FEDERAL COAL LEASING MORATORIUM: AN EXAMINATION OF THE REASONS DRIVING A DISRUPTIVE POLICY

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EXECUTIVE SUMMARY

The Department of Interior (DOI) previously rejected the very reasons it now relies upon for the January 15, 2016, Secretarial Order imposing a moratorium on future federal coal leasing. Organizations resurrecting the claims raise unsubstantiated concerns and deploy a combination of incomplete and misinformation to produce a fictional narrative about the revenue and other economic returns to the public through bonus bids, royalties and surface rental fees. The Secretarial Order rests upon the uncritical acceptance of these contrived "fair market value" (FMV) concerns by allowing them to serve as proxies for substituting climate-centric for market-based policies in the management of the nation's largest energy resource.

- The DOI previously rejected a petition from WildEarth Guardians (WEG) requesting abandonment of the lease-by-application (LBA) method for lease sales and the imposition of "carbon fees." In a 2011 decision denying the petition, the Bureau of Land Management (BLM) explained: how the competitive LBA method ensures receipt of FMV; the pace of leasing occurred at generally the same rate as reserve depletion at existing mines; the National Environmental Policy Act (NEPA) analyses for lease sales evaluate greenhouse gas (GHG) emissions; and, imposing a carbon or other externality-based fee would require congressional action authorizing such fees.
- The DOI Inspector General (IG) and General Accountability Office (GAO) reports which play prominently in the rationale for the moratorium did not identify systemic weaknesses in the current leasing system. Each identified some inconsistencies in the application of guidance or documentation for decisions. BLM has addressed those concerns. Specifically, GAO did not repudiate its 2010 finding that the LBA method can achieve the objectives of ensuring fair return to the public. The IG testified before Congress that in her opinion the taxpayers are receiving a fair return from the federal coal program, and in many cases receiving more than FMV. DOI informed members of the U.S. Senate that neither report identified concerns meriting a moratorium on federal coal leasing.

- The absence of more bidders for federal coal leases reflects the restructuring of the industry and the advanced development of the coal regions with federal lands. There are fewer mines and fewer coal companies today then during the period when the regional leasing process commenced in the 1980s. As one would expect, interest in leasing now arises primarily from companies with nearby existing operations seeking to replace coal reserves at roughly their depletion rate.
- The thinner pool of potential bidders has not prevented BLM from identifying accurately the FMV of coal for a lease sale. BLM relies upon peer-reviewed analysis that uses comparative sales. The successful bonus bids under the LBA leasing method have increased at a rate outpacing the increase in coal prices. The most recent bonus bids for coal leases in the Powder River Basin (PRB) are 700 percent higher than those in 1990.
- Abandoning the LBA method of leasing and returning to centralized or regional lease sales is unlikely to attract more bidders or yield higher bids. The earlier system of scheduling lease sales based upon national and regional demand forecasts failed with many tracts receiving one or no bids. The current structure of the coal industry and advanced development of the coal regions suggests an even lower probability that centralized or regional leasing will yield better results than the LBA method.
- The claims that federal royalty rates (12.5 percent surface mines; 8 percent underground mines) do not provide a fair return fail to consider that federal rates are substantially (30 percent to -65 percent) higher than the prevailing rates for private coal in the East. Moreover, private coal lessees rarely, if ever, pay bonus bids or surface rentals.
- Some organizations misuse data or create deceptive metrics for their claim coal producers do not pay the royalty on the market value of the coal. The Mineral Leasing Act imposes a *production* royalty on coal, oil and gas based upon the value as reflected by the sales price of the commodity at the mine or well. These organizations use artificial constructs such as "gross market price" or "full value" by adding to the commodity price the transportation costs incurred by buyers. They advocate moving the point of valuation for calculating the royalty from the sales price received by the coal producer to the point of its use by the buyer. The result is not a production royalty on the market price of the commodity, but rather a federal tax on two separate transactions: coal sales by

the coal producer and transportation services provided by the railroads to the coal buyer.

- Many of the potential policy options listed in BLM's Programmatic Environmental Impact Statement (PEIS) Scoping Notice disguised as measures for ensuring fair return are actually market distorting policies designed to make federal coal uneconomic to mine denying communities, states and all Americans the twin-benefits of coal revenues and access to lower cost and reliable electricity.

The performance of the federal coal leasing program as reflected in DOI's own data exposes the contrived nature of the reasons offered for the leasing moratorium and programmatic review:

- Earlier concerns about speculative holding of leases without production resulting in the enactment of the Federal Coal Leasing Amendments Act (FCLAA) in 1976 have been addressed successfully: the number of leases decreased and coal production increased. Since 1990, both the number of leases and the amount of acreage under lease have decreased substantially (35 percent).
- With the advanced development of the coal regions, coal companies have sought new leases at roughly the rate of depletion of coal at existing operations as predicted by BLM when it shifted to the LBA leasing method.
- Since 2003, total revenues from federal coal leases (bonus bids, royalties, and surface rentals) amount to $13.8 billion; lease revenues in 2014 were twice the amount in 2003; bonus bids have increased substantially (700 percent in the PRB); coal royalty revenue is 88 percent higher despite coal production increasing by only 2 percent; revenue per acre under lease has increased 40 percent despite lower coal prices recently.

The record of performance under the federal coal leasing program confirms the wide gulf between reality and rhetoric with the latter allowing politics to masquerade as policy.

INTRODUCTION – COAL LEASING ISSUES FOR STUDY

On January 15, 2016, The Secretary of the Interior issued Order No. 3338 imposing a moratorium, with limited exceptions, on new federal coal lease sales pending the completion of a Programmatic Environmental Impact Statement (PEIS) that analyzes potential leasing and management reforms to the current federal coal program.

The Secretary's Order references concerns expressed by "stakeholders" as the reason for imposing a moratorium pending a programmatic review. The Order summarizes these concerns under three broad categories:

- Fair Return to the Public: claims that taxpayers do not receive a fair return through bonus bids, royalties and other rental fees. Some claim that the lack of multiple bidders at lease sales precludes the Bureau of Land Management (BLM) from accurately determining fair market value (FMV) even with the use of peer-reviewed analysis for such determinations. Others believe that royalty rates are too low and contribute to low coal prices notwithstanding evidence that federal royalty rates are substantially higher than prevailing rates on private coal leases
- Market Conditions: some stakeholders suggest the federal coal program incentivizes "over-production" contributing to low prices of coal in the market. Others express concern that changes may needlessly raise costs and make federal coal less competitive in the market.
- Climate Change: a general assertion that the current leasing program does not consider the climate impacts of federal coal lease sales and production. Some recommend adjusting royalty rates and surface rentals to account for what they consider "externality" costs.

None of these concerns set forth in the Secretarial Order are accompanied by any independent corroboration or analysis by the Department of Interior (DOI). Rather they all appear to rely uncritically upon a series of advocacy materials prepared by groups associated with missions to reduce the nation's use of its vast hydrocarbon energy resources. This is confirmed by the BLM's subsequent "Notice of Intent to Prepare a PEIS" (81 Fed.

