sources of Error* that follows Table 5.)

Figure 6: Reported and Effective Royalty Rates, 2008-2012

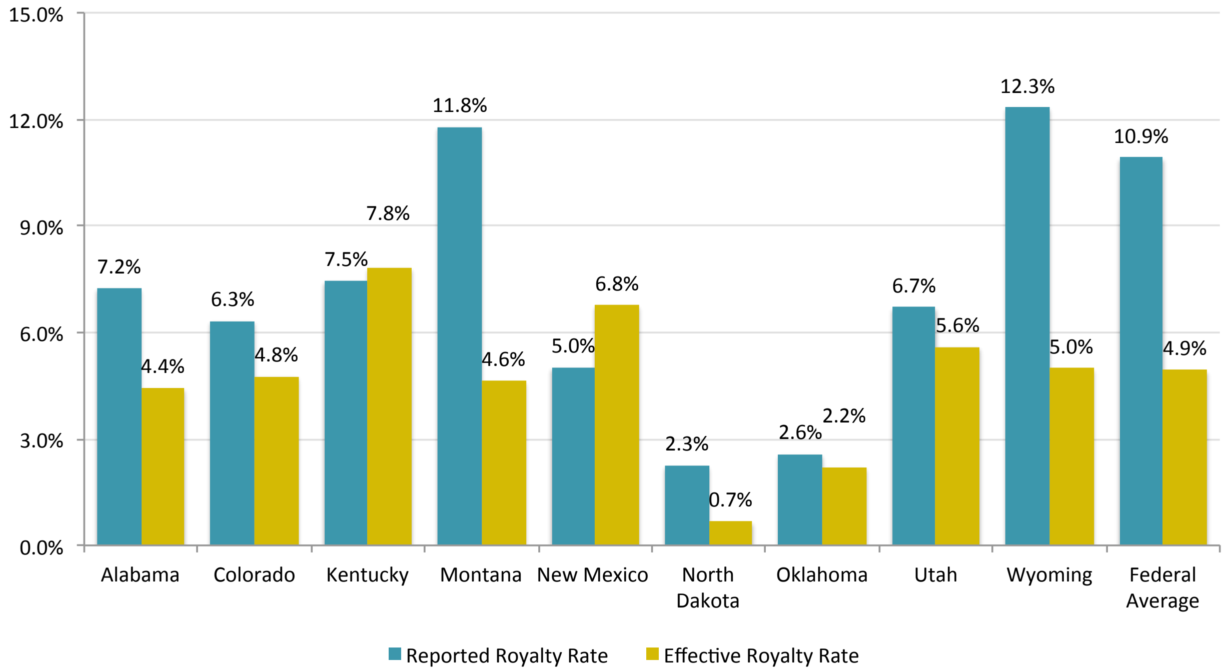


Table 5: Sales Volume, Gross Market Price, and Effective Royalty Rate, 2008-2012 (2013 $s)

State	Sales Volume (tons)	Gross Market Value of Federal Coal Sales	Gross Market Price	Total Royalties Due	Royalties Due ($/ton)	Effective Royalty Rate
Alabama	9,043,639	$784,434,555	$86.74	$34,830,873	$3.85	4.4%
Colorado	97,242,959	$5,651,339,647	$58.12	$269,460,788	$2.77	4.8%
Kentucky	977,116	$76,972,625	$78.78	$6,019,775	$6.16	7.8%
Montana	121,474,627	$4,724,611,243	$38.89	$219,090,309	$1.80	4.6%
New Mexico	18,418,053	$677,917,345	$36.81	$45,911,763	$2.49	6.8%
North Dakota	10,909,897	$561,134,088	$51.43	$3,822,998	$0.35	0.7%
Oklahoma	3,039,401	$182,653,002	$60.10	$4,046,018	$1.33	2.2%
Utah	55,144,127	$2,374,338,764	$43.06	$132,991,300	$2.41	5.6%
Wyoming	1,974,279,688	$63,828,848,193	$32.33	$3,183,032,256	$1.61	5.0%
Federal Total	**2,290,529,507**	**$78,862,249,462**	**$34.43**	**$3,899,206,080**	**$1.70**	**4.9%**

* Federal total gross market price, royalties due per ton, and effective royalty rate are weighted averages.

Data Withholdings and Sources of Error

In this report, we endeavor to bring together disparate datasets that have varying levels of specificity, data withholdings, and scales of assessment. This effort results in estimates with varying levels of accuracy, and introduces several sources of potential errors. Throughout the report, we document data sources and methods, and provide notes to orient the reader to how figures and tables should be interpreted.

Estimating effective royalty rates offers the first example of the challenges inherent in this project. To estimate effective rates, we compare sales values and royalty data reported by ONRR for federal leases in each state to the market price received for all coal sold from each state, including from leases on federal, tribal, state, and private land.

In Kentucky, for example, coal sales from federal leases account for one quarter of one percent of total coal sales. Prices received from this tiny fraction of all sales is unlikely to be representative of average market prices, and estimates that rely on comparing these two data sets will have high rates of error. Federal coal sales are a larger share in New Mexico (21% of total sales), but are still too small to provide reliable estimates of effective royalty rates. In Wyoming, coal sales from federal leases account for 93 percent of all coal sales in the state. As a result, we are more confident in estimates of effective tax rates in Wyoming.

Estimating Transportation Costs and Marketing Margins

The difference between the reported and effective rates in Figure 6 is the combined value of transportation costs between the mine and the consumer, and any margins earned when coal is remarketed by affiliates or independent brokers. In this case, transportation costs are costs incurred to move coal from the mine to the consumer.[33] In most cases, these costs are incurred after the coal has changed hands, and royalties have been paid, so they are outside of the royalty structure. Marketing margins are any profits earned by brokers who buy coal at a low price from the lessee at the mine, and sell the coal for a higher price for domestic consumption or for export.

To estimate the value of these marketing margins, we compare the net market price (gross market price less transportation costs) and the mine price. The difference is the increased value of coal, other than transportation costs that is created after royalties are assessed at the mine. Table 6 shows that the majority of the difference between net prices and mine prices is made up of transportation costs (about 92%). But the value of marketing margins is substantial, about $620 million in forgone royalties between 2008 and 2012. In other words, if lessees had paid royalties at current rates (including royalty rate reductions) on the net market value of coal during the five-year period, royalty collections could have been about $620 million higher, or $124 million annually. The majority of these gains would have been from Wyoming where the value of royalties forgone by not assessing them on marketing margins was about $520 million, or about $0.27 per ton.

Table 6: Estimated Value of Marketing Margins and Forgone Royalties due to Current Coal Valuation Policy 2008-2012 (2013 $s)

State	Sales Volume (tons)	Gross Market Price	Transportation Costs per ton	Net Market Price	Estimated Royalties at Current Rates	Estimated Total Royalties	Estimated Royalties Forgone
Alabama	9,043,639	$86.74	$4.21	$82.53	$5.98	$54,108,431	$19,277,557
Colorado	97,242,959	$58.12	$12.39	$45.73	$2.90	$281,636,042	$12,175,254
Kentucky	977,116	$78.78	$16.39	$62.39	$4.65	$4,543,465	-$1,476,311
Montana	121,474,627	$38.89	$19.09	$19.81	$2.34	$283,666,382	$64,576,073
New Mexico	18,418,053	$36.81	$9.73	$27.08	$1.36	$25,067,961	-$20,843,802
North Dakota	10,909,897	$51.43	W	NA	NA	NA	NA
Oklahoma	3,039,401	$60.10	W	NA	NA	NA	NA
Utah	55,144,127	$43.06	$2.55	$40.51	$2.72	$149,854,587	$16,863,287
Wyoming	1,974,279,688	$32.33	$17.08	$15.25	$1.88	$3,712,947,144	$529,914,888
Federal Total	**2,276,580,209**	**$34.43**	**$16.52**	**$17.79**	**$1.94**	**$4,511,824,011**	**$620,486,947**

* Federal total gross market price, transportation costs per ton, and net market price are weighted averages. "W" in the table indicates data withholdings.

Data Withholdings and Sources of Error:

Transportation costs are reported only for deliveries to domestic power plants, and not for deliveries for export markets, coke plants, and other industrial users. Where sales to these sectors other than domestic power plants are larger (as a share of total sales), transportation cost data may be poor proxies of costs for these markets.

All transportation costs are withheld for coal sales from North Dakota and Oklahoma, so it is not possible to estimate net market prices for these states at all. In Wyoming, by comparison, coal sales to domestic power generators account for 98.3 percent of all current coal deliveries (2008 to 2012). Montana coal sales to domestic power plants account for 95.7 percent of sales over the same period. As a result, the estimates for these two states are more realistic, and in total the value of forgone royalties during the five years is likely to be about $595 million.

Total Effective Bonus and Royalty Rates

To estimate the average effective return from bonus payments, we divide the per-ton bonus payment based on coal lease data between 1990 and 2013 by current market prices received for the same coal as it has been mined. Figure 7 shows that the total effective return on bonus payments in recent years for coal sold since 1990 is 1.7 percent. The highest effective return on bonus bids was in Wyoming at 2 percent, and the lowest was in North Dakota and Oklahoma at only 0.1 percent of the eventual mine price of the same coal when it was sold.

Bonus payments are included in this analysis because they are an important source of revenue and add to the total effective return on federal coal sales. There is also, in theory, some interaction between royalty costs to potential lessees and the price they are willing to bid to secure a federal coal lease. Finding that the average effective rate of bonus bids for coal sold since 1990 is less than two percent of the gross market value of coal sold over a recent five-year period suggests that bonus payments are less important than are royalties paid when coal is eventually mined from federal leases. On average, bonus payments contribute about a quarter of the total returns from federal coal leasing. Reforms to the royalty structure and coal valuation policy may have little or no effect on the BLM's fair market valuation determinations. Even if they do, the benefits of ensuring fair returns in the royalty structure will likely outweigh the potential for lower bonus payments.

Figure 7: Total Reported Bonus Payments and Royalties, Lease Data 1990-2013 (2013 $s)

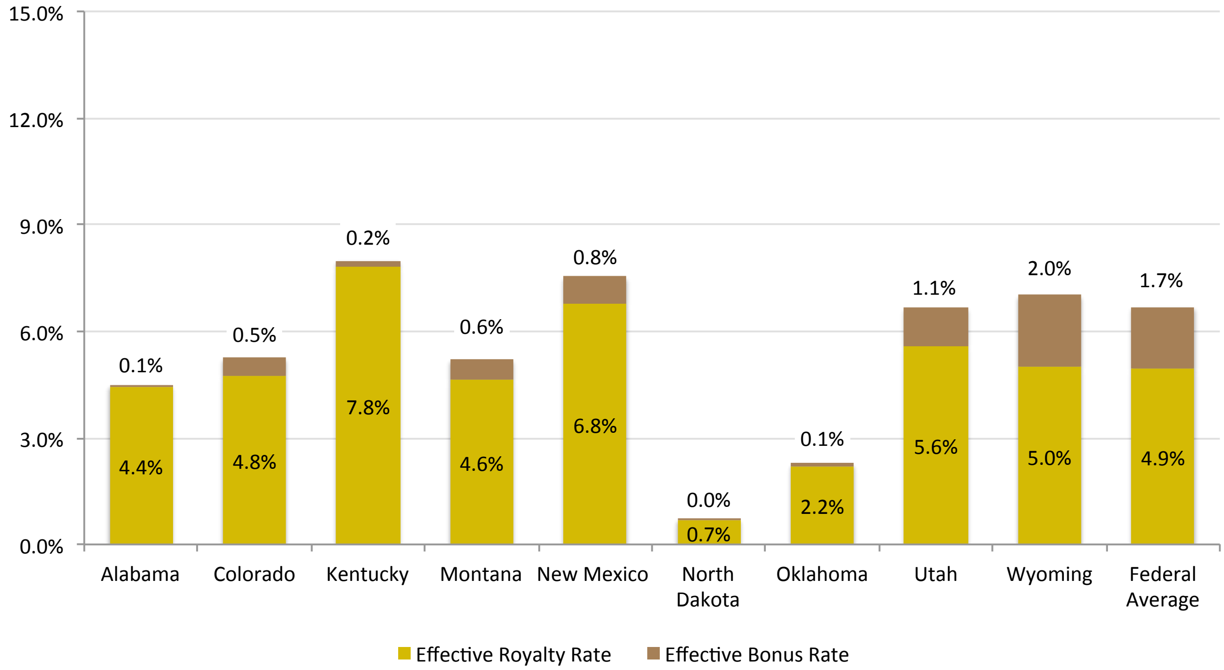


Table 7: Effective Bonus Rates, Coal Lease Data, 1990-2013 (2013 $s)

State	Estimated Amount of Coal Leased (thousand tons)	Total Accepted Bid (2013 $s)	Bonus Bid Per Acre (2013 $s)	Gross Market Price (2008-2012)	Effective Bonus Rate	Total Effective Bonus and Royalty Rate
Alabama	19,014	$955,923	$0.05	$86.74	0.1%	4.5%
Colorado	185,923	$52,513,849	$0.28	$58.12	0.5%	5.3%
Kentucky	9,400	$1,320,106	$0.14	$78.78	0.2%	8.0%
Montana	187,100	$41,897,475	$0.22	$38.89	0.6%	5.2%
New Mexico	63,000	$17,681,167	$0.28	$36.81	0.8%	7.5%
North Dakota	129,110	$999,259	$0.01	$51.43	0.0%	0.7%
Oklahoma	58,409	$2,432,282	$0.04	$60.10	0.1%	2.3%
Utah	198,786	$91,546,365	$0.46	$43.06	1.1%	6.7%
Wyoming	5,426,092	$3,568,766,373	$0.66	$32.33	2.0%	7.0%
Federal Total	**6,276,834**	**$3,778,112,799**	**$0.60**	**$34.43**	**1.7%**	**6.7%**

* Federal total bonus bid per acre, gross market price, effective bonus rate and total effective bonus and royalty rate are weighted federal averages.

Coal Compared to Federal Oil and Natural Gas Leasing

Oil and natural gas leased on federal lands generate revenue in the form of bonus payments, lease rentals, and royalties on the value of extraction. In general, the lease sale, bonus, and royalty structure are very similar to coal's: leases are sold through competitive lease sales, and lessees pay a bonus to the BLM to secure the lease and pay royalties based on gross value of the commodity when it is sold—in the case of oil and natural gas, typically at the wellhead. The statutory rate is 12.5 percent and rate reductions are available based on economic or cost considerations. Companies are also allowed to deduct transportation and processing costs.

Data on wellhead prices, gross taxable value, production, and benchmark market prices are more readily available for these commodities due to their different commercial and production characteristics. We use summary statistics for all oil and natural gas production between 1990 and

2013 to estimate total effective returns.[34] The effective rate is also estimated by dividing royalties paid by the market price of oil and natural gas.

Figure 8: Effective Bonus and Royalty Rate on Federal Oil, Natural Gas, and Coal Leases

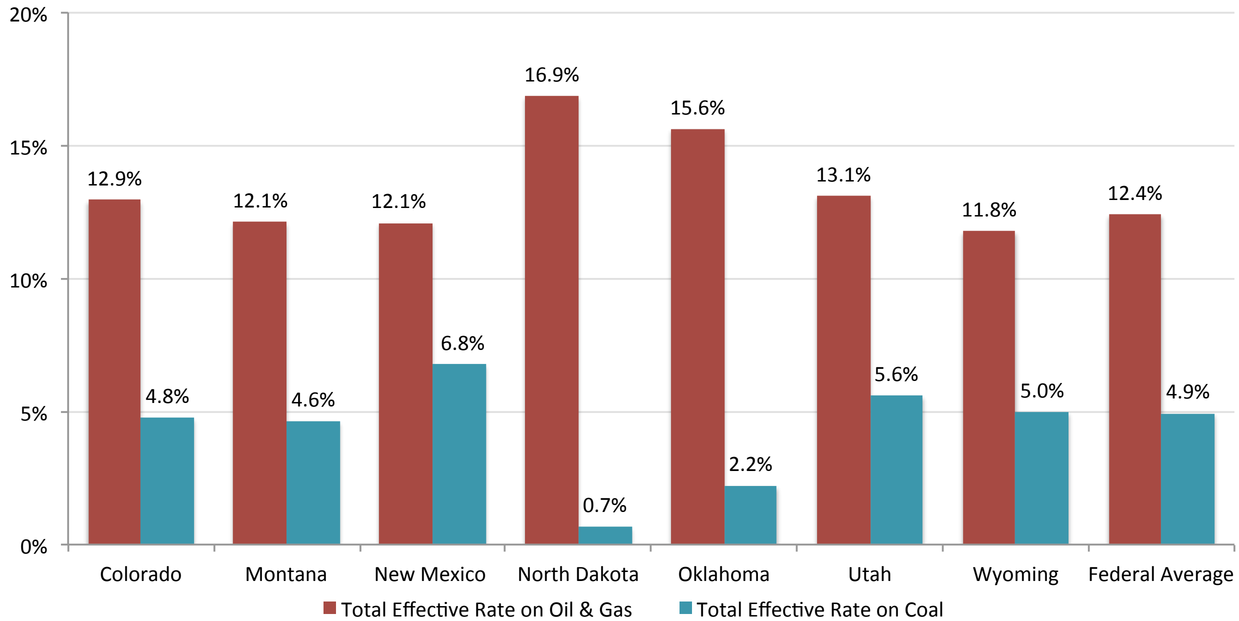


Figure 8 shows that oil and natural gas tends to pay a higher rate than coal. The difference has little to do with the royalty regulation, although it appears that royalty rate reductions are less often applied. More important is the different market for oil and natural gas. These resources are traded in global or national markets with many more individual producers and with greatly more value added in processing and refining after the resource is delivered to market. Transportation costs are lower, and the ability for brokers to earn margins by buying resources at low prices at the lease and remarketing them to consumers is more difficult—midstream brokers of oil and gas are typically selling to downstream brokers such as refiners who also buy in bulk. The difference between the wellhead price and the market price is therefore much smaller in oil and natural gas markets than in coal markets, and effective rates are much closer to the statutory rate.

