Outcomes of Higher Federal Coal and Natural Gas Royalty Rates

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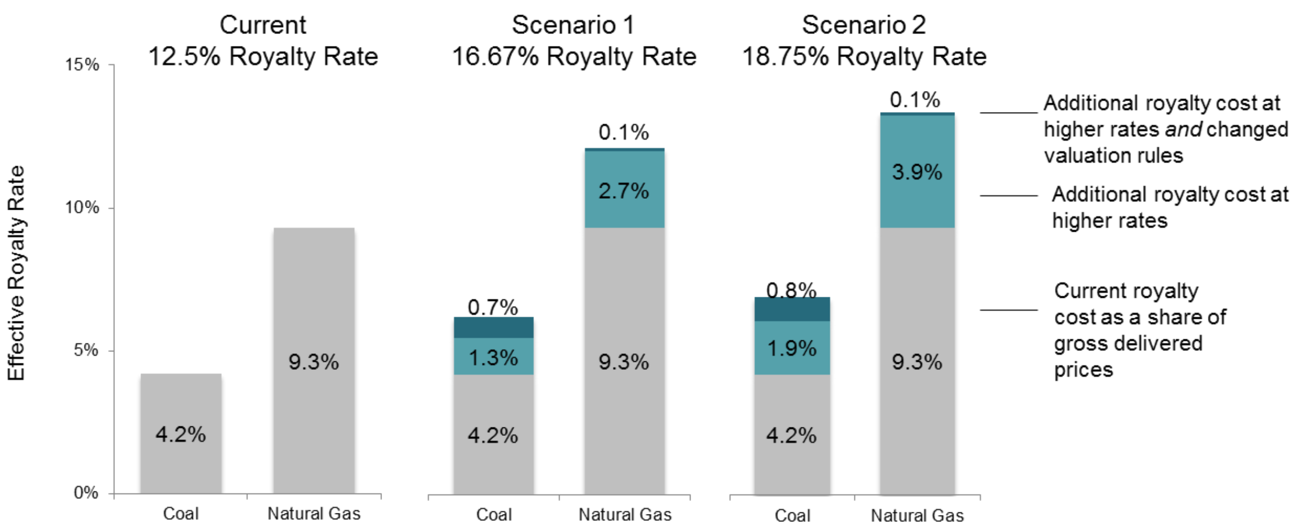
Introduction

The Department of Interior (DOI) is proposing a number of reforms to federal leasing, bonding, and royalty regulations related to oil, natural gas, and coal. The DOI is proposing these reforms to simplify and lower compliance costs, modernize rules to address a rapidly changing energy industry and energy markets, and better align regulations with the DOI's policy priorities—including securing a fair return to taxpayers and balancing energy extraction, economic development, and conservation goals.[1]

Two of several proposed reforms—higher federal royalty rates and a rule that would change product valuation for royalty assessment—would increase the cost of delivering coal and natural gas to the domestic electric power sector. These two fuels compete for market share in the U.S. electric power sector based on the relative cost of delivering these fuels from mines and wells to power plants. Persistent low natural gas prices are driving a transition away from coal to relatively less costly natural gas. New regulations on mercury emissions from coal-fired power plants and the Clean Power Plan will raise the cost of coal-fired electricity generation and contribute to additional fuel switching from coal to natural gas. In this context, royalty reform is of particular concern to coal-dependent states and communities. If increase royalty costs raise the price of coal relative to natural gas, proposed reforms could further reduce already weak demand for coal in domestic electric power markets.

Figure 1: The Impact of Federal Royalty Reforms on Effective Royalty Rates for Coal and Natural Gas*



* The effective royalty rate measures royalty costs as a percent of the gross price of coal and natural gas delivered to the domestic electric power sector. Figure shows the impact of proposed federal royalty reforms if they had been in place during 2010-2014.

In this report, we estimate how higher federal royalty rates and royalty valuation reforms could increase the cost of delivering natural gas and coal extracted from federal leases to U.S. power plants. Figure 1 shows federal royalty costs are already a larger share of total delivered costs for natural gas (9.3%) compared to coal (4.2%). We find that proposed reforms would increase federal royalty costs for natural gas by a larger amount compared to coal. Had proposed royalty rate and royalty valuation reforms been in effect during 2010-2014, royalty costs would have been between 6.2 and 6.9 percent of the gross price of coal delivered to the electric power sector and between 12.1 and 13.4 percent of the gross price of natural gas delivered to the electric power sector.

This result suggests that federal royalty reform is not likely to cause additional fuel switching from coal to natural gas in the electric power sector and therefore reforms should not be viewed as a significant challenge to the coal industry specifically.[2] A large body of research shows that fiscal policy has a limited effect on fossil fuel production,[3] and it should also be recognized that a small cost advantage for federal coal relative to natural gas is unlikely to result in significant new demand for coal production.

Additionally, increased transparency of the federal royalty program is a stated goal of proposed federal reforms and an important goal of our work. To that end, we make data on federal coal leases we utilize in this report and our analysis of it available to the public. We compile and organize data from a variety of federal sources, estimate data gaps, and do additional calculations that improve access to and understanding of current federal coal leases.

The web post for this report is at: http://headwaterseconomics.org/energy/coal/outcomes-higher-coal-naturalgas-royalties/.

A downloadable spreadsheet is available on our website at: http://headwaterseconomics.org/wphw/wp-content/uploads/data-outcomes-higher-coal-naturalgas-royalties.xlsx.