Reg. 17,720) referencing a series of advocacy group materials including:

- Center for American Progress, *Federal Coal Leasing in the Powder River Basin* (PRB) (July 29, 2014)
- Center for American Progress, *Modernizing the Federal Coal Program* (December 9, 2014)
- Center for American Progress, *Cutting Subsidies and Closing Loopholes in DOI Coal Program* (January 6, 2015)
- Headwaters Economics, *An Assessment of U. S. Federal Coal Royalties* (January 2015).

As a consequence, it is perhaps unremarkable that the policy changes BLM's PEIS Scoping Notice set forth for consideration mirror the menu offered by these groups, including:

- Abandon the market-based leasing system and substitute a centralized "climate change" leasing budget with a declining amounts of coal made available over time.
- Raise royalty rates by: including an "adder" for the social cost of carbon; establishing an energy content equivalent rate with oil and gas; or simply charge the same 18.75 percent rate applicable for off-shore oil and gas leases.
- Increase the surface rental fees to include "lost value" of other uses of the land.
- Setting the FMV for bonus bids on federal leases using a "nation-wide" price for coal rather than comparable coal.

The National Mining Association (NMA), with the assistance of Norwest, evaluated the claims that the current coal leasing program is not delivering fair value to the taxpayers as well as the policy suggestions advocated to address the purported shortcomings. Norwest's experience includes preparing FMV studies for coal lease sales and FMV studies in the U.S. and Canada on behalf of banks and mining companies for filing on various stock exchanges. It also includes experience in managing U.S. coal mines with federal coal and familiarity with the process for submitting bids for coal leases, administering federal coal leases and the royalty valuation, payment, and audit processes.

THE FEDERAL COAL LEASING PROCESS

BACKGROUND

Since 1920, the DOI has administered a leasing program that allows the private sector to develop federally owned coal resources. Prior to 1976, leases were issued by two methods: (1) competitively to the highest bidder at a lease sale; and (2) non-competitively to prospectors who discovered commercial quantities of coal reserves and submitted an application for a preference right lease (PRLA). Prior to 1976, half of all leases were issued under the non-competitive PRLA method.

Because many federal coal leases were being held and not developed, Congress amended the Mineral Leasing Act (MLA) by passing the Federal Coal Leasing Amendments Act (FCLAA) of 1976. To encourage the development of federal coal, FCLAA required leases issued after 1976 to produce commercial quantities of coal within 10 years (i.e., diligent development). FCLAA also provided for the combination of separate federal leases as well as non-federal leases into a logical mining unit (LMU) to promote the efficient, economical and orderly development of coal resources.

FCLAA also repealed the non-competitive PRLA method of leasing and required competitive lease sales and payment of FMV for future leases. New royalty rates were established by changing the cents-per-ton royalty to a fractional share of value or ad valorem royalty based upon a percentage of the proceeds received by the lessee for the sale of coal produced.

Competitive Coal Leasing

The Federal Coal Management Program currently provides two methods for competitive leasing: (1) regional leasing, where the Secretary of the Interior selects tracts within a region for competitive sale and (2) the lease by application (LBA), where companies express interest in leasing by submitting an application to nominate lease tracts for competitive bidding. Under both methods, BLM uses peer-reviewed analysis to estimate the FMV of the coal prior to the lease sale.

Since 1990, BLM has shifted from regional leasing to LBA as the primary competitive leasing method. Between 1987 and 1990, the DOI decertified six coal regions it had established under the regional leasing program, citing declining interest in coal leases and poor coal market conditions. With the decertification of the six regions, the LBA method remained in effect so existing mines could add reserves to maintain production at their existing mines.

Fair Market Value

The government is compensated for the coal in three forms: bonus bids, royalties and surface rental fees. Bonus bids are payments made to the federal government by mining companies for the right to mine coal from a federal lease tract. The process includes an assessment by the BLM to estimate the FMV for every lease made available for sale whether through the regional leasing method or the LBA method. This assessment forms the basis for BLM's minimum acceptable bid for each lease. If the bids do not meet or exceed this minimum established by the BLM, all bids are rejected and the lease is not sold at that time.

Bonus bids are paid well before the coal is mined. The bonus bid is non-recoupable with the government retaining the full amount even if all the recoverable coal estimated in the bid is not mined.

Bonus bids are unique to federal coal leases. They are rarely paid on private leases, especially in the Eastern U.S. where coal produced from federal leases competes for market share as fuel for utilities.

Royalties are paid on each ton of coal produced and sold at a rate of 12.5 percent of the value for surface mined coal and 8 percent for underground mined coal. The value is determined by the gross proceeds received by the coal company at or near the mine less allowable deductions for the actual costs of processing, if any. If the transaction includes transportation of the coal to a point of sale remote from the lease, the costs incurred for that transportation are deducted from the gross proceeds.

A surface rental fee of $3 per acre is paid annually for each acre in the entire lease, and the payment continues until the lease is relinquished or terminated.

From 2003 through 2015, the government has received more than $13.8 billion in bonus bids, royalties, and rentals from companies leasing federal coal.[1]

[1] DOI, Office of Natural Resources Revenue (statistical page), http://statistics.onrr.gov/ReportTool.aspx

COMPETITIVE LEASING PROCESS

The DOI offers federal coal resources through two types of competitive leasing methods—regional coal leasing and LBA. Regional coal leasing is initiated by BLM based on its determination of the demand for Federal coal. The LBA process is initiated by an applicant interested in leasing Federal coal. Both leasing methods require: conformance to applicable land use plans, consultation with states and surface management agencies, public hearings, environmental analysis and payment of FMV in the form of a bonus bid.[2].

Under the regional coal sale process intended for areas where new mines are anticipated, BLM makes multiple coal tracts available for sale on the same date based upon anticipated need in view of national and regional markets. LBAs are used in regions where little interest is anticipated in starting new mines and leasing interest arises primarily from the need for replacement of exhausted reserves in order to extend the life of an existing mine. The LBA process is in part an outgrowth of recommendations from the Linowes Commission that DOI leasing policies distinguish between new mine production tracts, mine maintenance tracts and bypass tracts where unleased federal coal would be sterilized, if not mined as part of a nearby operation. [3]

Under the LBA method, the mining companies nominate an area for leasing. They make this determination based on their view of the coal market, the future selling prices, the cost of producing the coal, their existing investment in infrastructure and equipment, the additional capital investment required and whether they believe they can make a profit in mining and selling the coal. The mining companies are taking all the risk. The company has paid for the geologic exploration. They pay a bonus bid and cannot recoup any part of it if they do not mine any or all the coal in the lease. They must develop the lease and begin production of commercial quantities within 10 years or incur the obligation to pay advance royalties to extend the development period or risk forfeiture of the lease.

Apart from an applicant initiating the process with a lease application, DOI remains in complete control of the process. BLM may—and often does—reconfigure the applicant's lease tract by

[2] See 43 CFR Subparts 3420-3425.
[3] Report of the Commission on Fair Market Value Policy for Federal Coal Leasing (Feb. 1984).

adding or subtracting land and reserves.[4] The lease sale is open to any bidder. The process assures competitive bids even in the absence of more than one bidder. BLM estimates the FMV using a peer-reviewed analysis and does not accept any bid that does not meet that value.[5] Those values are not disclosed. BLM has rejected numerous bids that do not meet the FMV determination set by its peer reviewed analysis.[6] In many cases, the bids exceed the FMV determination.[7]

BLM's H-3073 Coal Evaluation Handbook clearly demonstrates that the BLM retains total control over the LBA process.