The outcomes of similar royalty structures applied to commodities traded in different market environments are that oil and natural gas are subject to much higher effective royalty rates than coal extracted from public lands. Where coal and liquid fossil fuels (especially natural gas) compete as sources of electric energy, royalty policy confers an advantage to coal versus liquid fossil fuels, distorting energy markets.

Oil and natural gas also pay higher statutory rates when they are extracted from most U.S. states and from offshore federal waters. Royalty rates vary between 16.67 to 25 percent on state lands, and 18.5 percent in federal offshore waters.[35] By comparison, the U.S. onshore royalty rate of 12.5 percent for oil and natural gas is low, and the White House Office of Management and Budget (OMB) has initiated a review process to determine if the rate should be increased.[36]

V. STRUCTURAL REFORM OPTIONS: VALUING COAL USING MARKET PRICES

The Department of the Interior has identified coal valuation for royalties and current royalty rates as areas that deserve additional review and reform. The purpose of this report is to present data and analysis useful to decision makers as they evaluate options to update the federal coal royalty structure and valuation policy. The agency is already considering several reforms through a rulemaking process, including reconsidering current subsidies and closing marketing loopholes by addressing royalty valuation for coal sold through captive transactions (or non-arm's-length sales). It has also moved to improve transparency by making data more readily available to the public.

Addressing these issues independently may be ineffective and add to an already complex regulatory environment. Reforms may also fall short if they are not considered comprehensively. Reforming the current structure to use the gross market price of coal delivered for domestic use and export offers several benefits:

- Moving the point of valuation improves transparency. Market prices are known. The BLM and the public will all have easy access to coal valuation data.
- Because the structure would use published data, it greatly simplifies the valuation process and reduces administrative costs.
- Reforming the royalty structure also makes it easier to assess what a fair return is, and balance these returns against other competing interests.

Figure 9 illustrates the coal royalty structure and returns based on the current valuation policy of using the first sale, typically as coal leaves the mine. Figure 9 also illustrates the proposed reform that would value coal for royalties using market prices instead. The gross market price is the price paid by the ultimate consumers of federal coal, including domestic power plants, industrial users, coke plants, and coal sold for export. The net market price is the gross market price minus transportation costs incurred to move coal from the mine to the consumer.

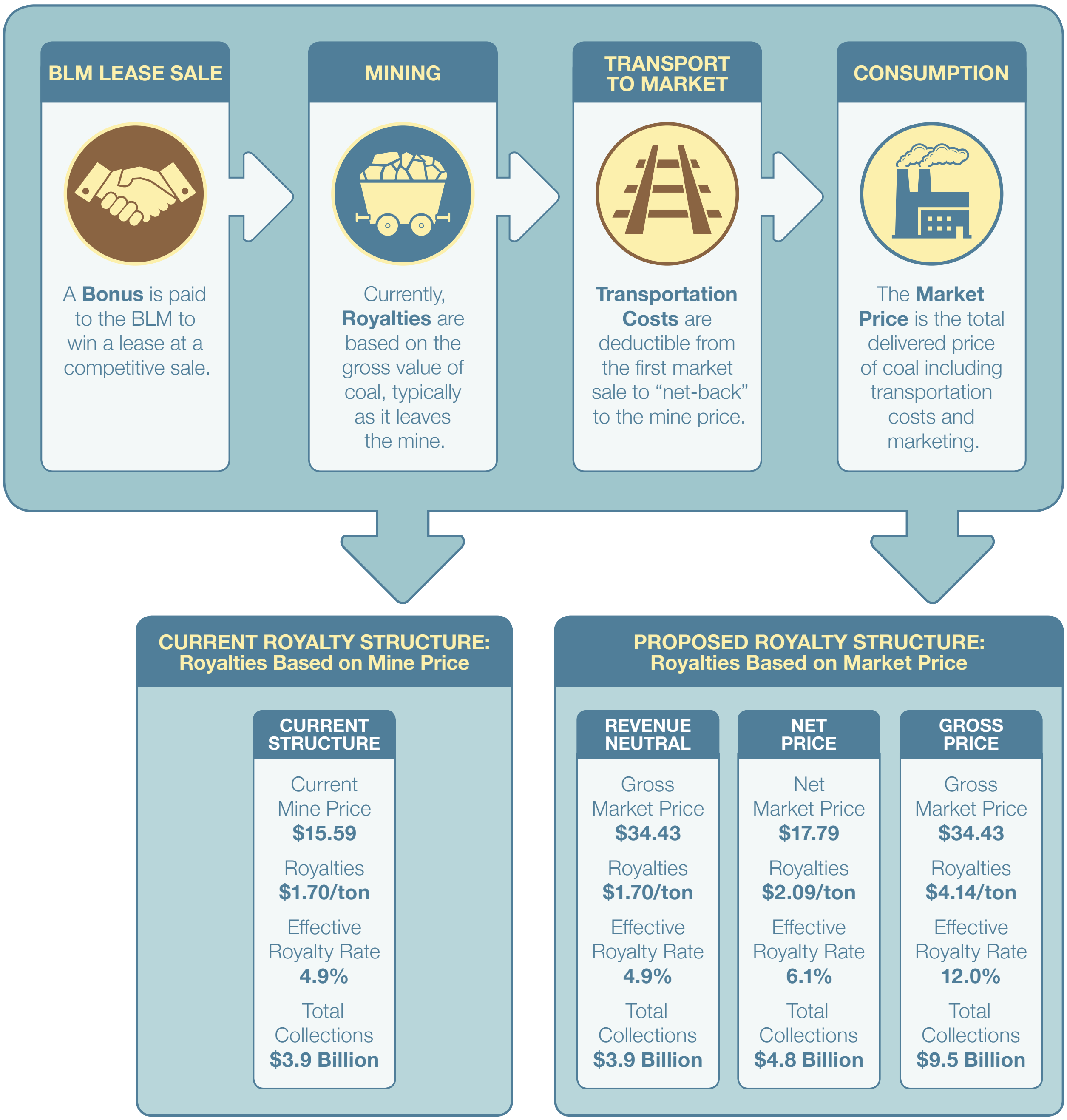
Revenue-Neutral Reforms

The BLM, which oversees the federal coal-leasing program, has multiple and diverse objectives: a fair return for U.S. taxpayers, economic development and jobs, energy security, and environmental protection. A royalty structure that is more easily understood will allow for a better assessment of how these goals are best met. The primary benefits of transparency, cost reductions, and policy flexibility can be achieved through revenue-neutral reforms. Moving the point of valuation from the mine price to the market price and lowering royalty rates to the current effective royalty rate would return the same revenue as the current royalty structure, but would do so with lower administrative costs.

The average effective rate for all federal leases between 2008 and 2012 was 4.9 percent. Ideally, the effective rate would be calculated and applied for each lease based on current production statistics. The data we provide here are all summarized at the state level, but provide the framework for how revenue-neutral reforms should be understood and implemented. The policy outcome would be a simple, transparent structure that effectively retains all current subsidies.

Figure 9:

Current U.S. Coal Royalty Structure, Valuation Policy, and Reform Options



http://headwaterseconomics.org

Royalty Valuation Based on Net Market Price

This reform option would apply current statutory rates to the net market price of coal. The policy outcome would be to simplify the royalty structure, eliminate subsidies in the regulation (royalty rate reductions), and close the affiliate broker loophole while retaining transportation cost deductions.

Figure 9 shows that the average net market price of coal delivered from states with federal production was $17.79 between 2008 and 2012. If royalties had been valued based on the net market price over this same period, total royalty revenue would have totaled $4.8 billion, or about $2.09 per ton. The effective rate would have been 6.1 percent. Had this reform been in place over the five-year period, royalty collections would have been about $865 million higher than actual collections.

The net cost to industry would have been smaller because higher royalty payments would result in lower state severance taxes and corporate income taxes.[37] For coal extracted from Montana and Wyoming (about 91 percent of total federal coal production), the total cost increase per ton would have been about $0.18, or about half a percent of the gross market price of coal. This additional cost may be passed forward as a higher delivered cost of coal, or it may be passed backwards onto the mining company or the marketing broker. If all costs are passed forward, it could result in a maximum increase in the delivered cost of coal of 0.5 percent.

Royalty Valuation Based on Gross Market Price

This option would apply current statutory rates to the gross market price of coal. The policy outcome would be to eliminate subsidies, cost deductions, and marketing loopholes—significantly raising royalty revenue. Figure 1 shows the average gross market price of coal delivered from states with federal production was $34.43 between 2008 and 2012. If royalties had been valued based on the gross market price over this same period, total royalty revenue would have totaled $9.5 billion, or about $4.14 per ton. The effective rate would have been 12.0 percent, compared to the actual effective rate of 4.9 percent.

In Montana and Wyoming, the reform would have produced more than $5.6 billion in additional royalty revenue. After considering the likely reduction in state severance and corporate income taxes, the net change in revenue would have been about $3.9 billion or $1.90 per ton.[38]

Interpreting Results

The Office of Natural Resources Revenue (ONRR) is currently proposing to change the regulations governing valuation of coal for royalty purposes. While this paper does not specifically address the rulemaking process, the results can inform public comment and ultimately the rule that ONRR adopts.

The ONRR proposes to retain royalty valuation at or near the lease, using gross proceeds from the first arm's-length transaction (or market sale) as the basis for royalties. The rule is specifically designed to address situations where the first sale is to an affiliate broker—in other words, it is not at arm's-length and may be structured only to avoid paying royalties on the higher market value of federal coal. In making this change, ONRR would use the first market sale to determine royalty valuation.

One way to interpret our results is that the rule would effectively change royalty valuation to the net market price of coal (if transportation costs are still deductible). However, non-affiliated brokers may still play an important role in the coal market, and the rulemaking would do little to affect royalty collections. Our results define the upper end of the possible outcomes that could range from very little change up to an increased royalty payment per ton averaging about $0.18 for federal coal in Montana and Wyoming (after accounting for state severance tax and corporate income tax interactions).

If the rulemaking additionally limits transportation costs deductions to 50 percent of actual costs, the effect of the rulemaking could be an average increase in royalty payments per ton of about $0.85 per ton (after accounting for state severance tax and corporate income tax interactions). Again, this estimate should be considered the upper end of costs that would accrue only if closing the affiliate broker loophole results in mines in Montana and Wyoming marketing all federal coal directly to consumers. If, however, brokers remain an important player in the market structure (and they still retain effectively a 12.5 percent cost advantage over a mine marketing coal directly), then changing royalty valuation and transportation deductions will have little, if any, effect on collections.

VI. CONCLUSION

Coal still supplies more than one-third of total U.S. electricity generation, and federal leases generate up to a billion dollars each year in bonus payments and royalties. Despite coal's importance to government revenue, the current royalty structure is opaque and costly to administer, and the returns to the U.S. public are unclear. Our assessment of the current royalty structure and estimates of effective tax rates suggest that the Bureau of Land Management is not receiving a fair return. The average effective tax rate of 4.9 percent (bonus payments contribute an additional 1.7 percent effective return) falls well short of statutory rates and is lower compared to the effective rates paid by oil and natural gas extracted from federal lands. We estimate that current subsidies in the regulation and marketing loopholes due to royalty valuation policy were worth about $850 million between 2008 and 2012.

The BLM and ONRR do not only manage the federal coal program to maximize returns. Federal coal leasing has multiple and diverse objectives: a fair return for U.S. taxpayers, economic development and jobs, energy costs and security, and environmental protection. However, significant changes in the structure of the coal market, including a larger share of production from western surface mines, an increasing role for brokers in the coal market, and the potential for significant new coal exports, have raised concerns about the current balance between competing interests.

The BLM and ONRR are undertaking several reforms, including a current rulemaking process to consider changes to the royalty valuation policy. The Department of the Interior is also revisiting royalty rates on oil, natural gas, and coal, and seeking to improve transparency of the lease sale and royalty program. This report concludes that moving the basis for coal royalty valuation from the mine price to the market price simplifies the royalty structure, creates transparency and lowers administrative costs, and allows for assessment of how the BLM is balancing competing interests in leasing federal coal.

APPENDIX A: DATA SOURCES

In order to calculate effective rates of return and assess the outcomes of reforms to the coal valuation structure, we combine statistics that describe annual production, total sales value, the value of cost allowances, royalties due, bonus bids, transportation costs between the mine and the point of consumption, and the market price of delivered coal. These data come from a variety of sources and must be joined to provide a full picture of the royalty structure.

BLM Lease Data

BLM lease data:

- Estimated amount of coal sold
- Bonus payment per ton
- Royalty rate reductions

ONRR Reported Royalties

ONRR revenue data:

- Sales value
- Sales volume
- Reported revenue (royalties and bonus payments)
- Allowable costs

Transportation Costs

EIA Transport Costs:

- Cost per ton for state-to-state deliveries by rail, truck, and waterway to the power sector

EIA Market Price Data

EIA Market Price Data:

- Delivered tons by consumer type and mine
- Market price by consumer type, including exports
- Primary transport mode to market

This section describes the various data and methods we use in this report.

Bureau of Land Management (BLM) Lease Data

Coal Lease Sales and Bonus Payment Statistics

Statistics for all leases sold from 1990 to the current year (2012) include the sale date, state, associated mine name, and lease-specific data including acres leased, estimated amount of coal leased, number of qualified bids, accepted bonus bid (total and per-ton), and the successful bidder.

Citation: U.S. Department of the Interior, Bureau of Land Management. "Total Federal Coal Leases in Effect, Total Acres Under Lease, and Lease Sales by Fiscal Year Since 1990." Washington, D.C. http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy/coal_lease_table.html.

Royalty Rate Reductions

Royalty rates are set for each lease and are considered proprietary and are withheld from public review. The Senate Energy and Natural Resources Committee conducted a review of the BLM lease process, including statistics that describe royalty rate reductions applied to BLM leases sold since 1990. These data were joined to the BLM Coal Lease Sales and Bonus Payment Statistics described above to estimate the value of royalty rate reductions granted to this same set of leases.

Citation: Royalty Rate Reductions for Leases Sold Since 1990. Personal communication, Senate Energy and Natural Resources Committee staff, June 13, 2014.

Office of Natural Resource Revenue (ONRR) Reported Royalties

Reported Sales Value, Sales Volume and Royalty Revenue

ONRR reports total sales volume and sales value for royalty purposes, and the resulting royalty, bonus, rental, and other revenue data. Statistics are organized by year and by state for specific commodity and product codes from 2003 to 2013. Royalty statistics prior to 2003 are only available at the commodity code, and bonus payment statistics are only available in total for all commodities combined. Statistics are reported for accounting year and sales year. Sales year statistics are used in this report.

Citation: U.S. Department of the Interior, Office of Natural Resources Revenue. Federal Onshore Reported Sales Value, Sales Volume, and Royalty Revenue. Sales Years 2003 to 2013. http://statistics.onrr.gov/.

Freedom of Information Act (FOIA) Request for Reported Sales Value, Sales Volume, and Royalty Revenue Associated with Leases Sold Since 1990

Data were requested through the Freedom of Information Act (FOIA) from the Office of Natural Resources Revenue (ONRR) on actual production, total sales value, cost deductions, and royalty payments data for coal produced from active leases sold since 1990.[39] Active leases are those that reported production since 2001.

In total, the BLM has leased over 6.3 billion tons of coal associated with the 83 leases since 1990. Cumulative production from these leases totals 3.3 billion tons, or a little more than half of the total coal sold over the same period. In real terms (expressed in 2013 dollars), the BLM received a total of $3.7 billion in bonus sales associated with these leases, and an additional $4.7 billion in annual royalty payments on actual production from these same leases.

Coal produced from the 83 leases in the dataset from 1990 to 2012 accounts for just more than a third of total federal coal production over the same period. The additional federal coal is produced from leases sold before 1990 that are still operating.

Citation: U.S. Department of the Interior, Office of Natural Resources Revenue. Reported Sales Value, Allowed Deductions, and Royalty Due for Federal Leases Sold Since 1990. FOIA Request no. 2014-0034, August 21, 2014.

Coal Production Data by Mine and Mine Type

These data are reported by operators at the mine scale on an annual and quarterly basis as part of their reporting requirements around mine safety. The original source is the quarterly Mine Safety and Health Administration survey that tracks production statistics as well as statistics on accidents, employment, and working hours by mine. U.S. Energy Information Administration makes these data available in several forms.

Citation: U.S. Department of Labor, Mine Safety and Health Administration Form 7000-2, Quarterly Mine Employment and Coal Production Report.
http://www.msha.gov/OpenGovernmentData/OGIMSHA.asp.

Data: U.S. Energy Information Administration. Coal Production Statistics.
http://www.eia.gov/coal/data.cfm#production.

EIA Transportation Costs

EIA Coal Transportation Rates to the Electric Power Sector

Transportation costs are reported by primary transportation mode (truck, waterway, and rail), by mine state, and destination state. The Energy Information Administration (EIA) compiles these data from form EIA-923. The reported data only include deliveries to electric power plants with at least 50 megawatt generating capacity. Data on transportation costs are withheld by EIA if there were too few mines or producers to maintain confidentiality.

Citation: U.S. Energy Information Administration. 2014. Coal Transportation Rates to the Electric Power Sector, Tables 4a, 4b, and 4c. http://www.eia.gov/coal/transportationrates/ Accessed 29 December 2014.