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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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Methods

Proposed Reforms

The DOI is considering comprehensive reforms to federal royalties collected when fossil fuels are extracted from federal lands.[4] These reforms address a wide range of leasing and royalty policies, including royalty rates, product valuation, allowable deductions, and bonding requirements. The reforms address all major fossil fuels extracted from federal lands: oil, natural gas, and coal. However, legal and administrative process requires that reforms be pursued independently. Table 1 describes three proposed rules currently in different stages of development and review.

Table 1: Proposed Rules That Could Affect Federal Natural Gas and Coal Royalty Costs

Royalty Policy Issue	Agency	Regulation	Timeline	Source
Changes to oil, natural gas, and coal valuation for royalty assessment	ONRR	Proposed rulemaking	Published January 6, 2015. Public comment closed May 8, 2015. Final rule currently being prepared.	U.S. Department of Interior, Office of Natural Resources Revenue. *Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform.*
Changes to coal royalty rates	BLM	Advanced notice of proposed rulemaking	BLM held listening sessions July 29-August 20, 2015. Written comment period ended September 17, 2015. The proposed rule is currently being developed and will be published for comment.	U.S. Department of Interior, Bureau of Land Management. *Coal; Royalty on Production and Bonding Requirements.*
Changes to oil and natural gas royalty rates	BLM	Advanced notice of proposed rulemaking	Published April 15, 2015; comment period ended June 29, 2015. Proposed rule currently being developed and will be published for comment.	U.S. Department of Interior, Bureau of Land Management. *Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments.*

Royalty Cost Scenarios

This report analyses how reforms resulting in higher royalty rates and changes to federal coal and natural gas valuation rules could affect the cost of delivering these fuels to the domestic electric power sector. We focus on coal and natural gas because these two fuels compete for market share in the U.S. electric power sector. We developed two scenarios for how royalty rates could be increased and consider the likely outcome of valuation reforms with each scenario.

> <u>Current 12.5 Percent Royalty Rate</u>: Current statutory rates on surface coal and onshore natural gas extracted from federal leases are set at 12.5 percent of the gross value of the resource to the lessee. Underground coal pays a reduced rate of eight percent.[5]
>
> <u>Scenario 1. 16.67 Percent Royalty Rate</u>: This scenario considers a rate increase from 12.5 percent to 16.67 percent for surface coal and onshore natural gas. The rate on underground coal would be increased from eight percent to 10.67 percent. This scenario is modeled on royalty rates commonly levied by states on oil and natural gas (Montana and Wyoming, where most federal coal is extracted, have typically adopted Bureau of Land Management [BLM] royalty rates and policy for coal extracted from state lands).
>
> <u>Scenario 2. 18.75 Percent Royalty Rate</u>: This scenario considers a rate increase from 12.5 percent to 18.75 percent for surface coal and onshore natural gas. The rate on underground coal would be increased from eight percent to 12.5 percent. This scenario is modeled on royalty rates levied on federal offshore oil and natural gas.

In a previous Headwaters Economics report, we estimated that the proposed ONRR valuation rule could increase the cost of delivering federal coal extracted from Wyoming to domestic power plants by up to $0.30 per ton, averaged across all federal coal sales from within the state.[6] To estimate the likely royalty costs associated with combined reforms (higher royalty rates and ONRR's proposed valuation rule), we apply the increased royalty rates from scenarios 1 and 2 to the higher price for Wyoming federal coal that would be used for royalty valuation if the proposed ONRR rule is finalized.

Estimating Reported Royalty Rates

Coal and natural gas producers do not, on average, pay the full statutory royalty rate on federal leases. Several factors can reduce royalty liability, primarily allowable royalty rate reductions granted to encourage the greatest utilization of federal coal and natural gas.[7] We first estimate the average "reported royalty rate"—royalty costs per unit (ton of coal or thousand cubic feet (mcf) of natural gas) as a share of the price used for royalty valuation. The reported royalty rate measures the average royalty rate paid by federal lessees within a state.

Tables 2 and 3 show the average reported royalty rate for federal coal and natural gas during the period 2010-2014.[8]

Table 2: Coal Sales Volume, Sales Value, and Reported Revenue, 2010-2014

State	Sales Volume (ton)	Sales Value	Reported Revenue	Average Reported Price ($/ton)	Average Royalty Revenue ($/ton)	Average Reported Royalty Rate
Alabama	8,740,185	$454,007,976	$33,071,159	$51.94	$3.78	7.3%
Colorado	91,498,703	$4,069,296,659	$236,398,486	$44.47	$2.58	5.8%
Kentucky	688,576	$62,614,085	$4,749,414	$90.93	$6.90	7.6%
Montana	113,462,145	$1,855,834,443	$217,269,689	$16.36	$1.91	11.7%
New Mexico	23,545,378	$1,210,380,264	$61,272,274	$51.41	$2.60	5.1%
North Dakota	15,120,054	$279,984,465	$6,159,658	$18.52	$0.41	2.2%
Oklahoma	2,887,661	$161,585,430	$4,245,686	$55.96	$1.47	2.6%
Utah	59,920,648	$2,342,528,659	$162,886,733	$39.09	$2.72	7.0%
Wyoming	1,833,500,033	$24,329,955,704	$2,986,768,091	$13.27	$1.63	12.3%
All Federal Coal	**2,149,363,383**	**$34,766,187,684**	**$3,712,821,190**	**$16.18**	**$1.73**	**10.7%**