1.3. Lease-by-Application Process

Determining the pre-sale FMV estimate of a federal coal property is one of many integral parts of the lease-by-application process described in 43 CFR Subpart 3425. The federal coal lease-by-application process involves an extensive procedure that is illustrated by Figure 2.1. The leasing process includes consultation with the State Governor, completion of an environmental analysis under the National Environmental Policy Act (NEPA), review for compliance with established land use plans, review for unsuitability for mining under 43 CFR Subpart 3461, analysis of maximum economic recovery, several opportunities for public outreach, and establishment of the pre-sale FMV estimate.

Once a tract is nominated for leasing, the BLM makes its own assessment of the delineation of the tract and the recoverable tons from their delineation of the tract. Other than the tract delineation, potential bidders are not made aware of the BLM's assessment of the recoverable tons in the tract proposed for leasing. The final determination of the tract delineation and the recoverable tons rests with the BLM.
Factors the BLM considers in delineating a tract include:

- Providing development potential to as many potential bidders as possible.

[4] In fact, in almost every LBA for the PRB, BLM has reconfigured the lease tract from the one preferred by the applicant. See BLM Jan. 28, 2011 Letter to WildEarth Guardians.
[5] BLM Handbook, H-3070-1, *Economic Evaluation of Coal Properties*.
[6] See Table 2.1 (BLM rejecting 45 percent of the high bids for PRB lease sales between 1992-2012.
[7] See H.R. Rep. No. 29, 112th Cong. 1st Sess. 47 (July 9, 2013) (statements of Rep. Steve Daines and Dep. Inspector General for DOI Mary Kendall).

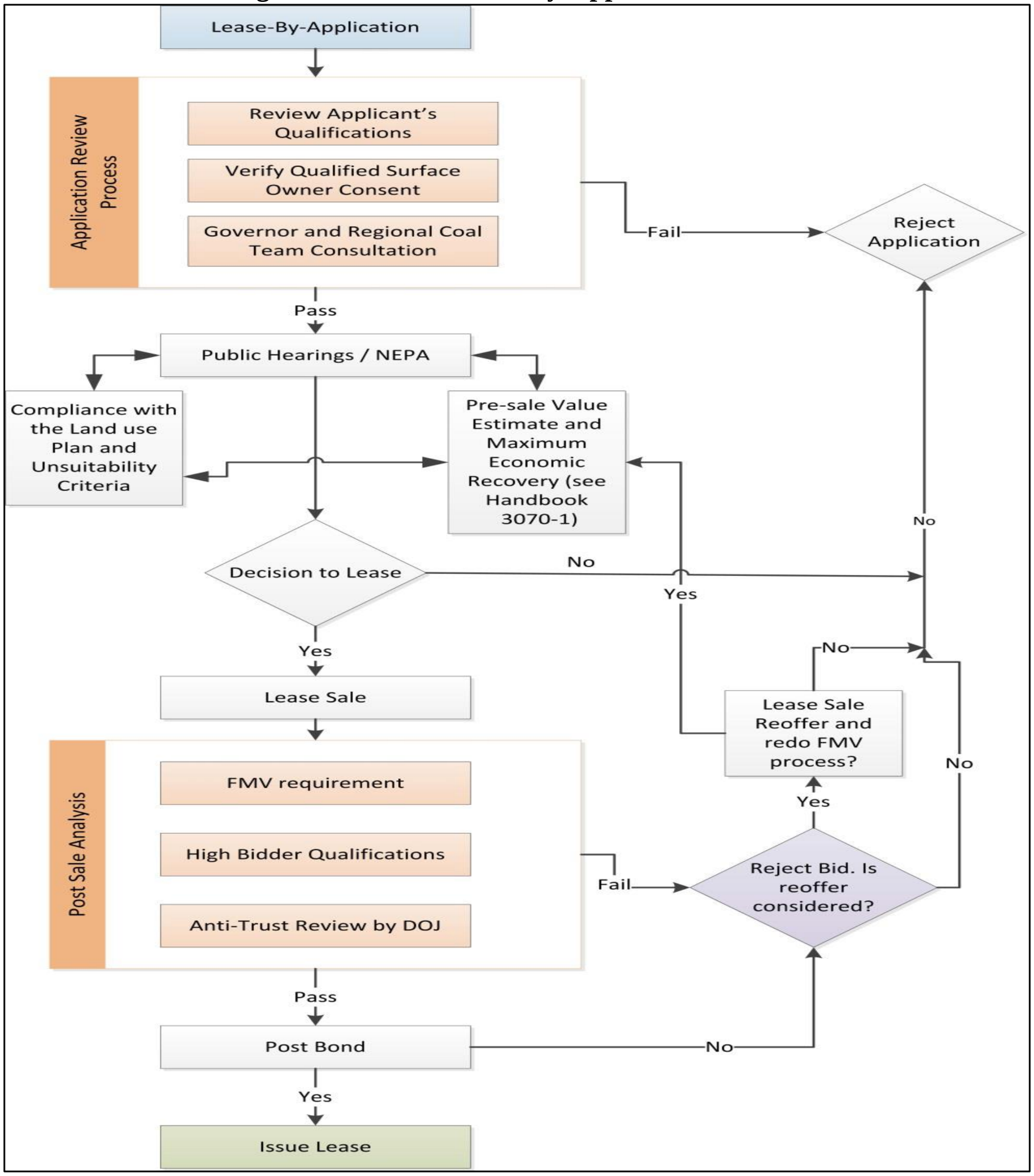
- Encompassing as much federal coal as possible that can currently be economically developed and assure consistent application of maximum economic recovery (MER) principles.
- Accommodating other prior existing rights, resource requirements, or land use planning requirements.
- Not allowing any portion of the coal deposit to be stranded into isolated tracts that are too small to be economically developed independently or in combination with other adjoining mining operations.
- Assuring that all economically recoverable federal coal resources outside of a tract configuration may be efficiently mined by other adjoining or future mining operations.

The high bid and high bidder are evaluated to determine:

- If the bid meets or exceeds the pre-sale FMV estimate (43 CFR 3422.1(c)(1));
- If the high bidder is qualified to hold a federal coal lease (43 CFR Subpart 3472);
- If the Department of Justice (DOJ) review of the high bidder's assets comply with antitrust requirements (43 CFR 3422.3-4).

The flowchart in the BLM Handbook (Fig. 2.1) shows that the LBA method provides several check points where the BLM may choose not to proceed with the lease sale. The mining company that proposed the lease for sale has no control or influence over that decision apart from the bid it offers if a sale is scheduled.

Figure 2.1 Federal Lease-By-Application Process



ESTABLISHING FAIR MARKET VALUE

Under the Mineral Leasing Act as amended, the DOI cannot sell a lease unless the bid meets or exceeds the FMV as determined by the DOI.

Prior to any lease sale the DOI estimates the FMV of the proposed lease tract using peer reviewed analysis. This requirement applies to both regional coal sales and LBAs.[8] The BLM Coal Evaluation Handbook[9] (the Handbook) requires preparation of the FMV estimate by a team of qualified persons including a geologist, a mining engineer, an economic and market specialist and a mineral evaluation analyst. It sets out the qualifications and experience for the team members and the role each plays in preparing the FMV. The team can be completely comprised of BLM employees or can include contractors that meet the same qualifications of BLM employees.