EIA Coal Price Statistics

EIA Delivered Prices to the Domestic Power Generation Sector

Data for the total quantity of coal delivered (measured in tons), average heat content (measured in millions of BTUs), and fuel cost (measured in cents per BTU) were obtained for individual coal deliveries monthly from 2008 through 2012 using data from the Fuel Receipts Data section of form EIA-923. These data report the state where the coal originated and the state where it was delivered.

Citation: U.S. Energy Information Administration. 2014. Electric Power Generation and Fuel Consumption, Stocks, and Receipts Monthly Time Series Data, Page 5 Fuel Receipts and Costs. http://www.eia.gov/electricity/data/eia923/ Accessed 30 December 2014.

EIA Metallurgical Coal and Industrial Consumer Prices

EIA provides average prices by the state of origin (the state where coal is mined) for deliveries to domestic power generators, industrial users, and coke plants (metallurgical coal).

EIA data sources are: U.S. Energy Information Administration Form EIA-923, Power Plant Operations Report, Form EIA-3, Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users, and Form EIA-5, Quarterly Coal Consumption and Quality Report, Coke Plants.

Citation: U.S. Energy Information Administration. Annual Coal Report. Table 34. Average Price of Coal Delivered to End Use Sector by Census Division and State. http://www.eia.gov/coal/annual/ Accessed 30 December 2014.

EIA Export Prices

Average price is based on the free alongside ship (f.a.s.) value for steam coal exports and metallurgical coal exports by foreign nation and regional totals. Data used in this report are total national average export prices, with the exception of exported coal originating in Wyoming and Montana. We use the total Asia export price for steam coal for these states (we assume since there are no domestic deliveries of metallurgical coal from these states that there are similarly no metallurgical coal exports).

EIA data source is Bureau of the Census, U.S. Department of Commerce, Monthly Report EM 545.

Citation: U.S. Energy Information Administration. Quarterly Coal Report. Average Price of U.S. Steam Coal and Metallurgical Coal Exports. http://www.eia.gov/coal/production/quarterly/ Accessed 30 December 2014.

APPENDIX B: METHODS

Estimating Average Statutory Rates

The average statutory rate is the weighted average of all surface coal mined in states with federal leases times 12.5 percent and all underground coal times eight percent. The formula is:

$$\text{Weighted Average Statutory Rate} = \frac{(\text{Surface coal (tons)} * 12.5\% + \text{Underground coal (tons)} * 8\%)}{\text{total coal (tons)}}$$

Table B1 shows the results of this calculation using current state production data. Data for surface and underground coal production are reported by MSHA for all coal extracted from each state, including federal, tribal, state, and private leases[40] (see the sidebar titled *Production Data: Federal vs. State Statistics*). These state data are compared to the reported royalty rate for federal production in Figure 3 to estimate the size of royalty rate reductions and allowable cost deductions.

Because not all state production comes from federal leases, comparing state production statistics to federal production statistics introduces error to the estimates. The ratio of surface and underground coal production in each state is more likely to be representative of the same ratio on federal lands if federal production makes up a large portion of total coal mined across the state. Table B2 shows the federal share of state production for each state, and the weighted average for all states with active federal leases. In Wyoming, federal production is more than 90 percent of all state production. In this case, the estimated average statutory rate is likely to be confident.

Table B1: Average Statutory Rate, Current State Production 2008-2012

State	State Surface Coal	State Underground Coal	Total State Production	Average State Statutory Royalty Rate
Alabama	37,967,229	59,747,469	97,714,698	9.7%
Colorado	29,106,476	111,807,443	140,913,919	8.9%
Kentucky	212,184,246	320,064,588	532,248,834	9.8%
Montana	191,530,083	16,175,839	207,705,922	12.1%
New Mexico	88,713,582	27,420,685	116,134,267	11.4%
North Dakota	144,281,418	0	144,281,418	12.5%
Oklahoma	3,652,006	1,976,744	5,628,750	10.9%
Utah	570,138	101,527,508	102,097,646	8.0%
Wyoming	2,162,916,368	18,471,802	2,181,388,170	12.5%
State Total	**2,870,921,546**	**657,192,078**	**3,528,113,624**	**12.3%**

*State total average royalty rate is a weighted average.

Table B2: Federal Share of Total Coal Mined by State, 2008-2012

State	Sales Volume from Federal Leases (tons)	Cumulative State Production, All Leases	Federal Share of State Total
Alabama	9,043,639	97,714,698	9.3%
Colorado	97,242,959	140,913,919	69.0%
Kentucky	977,116	532,248,834	0.2%
Montana	121,474,627	207,705,922	58.5%
New Mexico	18,418,053	116,134,267	15.9%
North Dakota	10,909,897	144,281,418	7.6%
Oklahoma	3,039,401	5,628,750	54.0%
Utah	55,144,127	102,097,646	54.0%
Wyoming	1,974,279,688	2,181,388,170	90.5%
Total	**2,290,529,507**	**3,528,113,624**	**64.9%**

*Total federal share of state total is a weighted average.

A second way to estimate an average statutory rate is to use the estimated amount of surface and underground coal leased since 1990 to describe current production from federal leases. Table B3 shows these results. These data indicate something about the resource base available for production in each state. However, it says little about actual production from all federal leases between 2008 and 2012. The leases sold since 1990 account for just more than a third of actual federal coal production during this recent five-year period.

The results vary very little regardless of which estimate of statutory rates are used. In Wyoming, where most federal coal production and coal value is produced, the difference in estimated statutory rate between the two methods is only .04 percent (four one-hundredths of one percent). The estimate of royalties that would be due if coal valuation were based on net market values would change by 3 cents, falling from an estimate of $2.09 in royalties due per ton to $2.06 in royalties due per ton. The effective rate estimate changes by less than a tenth of a percent (0.07%). In either case, is impossible to assess if the error introduced by poor data accuracy leads to over estimates or under estimates of actual statutory rates.

Table B3: Estimated Amount of Surface and Underground Coal Leased and Estimated Statutory Rate, All Leases Sold Since 1990

State	Estimated amount of coal leased	Coal leased from Surface Mines	Coal leased from Underground Mines	Percent of Coal from Surface Mines	Average Statutory Rate
Alabama	19,014	160	18,854	0.8%	8.0%
Colorado	185,923	0	185,923	0.0%	8.0%
Kentucky	9,400	0	9,400	0.0%	8.0%
Montana	187,100	187,100	0	100.0%	12.5%
New Mexico	63,000	0	63,000	0.0%	8.0%
North Dakota	129,110	129,110	0	100.0%	12.5%
Oklahoma	58,409	58,040	369	99.4%	12.5%
Utah	198,786	0	198,786	0.0%	8.0%
Wyoming	5,426,092	5,327,867	32,445	98.2%	12.4%
Federal Total	**6,276,834**	**5,702,277**	**508,777**	**90.8%**	**12.1%**

*The federal total average statutory rate is a weighted average.

Production Data: Federal vs. State Data

Production statistics are often available at the state level using MSHA and EIA reports. Equivalent data, including delivered costs, transportation costs, extraction from surface and underground mines, and others, are not available for production on federal leases reported by ONRR. When these data are not published for federal leases, we use the state data as a proxy, assuming that characteristics of federal production are similar to the broader production profile of all coal extracted from each state.

We use Federal Total and State Total to distinguish at which scale the data presented in a table or column are organized and reported. For example, Table B1 uses state data to estimate the average statutory rate paid by all coal extracted from each state—not only coal extracted from federal leases—based on the share of mining from surface and underground mines respectively.

See Appendix C for more.

Estimating Average Market Prices by State

Average market prices for each mine state and end use sector are estimated by combining total tons of coal distributed with the delivered price to calculate a weighted average. The EIA reports production and price statistics by state of origin for four types of domestic consumers, and for steam and metallurgical coal exports. Table B4 summarizes these data.[41]

Table B4: Domestic and Foreign Distribution of U.S. Coal by State or Origin and Consumer Type, 2008-2012 (thousand short tons)

State	Electric Power Sector	Commercial/ Institutional	Industrial Plants Excluding Coke	Coke Plant	Total Exports	Total State Distributions*
Alabama	38,786,509	0	6,490,079	5,913,879	46,993,100	98,183,567
Colorado	111,285,735	1,035,698	10,014,682	1,641	13,032,830	135,370,586
Kentucky	450,725,624	2,315,733	36,937,507	4,226,068	33,296,760	527,501,692
Montana	157,090,721	497,850	6,597,881	0	28,086,490	192,272,942
New Mexico	117,007,630	0	1,651,223	0	200	118,659,053
North Dakota	115,291,845	0	29,925,588	0	0	145,217,433
Oklahoma	2,194,940	0	2,141,078	96,375	6,000	4,438,393
Utah	83,977,784	37,655	12,967,191	0	3,498,110	100,480,740
Wyoming	2,115,595,143	280,318	36,538,888	0	20,480,830	2,172,895,179
State Total	**3,191,955,931**	**4,167,254**	**143,264,117**	**10,237,963**	**145,394,320**	**3,495,019,585**

*Note that Total State Distributions in Table B4 do not match Total State Production figures in Tables B1 and B2. Tables B1 and B2 include data from MSHA reports, while data included in B4 are from a variety of EIA reports on coal deliveries. These data sources rely on different methods and do not match perfectly.

Table B5 shows the price received for coal delivered to consumers[42] and for export[43] from each state. Market price estimates are based on EIA price data for domestic consumption and for export. We estimate weighted market prices by state of origin and by consumer type, including domestic consumption and export.

Table B5: Average Market Price of U.S. Coal Delivered to Consumer Types by State of Origin, 2008-2012 (2013 $s per ton)

State	Electric Power Sector	Commercial/ Institutional	Industrial Plants Excluding Coke	Coke Plant	Total Exports
Alabama	$81.52	$96.74	$70.38	$165.76	$83.36
Colorado	$54.66	$97.48	$70.34	$191.01	$75.09
Kentucky	$78.79	$96.33	$70.34	$172.76	$74.72
Montana	$33.42	$96.57	$70.54	$169.39	$61.05
New Mexico	$36.33	$96.74	$70.35	$169.39	$76.16
North Dakota	$46.49	$96.74	$70.48	$169.39	$74.13
Oklahoma	$46.36	$96.74	$70.18	$148.02	$72.78
Utah	$37.52	$96.41	$70.36	$169.39	$74.32
Wyoming	$31.24	$96.92	$70.50	$169.39	$75.60

Weighted average market prices for coal deliveries from federal land are calculated in two steps. First, the average market prices for all coal deliveries from each state (state total) are estimated by summing the gross proceeds for coal delivered to each end use sector (or consumer type), divided by total delivered tons to all sectors. The formula is:

$$\text{Weighted Average Market Price} = \frac{(\text{EP Value} + \text{CP Value} + \text{IP Value} + \text{CI Value} + \text{SE Value} + \text{ME Value})}{\text{Total Delivered Tons}}$$

Where:

EP Value = Delivered Tons * Delivered Price (Electric Power Sector)
CP Value = Delivered Tons * Delivered Price (Coke Plants)
IP Value = Delivered Tons * Delivered Price (Industrial Plants Excluding Coke)
CI Value = Delivered Tons * Delivered Price (Commercial/Institutional)
SE Value = Delivered Tons * Delivered Price (Steam Coal Exports)
ME Value = Delivered Tons * Delivered Price (Metallurgical Coal Exports)

The results are shown in Table B6.

Table B6: Total Gross Proceeds and Market Price for State Coal Distributions by State of Origin and Consumer Type, 2008-2012 (2013 $s per short ton)

State	Electric Power Sector	Commercial/ Institutional	Industrial Plants Excluding Coke	Coke Plant	Total Export	Total Gross Receipts	Average Gross Market Price (State)
Alabama	$3,161,809,501	$0	$456,760,209	$980,312,270	$3,917,444,542	$8,516,326,522	$86.74
Colorado	$6,082,859,024	$100,959,056	$704,442,020	$313,455	$978,578,654	$7,867,152,209	$58.12
Kentucky	$35,514,786,325	$223,084,092	$2,598,185,815	$730,101,088	$2,487,956,742	$41,554,114,061	$78.78
Montana	$5,249,951,047	$48,075,227	$465,421,015	$0	$1,714,780,271	$7,478,227,561	$38.89
New Mexico	$4,251,328,317	$0	$116,166,423	$0	$15,232	$4,367,509,971	$36.81
North Dakota	$5,359,812,923	$0	$2,109,226,601	$0	$0	$7,469,039,524	$51.43
Oklahoma	$101,765,335	$0	$150,257,904	$14,265,606	$436,674	$266,725,518	$60.10
Utah	$3,150,434,125	$3,630,284	$912,355,542	$0	$259,975,787	$4,326,395,738	$43.06
Wyoming	$66,098,624,933	$27,168,579	$2,576,029,876	$0	$1,548,302,450	$70,250,125,837	$32.33
Total States	**$128,971,371,529**	**$402,917,238**	**$10,088,845,405**	**$1,724,992,418**	**$10,907,490,352**	**$152,095,616,941**	**$43.52**

*The total state average gross market price is a weighted average.

Next, we apply the weighted average price for state coal to the total number of tons extracted from federal leases (federal total) within each state. This provides a weighted average national price for coal delivered from federal lands. The results are shown in Table B7.

Table B7: Total Gross Proceeds and Market Price for Federal Coal Distributions by State of Origin and Consumer Type, 2008-2012 (2013 $s per short ton)

State	Deliveries from Federal Leases 2008-2012	Gross Value of Federal Deliveries	Average Gross Market Price (Federal)
Alabama	9,043,639	$784,434,555	$86.74
Colorado	97,242,959	$5,651,339,647	$58.12
Kentucky	977,116	$76,972,625	$78.78
Montana	121,474,627	$4,724,611,243	$38.89
New Mexico	18,418,053	$677,917,345	$36.81
North Dakota	10,909,897	$561,134,088	$51.43
Oklahoma	3,039,401	$182,653,002	$60.10
Utah	55,144,127	$2,374,338,764	$43.06
Wyoming	1,974,279,688	$63,828,848,193	$32.33
Total Federal	**2,290,529,507**	**$78,862,249,462**	**$34.43***

*The Federal Average Gross Market Price is a weighted average price.

Estimating Transportation Costs and Net Market Prices

We estimate net market prices by subtracting transportation costs from the gross market price estimated above. Transportation costs are from EIA 923 Reports, and are only available for coal deliveries to the domestic power generation sector. The estimates assume that transportation costs for deliveries to other end use sectors (including deliveries to domestic coke plants and to export terminals) from each state will be similar, on average, to transportation costs for deliveries to the domestic power sector.

Table B8 shows total state deliveries by state of origin, the share of total state deliveries for which transportation costs are reported, and average state transportation costs per ton by state of origin.

Table B9 shows the weighted average for federal coal deliveries. The federal weighted average of transportation costs by state of origin is calculated in Table B9 by applying the average state transportation cost to the tons extracted from federal lands. We assume that federal coal is delivered to consumers in the same proportion as state deliveries.

Table B8: Transportation Costs for State Coal Deliveries to the Domestic Power Generation Sector by State of Origin, 2008-2012 (2013 $s per ton)

State	State Coal Deliveries (tons) For Which Transportation Costs are Reported	Cumulative Value of State Coal Deliveries For Which Transportation Costs are Reported	Average State Transportation Costs per ton	Percent of Total State Deliveries For Which Cost Data are Reported
Alabama	30,252,466	$127,291,856	$4.21	79.0%
Colorado	64,604,974	$800,143,011	$12.39	59.5%
Kentucky	409,783,398	$6,715,100,463	$16.39	96.5%
Montana	87,672,678	$1,673,328,877	$19.09	87.9%
New Mexico	39,743,496	$386,755,239	$9.73	34.2%
North Dakota	0	$0	W	0.0%
Oklahoma	0	$0	W	0.0%
Utah	63,886,807	$162,857,815	$2.55	79.5%
Wyoming	1,390,646,171	$23,752,227,193	$17.08	86.4%
Total State	**2,086,589,990**	**$33,617,704,453**	**$30.72**	**87.3%**

*Total state average transportation cost is a weighted average.

Table B9: Transportation Costs for Federal Coal Deliveries to the Domestic Power Generation Sector by State of Origin, 2008-2012 (2013 $s per ton)

State	Federal Coal Production	Average State Transportation Costs per ton	Estimated Cumulative Value of Transportation Costs for Federal Coal Deliveries
Alabama	9,043,639	$4.21	$38,052,488
Colorado	97,242,959	$12.39	$1,204,369,713
Kentucky	977,116	$16.39	$16,011,952
Montana	121,474,627	$19.09	$2,318,476,016
New Mexico	18,418,053	$9.73	$179,231,301
North Dakota	10,909,897	W	NA
Oklahoma	3,039,401	W	NA
Utah	55,144,127	$2.55	$140,571,308
Wyoming	1,974,279,688	$17.08	$33,720,683,715
Federal Total	**2,276,580,209**	**$16.52**	**$37,617,396,492**

*Total federal average transportation cost is a weighted average.

Subtracting transportation costs from the gross market price provides an estimate of the average net market price received for coal delivered from federal lands in each state to all types of consumers. Table B10 shows the net market price estimates.

Table B10: Estimated Net Market Price for Federal Coal Deliveries by State of Origin, 2008-2012 (2013 $s per ton)

State	Total Coal Production from Federal Leases	Average Gross Market Price for Federal Deliveries	Transportation Costs per ton	Cumulative Net Value	Net Market Price per ton
Alabama	9,043,639	$86.74	$4.21	$746,382,067	$82.53
Colorado	97,242,959	$58.12	$12.39	$4,446,969,934	$45.73
Kentucky	977,116	$78.78	$16.39	$60,960,673	$62.39
Montana	121,474,627	$38.89	$19.09	$2,406,135,227	$19.81
New Mexico	18,418,053	$36.81	$9.73	$498,686,044	$27.08
North Dakota	10,909,897	$51.43	W	NA	NA
Oklahoma	3,039,401	$60.10	W	NA	NA
Utah	55,144,127	$43.06	$2.55	$2,233,767,456	$40.51
Wyoming	1,974,279,688	$32.33	$17.08	$30,108,164,478	$15.25
Federal Total	**2,276,580,209**	**$34.43**	**$16.52**	**$40,501,065,879**	**$17.79**

*Total state average market prices and transportation costs are weighted averages.