Table 3: Natural Gas Sales Volume, Sales Value, and Reported Revenue, 2010-2014

State	Sales Volume (ton)	Sales Value	Reported Revenue	Average Reported Price ($/ton)	Average Royalty Revenue ($/ton)	Average Reported Royalty Rate
Arkansas	65,597,302	$244,200,426	$29,529,583	$3.72	$0.45	12.1%
Colorado	1,595,938,519	$6,161,569,833	$623,453,752	$3.86	$0.39	10.1%
Louisiana	83,585,961	$302,948,980	$42,274,082	$3.62	$0.51	14.0%
Montana	89,614,311	$283,417,792	$32,705,459	$3.16	$0.36	11.5%
New Mexico	3,459,087,465	$14,051,661,606	$1,566,648,515	$4.06	$0.45	11.1%
North Dakota	53,629,074	$274,217,463	$31,752,775	$5.11	$0.59	11.6%
Oklahoma	65,993,507	$251,621,985	$30,069,825	$3.81	$0.46	12.0%
Texas	189,556,167	$814,868,722	$92,580,939	$4.30	$0.49	11.4%
Utah	1,353,887,834	$5,231,812,351	$554,841,455	$3.86	$0.41	10.6%
Wyoming	6,787,521,617	$26,466,644,510	$2,836,572,177	$3.90	$0.42	10.7%
Other States	163,940,905	$731,806,938	$91,139,662	$4.46	$0.56	12.5%
All Federal Coal	**13,908,352,662**	**$54,814,770,605**	**$5,931,568,224**	**$3.94**	**$0.43**	**10.8%**

* Federal reported price and royalty rate are weighted averages for total federal production.

The average reported royalty rate falls well below the current statutory rate in several states, particularly for federal coal. This is mainly due to reduced royalty rates for a number of federal coal leases in these states.[9] For example, fourteen federal coal leases in North Dakota have reduced royalty rates and the average reported royalty rate is less than three percent for all federal coal extracted from the state.

Table 4 shows that in total, nearly one-fifth of active coal leases have been granted reduced royalty rates. By volume, royalty rate reductions are applied to about four percent of the total tons of coal associated with active coal leases.

Table 4: Estimated Tons of Coal Associated With all Currently Active Federal Leases

State	Active Coal Leases	Active Coal Leases With Current Rate Reductions	Percent of Coal Leases With Current Rate Reductions	Total Tons Offered	Tons Offered With Rate Reductions	Percent of Tons Offered With Rate Reductions
Alabama	1	0	0%	8,065,000		0%
Colorado	61	25	41%	1,267,650,133	415,421,765	33%
Kentucky	4	0	0%	12,725,097		0%
Montana	41	3	7%	3,449,795,618	29,435,050	1%
New Mexico	12	2	17%	323,594,666	141,500,000	44%
North Dakota	14	8	57%	183,975,667	145,991,598	79%
Oklahoma	9	5	56%	63,998,559	29,803,173	47%
Utah	71	9	13%	728,661,279	77,666,452	11%
Wyoming	102	7	7%	25,930,679,067	433,439,628	2%
All Federal Coal	**315**	**59**	**19%**	**31,969,145,087**	**1,273,257,665**	**4%**

If the BLM chooses to increase current statutory rates, the agency will also decide to eliminate or retain regulations allowing royalty rate reductions. We assume for the purpose of this analysis that BLM will retain royalty rate reductions and that all active BLM leases with reduced rates will retain these reduced rates in the future (and not be subject to higher royalty rates as a result of reform).

Data on coal extracted from individual federal leases are withheld, making it difficult to determine what volume of coal is extracted from leases with and without royalty rate reductions. An estimate of these volumes is important because it indicates what share of coal extracted from federal leases will pay higher royalty rates in the future. Without lease-specific coal production data, we use information about the total amount of coal sold when the lease was first offered (a measure of the total volume of coal associated with the lease) as a proxy for annual production. Each federal coal lease is assumed to produce a share of total annual coal production equal to its relative size in terms of the total volume of coal leased with all active federal coal leases.

Table 5 shows that, on average, Scenario 1 would have increased the reported federal coal royalty rate from 10.7 percent to 14.2 percent had higher statutory rates been in effect during 2010-2014. Scenario 2 would have increased the reported federal coal royalty rate from 10.7 percent to 16 percent during the same period. The increase in the reported federal coal royalty rate would have been largest in Wyoming (an increase from 12.3% to 16.3% and 18.3% respectively). Scenarios 1 and 2 would have resulted in average additional federal royalty costs of $0.57 and $0.86 per ton, respectively, during 2010-2014.

By comparison, Table 5 also shows that average reported royalty rates for federal natural gas production would have risen from 10.8 percent to 14.4 percent and 16.2 percent for the two scenarios respectively during 2010-2014.