The Handbook also prescribes the process and tasks to be undertaken by the Evaluation Team. This includes a comprehensive data collection and analysis process covering the environmental assessment from the NEPA process, tract configuration data, geologic data, engineering and operating cost data, general economic data, domestic coal market data, export coal market data, specific lease tract economic data and lease specific comparable sales data.

The Myth: LBA Sales Do Not Yield Fair Market Value

The oft-repeated myth that the LBA competitive leasing method does not ensure the public receives FMV through bonus bids finds it roots in WildEarth Guardians' (WEG) paper "Under Mining the Climate,"[10] claiming that:

"In the Powder River Basin, the "decertification" and use of the "Lease by Application" process has severely diminished competition for coal. In the last 20 years, the BLM has offered 21 "Leases by Application" for sale in the PRB.

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[8] See 43 CFR 3422.1 and 343425.4(b) (referencing FMV requirements of 3422 for LBAs).

[9] BLM Manual Handbook 3073 (10/02/2014) (http://www.blm.gov/style/medialib/blm/wo/Information_Resources_Management/policy/blm_handbook.Par.58766.File.dat/H-3073.pdf).

[10] Nichols, J., "Under Mining the Climate, The Powder River Basin of the West: Key to Solving Global Warming," Nov. 23, 2009).

During this time, there have been only three sales where more than one company has bid on a coal lease.[11]

The WEG Report was the basis for a petition requesting the Secretary to abandon the LBA methods and reinstitute the regional coal leasing method.[12] On January 28, 2011, DOI denied WildEarth Guardians' petition, finding that:

- Leasing had occurred at "essentially the same rate as reserves have been depleted" and "no new mining operations" had opened since decertification.
- The LBA process was conducive to "maintenance leasing," under which existing operations expand into adjacent tracts as reserves are depleted "without leaving tracts un-leased and undeveloped."
- The regional leasing process could result in a "reduced return to the public from coal sales (due to timing), a higher potential for bypass . . . , and forced emergency leasing."
- Lease "sales are always competitive" under either leasing process "because the BLM sets a [fair market value] . . . and will not accept any bid that does not meet that value."
- The LBA process requires the agency to conduct environmental analyses in connection with specific lease sales, including a "cumulative impact analysis [that] evaluates the contribution of the site-specific alternatives to cumulative effects on the environment."[13]

WEG appealed DOI's denial of the petition. The United States District Court for the District of Columbia dismissed WEG's appeal and made the following observations:

(1) Both the regional leasing process and the lease-by application process are forms of competitive leasing;
(2) Both are an open, public and competitive sealed-bid process; and

[11] *Id*. at 17 (Table 4).
[12] WEG Nov. 23, 2009 Petition to BLM
[13] BLM Jan. 28, 2011 Decision available at http://www.wildearthguardians.org/site/DocServer/BLM_Director_response_Jan_28_2011.pdf.

(3) Both preclude issuing a coal lease if the highest bid does not meet or exceed fair market value.[14]

Similar claims have been rejected repeatedly by the courts in the context of challenges to specific lease sales.[15]

Neither the Secretarial Order nor BLM's PEIS Scoping Notice directly repudiate the reasoning for rejecting WEG's claims. Both merely repeat these previously discredited claims as "concerns" raised by stakeholders, but fail to provide any analysis to validate the claim fair market value is not obtained under the LBA method or that the policy changes offered would produce more or higher bids.[16]

Critics of the LBA method assume, without any explanation, that in the absence of multiple bidders, lease sales are not capable of producing bonus bids at FMV. Their premise presumably is that competition among more bidders will bid the transaction value up to what economists may refer to as the fundamental value. This might be true in theory, but in reality many mineral asset and lease sales are successfully transacted for FMV with a single buyer.

The aim of FMV is finding the transaction price that would most likely be negotiated between a typical buyer and seller each having reasonable but not absolute knowledge of the reserve. Comparable sales produce fair market valuations because they measure transaction values. The comparable sales method is the preferred method of valuation by the BLM when reliable market and sales data are available.

The Handbook follows a sequential method using the comparable sales approach and the income approach to determine the FMV estimate. The comparable sales approach is the preferred method in the Handbook but it by no means limits the valuation to that

[14] WildEarth Guardians v. Salazar, Slip Op. at 3, CA No. 11-000670 (CKK) (D.D.C. May 10, 2012). Accord WildEarth Guardians v. Salazar, 783 F. Supp. 2d 61 (D.D.C. 2011) (holding that nothing in the Mineral Leasing Act or its implementing regulations require DOI to recertify a coal production region).

[15] . See., e.g., *WildEarth Guardians v. Salazar*, 880 F. Supp. 2d 77 (D.D.C. 2012), aff'd *WildEarth Guardians v. Jewell*, 738 F. 3d 298 (D.C. Cir. 2013); *WildEarth Guardians v. Salazar*, 783 F. Supp. 2d 61 (D.D.C. 2011); *Western Organization of Resource Councils v. Jewell*, Civ. No. 14-1993 (RBW) (D.D.C. Aug. 27, 2015); *WildEarth Guardians v. U.S. Forest Service*, Civ. No. 12-CV-85 ABJ (D. Wyo. Aug 17, 2015).

[16] *Compare* Sec. Order 3338 at 3 and 81 FR 17720, 17725 (March 30, 2016) (given concerns about the lack of competition, BLM will examine issues of when to lease) *with* Center for American Progress, "Modernizing the Federal Coal Program," (Dec. 10, 2014) (coal leasing program not competitive since decertification of coal leasing regions).

method. If the analysis of comparable sales proves inadequate to provide a well-documented valuation report, the Handbook requires that the income approach be used. The Handbook is consistent with mineral valuation and appraisal methods used throughout the minerals industry both domestically and internationally.

Several advocacy organizations have criticized the comparable sales method, claiming it perpetuates the values based on what they characterize as previous below market values by using them as a basis for future sales. In reality, when properly applied as prescribed by the Handbook, the method accounts for the passage of time and changed market conditions. The Handbook requires that the analysis of comparable sales include:

- Engineering and geologic conditions
  - *Time elapsed since sale*
  - *Current market conditions compared to previous sale*
- Terms of sale
  - *Coal characteristics*
- Access to and transportation of the resource.

In other words, BLM’s evaluation procedure provides that comparable sales be evaluated and adjusted as necessary to account for the passage of time, changes in market conditions, as well as differences in the coal characteristics between the property and earlier lease sales. If the evaluation team determines that the resulting value is not representative or cannot be defended, then the income approach is used to estimate FMV.