Estimating the Outcome of Levying Royalties on Net Market Prices

Royalties based on the net market price of coal deliveries from each state are estimated by applying the average statutory rate (Table B1) to the average net market price (Table B10). Using the average statutory rate implies that royalty rate reductions are eliminated and the statutory rate is levied on the net market price of coal deliveries from each state. Effective royalty rates are calculated by dividing the royalties due per ton by the average gross market price. Table B11 shows estimates of total royalties due, royalties due per ton, and the effective royalty rate.

Table B11: Royalties Due and Effective Royalty Rate Using Net Market Price by State of Origin for Royalty Valuation, 2008-2012 (2013$s)

State	Total Federal Coal Production	Estimated State Statutory Royalty Rate	Net Market Price per ton	Royalties Due Based on Net Market Price	Royalties Due per ton	Average Gross Market Price for Federal Deliveries	Effective Royalty Rate Using Net Market Price
Alabama	9,043,639	9.7%	$82.53	$72,760,932	$8.05	$86.74	9.3%
Colorado	97,242,959	8.9%	$45.73	$397,092,071	$4.08	$58.12	7.0%
Kentucky	977,116	9.8%	$62.39	$5,970,459	$6.11	$78.78	7.8%
Montana	121,474,627	12.1%	$19.81	$292,334,517	$2.41	$38.89	6.2%
New Mexico	18,418,053	11.4%	$27.08	$57,037,198	$3.10	$36.81	8.4%
North Dakota	10,909,897	12.5%	NA	NA	NA	$51.43	NA
Oklahoma	3,039,401	10.9%	NA	NA	NA	$60.10	NA
Utah	55,144,127	8.0%	$40.51	$179,262,722	$3.25	$43.06	7.6%
Wyoming	1,974,279,688	12.5%	$15.25	$3,752,047,662	$1.90	$32.33	5.9%
Total	**2,276,580,209**	**12.3%**	**$17.79**	**$4,756,505,562**	**$2.09**	**$34.43**	**6.1%**

*Total average market prices, royalties due, and royalty rates are weighted averages.

Table B12 shows a comparison between actual royalties collected between 2008 and 2012 and royalties that would have been due if statutory rates had been levied on the net market price over the same period. Table B12 includes gross royalty collections and effective tax rates.

Table B12: Comparison of Reported Royalties to Estimated Royalties Using Net Market Price, Current Production 2008-2012 (2013 $s)

State	Royalties Due Based on Net Market Price	Reported Royalties Due	Difference Between Royalties Based on Net Prices and Current Royalties	Effective Royalty Rate Using Net Market Price	Actual Effective Royalty Rate, 2008-2012
Alabama	$72,760,932	$34,830,873	$37,930,059	9.3%	4.4%
Colorado	$397,092,071	$269,460,788	$127,631,283	7.0%	4.8%
Kentucky	$5,970,459	$6,019,775	-$49,316	7.8%	7.8%
Montana	$292,334,517	$219,090,309	$73,244,209	6.2%	4.6%
New Mexico	$57,037,198	$45,911,763	$11,125,435	8.4%	6.8%
North Dakota	NA	$3,822,998	NA	NA	0.7%
Oklahoma	NA	$4,046,018	NA	NA	2.2%
Utah	$179,262,722	$132,991,300	$46,271,422	7.6%	5.6%
Wyoming	$3,752,047,662	$3,183,032,256	$569,015,406	5.9%	5.0%
Federal Total	**$4,756,505,562**	**$3,899,206,080**	**$865,168,498**	**6.1%**	**4.9%**

*Federal total royalty rates are weighted averages.

Royalties based on the gross market price of coal deliveries from each state are estimated by applying the average statutory rate (Table B1) to the average gross market price (Table B7). Using the average statutory rate implies that royalty rate reductions are eliminated and the statutory rate is levied on the gross market price of coal deliveries by state of origin. Effective royalty rates are calculated by dividing royalties due per ton by the average gross market price. Table B13 shows estimates of total royalties due, royalties due per ton, and the effective royalty rate.

Table B13: Royalties Due and Effective Royalty Rate Using Gross Market Price for Royalty Valuation, 2008-2012 (2013$s)

State	Total Federal Coal Production	Estimated Statutory Royalty Rate	Gross Market Price per ton	Royalties Due Based on Gross Market Price	Royalties Due per ton	Average Gross Market Price for Federal Deliveries	Effective Royalty Rate Using Gross Market Price
Alabama	9,043,639	9.7%	$86.74	$76,470,473	$8.46	$86.74	9.7%
Colorado	97,242,959	8.9%	$58.12	$504,636,235	$5.19	$58.12	8.9%
Kentucky	977,116	9.8%	$78.78	$7,538,662	$7.72	$78.78	9.8%
Montana	121,474,627	12.1%	$38.89	$574,018,838	$4.73	$38.89	12.1%
New Mexico	18,418,053	11.4%	$36.81	$77,536,772	$4.21	$36.81	11.4%
North Dakota	10,909,897	12.5%	$51.43	$70,141,761	$6.43	$51.43	12.5%
Oklahoma	3,039,401	10.9%	$60.10	$19,945,084	$6.56	$60.10	10.9%
Utah	55,144,127	8.0%	$43.06	$190,543,751	$3.46	$43.06	8.0%
Wyoming	1,974,279,688	12.5%	$32.33	$7,954,283,657	$4.03	$32.33	12.5%
Federal Total	**2,290,529,507**	12.3%	**$34.43**	**$9,475,115,233**	**$4.14**	**$34.43**	**12.0%**

*Federal total royalty rates and market prices are weighted averages.

Table B14 shows a comparison between actual royalties collected between 2008 and 2012 and royalties that would have been due if statutory rates had been levied on the gross market price over the same period. Table B14 includes gross royalty collections and effective tax rates.

Table B14: Comparison of Current Royalties Due to Royalties Due Using Gross Market Price, 2008-2012 (2013 $s)

State	Royalties Due Based on Gross Market Price	Reported Royalties Due	Difference Between Royalties Based on Gross Prices and Current Royalties	Effective Royalty Rate Using Gross Market Price	Actual Effective Royalty Rate, 2008-2012
Alabama	$76,470,473	$34,830,873	$41,639,599	9.7%	4.4%
Colorado	$504,636,235	$269,460,788	$235,175,447	8.9%	4.8%
Kentucky	$7,538,662	$6,019,775	$1,518,887	9.8%	7.8%
Montana	$574,018,838	$219,090,309	$354,928,530	12.1%	4.6%
New Mexico	$77,536,772	$45,911,763	$31,625,009	11.4%	6.8%
North Dakota	$70,141,761	$3,822,998	$0	12.5%	0.7%
Oklahoma	$19,945,084	$4,046,018	$0	10.9%	2.2%
Utah	$190,543,751	$132,991,300	$57,552,451	8.0%	5.6%
Wyoming	$7,954,283,657	$3,183,032,256	$4,771,251,401	12.5%	5.0%
Federal Total	**$9,475,115,233**	**$3,899,206,080**	**$5,575,909,153**	**12.0%**	**4.9%**

*Federal total royalty rates are weighted averages.

Appendix C: Data Withholdings, Database Comparisons, and Interpreting Results

To estimate the effective royalty rate received under the current royalty structure, and to assess the potential changes that would result if reforms are pursued, it is necessary to bring together disparate datasets that have varying levels of specificity, data withholdings, and scales of assessment. This effort results in estimates with varying levels of confidence, and introduces several sources of potential errors.

Data sources are described in Appendix A and the report provides detailed citations where they are used. We also identify in tables and text throughout the report where data withholdings and uncertainty that arises from comparing different databases are relevant to interpreting the results.

Throughout this report we endeavor to use publically available statistics. We do this for two reasons:

first so that our methods and data can be easily assessed and replicated; and second to provide a view of the challenges created by federal data withholdings. It is difficult to characterize accurately the effective rate of return received under the current royalty structure and to assess the potential outcome of reforms. This is not because of difficult assumptions or calculations that must be made. Understanding the coal royalty structure is limited primarily by data availability.

The two main data challenges are first, comparing production statistics for federal leases to total coal production from all land ownership. This challenge applies to production statistics and prices. Second, transportation costs are only provided for deliveries to domestic power providers. These issues are discussed in more detail below.

Lease Data vs. Current Data
Data to describe current royalties, royalty rate reductions, and allowable cost deductions are from two different sources.

Current Production, 2008 to 2012
The main findings presented in Figure 1 are based on the most current production data, including sales volume, sales value, royalties, transportation costs between the mine and consumers, and market prices between 2008 and 2012.

Lease Data, 1990 to 2013
Because of data withholdings, we requested data from ONRR for a known set of leases for which we have additional information on bonus payments, allowable transportation and processing cost deductions, and royalty rate reductions.

The size and value of royalty rate reductions and allowable costs deductions are calculated using the lease data. We use these averages as a share of current reported royalty rates to estimate their relative size and value for current production from all leases between 2008 and 2012. If royalty rate reductions and cost allocations are quite different as they apply to coal extracted from leases sold prior to 1990, then our estimates will contain error.

Federal vs. State Statistics
Production statistics are often available at the state level using MSHA and EIA reports. Equivalent data, including delivered costs, transportation costs, extraction from surface and underground mines, and others, are not available for production on federal leases reported by ONRR. When these data are not published for federal leases, we use the state data as a proxy, assuming that characteristics of federal production are similar to the broader production profile of all coal extracted from each state.

Transportation Costs
Transportation costs are reported only for deliveries to domestic power plants, and not for deliveries for export markets, coke plants, and other industrial users. Where sales to these sectors other than domestic power plants are larger (as a share of total sales), transportation cost data may be poor proxies of transportation costs to these consumers.

All transportation costs are withheld for coal sales from North Dakota and Oklahoma, so it is not possible to estimate net market prices for these states at all. In Wyoming, by comparison, coal sales to domestic power generators account for 97 percent of all current coal deliveries (2008 to 2012). Montana coal sales to domestic power plants account for 82 percent of sales over the same period. As a result, the estimates for these two states are more realistic, and in total the value of marketing margins during the five years is likely to be more than $4 billion dollars, and forgone royalties on these values are likely to be about $100 million annually during the same period.

Figure C1 provides a visual assessment of where error is likely to be higher or lower based on the quality of database comparisons. Throughout the report we use one database to make estimates that are applied to a second database. For example, we use data reported for all coal extracted from a state to draw conclusions about the makeup of coal extracted only from federal leases in the same state. When federal coal represents a large share of total state production, the comparisons are more likely to be robust than when the share of federal coal makes up only a small percent of total state production. The larger the percent listed in the table, the larger the correlation between the two datasets.

Table C1: Assessment of Data Withholdings, State and Federal Production and Price Statistics, and Transportation Costs

State	Federal Share of State Total	Share of State Production Delivered to Domestic Power Generators that Transportation Costs are Available	Share of Deliveries to Domestic Power Generators of Total
Alabama	9.3%	79.0%	39.5%
Colorado	69.0%	59.5%	82.2%
Kentucky	0.2%	96.5%	85.4%
Montana	58.5%	87.9%	81.7%
New Mexico	15.9%	34.2%	98.6%
North Dakota	7.6%	W	NA
Oklahoma	54.0%	W	NA
Utah	54.0%	79.5%	83.6%
Wyoming	90.5%	86.4%	97.4%

Reported Data as a Share of Estimated Data

- 90-99%
- 80-89%
- 70-79%
- 60-69%
- 50-59%
- Less than half

Table C1 shows that certain data are withheld for North Dakota and Oklahoma, and we do not have estimates of transportation costs or net market prices for these states. By comparison, Wyoming has excellent data across all data sets. Wyoming's coal production is dominated by production on federal land (90.5 percent). Using statewide coal production data to estimate prices and costs for Wyoming's federal coal should produce confident results.

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A Research Paper by

HEADWATERS ECONOMICS

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ABOUT HEADWATERS ECONOMICS

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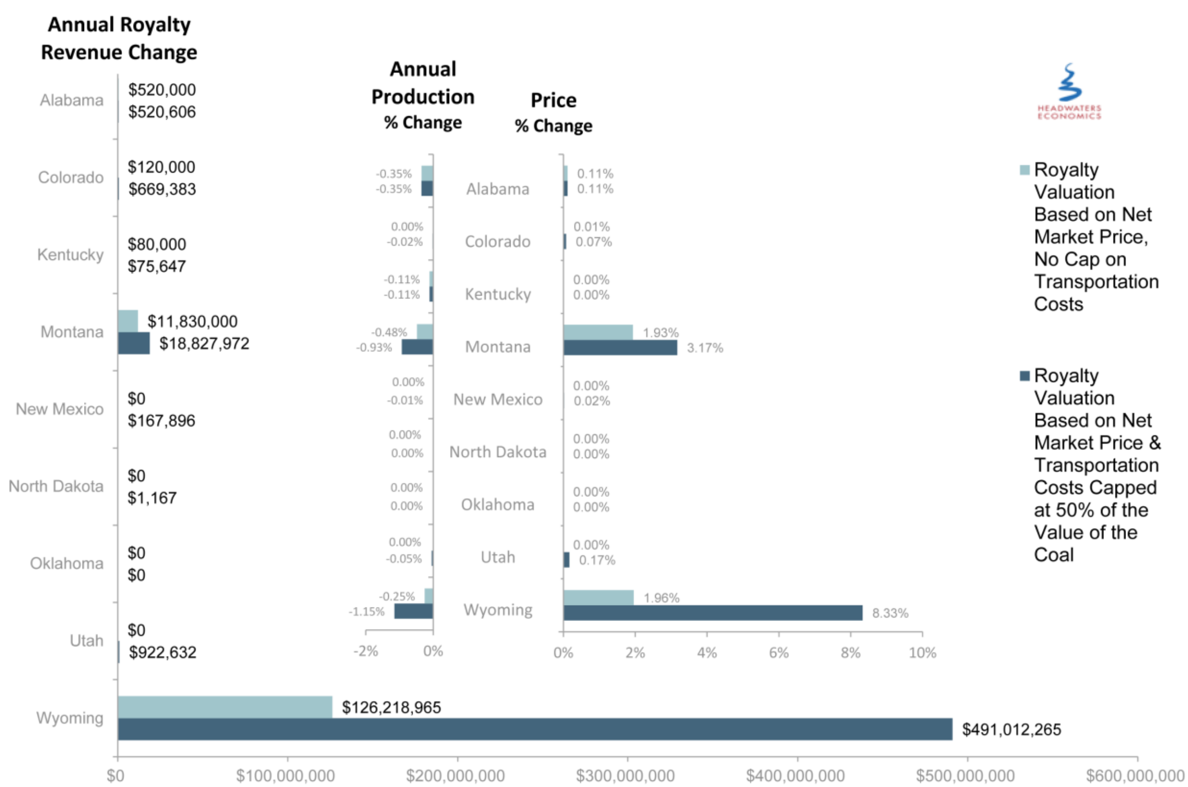
I. EXECUTIVE SUMMARY

The Office of Natural Resources Revenue (ONRR) of the Department of Interior has proposed to reform the way federal coal is valued for federal royalty assessment.[1] The proposed rule would change the method for determining the price used for valuation for non-arm's length sales of coal to simplify compliance for industry and compliance review for ONRR. The proposed rule would use arm's length transactions to value coal for royalties for both arm's length and non-arm's length sales.

The proposed rule also asks for additional comment about how the regulation could be finalized, including what alternative methods might be used to value coal sold in non-arm's length sales,[2] and whether transportation cost deductions should be limited.[3]

This report presents data and analysis that evaluate the revenue, price, and production implications of federal royalty reform on coal deliveries to the domestic power sector. We model three scenarios for how the final rule could be implemented: 1.) valuing coal based on the first arm's length sale price, 2.) valuing coal based on delivered prices net of transportation costs, and 3.) valuing coal based on delivered prices net of transportation costs, which are capped at 50 percent of the value of coal. Scenario One is not expected to change revenue, production, or price. The results of Scenarios Two and Three are shown in Figure 1 in terms of revenue, delivered prices, and production changes had reforms been in place from 2008 to 2013.

Figure 1: Changes in Royalty Revenue, Coal Production, and Coal Price from Two Federal Coal Royalty Reform Scenarios



Scenario One, proposed by ONRR, would have no effect on revenue, prices, or production.

We find that changes in federal royalty policy could have substantial revenue benefits for federal and state governments with limited impact on coal production or prices on federal lands. Specifically:

- If the rule is implemented using net delivered prices to reveal the value of federal coal for royalty assessment, royalty revenue could increase by $139 million annually (a 20% increase), with 91 percent of new revenue generated in Wyoming. On average, gross delivered prices would rise by $0.28 per ton, or a 1.6 percent increase. Demand for coal for the domestic power sector would fall by nearly 1 million tons annually, a 0.2 percent decline.

- If transportation cost deductions were limited to 50 percent of the net delivered price of coal, revenue would increase by $512 million annually (a 73% increase) with 96 percent of the additional revenue coming from Wyoming. On average, gross delivered prices would rise by $1.17 per ton, or a 6.7 percent increase. Demand for coal for the domestic power sector would fall by 4.3 million tons, a 1 percent decline.

At the state level, higher federal royalty distributions to the states outweighs declines in state tax revenue that would occur due to tax interactions that lower the taxable value of state severance taxes where royalties are deductible expenses, and from the small declines in production. Overall, the largest changes in revenue, price, and production are expected to occur in Montana and Wyoming. Montana could receive between $5.1 and $8.8 million in additional annual revenue. Wyoming could receive between $58 and $234 million in additional annual revenue.