Table 5: Coal and Natural Gas Average Royalty Rates and Average Royalty Cost Estimates under Two Royalty Rate Scenarios, 2010-2014

Region	Average Reported Royalty Rate			Average Royalty Cost ($/ton/mcf)		
	Current (12.5%)	Scenario 1 (16.67%)	Scenario 2 (18.75%)	Current (12.5%)	Scenario 1 (16.67%)	Scenario 2 (18.75%)
Coal						
Alabama	7.3%	9.7%	10.9%	$3.78	$5.05	$5.68
Colorado	5.8%	7.1%	7.8%	$2.58	$3.16	$3.45
Kentucky	7.6%	10.1%	11.4%	$6.90	$9.20	$10.35
Montana	11.7%	15.6%	17.5%	$1.91	$2.55	$2.86
New Mexico	5.1%	6.0%	6.5%	$2.60	$3.09	$3.33
North Dakota	2.2%	2.4%	2.4%	$0.41	$0.44	$0.45
Oklahoma	2.6%	3.1%	3.3%	$1.47	$1.73	$1.86
Utah	7.0%	9.0%	10.1%	$2.72	$3.53	$3.93
Wyoming	12.3%	16.3%	18.3%	$1.63	$2.16	$2.43
All Federal Coal	**10.7%**	**14.1%**	**15.8%**	**$1.73**	**$2.28**	**$2.56**
All Federal Gas	**10.8%**	**14.4%**	**16.2%**	**$0.43**	**$0.57**	**$0.64**

Estimating Effective Royalty Rates

The average reported royalty rates calculated above are one measure of royalty costs paid by federal lessees. But the reported rate does not provide a good basis for estimating how new royalty costs might affect competition between coal and natural gas in electric power markets. The effective royalty rate is a better metric to both compare royalty costs for coal and natural gas and as a fair way to compare how increased royalty costs will impact the two resources. The effective royalty rate measures royalty costs per unit (ton or mcf) as a share of the total cost of delivering coal and natural gas to electricity generating facilities.[10]

Table 6 shows that federal royalty costs currently make up a larger share of the total cost of delivering natural gas to domestic power generators when compared to coal (9.3% and 4.2%, respectively). The difference is the outcome of royalty rate reductions, which are more prevalent for federal coal leases, and the fact that transportation costs between coal mines and power plants are a larger share of total delivered costs than are transportation costs between natural gas wellheads and natural gas-fired power plants.

Table 6: Change in Effective Royalty Rate for Royalty Rate Increase Scenarios, 2010-2014

		Current 12.5% Royalty Rate		Scenario 1: 16.67% Royalty Rate		Scenario 2: 18.75% Royalty Rate	
	Gross Delivered Price ($/ton/mcf)	Revenue ($/ton/mcf)	Effective Royalty Rate	Revenue ($/ton/mcf)	Effective Royalty Rate	Revenue ($/ton/mcf)	Effective Royalty Rate
Coal							
Alabama	$85.95	$3.78	4.4%	$5.05	5.8%	$5.68	6.5%
Colorado	$59.19	$2.58	4.4%	$3.16	5.3%	$3.45	5.7%
Kentucky	$78.33	$6.90	8.8%	$9.20	11.4%	$10.35	12.7%
Montana	$33.41	$1.91	5.7%	$2.55	7.5%	$2.86	8.3%
New Mexico	$42.36	$2.60	6.1%	$3.09	7.2%	$3.33	7.7%
North Dakota	$19.09	$0.41	2.1%	$0.44	2.3%	$0.45	2.3%
Oklahoma	$40.58	$1.47	3.6%	$1.73	4.2%	$1.86	4.5%
Utah	$46.27	$2.72	5.9%	$3.53	7.5%	$3.93	8.3%
Wyoming	$34.62	$1.63	4.7%	$2.16	6.2%	$2.43	6.9%
All Federal Coal	**$41.33**	**$1.73**	**4.2%**	**$2.28**	**5.4%**	**$2.56**	**6.1%**
All Federal Gas	**$4.63**	**$0.43**	**9.3%**	**$0.57**	**12.0%**	**$0.64**	**13.2%**

Table 6 shows that if statutory rates are increased, natural gas will see its already larger royalty costs (as a share of total delivered costs) rise by a disproportionate share—from 9.3 percent to 12 percent and to 13.2 percent for Scenarios 1 and 2, respectively. Coal will see royalty costs grow from 4.2 percent of gross delivered prices to 5.4 percent and to 6.1 percent for Scenarios 1 and 2, respectively.

Estimating the Additional Costs Associated with Valuation Reforms

In a previous Headwaters Economics report, we estimated that valuation reforms could increase the cost of delivering federal coal extracted from Wyoming to domestic power plants by up to $0.30 per ton, averaged across all federal coal sales to the electric power sector from within the state.[11] Wyoming accounted for 85 percent of all coal extracted from federal leases and nearly all of this coal (98%) was shipped to the electric power sector during 2010-2014.[12] The Office of Natural Resources Revenue (ONRR) estimates that valuation reform could increase federal natural gas royalty costs by an average of 0.1 percent nationally.[13]

Reforms to federal coal and natural gas valuation would increase royalty costs by changing the way coal sold through non-arm's length sales are valued for royalty assessment. Royalties are levied on the gross commodity value of coal and natural gas received by the lessee from the first sale at arm's length to an unaffiliated customer. When natural gas and coal is first sold to affiliated companies through a non-arm's length (captive) transaction, ONRR applies a series of five benchmarks to audit that the price and royalty payment reported to the agency by the lessee is fair. For coal, the proposed rule would eliminate these benchmarks and instead use gross proceeds from the first arm's-length transaction (or the affiliate resale price) less deductible transportation costs as the basis for royalties. For natural gas, the proposed rule would use the first arm's length transaction, index prices, or weighted average natural gas pool prices to value natural gas sold through non-arm's length transactions.[14]