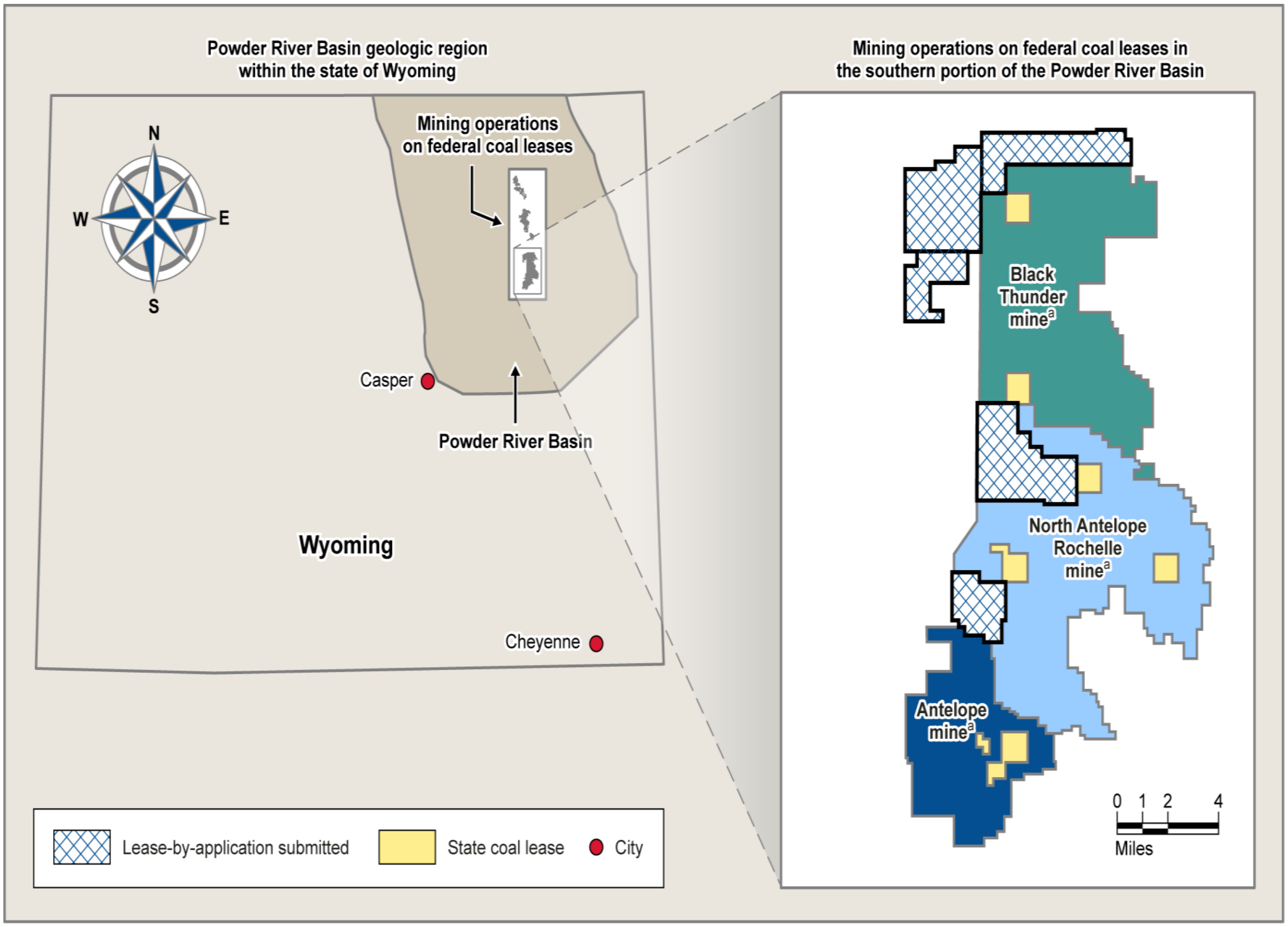
As coal producing regions matured with existing federal coal leases moving from exploration to development stage and eventually to production properties, expressions of interest in leasing federal coal for new stand-alone mines diminished. The last new mine started on a PRB federal coal lease occurred in 1982. The existing capital investments in large scale and long-lived mining complexes including transportation infrastructure poses a hurdle for the entry of a successful new stand-alone mine. As a consequence, future interest in leasing largely arises from mines seeking to extend the life of existing operations in an orderly manner.

These structural realities explain why fewer multiple bids occur in lease sales in mature coal regions. Many of the single bid lease sales involve lease tracts adjacent to an existing mine operation. In those cases, the adjacent mine operator has an advantage over other operators in that he can use existing investment in equipment and infrastructure to more efficiently mine the tract. Another operator would be required to make significant investments in equipment and infrastructure to mine the same tract as a stand-alone mining operation. The magnitude of the required investment, depending on the amount and quality of recoverable reserves, is in the hundreds of millions of dollars which, in turn, reduces the amount another bidder can pay for the lease and still remain competitive with nearby mines. A lessee with an existing adjacent mine would more likely bid higher for the tract than an operator who would also have to make a more sizable capital investment to build and operate the tract as a new mine.

The map below (Figure 2.2) from the Government Accountability Office (GAO) Report on Coal Leasing (2013) illustrates the practical and economic realities of coal leasing in a mature coal leasing region. As GAO explained:

[T]racts submitted for lease-by-application that are north and west of the Black Thunder mine are less likely to be bid on by the operators of the North Antelope Rochelle or Antelope mines. This is because it would be too costly and take significant time for these mine operators to move their heavy equipment to extract coal from these lease tracts, which are not directly adjacent to their existing operations. In contrast, the lease tracts that are located between two mines are more likely to be bid on by multiple mine operators, according to BLM officials.

Figure 2.2 Powder River Basin Coal Operations on Federal Coal Leases



Source: GAO analysis of BLM information.

The BLM addresses this economic reality in its fair market analysis. These tracts, described in the Handbook as Type 3 Tracts, are valued based on the incremental value to the existing mining operation and not on its "stand-alone" value to the federal government. The value is determined by either comparable sales or an income approach if that proves more reliable. The income approach calculates a net present value of the mine including the adjacent lease and a net present value of the mine without the adjacent lease. The difference in the two net present value calculations is used by the BLM as the value of the adjacent lease to the mine operator and sets that as the minimum bid. The effect of this provision is that the minimum acceptable bid is higher for this type of tract than for a tract that must be developed as a new stand-alone mine operation.[17]

Center for American Progress (CAP) and other reports claiming the LBA method does not produce FMV for bonus bids are devoid of any discussion or analysis of BLM's appraisal process or methods. They simply rely on a talking point about the lack of multiple bids and using that unremarkable observation, but no analysis, argue the LBA method should be abandoned and replaced with the former regional sales. As the experience under the former regional sales process reveals, CAP is unlikely to be satisfied with that outcome if its concerns are authentically about the public receiving a fair return.

Similar Results Under Regional and LBA Methods

The bidding experience, under the LBA method, is similar to that under the regional sales method. Table 2.1 below provides more complete information as compared to the WEG Report. Table 2.1 includes the tracts for which more than one sale was held and sales for which there was more than one bidder. BLM received more than one bidder on 5 of the 27 tracts (19 percent) leased since decertification of the PRB in 1990. Moreover, 7 of the remaining 22 tracts (32 percent) were subject to multiple (two or more) sales to ensure BLM received bids that met or exceeded the fair market estimate. Combined, 12, or 45 percent, of the tracts leased since 1990 received either multiple bidders or multiple sales.

[17] BLM Manual Handbook 3073 (10/02/2014) (http://www.blm.gov/style/medialib/blm/wo/Information_Resources_Management/policy/blm_handbook.Par.58766.File.dat/H-3073.pdf).