Because of significant data limitations, we do not have price statistics on arm's length and non-arm's length sales from ONRR to analyze the outcomes of reforms that would use the first arm's length transaction price. Results for the other two scenarios are only robust for Montana and Wyoming, where the large majority of sales from mines with active federal leases are to the domestic power sector. The results for the other states with active federal leases–Alabama, Colorado, Kentucky, New Mexico, North Dakota, Oklahoma, and Utah–are less robust.

Concerns with the current regulation related to coal royalty valuation include: that the current regulation is unwieldy for industry and ONRR to follow; that the current regulation lacks transparency; and that the current regulation is outdated and changes in the coal market may have led to undervaluation of federal coal in some instances. For example, companies have arguably exploited a loophole that allows mines to transfer coal for low mine prices to affiliates who then remarket coal to consumers at the higher full commodity value of the coal.

Reforms that would utilize the first arm's length sale price would address the first concern by using contract prices for royalty valuation. However, the challenges associated with this analysis speak to the opaque nature of the current regulation and this reform would do little to add transparency. ONRR's assessment that proposed reforms would not generate additional revenue suggests arm's length price reforms would not effectively close the "affiliate" loophole. This is at least partially due to the fact that the loophole would remain open for independent brokers.

Further reforms that would use net delivered prices would lead to greater transparency by revealing to the public the prices used for royalty valuation. These reforms also appear to be the most efficient and effective way to value federal coal for royalty assessment without introducing new distortions with regard to contract and sale structures.

We hope these data and analysis will be useful to decision makers, states and communities seeking to understand the likely outcome of changes to federal coal royalty regulations, and the impact these changes are likely to have on governmental revenue and on coal prices and production.

II. INTRODUCTION

Coal extracted from federal land is an important source of energy and revenue in the United States. Bonus payments and royalty revenue from minerals extracted from public lands and waters represent the largest non-tax source of income for the federal government. Distributions of federal royalty revenue to states and state and local severance taxes also make up a significant share of revenue for coal-producing states.

The U.S. government owns roughly 1/3 of total coal reserves. Production from federal leases has increased steadily from a low of about 3 percent of all mining in 1960 to 43 percent of total domestic coal production in 2014. The increase in federal coal production was ushered in by a shift toward large western surface mines—80 percent of federal production now comes from the Powder River Basin in Wyoming and Montana.[4]

Despite the importance of coal revenue streams and the large share of coal extracted from federal leases, little information is available to describe accurately the return to the public from taxation of federal coal resources. The Bureau of Land Management (BLM) and the Office of Natural Resources Revenue (ONRR) administer the federal coal-leasing program and have multiple and diverse objectives: a fair return for U.S. taxpayers, economic development and jobs, energy costs and security, and environmental protection.

Recent reports from the U.S. Government Accountability Office (GAO)[5] and the Department of Interior (DOI) Inspector General[6] raised issues with the BLM's leasing program and the royalty valuation process. Concerns raised include: that the current regulation is unwieldy for industry and ONRR to follow; that the current regulation lacks transparency; and that the current regulation is outdated and changes in the coal market may have led to undervaluation of federal coal in some instances.

The Office of Natural Resources Revenue (ONRR) of the Department of Interior has proposed to reform the way federal coal is valued for the purpose of assessing federal royalties.[7] The proposed rule would change the method for determining the price used for valuation for non-arm's length sales of coal. In the current regulation, ONRR defines five benchmarks that industry follows sequentially to determine the gross value of coal sold in non-arm's length transactions that should be used for royalty valuation. The proposed rule would replace the benchmarks with the single method of using arm's length transactions in all cases to value coal for royalties. The rule is intended to simplify industry compliance and compliance review for ONRR.

The proposed rule asks for additional comment on additional ways that federal coal could be valued for royalty purposes and whether transportation costs should be limited. Specifically, the rule asks: "What other methodologies might ONRR use to determine the royalty value of coal not sold at arm's length that we may not have considered?;" and "…whether we should limit coal allowances to 50 percent of the value of the coal."

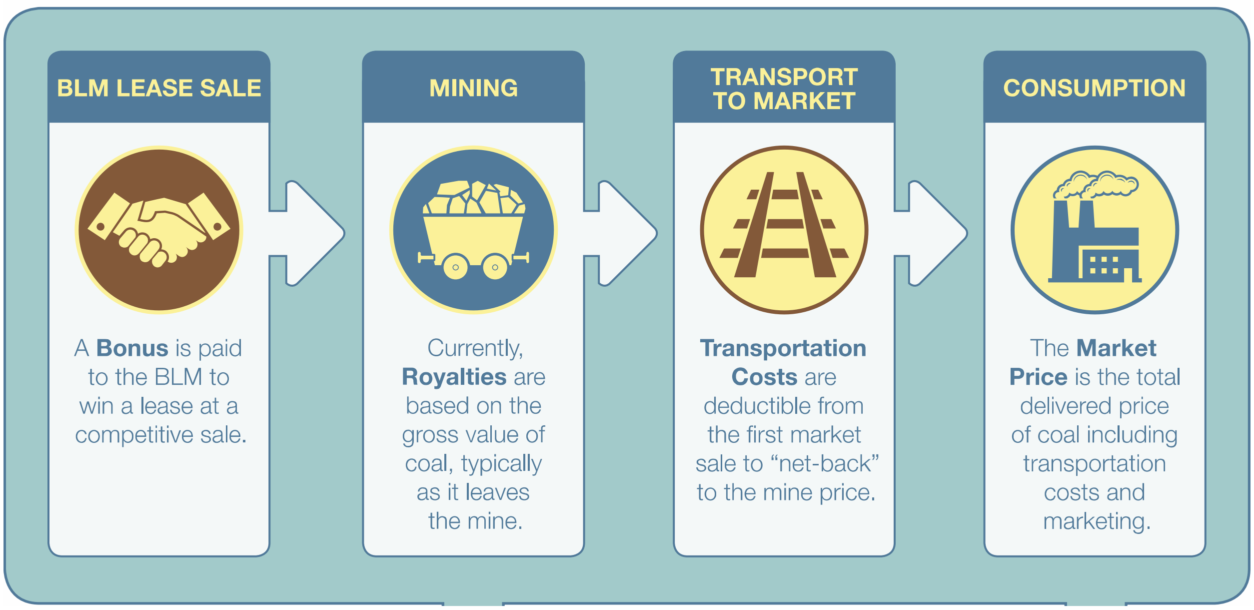
This report presents data and analysis that evaluate the revenue, price, and production implications of federal royalty reform on coal deliveries to the domestic power sector. In the next section, we provide an overview of the current federal royalty regulations as they relate to coal valuation. Next, we describe the data and methods used to evaluate the implications of federal royalty reform on revenue, delivered prices, and production. We define three scenarios for how the final regulation could be implemented including valuing coal based on the first arm's length transaction, valuing coal using net delivered prices and a limit on transportation deductions equal to 50 percent of the value of coal. The next section describes the results and in the Conclusion we offer some thoughts on what the findings mean for reforms.

Coal Fiscal Policy Primer

Coal extracted from federal leases will pay a variety of royalties, bonus payments and local, state, and federal production taxes on the value or volume of coal. Figure 2 shows the current fiscal policy related to federal coal leasing. Lessees first pay a "bonus" to secure a federal lease at a competitive lease sale. Once production on federal leases begins, royalties are paid on the actual value of production, defined as the gross value of coal FOB (or "freight on board") at the mine.[8] "Downstream" from the mine, the coal is transported primarily by railroad, but also by truck, waterway, and conveyor belt to a domestic power plant, industrial consumers, or exported to foreign markets depending on its energy content and other qualities.

The market price or gross delivered price (the price paid by the consumer) is the gross value of coal and transportation costs. We find that often the market price less transportation costs is higher than the value of coal sold at the mine. The difference is an estimate of the portion of the value of coal captured by affiliated and independent coal brokers that is currently not exposed to royalties but could be if the final regulation defines the net delivered price as the gross value of coal for royalty assessment.

Figure 2: Current U.S. Coal Royalty Structure



In addition to federal bonus payments and royalties, coal extracted from federal leases will also pay state severance taxes. State severance taxes are paid on all coal extracted, or "severed" from the earth in each state. Industry also pays corporate income taxes on profits earned, and the general tax structure in each state will levy a mix of sales taxes, property taxes, charges for services, and fees on the economic activity associated with coal mining. The sidebar *"Revenues from Oil, Natural Gas, and Coal Production on Federal Lands"* on the next page defines the several bonuses, royalties, and taxes coal companies pay.

Taken together, royalties and state severance taxes are the largest source of revenue from coal mining, greatly outstripping taxes on the related economic activity, including sales taxes, property taxes, and income taxes.

About half of federal coal royalty collections are distributed back to the state where the coal is extracted. States use these revenues and revenue from state taxes for a variety of purposes. In this report, we describe how these revenues are allocated to state governments, local governments, and to permanent savings.

State governments typically retain the largest share of royalty and production tax revenue from coal extraction. A large share of these dollars is directed to state General Funds and is used to support state operating budgets and basic governmental services. Some portion is also typically allocated to specific uses, including education, infrastructure projects, and environmental funds.

Each state allocates a share of revenue to local governments. In Colorado, Utah and Wyoming, local governments tax the value of coal directly through the local property tax structure. In other states including Montana, North Dakota and New Mexico, the state levies a severance tax in lieu of local taxation and makes direct distributions to local governments where coal is extracted. Several states, including Colorado and Wyoming also use state severance tax revenue to fund local impact grant programs.

Finally, some states save a portion of annual coal revenue in permanent trusts. Montana allocates half of the state severance tax to the Coal Tax Trust Fund. Wyoming and New Mexico also utilize permanent funds to invest a portion of the annual revenue to provide a lasting fiscal legacy from the depletion of non-renewable resources. The income earned from these funds are also used for a variety of purposes, including community impact assistance programs and deposits to state General Funds.

One of the purposes of this report is to describe the change in revenues states could expect from federal reforms. Because these revenues will come from different sources (higher distributions of federal coal royalties and lower state production taxes) we also track how the allocation of revenue to state and local governments and investments in permanent savings may change.

Revenues from Coal Production on Federal Lands

Bonus Payments and Rents: Companies pay bonuses (a premium paid to the BLM to win a leasing contract to mine in a specific area) through the competitive leasing process, and fees or rents to maintain a lease. Bonuses are one-time payments generally calculated on a price per ton basis. Rental payments are charged on a per acre basis and are paid annually to maintain the lease.

Royalties: Royalties are production taxes paid on the volume or value of coal extracted annually to the owner of the resource, including federal, tribal, state, and private landowners. Federal royalties are paid to the U.S. Treasury, and roughly half are returned to the states where drilling takes place. Federal royalties are 12.5 percent for surface coal, oil and natural gas; 18.75 percent for offshore oil and natural gas; and 8 percent for coal extracted from underground mines. Most states charge higher royalties of 16.67 to 25 percent on oil and natural gas while state coal royalty rates tend to mirror federal coal royalty rates.

State Production Taxes: A production tax is any tax levied against the production value or volume of coal, oil, and natural gas extracted or "severed" from the earth. Montana levies a severance tax, a gross production tax in lieu of local government property taxes, and the Resource Indemnity Tax.

Federal Production Taxes: The federal black lung excise tax and abandoned mine fees are levied at a fixed rate on each ton of coal extracted.

Corporate Income Taxes: Production taxes and royalties are distinct from corporate income taxes levied on net profits. The federal corporate income tax rate is 35 percent and Montana's state corporate income tax is 6 percent. Compared to production taxes, bonus payments, and royalties, corporate income tax is paid on a smaller tax base (net profit compared to gross production value), and generates relatively less revenue for the federal and state governments.

General Taxes and Fees on Mining Activity: State and local governments also levy taxes and fees on the value of labor, purchases, land, and equipment associated with drilling and mining activities. These include sales, property, and personal income taxes, charges for services, license and permit fees, and other miscellaneous revenue. The general tax structure can be important to local governments, but the role they play varies from state to state. Revenue generated from the general tax structure is relatively small compared to federal royalty distributions and state production taxes.

III. DATA AND METHODS

In this section, we describe the data and methods used to estimate the likely implications of the proposed rule on revenue, prices and production.

Three Reform Scenarios

The proposed rule considers reforms to federal coal royalty valuation that would clarify that coal sold thorough non-arm's length sales will be valued for royalties using the price received at the first arm's length (or market) transaction net of allowable transportation and washing costs. Under the current regulation, the lessee follows a sequential set of five benchmarks to determine the price to use for royalty valuation. The proposed regulation would eliminate the benchmarks in favor of using the first arm's length sale price for royalty valuation in all instances.

The rule also asks additional questions, including: "What other methodologies might ONRR use to determine the royalty value of coal not sold at arm's length that we may not have considered?;" and "…whether we should limit coal allowances to 50 percent of the value of the coal."[9]

In a previous report we proposed that ONRR use net delivered prices (or market prices) to value coal for royalty assessment. In theory, the gross commodity value of coal is the delivered price less transportation costs. Using net delivered prices reveals the gross commodity value of coal required for federal royalty valuation. This reform would improve transparency and provide a consistent and fair valuation method for all sales of federal coal without regard to the sale structure.

Lessees would be required to pay royalties on the same delivered price whether they market coal directly to consumers, transfer coal to affiliates, or sell at the mine to independent coal brokers. In the majority of sales where mines and affiliates are marketing coal directly to consumers, the net delivered price is known. When delivered prices are unknown to the lessee, they would be required to report delivered prices for similar sales based on their own marketing contracts, prices reported for deliveries to regulated utilities, and spot market and index prices for coal sold into similar markets. Mines would add the additional royalty liability to the first arm's length sale price when this price is not to a consumer.

We also consider the revenue, price and production effects of limiting transportation cost deductions to 50 percent of the value of coal.

Estimating Changes in Royalty Revenue

We model three scenarios for how the final rule could be implemented: valuing coal based on the first arm's length sale price; valuing coal based on net delivered prices; and responding to the second question asked by the proposed rule, a cap on transportation deductions equal to 50 percent of the value of coal.

In order to model the outcomes of these scenarios, we require data on freight-on-board (FOB) prices used for royalty valuation under the current regulation, royalty rates applied to federal coal sales, and delivered price and transportation costs for sales to the domestic power sector.

Information regarding federal production, sales value and reported prices are from ONRR.[10] These data are used to estimate current prices used for royalty valuation and average royalty rates applied to federal coal in each state.

Dividing total coal sales value by the sales volume reveals the current FOB price at the mine used for royalty valuation. Dividing royalties due by the total sales value reveals the average royalty rate. Royalty rates are set at a minimum of 12.5 percent of the gross value of coal extracted from surface mines and 8 percent for coal extracted from underground mines. Coal lessees can apply for a royalty rate reduction if the current royalty rate imposes economic hardship that would otherwise result in abandoning the lease, or in less than full recovery of leased coal.[11] Table 1 shows reported prices and royalty rates for federal coal extracted between 2008 and 2013.

Table 1: Sales Volume, Sales Value, Royalties, and Reported Royalty Rate, 2008-2013

State	Sales Volume (tons)		Sales Value		Royalty Payment Due	Royalty Per Ton	Reported Price	Reported Royalty Rate
Alabama	10,247,787	$	522,147,639	$	37,867,926	$3.70	$50.95	7.3%
Colorado	131,470,351	$	5,520,508,089	$	337,536,012	$2.57	$41.99	6.1%
Kentucky	1,269,656	$	99,528,263	$	7,457,101	$5.87	$78.39	7.5%
Montana	163,732,383	$	2,484,233,697	$	293,172,400	$1.79	$15.17	11.8%
New Mexico	30,853,083	$	1,522,423,690	$	77,073,304	$2.50	$49.34	5.1%
North Dakota	19,746,655	$	336,468,928	$	7,498,851	$0.38	$17.04	2.2%
Oklahoma	4,249,094	$	216,007,519	$	5,532,999	$1.30	$50.84	2.6%
Utah	83,541,665	$	3,030,170,335	$	208,244,898	$2.49	$36.27	6.9%
Wyoming	2,648,832,479	$	33,574,704,628	$	4,126,196,048	$1.56	$12.68	12.3%
Total	**3,093,943,153**	**$**	**47,306,192,788**	**$**	**5,100,579,536**	**$1.65**	**$15.29**	**10.8%**

*Royalties per ton, reported price, and royalty rate are weighted averages.

Data on market prices, transportation costs and quantities delivered to the domestic power sector are from the Energy Information Administration (EIA) 923 reports.[12] Additional price and transportation cost estimates were downloaded from SNL Financial, a data subscription service that provides energy industry data, including estimates for delivered prices and transportation costs to unregulated utilities and power plants. Royalty rates are calculated from reported prices and royalties due to ONRR.

Net delivered prices and transportation costs are estimated only for deliveries to the domestic power sector from mines with active federal leases during the assessment period 2008 to 2014. EIA and SNL energy data include the Mine Safety and Health Administration (MSHA) ID for all coal deliveries, identifying the mine where the coal is sourced. These MSHA IDs are matched to a table correlating BLM lease IDs with the MSHA ID of the associated mines. Table 2 shows delivered prices and transportation costs uses in this report, and Appendix A provides more detailed methods on how net delivered prices are calculated.