U.S. Energy Information Administration (EIA) data also shows domestic coal delivered to electric utilities is increasingly sold first through a captive transaction to affiliated companies, suggesting reforms would result in higher royalty costs. In 2013, about one-third of domestic coal sales from Wyoming mines (130.6 million tons) were sold through captive transactions, up from only four percent of sales in 2004.[15] In 2013, at least one-fifth of coal delivered from Wyoming mines to out of state electric utilities was sold first to affiliated companies through captive transactions—about 90 million tons. The ONRR rule would increase the royalty cost for captive sales if the affiliate resale price that would be used for royalty valuation under the proposed rule is higher when compared to the price the coal was originally traded to the affiliate from the parent company that is currently used for royalty valuation.[16]

Taken together, increased royalty rates and valuation reforms would apply higher royalty rates to a higher commodity price for all non-arm's length sales where affiliated logistics companies resell coal at a higher price than the price they purchased coal from the parent mining company. The opposite is also true: if affiliate logistics companies lose money on the resale of federal coal, valuation reforms could result in lower royalty costs.

Table 7 shows that combined royalty rate and valuation reforms could increase average effective coal royalty rates up to 8 percent for federal coal extracted from Wyoming and delivered to the electric power sector and up to 6.9 percent on average for all federal coal delivered to the electric power sector. These average effective coal royalty rates are about a percentage point higher when compared to the average effective coal royalty rates reported in Table 6 that would result from increased royalty rates alone. The additional effect of valuation reforms on federal natural gas would be lower, raising the average effective natural gas royalty rate by only 0.1 to 0.2 percent for Scenarios 1 and 2 respectively. The total impact of combined federal royalty reforms would still be relatively larger for natural gas when compared to coal.

Table 7: Change in Effective Royalty Rate for Royalty Rate Increase Scenarios with Valuation Reform, 2010-2014

	Gross Delivered Price ($/ton/mcf)	Current 12.5% Royalty Rate Revenue ($/ton/mcf)	Current 12.5% Royalty Rate Effective Royalty Rate	Scenario 1: 16.67% Royalty Rate Revenue ($/ton/mcf)	Scenario 1: 16.67% Royalty Rate Effective Royalty Rate	Scenario 2: 18.75% Royalty Rate Revenue ($/ton/mcf)	Scenario 2: 18.75% Royalty Rate Effective Royalty Rate
Coal							
Alabama	$85.95	$3.78	4.4%	$5.05	5.8%	$5.68	6.5%
Colorado	$59.19	$2.58	4.4%	$3.16	5.3%	$3.45	5.7%
Kentucky	$78.33	$6.90	8.8%	$9.20	11.4%	$10.35	12.7%
Montana	$33.41	$1.91	5.7%	$2.55	7.5%	$2.86	8.3%
New Mexico	$42.36	$2.60	6.1%	$3.09	7.2%	$3.33	7.7%
North Dakota	$19.09	$0.41	2.1%	$0.44	2.3%	$0.45	2.3%
Oklahoma	$40.58	$1.47	3.6%	$1.73	4.2%	$1.86	4.5%
Utah	$46.27	$2.72	5.9%	$3.53	7.5%	$3.93	8.3%
Wyoming	*$34.92*	*$1.93*	*5.5%*	*$2.56*	*7.2%*	*$2.88*	*8.0%*
All Federal Coal	***$41.63***	***$1.98***	***4.8%***	***$2.62***	***6.2%***	***$2.93***	***6.9%***
All Federal Gas	***$4.63***	***$0.43***	***9.4%***	***$0.58***	***12.1%***	***$0.65***	***13.4%***

Timing of Royalty Rate Increases

Our analysis so far has relied on actual coal production, prices, and royalty collections during the period 2010-2014 to estimate the relative size of the royalty cost increase for federal coal and natural gas, assuming they are fully implemented. In practice, higher royalty rates would be phased in gradually as new coal and natural gas leases are sold, or as existing leases require readjustment. Federal leases generally require readjustments every 10 years (some federal leases only require readjustments every 20 years).

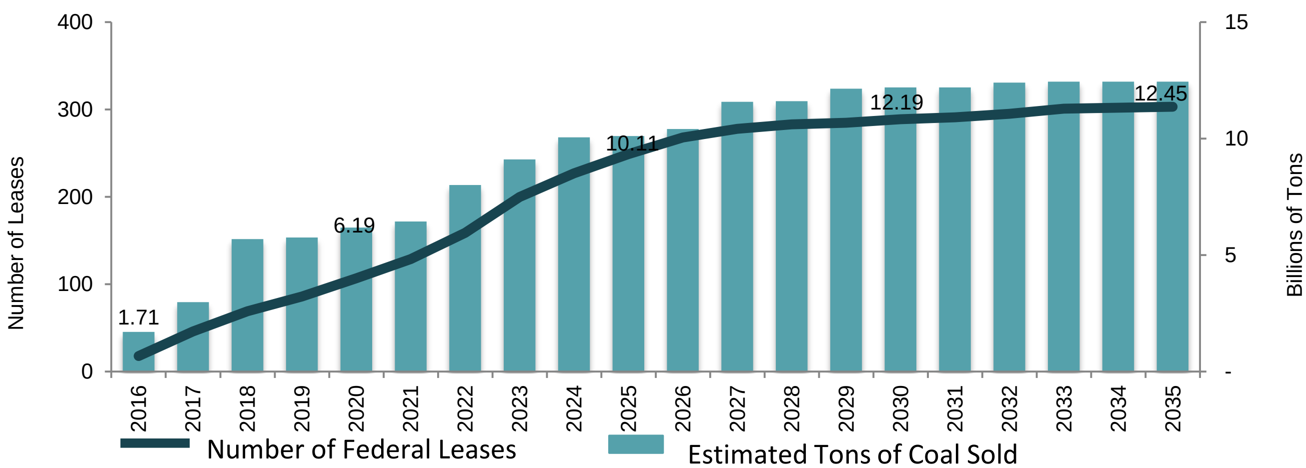
Table 7 shows the number of leases up for readjustment in each of the next 20 years, beginning in 2016, and the number of leases with and without approved royalty rate reductions.[17] Figure 1 shows the total estimated volume of coal (total tons offered) associated with federal coal leases as they require readjustment. The volume of coal that requires adjustment in each year is one estimate of the share of annual production from these leases that will likely have to pay higher royalty rates. The fact that royalty rate reforms will likely be phased in over time will lessen the impact of higher royalty costs on federal lessees.