Table 2.1 Wyoming PRB Successful Federal Coal Lease Sales (as of 10/21/2015)

Mine Name	Successful Bid	Lease Effective Date	Bid $/Ton	Total Bonus Bid	Tons
Jacobs Ranch	Kerr McGee	1992	0.1250	$20,114,930	161,216,060
W. Black Thunder	ARCO	1992	0.1680	$71,909,283	429,048,216
N. Antelope/Rochelle	Peabody	1992	0.2160	$86,987,765	403,500,000
W. Rocky Butte	MT Power - Bid Rejected		0.2600	$14,200,000	55,000,000
W. Rocky Butte	MT Power (Second Sale)	1993	0.3000	$16,500,000	55,000,000
Eagle Butte	RAG	1995	0.1110	$18,470,400	166,400,000
Antelope	Kennecott - Bid Rejected		0.1101	$6,645,045	60,364,000
Antelope	Antelope-Kennecott (Second Sale)	1997	0.1500	$9,054,600	60,364,000
North Rochelle	Zeigler - Bid Rejected		0.1700	$26,800,500	157,610,000
Zeigler (Second Sale)	Zeigler (Second Sale)	1998	0.1940	$30,576,340	157,610,000
Powder River	Peabody	1998	0.2060	$109,596,500	532,000,000
Thundercloud	Kerr McGee - Bid Rejected		0.3012	$124,113,546	412,000,000
Thundercloud	Arch Coal (Second Bidder)	1999	0.3835	$158,000,009	412,000,000
Horse Creek	Kennecott	2000	0.3300	$91,220,121	275,577,000
North Jacobs Ranch	Kennecott	2002	0.7060	$379,504,652	537,542,000
North Jacobs Ranch	Arch Coal (Second Bidder)		0.6030	$324,007,865	537,542,000
NARO South	Peabody	2004	0.9200	$274,117,684	297,469,000
Little Thunder	Arch	2005	0.8500	$610,999,950	718,719,000
West Hay Creek	Triton	2005	0.3000	$42,809,400	142,698,000
West Antelope	Kennecott	2005	0.7500	$146,311,000	194,961,000
NARO North	Peabody - Bid Rejected		0.7300	$237,464,651	324,627,000
NARO North	Peabody - Second Sale	2005	0.9200	$299,143,785	324,627,000
West Roundup	Ark Land WR, Inc. - Bid Rejected		0.6700	$220,035,392	327,186,000
West Roundup	BTU Western Resources (Second Bidder)	2005	0.9710	$317,697,610	327,186,000
Eagle Butte	West - RAG	2008	0.7080	$180,540,000	255,000,000
Maysdorf	Cordero - Bid Rejected		0.4234	$121,987,050	288,081,000
Maysdorf South	Cordero - (Second Sale)	2008	0.8710	$250,800,000	288,081,000
Maysdorf North	Cordero - Bid Rejected		0.3842	$21,001,419	54,657,000
Maysdorf North	Cordero - Second Sale - Bid Rejected		0.8013	$43,797,200	54,657,000
Maysdorf North	Cordero - Third Sale	2009	0.8800	$48,098,424	54,657,000
West Antelope II	Kennecott - (North Tract)	2011	0.8500	$297,723,228	350,263,000
West Antelope II	Kennecott - (South Tract)	2011	0.8750	$49,311,500	56,356,000
Belle Ayr North LBA	Alpha West - Bid Rejected		0.7820	$173,396,614	221,734,800
Belle Ayr North LBA	BTU Caballo Mine - Second Bidder	2011	0.9500	$210,648,060	221,734,800
West Caballo	BTU Western - Bid Rejected		0.9800	$127,592,080	130,196,000
West Caballo	Alpha West - Second Bidder	2011	1.1016	$143,417,404	130,196,000
South Hillight Field	Ark Land Company	2012	1.3476	$300,001,012	222,676,000
South Porcupine	BTU Western - Bid Rejected		0.9000	$361,647,000	401,830,508
South Porcupine	BTU Western (Second Sale)	2012	1.1100	$446,031,864	401,830,508
North Porcupine	BTU Western	2012	1.1000	$793,270,311	721,154,828
			Totals	**$5,402,855,832**	**7,897,866,412**

During the period BLM used the regional coal leasing method

(1976-1990), only 18 percent of the leases offered received multiple bids. [18] Between 1981 and 1984—the peak period of lease sales—thirty percent of the lease tracts offered did not receive any bids or did not receive bids that met or exceeded BLM's FMV estimate. [19] This experience discloses that the regional coal leasing method did not result in producing more multiple bids than the LBA method.

Centralized Leasing Process Experience

The Secretarial Order suggests the concerns about the number of LBA sales that lacked multiple bidders may require it to "examine whether scheduled sales should be used for federal coal."[20] However, the regional coal leasing experience teaches that using an established schedule limiting when coal will be leased will fare no better than the LBA method in attracting more bidders for a single lease tract.

The dismal results, under the regional leasing method, are a product of a leasing framework that depended upon perfect foresight in anticipating coal demand and, in turn, leasing interest. The DOI's leasing framework was built around centralized planning whereby leasing targets and schedules were established to match the forecasted demand and production estimates by the Department of Energy (DOE). The purpose of the centralized process was to meet the nation's energy needs and foster competition in lease sales.

Because of the great uncertainties surrounding a wide range of factors affecting demand and supply—nationally and regionally—the exercise produced rapidly changing targets year over year.[21] The DOE's 1978 coal demand projections for 1985 and 1990 used to set leasing targets were off by 36 percent and 70 percent, respectively.[22]

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[18] See BLM Reply Brief in *Powder River Basin Resource Council* , 124 IBLA 83 (Sept. 15, 1992) (stating that between 1975-1990 81.5 percent of lease tracts received either one or no bids; and that if the U.S. wishes to sell coal, oil or gas, it simply has to recognize that most tracts do not receive more than one bid).

[19] DOI, Draft Environmental Impact Statement Supplement, Federal Coal Management Program, pp. 17-19 (Feb. 1985).

[20] Sec. Order at 7.

[21] The factors that influence both the demand for coal, and in turn, demand for federal coal leases include: demand for electricity, coal prices, cost of transportation to buyers, coal quality, availability of alternative energy sources, federal and state laws and many of these factors will also vary by coal producing regions.

[22] General Accounting Office, MINERAL RESOURCES, Federal Coal-Leasing Program Needs Strengthening, GAO/RECD-94-10 pp. 42-43 (Sept. 1994).

In the PEIS Scoping Notice, BLM asks whether market conditions should influence the timing of lease sales to assure sales occur when coal values are higher rather than during periods of market downturns in order to potentially generate higher bonus bids. The poor track record for market forecasts and timing under the regional coal sales method strongly advises that similar efforts will be equally unsuccessful. In view of the time between the planning and holding of a lease sale—as well over the life of the operation—market conditions change leaving a low probability that BLM can time the market and sales in a way that would coincide with potential bidders materially changing their opinion about the value of the lease tract. Moreover, BLM should weigh the risk of reducing the net present value of the coal resource—and in turn, the bonus bid received—by delaying a sale in the hopes of timing the market. The GAO has previously dismissed the reasoning behind BLM's suggestion.[23]

There is nothing in the MLA, as amended by FCLAA, requiring that lease sales or leasing levels be tied to projected coal demand or other market conditions. GAO has found that the purposes of the MLA—ensuring receipt of FMV, diligent development and maximum economic recovery of coal -- can be met using the LBA leasing method.[24] Moreover, the MLA's mandate is for the government to receive *FMV*, not maximization of revenues.[25]