Table 2: Weighted Average Delivered Prices and Transportation Cost for Coal Sales to the Domestic Power Sector, 2008-2013

	All Coal Deliveries to the Power Sector				Coal Deliveries from Mines with Federal Leases			
State	Thousand Tons	Transportation Cost	Delivered Price	FOB Mine Price	Thousand Tons	Transportation Cost	Delivered Price	FOB Mine Price
Alabama	40,371	$15.93	$77.14	$61.21	1,260	$ 18.36	$ 83.50	$ 65.13
Colorado	140,923	$12.05	$53.63	$41.57	138,570	$ 12.20	$ 53.92	$ 41.73
Kentucky	503,924	$16.47	$73.14	$56.67	1,483	$ 24.32	$ 126.07	$ 101.75
Montana	176,488	$10.08	$30.71	$20.63	137,901	$ 8.59	$ 30.23	$ 21.64
New Mexico	161,305	$4.88	$36.80	$31.92	82,412	$ 6.70	$ 41.89	$ 35.19
North Dakota	158,484	$0.73	$17.05	$16.32	158,484	$ 0.73	$ 17.05	$ 16.32
Oklahoma	3,069	$4.32	$35.88	$31.56	2,803	$ 4.27	$ 33.21	$ 28.93
Utah	118,960	$11.27	$42.21	$30.94	112,036	$ 11.62	$ 42.52	$ 30.89
Wyoming	2,809,267	$15.96	$31.30	$15.34	2,573,019	$ 16.04	$ 31.54	$ 15.50
Total	**4,112,791**	**$14.47**	**$37.60**	**$23.13**	**3,207,965**	**$ 14.39**	**$ 32.45**	**$ 18.05**

*Transportation cost, delivered price, and FOB mine price are weighted averages.

We find differences between the FOB mine price reported to ONRR for royalty purposes and the net market price estimated using published delivered prices and transportation costs. This difference between the reported price and the net market price is an estimate of the commodity value of coal that would be exposed to royalties if the price used for valuation is changed from the value of coal FOB to the commodity value of coal delivered to the ultimate consumer.

However, we do not find differences in every state. The most likely explanation is that withholdings from ONRR do not allow for a careful assessment of price differences for federal coal sales into different markets. ONRR only reports the gross value of all coal sales from federal leases in each state on an annual basis. The value of sales from federal leases will vary based on the qualities of the coal and the market coal is sold into. In general, sales to the domestic power sector receive prices lower than sales to industrial consumers, including coke plants, and export sales. As a result, our results are only robust for states where the large majority of sales from mines with active federal leases are to the domestic power sector. This is true of Montana and Wyoming. The results for the other states are less robust and we do not have data sufficient to analyze the implications of additional reforms in New Mexico, North Dakota, Oklahoma, and Utah.

Scenario One: Arm's Length Sale Prices

The formula to estimate the likely change in royalty revenue for Scenario One is:

Royalty revenue = (first arm's length price - non-arm's length price) * royalty rate

The non-arm's length sale price is the value of coal determined by the current regulation for non-arm's length sales. The first arm's length price is the price that would be used for royalty valuation if the rulemaking is implemented. The royalty rate is the rate applied to each lease, including any royalty rate reductions.

Due to data limitations, we cannot describe the difference between the current prices and prices that would result from valuation using arm's length sales.

Scenario Two: Net Delivered Prices

Scenario Two would determine valuation of federal coal using delivered prices. The net delivered price for deliveries to the domestic power sector is the price paid by a power plant, net of allowable transportation and washing costs. The net delivered price reveals the gross commodity value of federal coal required for royalty valuation.

The formula to estimate the likely change in royalty revenue for Scenario Two is:

Royalty revenue = ((net delivered price – reported price) * tons) * royalty rate

The net market price is the cost of coal delivered to power plants less transportation costs. The reported price is the current value of coal at the mine reported to ONRR for royalty valuation inclusive of all arm's length and non-arm's length sales. Tons are the volume of coal extracted from federal leases and delivered to the domestic power sector.

Scenario Three: Transportation Deductions Capped

Scenario Three considers a cap on these transportation allowances equal to 50 percent of the value of coal.

Royalty revenue = ((transportation costs – (net market price * .5)) * tons) * royalty rate

Transportation costs are the cost of delivering coal from a mine to a domestic power plant.

We assume that the cap on transportation costs only has an effect if the rule is implemented using net delivered prices for royalty valuation. ONRR data shows that the value of transportation and washing deductions combined account for only 0.3 percent of total sales value of coal for all federal coal sold from leases sold since 1990.[13] Under the current regulation, capping transportation costs at 50 percent of the value of coal would result in no additional royalty revenue or cost.

Because Scenario One values coal using the FOB price at the mine, we also assume that transportation costs would remain a small portion of the gross value of coal and a limit on transportation allowances would not result in additional royalty liability. In cases where coal is marketed downstream (remote from the lease) by affiliated brokers, a cap on transportation costs may simply provide a strong incentive to restructure sales so that the consumer takes possession of coal at the lease and is responsible for transporting coal from the mine to the power plant.

Price and Production Effects

An increase in federal royalty revenue is expected to raise the price of delivering coal to domestic power generators and to reduce demand for coal due to competition with natural gas in electricity markets, resulting in lower levels of production. While the direction of change in prices, quantities and revenues is straightforward, the focus of this paper is the associated magnitudes of those changes.

A portion of higher costs to deliver coal to markets may be shifted forward as a higher delivered price, and a portion will be shifted backwards, meaning mines will receive a lower net price for the commodity value of coal.[14] The portion of price that is shifted forward will change the demand for coal due to substitution for natural gas in the power sector.

To estimate the magnitude of the changes in prices and production associated with the policy changes considered, we constructed a partial equilibrium model of the coal market. The equilibrium condition describes the amount of coal demanded at the current price. Changing the point of royalty valuation or the extent to which transportation costs are deductible will result in a marginal increase in the cost of delivering coal to consumers. The model uses data on quantities, prices, transportation costs and elasticities of supply and demand to predict the how the marginal change in the delivery cost affects prices, quantities, and revenue collections.[15]

State Tax Interactions

In addition to federal royalties, states levy a variety of severance taxes and local government ad valorem taxes on the value of coal, and corporate income taxes at the federal and state level on net profits. Changes in the price and production volume of coal will have an effect on the taxable value used for severance tax collections, and on net profits used for corporate income tax liability.

In several instances, royalties paid to federal, state, and tribal governments are exempt from the taxable value. Reform to federal royalty valuation policy that results in higher federal revenue would result in additional reductions to the taxable value for these state and local taxes.

Appendix B shows relevant state and local government severance (production) taxes in each state, including how taxable value is defined, the tax rate, and relevant deductions and exemptions. These data are used to model the change in severance tax revenue.

Corporate income taxes are levied at the federal and state level. The federal statutory rate is 35 percent and states levy rates ranging from zero (Wyoming) to 7.3 percent in New Mexico.[16] These statutory rates indicate tax liability before accounting for a variety of deductions and benefits in the tax code. For example, coal mining companies can expense exploration and development costs and capital costs can be recovered using percentage depletion.[17] The U.S. Government Accountability Office (GAO) recently estimated the average U.S. corporate income tax across all industries at 17 percent.[18]

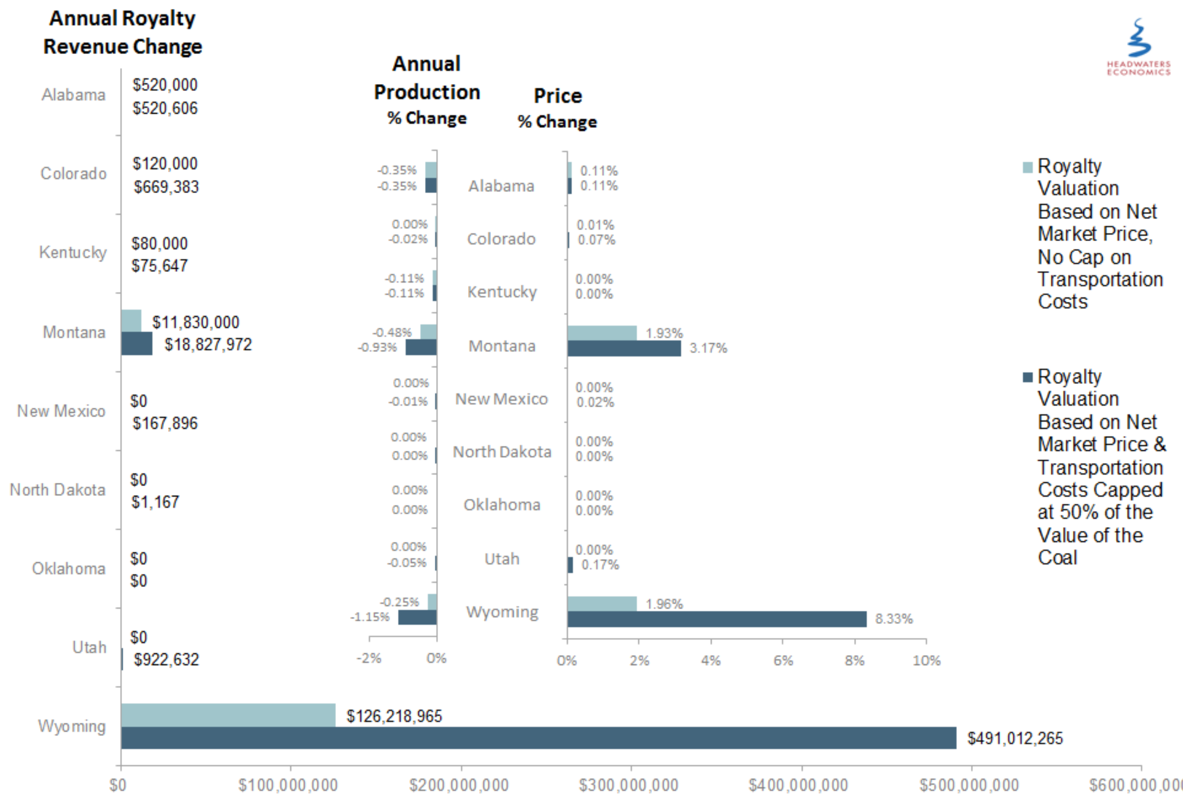
The effective federal corporate income tax rate for the coal industry (including profitable and non-profitable companies) varies significantly over time. Data reported by the New York Times showed the effective rate varied from between 17 to 22.6 percent in 2011 to less than one percent in 2014 when companies were reporting losses.[19] We use a federal effective tax rate for the coal industry of 20 percent and adjust each state's statutory corporate income tax rate down by the same share (the effective rate is 57 percent of the statutory rate).

IV. RESULTS

The main finding is that changes in federal royalty policy could have substantial revenue benefits for federal and state governments with limited impact on coal production from federal lands. Stated differently, we find that not pursuing reforms will generate few benefits in terms of additional coal extraction and related economic activity, but result in significantly less revenue accruing to federal and state governments.

Figure 3 shows how revenue, delivered prices, and production would have changed had reforms described in the three scenarios been in place over the period 2008 to 2013.

Figure 3: Changes in Royalty Revenue, Coal Production, and Coal Price from Two Federal Coal Royalty Reform Scenarios



* Scenario One, proposed by ONRR, would have no effect on revenue, prices, or production.

The main finding is that changes in federal royalty policy could have substantial revenue benefits for federal and state governments with limited impact on coal production from federal lands. Specifically, we find that:

- If the rule is implemented using net delivered prices to reveal the value of federal coal for royalty assessment, we estimate that royalty revenue could increase by $139 million annually (a 20% increase), with 91 percent of new revenue generated in Wyoming. On average, gross delivered prices would rise by $0.28 per ton, or a 1.6 percent increase. Demand for coal would fall by nearly 1 million tons annually, a 0.2 percent decline in coal deliveries to the domestic power sector.

- If additional transportation cost deductions were limited to 50 percent of the net delivered price of coal, revenue would increase by $512 million annually (a 73% increase) with 96 percent of the additional revenue coming from Wyoming. On average gross delivered prices would rise by $1.17 per ton, or a 6.7 percent increase. Demand for coal would fall by 4.3 million tons, a 1 percent decline in coal deliveries to the domestic power sector.

Tables 3 to 6 show detailed results by state for Scenarios Two and Three.

Table 3: Predicted Change in Delivered Price and Annual Production, Net Market Prices

State	Change in Net Delivered Price ($/ton)	Change in Coal Production (tons)	Percent Change in Net Delivered Price	Percent Change in Coal Production
Alabama	$0.08	(1,520)	0.11%	-0.35%
Colorado	$0.01	(445)	0.01%	0.00%
Kentucky	$0.00	(143)	0.00%	-0.11%
Montana	$0.44	(67,744)	1.93%	-0.48%
New Mexico	$0.00	0	0.00%	0.00%
North Dakota	$0.00	0	0.00%	0.00%
Oklahoma	$0.00	0	0.00%	0.00%
Utah	$0.00	0	0.00%	0.00%
Wyoming	$0.30	(907,912)	1.96%	-0.25%

Table 4: Predicted Change in Annual Revenue, Net Market Prices

State	Change in Royalty Revenue	Change in Severance Revenue	Change in Corporate Income Tax Revenue	Percent Change in Royalty Revenue	Percent Change in Severance Revenue	Percent Change in Corporate Income Tax Revenue
Alabama	$520,000	($600)	($33,495)	39.80%	-0.03%	-0.07%
Colorado	$120,000	($2,198)	($10,982)	0.86%	-0.01%	-0.01%
Kentucky	$80,000	($9,853)	($10,474)	30.85%	0%	0%
Montana	$11,830,000	($531,125)	($326,067)	50.07%	-0.48%	-0.87%
New Mexico	$0	$0	$0	0%	0%	0%
North Dakota	$0	$0	$0	0%	0%	0%
Oklahoma	$0	$0	$0	0%	0%	0%
Utah	$0	$0	$0	0%	0%	0%
Wyoming	$126,218,965	($2,406,203)	($2,238,858)	21.78%	-0.36%	-0.60%

Table 5: Predicted Change in Delivered Price and Annual Production, Net Market Prices and Transportation Deductions Limited

State	Change in Coal Prices ($/ton)	Change in Coal Production (tons)	Percent Change in Coal Price	Change in Coal Production
Alabama	$0.08	(1,532)	0.11%	-0.35%
Colorado	$0.03	(2,722)	0.07%	-0.02%
Kentucky	$0.00	(143)	0.00%	-0.11%
Montana	$0.71	(130,977)	3.17%	-0.93%
New Mexico	$0.01	(594)	0.02%	-0.01%
North Dakota	$0.00	(16)	0.00%	0.00%
Oklahoma	$0.00	0	0.00%	0.00%
Utah	$0.05	(5,057)	0.17%	-0.05%
Wyoming	$1.29	(4,119,479)	8.33%	-1.15%

Table 6: Predicted Change in Annual Revenue, Net Market Prices, and Transportation Deductions Limited

State	Change in Royalty Revenue	Change in Severance Revenue	Change in Corporate Income Tax Revenue	Percent Change in Royalty Revenue	Percent Change in Severance Revenue	Percent Change in Corporate Income Tax Revenue
Alabama	$520,606	($513)	($19,199)	32.05%	0.03%	0.10%
Colorado	$669,383	($4,789)	($13,432)	1.86%	0.02%	0.06%
Kentucky	$75,647	($3,139)	($2,246)	9.79%	0.00%	0.00%
Montana	$18,827,972	($349,986)	($256,710)	74.70%	0.62%	3.41%
New Mexico	$167,896	($1,830)	($1,648)	1.88%	0.00%	0.01%
North Dakota	$1,167	($6)	($36)	0.14%	0.00%	0.00%
Oklahoma	$0	$0	$0	0.00%	0.00%	0.00%
Utah	$922,632	($1,791)	($14,658)	4.03%	0.03%	0.08%
Wyoming	$491,012,265	($3,110,821)	$3,127,967	87.94%	0.61%	9.51%

Because of significant data limitations, we do not have price statistics on arm’s length and non-arm’s length sales from ONRR to analyze the outcomes of reforms that would use the first arm’s length transaction price. Results for the other two scenarios are only robust for states where the large majority of sales from mines with active federal leases are to the domestic power sector. This is true of Montana and Wyoming. The results for the other states are less robust and we do not have data sufficient to analyze the implications of additional reforms in New Mexico, North Dakota, Oklahoma, and Utah.

Overall, the largest changes in revenue, price and production are expected to occur in Montana and Wyoming. At the state level, higher federal royalty distributions to the states outweigh declines in state tax revenue that would occur due to tax interactions that lower the taxable value of state severance taxes where royalties are deductible expenses, and from the small declines in production. Montana could receive between $5.1 and $8.8 million in additional annual revenue. Wyoming could receive between $124 and $488 million in additional annual revenue.

Montana

Current Federal Royalty and Severance Tax Revenue

Montana has two main production taxes, a state severance tax and a gross proceeds tax collected in lieu of local property taxes. The state also levies a fee to fund environmental clean-up and reclamation related to resource extraction, called the Resource Indemnity and Ground Water Assessment Tax (RIGWAT). Combined, these taxes generated $1.62 per ton, or about 10.6 percent of the net delivered price.[20] Table 7 shows federal royalty distributions and state tax revenue in Montana from 2008-2013.