Data are from a variety of BLM sources that we have compiled into a single database and make available at: http://headwaterseconomics.org/wphw/wp-content/uploads/data-outcomes-higher-coal-naturalgas-royalties.xlsx.

Table 8: Federal Coal Lease Readjustment Schedule

Year	Cumulative Leases Requiring Readjustment With Active Royalty Rate Reduction	Cumulative Leases Requiring Readjustment, No Royalty Rate Reduction	Total Leases Requiring Readjustment	Share of Leases with Active Royalty Rate Reductions
2016	1	20	21	5%
2017	11	45	56	20%
2018	15	61	76	20%
2019	17	75	92	18%
2020	25	89	114	22%
2021	34	112	146	23%
2022	43	144	187	23%
2023	49	173	222	22%
2024	52	194	246	21%
2025	53	211	264	20%
2026	59	233	292	20%
2027	60	237	297	20%
2028	60	239	299	20%
2029	60	243	303	20%
2030	60	245	305	20%
2031	60	249	309	19%
2032	60	255	315	19%
2033	61	255	316	19%
2034	61	256	317	19%
2035	61	256	317	19%

Figure 2: Readjustment Date for Federal Coal Leases and Estimated Volume of Coal Sold (Billion Tons)



Potential Sources of Error

Assessing the federal coal royalty program is limited by a lack of transparency. Data on sales volumes, sales values, and federal royalty revenue from individual federal coal leases is withheld to protect proprietary company data. Data is only available aggregated to the state level. The lack of data for federal leases may introduce error into our estimates of average royalty costs and effective tax rates.

For example, average effective royalty rates are calculated by dividing state average royalty revenue by the average price of coal delivered from the same state to power plants across the U.S. State average royalty costs are based on total federal deliveries to all markets—including sales to the electric power sector and higher-value industrial, commercial, and export markets—aggregated to the state level. By comparison, the gross delivered price is only for deliveries to the electric power sector. As a result, the effective royalty rates for federal coal will be overstated (because royalty revenue is too high).

Additionally, estimating the volume of federal coal that will pay higher statutory rates is limited because we do not have production data for leases that have and do not have royalty rate reductions; the average gross delivered price is for coal deliveries based on all coal sales from a state may be higher or lower when compared to coal deliveries only from federal leases within the same state (for example, federal coal may be of relatively poor quality, on average, when compared to all coal extracted from a state).

Understanding potential sources of error is important for several reasons. First, it demonstrates where additional information could improve understanding of the federal coal royalty program. Second, recognizing potential error helps understand the accuracy of results. It is important to recognize that the results are averages for all federal resources extracted from a state (in the case of coal) or nationally (in the case of natural gas). It is also important to understand that these average results may be too high or too low for a variety of reasons. However, the finding that the effective royalty rate is higher for natural gas when compared to coal, or that reforms will increase this effective royalty rate by a larger amount for natural gas compared to coal are unlikely to be incorrect, only the relative size of the change is in question.

Discussion

Our finding that federal royalty reforms will raise the cost of delivering federal natural gas to domestic power plants by a greater amount when compared to coal warrants further discussion. In this section, we explore in more detail why higher royalty costs are unlikely to result in reduced federal coal production.

Coal increasingly is being replaced by natural gas in U.S. domestic electric power markets. In 2013, coal production fell below one billion tons annually for the first time in 20 years.[18] By 2015, natural gas surpassed coal as the leading source for domestic electric power generation for the first time ever.[19] Some analysts see this trend continuing. For example, UBS (a global financial services firm) recently projected a decline in U.S. coal consumption of 22 percent by 2020 and 49 percent by 2030. These projections are based on current market trends, primarily driven by persistent low natural gas prices. UBS predicts that demand for coal would decrease further if the Clean Power Plan carbon targets are fully implemented and if renewables accelerate faster than expected.[20]

Our finding that comprehensive federal royalty reforms will not likely cause electric power plants to prefer additional switching from coal to natural gas should ease concerns that royalty reform will negatively affect coal-dependent states and communities. Previous research shows that small changes in the cost of delivering coal to the domestic power sector when compared to natural gas will have little to no effect on domestic energy markets.[21] The opposite is also true—a small price advantage for coal relative to natural gas is unlikely to result in significant new demand for coal production.

Another concern is that higher federal rates could drive substitution between federal and non-federal coal leases in Wyoming and Montana (where the large majority of federal coal is produced), or between federal coal leases in these states and non-federal coal leases in other states. We do not expect this to occur for several reasons. First, natural gas already pays higher royalty rates on state-owned lands in Montana and Wyoming and in other states (with natural gas royalties ranging from16.67% to 25%).