LBA Bonus Bid Increases Outpaces Market Prices

The bonus bid trend demonstrates that the LBA method has resulted in higher bids over time especially in coal regions where federal coal dominates the resource base. In the PRB, bonus bids under the LBA method steadily increased by almost 700 percent between 1990 and 2012.[26] In the Colorado Plateau--the second largest basin for federal coal resources-- [27] bonus bids doubled (Utah) and tripled (Colorado) despite the prevalence of deeper coal reserves that must be mined by more expensive underground methods.[28]

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[23] General Accounting Office, MINERAL RESOURCES p. 44.
[24] Id. at 42, 44.
[25] Id. at 44.
[26] BLM, Successful Competitive Lease Sales Since 1990—Wyoming, (http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/coaltables.html)
[27] DOE, DOI and DOA, *Inventory of Assessed Federal Coal Resources and Restrictions to Their Development*, p. 1 (2007).
[28] BLM Successful Competitive Lease Sales Since 1990—Utah (http://www.blm.gov/ut/st/en/prog/energy/coal/coaltables.html); Successful Competitive Lease Sales Since

These increases in bonus bids substantially exceeded the increase in coal prices during this period. Between 1989 and 2001, coal prices decreased by 20 percent nationally and by 40% for subbituminous coal. Although prices recovered in 2002, subbituminous coal prices were only 55 percent higher in 2011 than 1989, and, in real terms, the 2011 price remained slightly below the price in 1989.[29]

The available data demonstrates that the Federal Coal Management Program has delivered the results intended in terms of energy and value. The purpose of FCLAA was to spur federal coal production, cease the speculative holding of coal leases and ensure the public receives a fair return on coal produced and sold.[30]

In 1980, before the LBA method of leasing, there were 565 federal coal leases in existence covering 812,000 acres of land[31]. By 1990, the number of leases had dropped to 489, and as of 2014 there were 308 leases covering approximately 474,000 acres.[32] Over the period of almost 25 years the number of leases dropped by 45 percent and the acreage under lease decreased by 41 percent.

Coal production from federal leases has increased while the number of leases has decreased. In 1970, only 7 million tons of coal was produced from federal leases, rising to 69 million tons by 1980—about 8.5 percent of U.S. coal production. [33] In 1992, federal coal production increased to 239 million tons or 24 percent of U.S. production (1.03 billion tons).[34] By 2014, federal coal production grew to more than 409 million tons—41 percent of total U.S. production.[35]

In the span of just a decade (2003-2014) annual federal coal revenue more than doubled from slightly less than $600 million in

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1990—Colorado (http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy/coal_lease_table/Colorado_Coal_Table.print.html)

[29] Energy Information Administration, Annual Energy Review (Table 7.9 Coal Prices, 1949-2011) (Sept. 2012).

[30] H.R. Rep. No. 681, 94th Cong. 1st Sess. At 9-11 (1975).

[31] Office of Technology Assessment, An Assessment of Development and Production Potential of Federal Coal Leases p. 4 (Dec. 1981)

[32] BLM , Coal Leases in Effect 1990-2014 (http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy/coal_lease_table.html)

[33] Office of Technology Assessment at 4.

[34] General Accountability Office, COAL LEASING, GAO-14-140 p 20 (Dec. 10, 2013).

[35] DOI, Office of Natural Resources Revenue Statistical Information (http://statistics.onrr.gov/ReportTool.aspx); Energy Information Administration, Monthly Energy Review May 2016, Table 6.1 Coal Overview.

2003 to almost $1.3 billion in 2014.[36] Per leased acre, revenues increased by 66 percent. The largest component of the revenue stream, royalties, steadily increased even when production decreased after 2008 reflecting the value captured from higher sales prices. Royalties paid in 2012 were 88 percent higher than 2003 while production was a mere 2 percent higher than 2003 levels.[37]

THE GAO AND IG REPORTS

The Secretarial Order and BLM Scoping notice rely heavily on reports by GAO and the DOI Inspector General (IG) evaluating federal coal program as reasons for the moratorium. However, neither report suggests systemic flaws in the current leasing system requiring a moratorium on coal leasing while the recommendations were addressed. Indeed, the recommendations in both reports were acted upon by BLM prior to the January 15, 2016, Secretarial Order. Moreover, the DOI informed members of the Senate they saw no need to suspend new coal leasing while they implemented the recommendations from the IG and GAO reports. [38]

GAO did not repudiate its prior finding in 2010 that the LBA leasing method can achieve the objectives of the MLA as amended. At most, the reports identified several discrepancies among state offices in administering the program. Neither report states that the existing federal coal leasing process is non-competitive, that it relies on valuation methods inadequate to the task of estimating FMV or that industry is able to manipulate it as various NGO advocacy papers claim. While there are recommendations to improve the process, the reports acknowledge that the BLM Handbook follows generally accepted appraisal practices for mineral properties both in the U.S. and internationally.

The recommendations from the GAO report are:

- Revise the Handbook to require the use of both the comparable sales approach and the income approach where practicable.

[36] DOI, Office of Natural Resources Revenue Statistical Information (http://statistics.onrr.gov/ReportTool.aspx); BLM , Coal Leases in Effect 1990-2014 (http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy/coal_lease_table.html)
[37] DOI, Office of Natural Resources Revenue Statistical Information (http://statistics.onrr.gov/ReportTool.aspx);
[38] BLM Aug. 14, 2014 Letter to Senator Edward Markey.

- Ensure an independent review of appraisal reports by the Office of Valuation Services.
- Specify the required documentation for post-sale analyses where a decision is made to revise the FMV, including the rationale for the decision and the appropriate review of the decision.
- Develop guidance on how to consider export sales as part of the appraisal process.
- Revise guidance on the extent and type of information regarding the FMV estimate that should be shared with the public.
- Make electronic information on the coal leasing program more accessible to the public.

The GAO acknowledged that the prevalence of one bidder as opposed to multiple bidders was a product of maturation of federal coal regions with the significant capital investments and supporting transportation infrastructure at existing mines posing a high barrier for entry for new stand-alone operations.[39] Indeed, the last new mine started on a federal coal lease in the PRB occurred in 1982. Even when BLM altered the configuration of the lease tracts submitted under a LBA to make them potentially more attractive for multiple bids, such actions did not attract multiple bids. GAO also noted that this structural reality also largely explained the absence of multiple bids under BLM's regional coal sales in 1982 through 1984. [40] Moreover, independent appraisal organizations confirmed that even with a single bidder, it was unsurprising that the single bid often exceeded the FMV estimate because of the willingness of mine owners to submit higher bids to ensure they secured the lease in order to continue operations.[41]

The IG report covered several issues related to estimating the FMV for coal on public lands. The report states "[w]e found weaknesses that could put the Government at risk of not receiving full value for the leases." The IG speculates that revenues of $2 million were lost from recent sales because in four sales a bid that was lower than the estimated FMV was accepted. The IG did not provide any information about how it calculated the $2 million in purported lost revenue. However, the IG recommends in cases where there is an

[39] General Accountability Office, COAL LEASING, GAO-14-140 p. 17 (Dec. 2013).
[40] Id.
[41] Id. at 19.

unsuccessful sale, that direct negotiations take place which is essentially the same as revising the FMV in light of better information. This recommendation was intended to make the process more efficient and less time-consuming to execute a timely sale. The end result logically will still be a value lower than the original FMV.