Table 7: Total Federal Royalty Distributions and State Tax Revenue to Montana

Year	Federal Royalty Distributions	Severance Tax	Gross Proceeds	RIGWAT
2008	$18,018,410	$45,331,871	$12,859,110	$1,366,020
2009	$18,414,891	$49,564,120	$14,458,854	$1,465,476
2010	$20,238,136	$44,177,434	$15,613,757	$1,457,310
2011	$20,784,673	$54,970,717	$15,703,152	
2012	$22,028,834	$52,742,627	$19,826,095	
2013	$20,261,229	$56,573,818	$19,444,335	
Total Revenue	$119,746,172	$303,360,587	$97,905,303	$4,288,806
Total Production (tons)		249,937,405	249,937,405	249,937,405
Revenue Per Ton		$1.21	$0.39	$0.02
Average Price		$15.32	$15.32	$15.32
Effective Tax Rate		7.9%	2.6%	0.1%

Current Allocation of Federal Royalty and Severance Tax Revenue

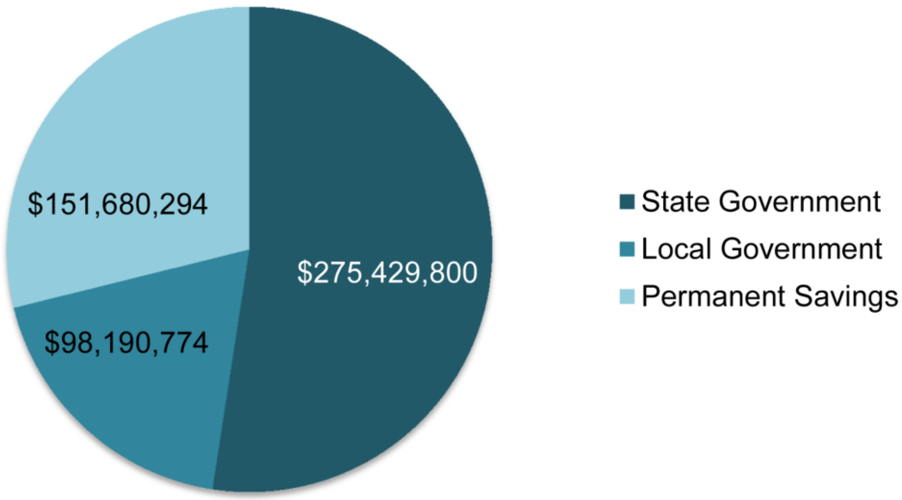
A quarter of federal mineral royalties distributed to Montana are further allocated to the counties and school districts where coal production occurs. The remaining 75 percent is allocated to the state’s General Fund.

Half of Montana's coal severance tax is deposited into the Coal Tax Trust Fund, a permanent fund intended to provide long-term fiscal benefits from the depletion of the state's coal resources. Proceeds from the Trust Fund are allocated to a variety of infrastructure and economic development accounts. The remaining coal severance tax is used for a variety of state purposes, with a small share (5.5%) going to a local impact fund. The Gross Proceeds Tax is levied in lieu of local property taxes and about 53 percent of revenue was allocated back to local governments between 2008 and 2014. Table 8 and Figure 4 show the general allocation of federal coal royalty revenue and state and local production taxes.

Table 8: Allocation of Federal Royalty and State Tax Revenue to Montana

Revenue Allocation	Federal Royalty Distributions	Severance Tax	Gross Proceeds	RIGWAT	Total Federal Royalty and State Revenue Allocations
State Government	$89,809,629	$134,995,461	$46,335,904	$4,288,806	$275,429,800
Local Government	$29,936,543	$16,684,832	$51,569,399		$98,190,774
Permanent Savings	$0	$151,680,294			$151,680,294

Figure 4: Allocation of Federal Royalty and State Tax Revenue to Montana



Change in Federal Royalty and Severance Tax Revenue Allocations

Federal royalty reform is expected to generate higher royalty revenue and result in higher costs to deliver coal to the domestic power sector and lower the demand for coal that will lower production from federal leases. The impact on state taxes is the result of higher prices, lower production, and interactions between federal royalty revenue and state severance taxes. For example, in Montana federal royalties paid are deductible from the taxable value used for severance tax purposes.

Montana could receive $5.1 million to $8.8 million in additional annual revenue due to federal royalty reform. This is because the increase in royalty collections greatly outweighs the modeled decline in production and taxable value for state severance taxes.

Revenue is received as higher federal mineral royalty distributions while state taxes decline. The increase in total revenue will result in different allocations based on how each individual tax is distributed between the state, local governments, and permanent savings. Table 9 shows the estimated impacts on state revenue from federal royalty reform.

Table 9: Estimated Impact of Federal Royalty Reform on Revenue Allocations to Montana

Scenario	Revenue Allocation	Change in Federal Royalty Distributions	Change in Combined State Taxes	Net Change in Revenue	Percent Change in Federal Royalty Distributions	Percent Change in Combined State Taxes	Percent Change of Net Revenue Benefit
Net Market Price	Total Revenue	$5,678,400	($531,125)	$5,147,275	28.5%	0.8%	5.9%
	State Government	$5,678,400	($243,093)	$5,435,307	28.5%	0.4%	6.2%
	Local Government	$0	($89,388)	($89,388)	0.0%	0.1%	0.1%
	Permanent Savings	$0	($198,644)	($198,644)	0.0%	0.3%	0.2%
Net Market Price and Transportation Cap	Total Revenue	$9,037,427	($349,986)	$8,687,441	45.3%	0.5%	9.9%
	State Government	$9,037,427	($160,187)	$8,877,240	45.3%	0.2%	10.1%
	Local Government	$0	($58,902)	($58,902)	0.0%	0.1%	0.1%
	Permanent Savings	$0	($130,897)	($130,897)	0.0%	0.2%	0.1%

In Montana, the state government could see a change in federal royalty distributions of 29 to 45 percent. Local governments and the Coal Tax Trust Fund would see no change in revenue.

Wyoming

Current Federal Royalty and Severance Tax Revenue

Wyoming levies a severance tax at the state level and local governments also collect revenue on the gross value of production based on local property tax mill levies. Combined, these taxes generated $1.20 per ton, or about 9.2 percent of the net delivered price. Table 10 shows federal royalty distributions and state tax revenue in Wyoming for 2008-2013.

Table 10: Total Federal Royalty Distributions and State Tax Revenue to Wyoming

Year	Federal Royalty Distributions	Severance Tax	Property Tax
2008	$264,557,943	$238,598,329	$210,884,760
2009	$283,941,537	$273,281,570	$234,168,035
2010	$289,578,588	$269,081,349	$230,576,515
2011	$301,062,012	$294,278,928	$246,002,072
2012	$305,152,852	$293,110,118	$256,803,632
2013	$269,179,394	$282,081,447	$251,614,091
Total Revenue	$1,713,472,326	$1,650,431,741	$1,430,049,105
Total Production (tons)		2,569,311,998	2,569,311,998
Revenue Per Ton		$0.64	$0.56
Average Price		$13.01	$13.01
Effective Tax Rate		4.9%	4.3%

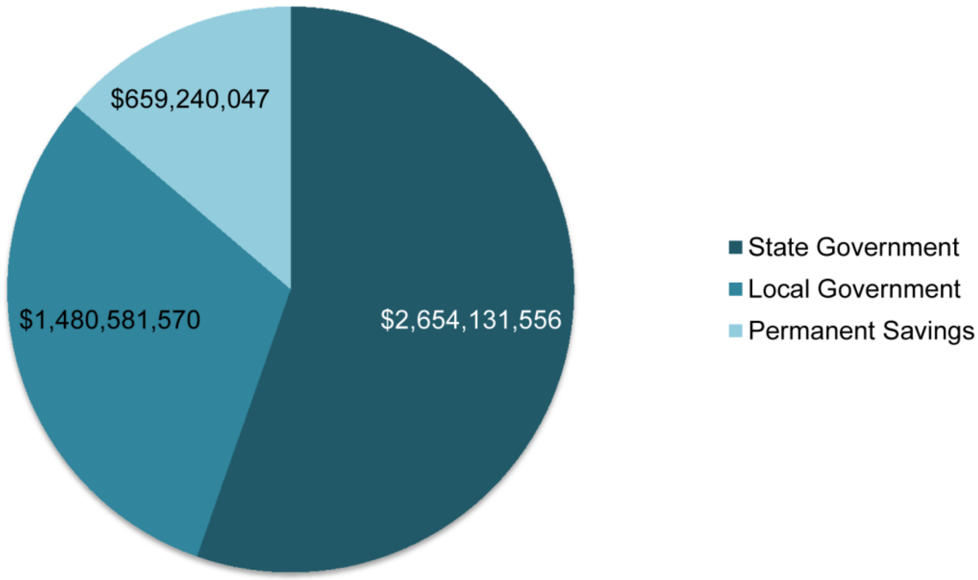
Current Allocation of Federal Royalty and Severance Tax Revenue

Wyoming is one of the states most dependent on revenue from natural resources extraction to fund basic government services. A significant portion of annual revenue is deposited in the state's General Fund and is collected by local governments to fund operating budgets. Wyoming has also made some smart decisions about natural resources revenue. The state maintains a relatively high tax rate on the value of coal and other fossil fuels. The state saves a good portion of severance taxes, building up a permanent fund that provides stable fiscal benefits over time. The state also invests natural resource revenue into education and infrastructure. Table 11 and Figure 5 show the general allocation of federal coal royalty revenue and state and local production taxes.

Table 11: Allocation of Federal Royalty and State Tax Revenue to Wyoming

Year	Federal Royalty Distributions	Severance Tax	Property Tax	Total Federal Royalty and State Revenue Allocations
State Government	$1,713,472,326	$940,659,229	$0	$2,654,131,556
Local Government	$0	$50,532,465	$1,430,049,105	$1,480,581,570
Permanent Savings	$0	$659,240,047	$0	$659,240,047

Figure 5: Allocation of Federal Royalty and State Tax Revenue to Wyoming



Change in Federal Royalty and Severance Tax Revenue Allocations

Even though Wyoming is expected to receive significant benefits in terms of higher federal royalty distributions to the state, revenue will be received from different sources and the allocation to local government and permanent savings would actually decline slightly as a result of federal royalty reform. Table 12 shows the results. Wyoming could receive $58 million to $234 million in additional annual revenue due to federal royalty reform. State government could see a change in federal royalty distributions of 21 to 83 percent.

Table 12: Estimated Impact of Federal Royalty Reform on Revenue Allocations to Wyoming

Scenario	Revenue Allocation	Change in Federal Royalty Distributions	Change in Combined State Taxes	Net Change in Revenue	Percent Change in Federal Royalty Distributions	Percent Change in Combined State Taxes	Percent Change of Net Revenue Benefit
Net Market Price	Total Revenue	$60,585,103	($2,406,203)	$58,178,900	21.2%	0.5%	7.3%
	State Government	$60,585,103	($734,761)	$59,850,342	21.2%	0.1%	7.5%
	Local Government	$0	($1,156,501)	($1,156,501)	0.0%	0.2%	0.1%
	Permanent Savings	$0	($514,941)	($514,941)	0.0%	0.1%	0.1%
Net Market Price and Transportation Cap	Total Revenue	$235,685,887	($3,110,821)	$232,575,066	82.5%	0.6%	29.1%
	State Government	$235,685,887	($949,924)	$234,735,963	82.5%	0.2%	29.4%
	Local Government	$0	($1,495,164)	($1,495,164)	0.0%	0.3%	0.2%
	Permanent Savings	$0	($665,733)	($665,733)	0.0%	0.1%	0.1%

Wyoming discontinued direct payments to counties from federal mineral royalty distributions in order to maximize Payments in Lieu of Taxes (PILT) to counties (the PILT "full payment amount" is reduced by the amount of Federal Mineral Royalties the county receives, along with other federal revenue sharing payments [e.g., Forest Service and BLM payments] that accrue directly to county governments). The decrease in federal mineral royalty payments to counties was offset by an increase in state severance tax distributions to counties. However, if federal royalty reforms are implemented in a way that increases royalty revenue, local governments in Wyoming would see a decline in revenue. The state may consider changes to allocation formulas that keep local governments whole.

V. CONCLUSION

The main finding is that changes in federal royalty policy could have substantial revenue benefits for federal and state governments with limited impact on coal production from federal lands. Stated differently, we find that not pursuing reforms will generate few benefits in terms of additional coal extraction and related economic activity, but result in significantly less revenue accruing to federal and state governments.

Implementing the proposed rule using the first arm's length sale price would result in little to no new revenue in ONRR's assessment. We do not have data on arm's length and non-arm's length sale prices for coal FOB at the mine that we could use to provide an independent analysis.

In theory the price set at the mine should be revealed using any one of the five benchmarks currently employed. The arm's length sale method should not reveal a different FOB price at the mine than is currently being used for royalty valuation. Further, because the proposed rule would still allow for independent brokers to remarket coal to consumers without royalty liability, the proposed rule could create a preference for particular sale structures (potentially disadvantaging affiliated mining and logistics companies) without resulting in additional revenue.

Using Net Delivered Prices Offers Multiple Benefits

Changing the price used for valuation to net delivered prices has multiple advantages over using the first arm's length sale price. The gross commodity value of federal coal is best revealed by determining its value delivered to the consumer less transportation costs. This method of valuation closes the loophole that may allow for companies to structure sales using affiliated brokers to artificially reduce the commodity value of federal coal that is required for royalty valuation. Most importantly, using net delivered costs would close the loophole for all sales, not only for sales where coal is marketed directly by mines and their affiliates.

The net delivered price and the first arm's length sale price are the same price for all sales where mines and their affiliates are marketing coal directly to consumers. In these instances, the contract value reveals the price that would be used for royalty valuation.

In instances where independent brokers (or mines) are purchasing coal at the mine and remarketing the same coal downstream to consumers, the delivered price is unknown to the lessee responsible for royalty payment. In these cases, ONRR would define the process lessees would use to determine the net market price. The lessee would be responsible for estimating the net market price following ONRR rules. The lessee would add any additional royalty liability above the arm's length sale price, and pay royalties to the federal government.

Using net delivered price has significant transparency advantages, and similar benefits to streamline the assessment process for industry and ONRR compliance audits. Delivered prices are known for sales to regulated utilities (independent of the sale structure). Additional price data is revealed by sales on spot markets, and by market index prices for coal of varying qualities delivered to domestic and export markets. Market analysis firms including Platts and SNL Energy track market prices and transportation costs closely and could be used to reveal prices that would be used by mines for royalty valuation. This transparency would also allow for public review of federal royalty valuation without necessarily revealing contract prices, mining and marketing costs, and other proprietary data.

Do Not Base Transportation Deduction Limit on Natural Gas Regulation

The proposed regulation asks if transportation cost deductions should be limited to 50 percent of the value of coal. The question is relevant because the natural gas regulation includes this limitation on transportation costs. We find that such a limit would increase royalty revenue significantly with a modest decline in production.

The regulation as it applies to natural gas is intended to avoid "gaming" by the natural gas industry. Vertically integrated companies who are delivering natural gas to customers remote from the lease could inflate transportation costs to limit royalty obligations.[21] Placing a cap on deductible costs provides a check against gaming while still providing for reasonable cost deductions.

In the coal market, a cap equal to a percent of the value of coal is unlikely to function this way. Transportation costs are a much larger share of total delivered prices. In our analysis, we modeled a limit on transportation costs equal to 50 percent of the value of coal. Sales that travel longer distances would pay higher royalties because of higher transportation costs without regard to whether gaming is actually taking place.

If the goal is to limit gaming in the coal market, better options may include a fixed percent of transportation costs that would be deductible (to encourage cost reduction) or limits on cost deductibility based on an index of transportation costs for deliveries from states to different markets. A threshold could be set using market prices for deliveries on each route that would limit the ability of integrated companies to game the system by inflating costs beyond reasonable thresholds.

Appendix A: Estimating Market Prices and Transportation Costs

Deliveries to the Domestic Power Sector

The Energy Information Administration (EIA) publishes the price of coal deliveries to the domestic power generation sector. These data report the mine and state where the coal originated and the state and power plant where it was delivered for all regulated utilities.[22] SNL Energy, a data subscription service that provides energy industry data, gathers and reports these same data and provides additional estimates for delivered prices and transportation costs to unregulated utilities and power plants.[23]

All monthly coal deliveries to the electric power sector between October 2007 and September 2014 (federal fiscal years 2008 to 2014) including deliveries to regulated and private power generators were downloaded from SNL Financial. These data include identifiers for the mine and plant, tons delivered (Q), estimated transportation costs (T), delivered cost per ton (p), and original transportation mode (barge, mine mouth, railroad, or truck).

Each record was linked to a MSHA ID, which was then matched to a table listing the MSHA ID of all mines with Federal leases.[24] Of the 144,205 records in the SNL dataset between FY2008 and FY2014, 19,737 (11%) were missing the MSHA ID and deleted from the dataset. Thirty-one percent of these records missing a MSHA ID were also missing the mine state; of those records with a mine state, Kentucky accounts for 20 percent, Ohio for 11 percent, and West Virginia for 23 percent of these records that could not be linked back to a specific mine.

Transportation costs (T) are reported for regulated utilities in the U.S. by the Energy Information Administration.[25] Where these costs are not reported, SNL energy estimates transportation costs based on waybill samples from the U.S. Department of Transportation, Surface Transportation Board.[26] These data were missing for 4,572 records (4% of the remaining dataset), which were deleted from the analysis dataset. Twenty-two percent of these records missing transportation costs were from an unknown state, 27 percent were from Kentucky, and 20 percent were from West Virginia. Of the remaining records, 62 (0.05%) were missing price per ton and total delivered cost. Fifteen percent of these records were from West Virginia and 68 percent were from Wyoming. The final analysis dataset contained 124,944 records.

For deliveries listed as “mine mouth”, which indicates that the power plant is located at the mine, transportation costs were set to $0.

In the final analysis dataset, 37 percent of coal deliveries originated from mines with Federal leases. We assume that delivered coal prices and transportation costs from these mines will be constant for coal produced from federal leases associated with the mine, and from state and private leases associated with the same mine.

The total quantity of coal delivered (Q) is the sum of deliveries from all mines that have federal leases in each state.

The weighted average delivered cost per ton (p) from a particular state was calculated using the following formula, dividing the total cost of deliveries by the total quantity delivered within the state. *S* indexes the state, *m* indexes the mine and *l* indexes the plant:

$$\frac{\sum_s p_{m,l} * Q_{m,l}}{\sum_s Q_{m,l}}$$

The weighted average transportation cost per ton (T) from a particular state was calculated using the following formula, dividing the total transportation costs by the total quantity delivered within the state:

$$\frac{\sum_s T_{m,l} * Q_{m,l}}{\sum_s Q_{m,l}}$$

Table A1 summarizes the quantity delivered, weighted average delivered cost per ton and transportation cost per ton, by state for deliveries from all mines in the state and for deliveries from mines with federal leases.