Second, Wyoming and Montana have typically applied federal coal royalty rates to state coal leases. We expect this to continue because of the dominant ownership position of the federal government. State and privately owned coal is typically interspersed within larger BLM holdings, and it is difficult, particularly for large existing mines, to substitute non-federal resources to avoid higher royalty costs.[22]

Third, little substitution is expected across states from federal to non-federal coal basins. The Powder River Basin (PRB), where the coal resource is predominantly federally owned, is expected to maintain a cost advantage over other U.S. coal basins due to inexpensive mining costs and transportation rates.[23] Further, substitution between basins is expensive due to the different heat and pollution characteristics of coal in different regions of the U.S. and the costs associated with retooling boilers and pollution control equipment installed in existing coal-fired power plants to handle these different qualities.[24]

The last mitigating factor is that royalty reforms would not take effect immediately. Given the long timeline it will take to phase in higher royalty rates and the slow pace of change in the capital-intensive electric power sector, few significant changes should be expected in the short-term beyond coal-fired power plant retirements already planned.

Increased transparency of the federal royalty program is a stated goal of proposed federal reforms and an important goal of our work. To that end, we make data on federal coal leases we utilize in this report and our analysis of it available to the public. We compile and organize data from a variety of federal sources, estimate data gaps, and do additional calculations that improve access to and understanding of current federal coal leases. A downloadable spreadsheet is available on our website at: http://headwaterseconomics.org/wphw/wp-content/uploads/data-outcomes-higher-coal-naturalgas-royalties.xlsx.

Endnotes

[1] See for example "Secretary Jewell Offers Vision for Balanced, Prosperous Energy Future," *U.S. Department of the Interior Press Release*, March 17, 2015, https://www.doi.gov/news/pressreleases/secretary-jewell-offers-vision-for-balanced-prosperous-energy-future.

[2] The Energy Information Administration projects about 40 coal plants will be retired by 2040 with that number increasing to 90 with new environmental regulations. "Proposed Clean Power Plan would accelerate renewable additions and coal plant retirements." *U.S. Energy Information Administration, U.S. Department of Energy*, June 15, 2015. https://www.eia.gov/todayinenergy/detail.cfm?id=21532.

[3] The overarching finding of a growing body of research is that royalties and severances taxes are effective methods to generate revenue with limited tax burdens. The literature for coal is reviewed briefly in Pearcy, Jason, Mark Haggerty, and Megan Lawson, "Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation," *Social Science Research*, (August 10, 2015): 1-45. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2627865. Literature related to oil and natural gas is reviewed in "Benefiting from Unconventional Oil" *Headwaters Economics*. April 2012. http://headwaterseconomics.org/energy/oil-gas/unconventional-oil-and-north-dakota-communities.

[4] "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, Proposed Rulemaking," *U.S. Department of the Interior, Office of Natural Resources Revenue, Federal Register 30*, RIN 1012-AA13, January 6, 2015: http://www.doi.gov/news/pressreleases/upload/2014-30033_PI.pdf (Accessed November 29,

2015); "Coal; Royalty on Production and Bonding Requirements," *U.S. Department of Interior, Bureau of Land Management*, RIN: 1004-AE42, Spring, 2015, http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201504&RIN=1004-AE42 (Accessed November 29, 2015); "Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessment," *U.S. Department of Interior, Bureau of Land Management*, RIN 1004-AE41, April, 2015, http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.69389.File.tmp/OnshoreOGRoyaltyRateANPR_FinalDraft.pdf. (Accessed November 29, 2015).

[5] The royalty for federal coal has been established by law at 12.5% of the gross value of the coal produced. The 12.5% royalty rate applies to coal severed by surface mining methods. For coal mined by underground methods, the statute provides that the Secretary may establish a lesser royalty rate. By regulation, the BLM requires an 8% royalty for coal severed by underground mining methods. "Coal Operations." *U.S. Department of Interior, Bureau of Land Management*. http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy.html.

[6] "The Impact of Federal Coal Royalty Reform on Prices, Production, and State Revenue," *Headwaters Economics*, May 2015, http://headwaterseconomics.org/energy/coal/coal-royalty-reform-impacts. See also Pearcy, Jason, Mark Haggerty, and Megan Lawson, "Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation," *Social Science Research*, (August 10, 2015): 1-45. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2627865.

[7] "Part 203 – Relief or Reduction in Royalty Rates," *U.S. Code of Federal Regulations, Title 30 – Mineral Resources* 2, July 1, 2009, http://www.gpo.gov/fdsys/pkg/CFR-2009-title30-vol2/xml/CFR-2009-title30-vol2-part203.xml.

[8] "Federal Onshore Reported Sales Value, Sales Volume, and Royalty Revenue, Sales Years 2010- 2014," *U.S. Department of the Interior, Office of Natural Resources Revenue*. http://statistics.onrr.gov/ReportTool.aspx. (Accessed November 29, 2015).

[9] 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 granted to encourage the greatest utilization of federal coal. "Frequently Asked Questions about the Federal Coal Leasing Program: Royalty Rate Reductions." Wyoming Field Office, Bureau of Land Management, U.S. Department of Interior. Accessed September 2014. http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/coalfaqs/royalty_rate_reductions.print.html.