Table A1: Weighted Average Delivered Prices and Transportation Cost for Coal Sales to the Domestic Power Sector, 2008-2014

	All Coal Deliveries to the Power Sector				Coal Deliveries from Mines with Federal Leases			
State	Thousand Tons	Transportation Cost	Delivered Price	FOB Mine Price	Thousand Tons	Transportation Cost	Delivered Price	FOB Mine Price
Alabama	40,371	$15.93	$77.14	$61.21	1,260	$ 18.36	$ 83.50	$ 65.13
Colorado	140,923	$12.05	$53.63	$41.57	138,570	$ 12.20	$ 53.92	$ 41.73
Kentucky	503,924	$16.47	$73.14	$56.67	1,483	$ 24.32	$ 126.07	$ 101.75
Montana	176,488	$10.08	$30.71	$20.63	137,901	$ 8.59	$ 30.23	$ 21.64
New Mexico	161,305	$4.88	$36.80	$31.92	82,412	$ 6.70	$ 41.89	$ 35.19
North Dakota	158,484	$0.73	$17.05	$16.32	158,484	$ 0.73	$ 17.05	$ 16.32
Oklahoma	3,069	$4.32	$35.88	$31.56	2,803	$ 4.27	$ 33.21	$ 28.93
Utah	118,960	$11.27	$42.21	$30.94	112,036	$ 11.62	$ 42.52	$ 30.89
Wyoming	2,809,267	$15.96	$31.30	$15.34	2,573,019	$ 16.04	$ 31.54	$ 15.50
Total	**4,112,791**	**$14.47**	**$37.60**	**$23.13**	**3,207,965**	**$ 14.39**	**$ 32.45**	**$ 18.05**

*Transportation cost, delivered price, and FOB mine price are weighted averages.

Statutory Royalty Rates

The royalty rate is the rate applied to each lease, including any royalty rate reductions. The BLM and coal operators negotiate royalty rates on a lease-by-lease basis, but generally are set at a minimum of 12.5 percent of the gross value of coal after it is extracted from surface mines and 8 percent for coal extracted from underground mines. Coal lessees can apply for a royalty rate reduction if the current royalty rate imposes economic hardship that would otherwise result in abandoning the lease, or in less than full recovery of leased coal. Rate reductions are also granted to encourage the greatest utilization of federal coal,[27] even in instances when high-cost or low-value coal would otherwise be uncompetitive in the domestic energy market.

The BLM makes a determination and has discretion to grant royalty rate reductions if three basic requirements are met:

1. The royalty rate reduction must encourage the greatest ultimate recovery of the coal resource.
2. The royalty rate reduction must be in the interest of conservation of the coal and other resources.
3. The reduced royalty rate is necessary to promote development of the coal resource.[28]

Royalty rate reductions occurred on at least 30 out of 83 leases (36 percent of leases) offered for sale since 1990.[29] The GAO found that the royalty rate that lessees pay varied between 5.6 percent in Colorado and 12.2 percent in Wyoming.[30] Table 1 shows the average royalty rate paid on federal coal between 2008 and 2013.

APPENDIX B: ROYALTY AND PRODUCTION TAX SUMMARIES BY STATE

Alabama

Coal Excise and Privilege Tax

Tax of $0.135 per ton of coal severed.[31] Tax revenue is distributed to local governments to support local services and economic development.[32] The tax was reauthorized for a period of 10 years in 2011.[33]

Coal and Lignite Excise and Privilege Tax.

Tax of $0.20 per ton of coal or lignite severed.[34] The entire tax is distributed to local governments. Municipalities receive half of the tax on coal extracted within their jurisdiction. County governments receive the other half of the revenue and also receive 100 percent of revenue extracted within the unincorporated county jurisdiction.[35]

Property Tax

Coal production is not subject to real property taxation in Alabama.

Colorado

Federal Mineral Royalty Distributions

All federal mineral royalties distributed to Colorado are directed to local governments in some form. Half of the revenue is allocated to local schools: 1.7 percent is distributed directly to local school districts and 48 percent is directed to the State Public School Fund. Distributions to schools are capped at $76 million for the Public School Fund and $4.1 million for direct distributions in FY2015.[36] Any spillover amounts are distributed to a permanent fund for higher education.

Forty percent of Federal Mineral Royalties are deposited into the Energy and Mineral Impact Assistance Fund to be distributed by the Colorado Department of Local Affairs (DOLA) back to counties, cities, and school districts using both direct distributions and impact grants to affected communities. Direct distributions are made using a variety of impact metrics, including employment in mining and measures of mineral activity. Program guidelines and payment statistics can be accessed on the DOLA website.[37]

The purpose of the Energy and Mineral Impact Assistance Program is to assist political subdivisions that are socially and/or economically impacted by the development, processing, or energy conversion of minerals and mineral fuels. The department is assisted by a twelve-member Energy and Mineral Impact Assistance Advisory Committee, which meets several times each year, to consider applications for grants and low-interest loans. Eligible entities to receive grants and loans include municipalities, counties, school districts, special districts and other political subdivisions and state agencies. The kinds of projects that are funded include—but are not limited to—water and sewer improvements, road improvements, construction/improvements to recreation centers, senior centers and other public facilities, fire protection buildings and equipment, and local government planning.[38]

Ten percent of Federal Mineral Royalties is allocated to the Colorado State Water Conservation Board which deposits the funds in a perpetual base account used for loans for state water projects (10% of the total capped at 17.7 million in FY2015).[39] Any spillover amounts allocated to schools or the Water Conservation Board are allocated to a permanent fund for higher education.

In addition to royalty revenue, bonus payments from coal lease sales are shared between two permanent funds for local governments and higher education.[40]

The local government and higher education permanent funds have been raided in recent years. In 2009 for example, two bills transferred a total of $50.7 million to the state's General Fund.[41]

Coal Severance Tax

The state's severance tax is a per ton levy adjusted quarterly based on the producers' price index as published by the Bureau of Labor Statistics.[42] The base tax rate is $0.60 per ton, and the current inflation adjusted rate is $0.842 per ton. The tax is levied after the first 300,000 tons extracted each quarter.[43] Underground coal and lignite coal is taxed at half the per ton rate.

Property Taxes

Coal is also taxed as real property by local governments in Colorado. The taxable value of producing coal mines is based on an income formula that includes the volume of coal extracted, the price of coal extracted, and other factors, including the royalty rate based on the mining method. Prices are index prices published in the Colorado Real Property Valuation Manual. Importantly, the royalty rates used in the income formula are also published in the Manual and are set at 6 percent for underground coal and 9 percent for surface coal. That means changes to federal coal valuation policy will not have a direct effect on local property tax collections in Colorado without modification to the Manual.

Assessed value is 29 percent of gross taxable value. The average tax rate for county and school district levies was 59.895 (or 5.99%) in 2013.[44] The effective rate on taxable value is 29 percent of the 5.99 percent tax rate.

Kentucky

Severance Tax

The severance tax is 4.5 percent of the value of coal extracted, or a minimum of $0.50 per ton.[45] The tax rate is lowered to between 3.75 percent and 2.25 percent for factors including the thickness of the coal seam and the depth and the water drainage conditions of the mine.[46]

Gross value is defined as the price received by the "taxpayer" less certain costs, including transportation costs. The gross value is not reduced by royalties.[47] That means federal royalty collections are not considered deductible costs, and changes in federal royalty valuation will not affect the gross value on which state severance taxes are levied.

Severance tax revenue is allocated to the Transportation Cabinet for spending on state highways and to the Department for Energy Development and Independence for energy research and development (capped at $3 million annually). Any revenue in excess of the distributions to these funds is deposited in the state General Fund.[48] All revenue is used for state priorities and none is distributed to local governments or saved in a permanent trust.

Property Tax

Property tax valuation of producing mines is based on the income approach. The formula includes a range of factors, including the mine recovery rate (production) and royalty rates. Assessed value is 100 percent of gross value determined by the income formula. The average property tax rate for county and school district levies is 8.62 percent.[49]

The royalty rate varies by county and mining method. Royalty rates for deep mines range from $2.76 per ton to $3.45 per ton. Surface mine royalty rates range from $2.76 per ton to $3.68 per ton.[50] It appears that the royalty rates are determined for each mine, so a change in federal royalty valuation could have an impact on property tax collections. We assume that a change in federal royalty collections will reduce assessed valuation for property taxes by the same amount.

Montana

Federal Mineral Royalty Distributions

Montana began making direct distributions equal to 25 percent of the state's share of federal mineral royalties to the county of origin in 2005.[51] The remaining 75 percent is deposited in the state's General Fund.[52] State distributions to local governments are compiled and reported by the Montana Association of Counties (MACo).[53]

Coal Severance Tax (MCA 15-35-103)

Montana taxes all coal extracted, or "severed" from the state. The severance tax has several rates based on the type (surface or underground) and quality of coal. The highest rate for surface coal with a heat content greater than 7,000 BTU per pound is 15 percent of the taxable value. The lowest rate for underground coal with a heat content of less than 7,000 BTU per point is 3 percent of the taxable value.[54] Mines producing less than 50,000 tons annually are exempt from the tax.

Taxable value is the price received by the lessee at the mine. In cases where no arm's length sale exists, the severance tax is based on the value of the coal to the final consumer (e.g. a power plant), not the value of the coal to the lessee or an affiliated broker.[55]

Federal royalties are deductible from taxable value, along with a variety of other taxes. The first 20,000 tons of production annually from all mines is exempt from the severance tax.

The Montana Constitution[56] establishes that half of coal severance tax revenue be allocated to the Coal Severance Tax Trust Fund while the other half is directed to other funds[57] including the state's General Fund and a special state account that receives $250,000 for coal and uranium mine reclamation. The remaining balance of the revenue after the reclamation fund distribution is made is allocated to various funds. About 5 percent of the total is allocated to a Local Impact Fund.

Montana Coal Gross Proceeds Tax

Montana has a gross proceeds tax that is levied on the gross value of coal sold in the state. The tax is levied in lieu of local property taxes. Taxable value is defined as the contract sales price, or the price received by the lessee at the mine.

The tax rate is 5 percent of taxable value for surface coal and 2.5 percent for underground coal.

Taxable value is defined as the contract price of coal sold at the mine. The price used to determine value is the "mine price," or the FOB price of coal reported by the lessee or as determined by the Department of Revenue when no arm's length sale exists.

The revenue is proportionally distributed to the appropriate taxing jurisdictions in which production occurred based on the total number of mills levied in fiscal year 1990.[58] Between fiscal year 2008 and 2014, 52 percent of the tax was distributed to local governments and the rest was retained by the state.

Resource Indemnity and Ground Water Assessment Tax (RIGWAT)

The resource indemnity and ground water assessment tax (RIGWAT) was created to indemnify the citizens of Montana for the loss of long-term value resulting from the depletion of natural resource bases, and for environmental damage caused by mineral development. The tax is placed in a trust fund, which is managed by the state Board of Investments.[59]

The tax rate on coal is 0.4 percent of the taxable value. Royalties paid to the federal government are exempt from the tax (taxable value is reduced by the royalty liability). The first $6,500 in RIGWAT liability is exempt.

Revenue is distributed to several state funds and accounts: $366,000 to the Department of Environmental Quality (DEQ) ground water assessment account and $150,000 to the DEQ water storage state special revenue account each biennium. Of the remaining revenue, 25 percent is distributed to the hazardous waste/CERCLA special revenue account and another 25 percent is directed to the environmental quality protection fund; remaining revenue is distributed to the natural resources projects fund.

Reclamation Fee

Montana collects a fee for abandoned mine reclamation on all coal extracted from surface mines. The fee is $0.09 per ton for lignite coal and $0.315 per ton for all other coal.

Property Tax

Coal production is not subject to real property taxation in Montana.

North Dakota

Severance Tax

Tax of $0.375 per ton of coal or lignite severed in the state. An additional $0.02 per ton is levied to benefit the Lignite Research Fund. The severance tax is exempt if the coal extracted is used to heat buildings in North Dakota. The severance tax can be cut in half if the coal is burned in cogeneration plants where renewable energy makes up at least 10 percent of the generating capacity.

Revenue is allocated to the Coal Development Fund, which benefits local governments in a variety of ways. Seventy percent is allocated annually to coal producing counties proportional to respective production; counties further appropriate 40 percent of this income to their county general fund, 30 percent to cities within the county, and 30 percent to school districts. Nonproducing counties within 15 miles of an active coal mine and a city or school distance in those nonproductive counties receive a share of the coal producing county's severance revenue from that particular mine.

Thirty percent of revenue allocated to the Coal Development Fund is further allocated to a trust fund that makes loans to school districts for construction projects as well as loans to cities, counties and school districts impacted by coal development.[60]

Property Tax

Coal production is not subject to real property taxation in North Dakota.

New Mexico

Federal Mineral Royalty Distributions

New Mexico does not make direct distributions to local governments. An annual appropriation is made to the Instructional Material Fund and to the Bureau of Geology and Mineral Resources. The bulk of federal mineral royalties are directed to the Public School Fund.[61]

Severance Tax

New Mexico's severance tax has two parts. The severance tax on coal is levied on a per ton basis with no deductions. The rate is $0.57 per ton on surface coal and $0.55 on underground coal. Starting in 1994, the stated added a coal surtax on each ton of coal extracted that is adjusted annually based on the producer price index published by the Bureau of Labor Statistics.[62] The current rate is $1.28 for surface coal and $1.23 for underground coal.[63]

Tax Rate per Ton	Surface Coal	Underground Coal
Severance	$0.57	$0.55
Severance Surtax	$1.28	$1.23
Total	**$1.85**	**$1.78**

Resource Excise Tax

This is really two taxes, the producers tax and the processors tax levied on the gross value of coal after deducting royalties paid tribal governments. Federal royalties are not exempt from taxable value. The rates are 0.75 percent for each tax, or a combined 1.5 percent.[64] All revenue is deposited in the General Fund.[65]

Gross Receipts Tax

New Mexico levies a gross receipts tax on the value of coal sold in New Mexico. The gross receipts tax rate varies throughout the state from 5.125 percent to 8.6875 percent, depending on the location of the business. It varies because the total rate combines rates imposed by the state, counties, and, if applicable, municipalities where the businesses are located. The business pays the total gross receipts tax to the state, which then distributes the counties' and municipalities' portions to them.[66] The gross receipts tax in Cibola, San Juan, and McKinley counties where coal mining is active is about 6.5 percent outside of incorporated cities.[67]

The taxable value of coal as defined for severance and the resource excise tax is subject to the gross receipts tax. The value of resource excise taxes is deductible from gross receipts taxation.[68] The exemption lowers the effective rate to about 6.4 percent in coal producing counties.

Property Tax

The production value of coal is exempt from property taxation in New Mexico.

Oklahoma

Severance Tax

Oklahoma has no coal severance tax.

Property Tax

The production value of coal is exempt from property taxation in Oklahoma.

Utah

Federal Mineral Royalty Distributions

Utah makes direct distributions from the state's share of federal mineral royalties to the county of origin through the Permanent Community Impact Fund and through direct distributions made by the Utah Department of Transportation.[69] Together, direct distributions and grants return about 80 percent of the state's share of federal mineral royalties to local governments.

The Permanent Community Impact Fund Board (CIB) is a program of the state of Utah which provides loans and/or grants to state agencies and subdivisions of the state (counties, municipalities, schools, and special districts) which are or may be socially or economically impacted, directly or indirectly, by mineral resource development on federal lands.[70]

State Transportation Department Mineral Lease Fund Distributions are available online.[71]

Severance Tax

Utah has no severance tax on coal.

Property Tax

Property taxes on active coal mines in Utah are based on a discounted cash flow model. Taxable value is determined by the annual mineral sales plus income from other sources such as interest, bonuses, subsidies, or premiums. Expenses are deducted from the income, including salaries, severance taxes, sales/use taxes, and state and federal royalty payments.[72] The resulting net revenue is then taxed by a rate established by the county in which the mine resides. Average tax rates for county government and school districts are about 1.1 percent.[73]

Wyoming

Federal Mineral Royalty Distributions

Wyoming does not make direct distributions of Federal Mineral Royalties to counties. Distributions are made based on a complicated formula defined in state statute,[74] and statistics are reported by the Wyoming Consensus Revenue Estimating Group.[75]

In FY1995 direct payments to counties were discontinued in order to maximize PILT payments to counties (the PILT "full payment amount" is reduced by the amount of Federal Mineral Royalties the county receives, along with other federal revenue sharing payments [e.g., Forest Service and BLM payments] that accrue directly to county governments). The decrease in Federal Mineral Royalty payments to counties was offset by an increase in state severance tax distributions to counties.

Federal Mineral Royalties still benefit counties in other ways. They go into the Local Government Capital Construction Account that funds grants from the State Loan & Investment Board (SLIB) to cities, towns, counties, and special districts through the Mineral Royalty Grant Program. Distributions are also made to the Highway Fund County Roads and several funds that benefit school districts.

Severance Tax

Wyoming's severance tax is 7 percent of the gross value of surface coal and 3.75 percent of the gross value of underground coal. Gross value is defined as the value received by the lessee at the mine. Royalties paid to the federal government are deducted from gross value for severance taxes. Severance taxes are capped at a maximum of $0.60 per ton for surface coal and $0.30 for underground coal.

Property Tax

Local governments in Wyoming also levy property taxes on the gross value of coal. Gross value determined for severance taxation is used for local property tax assessments. Local mill levies vary by jurisdiction. The effective tax rate for Wyoming coal is reported at 4.76 percent.[76]

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