[10] "Coal Shipments to the Electric Power Sector: Price, by Mine State, Annual ($/Short Ton)," *U.S. Energy Information Administration Beta, Coal Data Browser*, http://www.eia.gov/beta/coal/data/browser/#/topic/44?agg=1,0&geo=vvvvvvvvvvvvo&rank=g&linechart=COAL.SHIP_MINE_PRICE.US-TOT.A&columnchart=COAL.SHIP_MINE_PRICE.US-TOT.A&map=COAL.SHIP_MINE_PRICE.US-TOT.A&freq=A&start=2008&end=2014&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0. (Accessed November 29, 2015)

[11] "The Impact of Federal Coal Royalty Reform on Prices, Production, and State Revenue," *Headwaters Economics*, May 2015, http://headwaterseconomics.org/energy/coal/coal-royalty-reform-impacts. See also Pearcy, Jason, Mark Haggerty, and Megan Lawson, "Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation," *Social Science Research*, (August 10, 2015): 1-45. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2627865.

[12] "Domestic Distribution of U.S. Coal by Origin State, Consumer, Destination and Method of Transportation" Annual Coal Distribution Report, U.S. Energy Information Administration, April 16, 2015, http://www.eia.gov/coal/distribution/annual/archive.cfm. (Accessed November 29, 2015).

[13] "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, Proposed Rulemaking," *U.S. Department of the Interior, Office of Natural Resources Revenue, Federal Register 80*, RIN 1012-AA13, January 6, 2015: http://www.doi.gov/news/pressreleases/upload/2014-30033_PI.pdf

[14] For an explanation of the ONRR valuation rule, see "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, Proposed Rulemaking," *U.S. Department of the Interior, Office of Natural Resources Revenue, Federal Register 80*, RIN 1012-AA13, January 6, 2015: http://www.doi.gov/news/pressreleases/upload/2014-30033_PI.pdf; and "The Impact of Federal Coal Royalty Reform on Prices, Production, and State Revenue," *Headwaters Economics*, May 2015, http://headwaterseconomics.org/energy/coal/coal-royalty-reform-impacts.

[15] "Coal Disposition by State, 2013*," Energy Information Administration, Annual Coal Report. Table 8,* http://www.eia.gov/coal/annual/.

[16] For example, Cloud Peak Energy, in their comments to ONRR on the proposed valuation rule, explain how the difference between the mine price used for royalty valuation and delivered prices cannot be wholly explained by deductible transportation costs alone. The difference also includes value added logistics services (including logistics costs and any revenues or losses earned from these activities) provided by affiliated companies. These value added logistics services are not currently deductible from the royalty regulation and would be included in royalty valuation using the first arm's length sale price as proposed by ONRR (performed by the parent mining company directly, marketing and logistics services are not deductible). See Marshall, Coleman, *"*RE: Comments on the Office of Natural Resource Revenue's Proposed Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform," *Cloud Peak Energy, April 29, 2015, Letter to Armand Southall, Office of Natural Resources Revenue, Docket No. ONRR-2012-0004 and RIN No. 1012-AA13,* http://www.onrr.gov/laws_r_d/PubComm/PDFDocs/AA13/Cloud%20Peak%20Energy-FINAL%20Comment%20Letter.pdf; and "Coal Disposition by State, 2013," *Energy Information Administration, Annual Coal Report. Table 8,* http://www.eia.gov/coal/annual/pdf/table8.pdf . (Accessed November 29, 2015).

[17] For leases with renewal dates prior to 2016 we assume they will be grandfathered and only have to pay higher renewal rates at the next renewal. For example, if a lease with a ten year term has the most recent renewal data in 2014, we assume it will pay higher royalty rates starting in 2024).

[18] "Annual Coal Report," *U.S. Energy Information Administration*, April 23, 2015, http://www.eia.gov/coal/annual/. (Accessed November 29, 2015).

[19] Mooney, Chris, "Why Natural Gas is Catching up to Coal in Powering U.S. Homes," *Washington Post*, (October 14, 2015), https://www.washingtonpost.com/news/energy-environment/wp/2015/10/14/why-natural-gas-is-catching-up-to-coal-in-powering-u-s-homes/. (Accessed November 29, 2015).

[20] "US Electric Utilities & IPPs: Pondering the Future Fuel Mix," *UBS Securities LLC, (Revised)*. September 14, 2015.

[21] "Fuel Competition in Power Generation and Elasticities of Substitution," *U.S. Energy Information Administration, U.S. Department of Energy*, June 2012 https://www.eia.gov/analysis/studies/fuelelasticities/pdf/eia-fuelelasticities.pdf. (Accessed November 29, 2015); and "Coal Market Module of the National Energy Modeling System: Model Documentation," *U.S. Energy Information Administration, U.S. Department of Energy*, July 2014. http://www.eia.gov/forecasts/aeo/nems/documentation/coal/pdf/m060(2014).pdf. (Accessed November 29, 2015).

[22] "Powder River Basin Coal Resource and Cost Study," *John T. Boyd Company, prepared for XCEL Energy, Denver Colorado*, September 2011, https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/8-Roberts-Exhibit-No-MWR-1.pdf. (Accessed November 29, 2015).

[23] Gerking, Shelby, and Stephen F. Hamilton, "What Explains the Increased Utilization of Powder River Basin Coal in Electric Power Generation?," *American Journal of Agricultural Economics* 90, no. 4 (2008): 933-950.

[24] Pearcy, Jason, Mark Haggerty, and Megan Lawson, "Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation," *Social Science Research*, (August 10, 2015): 1-45. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2627865.