The IG contends it identified a potential $60 million in lost revenue from several undervalued lease modifications because the price for the lease modification tract was lower than the existing lease tract. Again, the IG did not provide any information on how it calculated the purported lost revenue. [42] However, the IG acknowledged there are legitimate reasons for the lower lease modification price including lower coal quality, accessibility and other factors that rendered the coal of lower, and perhaps little, economic value. A lease modification is a small addition to an existing lease, less than 960 acres over the life of the lease, where the coal would otherwise not be mined (bypassed) due to its location or quality. The IG incorrectly assumed that the additional coal added by a modification would have the same value as the coal in the original lease tract. If that were the case, the additional acreage would have been included in the original lease tract configuration by the applicant or by BLM under its power to adjust the lease tract offered for sale. In reality, if the lease modification had not been approved at a lower price than the original lease, it would have been bypassed resulting in lost royalty and lease bonus revenues for the federal government.

For the most part, the reports identified a need for better documentation and greater consistency in the application of the policies underlying the federal coal program. Given the diversity in mining conditions, coal quality and changing market dynamics, there will always be difficulties in reconciling the application of general policies in every case to this array of factors. To put matters in perspective, even accepting the IG's theoretical estimate of $62 million in potential lost revenue, this amount represents less than 0.5 percent of the total coal revenues over the past decade. In any event, the IG testified to Congress that in her opinion the

[42] In the case of both the purported lost revenues for bids on new leases and modification of existing leases the IG report references an Appendix 2 which contains nothing in the way of any methodology for calculating the potential lost revenues. The Appendix only contains the sums it claims were potentially lost.

taxpayers are receiving a fair return from the federal coal program, and in many cases receiving more than FMV. [43]

The Secretarial Order does not dispute the limited nature of the recommendations in the GAO and IG reports. Moreover, the Order expressly acknowledges the measures taken to successfully address those recommendations. The Secretary summarily notes that these responses apparently did not satisfy certain stakeholders without explaining what additional measures would do so consistent with the findings of the reports or the governing law. In sum, the GAO and IG reports are being used as contrived reasons for taking the drastic action of imposing a coal leasing moratorium.

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[43] H. Rep. No. 113-29, *Mining In America: Powder River Basin Coal Mining, The Benefits and Challenges*, House Committee on Natural Resources Subcommittee on Energy and Mineral Resources, pp 38, 47 (testimony of Mary Kendall) (July 9, 2013).

ROYALTY RATES

BLM's PEIS Scoping Notice lists several options for raising royalty rates including: (1) an "adder" for the cost of externalities from coal development; or (2) using the same rate (18.75 percent) set for offshore oil and gas.[44] The first suggestion converts the royalty to an energy tax or fee, while the second would arbitrarily hike already above market federal coal royalty rates to bring them to parity with other fuel sources with different markets, different customers and distinct transactional arrangements. Both options would produce less, not more, revenue by making federal coal less competitive in the steam coal market.

A "royalty" is a share of the mineral payable "in kind "or "in value" to the Sovereign or landholder as a payment for the right to mine.[45] The royalty interest of the lessor reserves a right to a certain portion of the minerals, or monetary payment in lieu of a physical share of the minerals produced.[46]

Royalties have been expressed in terms of unit-of-production (a specified amount of money for each unit produced)[47] or a fractional share (a specified fraction, or percentage, of the production or dollar value measured at a specified point in the production process after deducting certain costs).[48] These forms of royalty are currently reflected in the mineral leasing laws. The Mineral Leasing Act originally imposed a unit of production royalty for coal.[49] The Federal Coal Leasing Amendments Act converted the coal royalty to a fractional share of value of coal

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[44] 81 Fed. Reg. 17,720, 17,726.

[45] *See* Royalty, *Black's Law Dictionary* (10th ed. 2014); U.S. Department of the Interior, A Dictionary of Mining, Mineral and Related Terms, p. 946 (1968); Mineral Leasing Act of 1920 (41 Stat. 437) § 7 ("for the privilege of mining or extracting the coal in the lands covered by the lease the lessee shall pay to the United States such royalties as may be specified in the lease . . .").

[46] 3, Rocky Mountain Mineral Law Foundation, American Law of Mining, 2d Ed. § 85.02 (LexisNexis Matthew Bender 2015).

[47] See, e.g., Wright v. Warrior Run Coal Co., 38 A. 491 (Pa. 1897).

[48] See 3, Rocky Mountain Mineral Law Foundation, *surpa* at § 85.03[2][a] (noting that in coal industry it is typical to write royalty clauses requiring payment of the higher of a specified cents per ton or a specified percentage of revenues received from the sale of coal F.O.B. mine.

[49] Mineral Leasing Act of 1920 (41 Stat. 437) § 7 (setting federal coal royalties at no less than 5 cents per ton).

produced.[50] The oil and gas leasing laws have long authorized acceptance of a fractional share of production in lieu of a share of the monetary value.[51]

A royalty rate that would include a so-called “externality adder” would not be a royalty. By changing the rate to include a “cost” derived for purported externalities the royalty would no longer reflect a share of a portion of either the minerals or their value which is the very purpose and meaning of a royalty. Oddly, an externality-based adder would decrease the value of the minerals by making them less economic to mine and sell (i.e., less valuable). DOI previously rejected a similar concept when it denied WEG’s rulemaking petition.[52]

Raising the royalty rate to the same level for federal offshore oil and gas (18.75 percent) appears motivated solely by a desire to make federal coal less economic to mine and sell. The higher royalty rate established for offshore leases was motivated by a variety of factors—none which apply to coal. They include: increased oil and gas prices; improvements in exploration technologies for deeper water; and, a growing expression of interest for offshore leases.[53] Both the Secretarial Order and BLM Scoping Notice mention a decrease in coal demand as well as flat and decreasing prices—market factors distinctly the opposite of those that served as the basis for raising offshore oil and gas royalty rates.

A better benchmark for measuring the adequacy of the federal coal royalty rate is a comparison to private lease rates. Federal coal competes with private coal to attract investment for development. A survey of members of the National Mining Association coal members producing coal in the major coal basins found federal rates for surface mines (12.5 percent) and underground mines (8

[50] Federal Coal Leasing Amendments Act of 1976 (Pub. L. 94-377, § 6 amending MLA § 7 (30 U.S.C.§ 207) (changing unit-of-production royalty to fractional share royalty of 12.5 percent of value of coal produced and authorizing a lower amount for coal produced by underground mining methods)

[51] Mineral Leasing Act of 1920 (41 Stat. 437), § 14 (royalty of 5 perecent in amount or value of the production); 42 U.S.C. § 15902 (authorizing acceptance of payment of royalty in-kind for federal oil or gas leases).

[52] DOI Jan. 28, 2011Response to WEG Petition (noting lack of authority to consider a carbon fee for coal leases under either the Mineral Leasing Act or Federal Land Policy Management Act). Nor does DOI have authority to adjust other fees for so-called externalities. See Sol. Op. M-36987, BLM’s Authority to Recover Costs of Mineral Documents Processing (cost recovery under FLPMA limited to processing fees related to applications and studies that have value to the applicant).

[53] See Government Accountability Office, OIL AND GAS RESOURCES: Actions Needed for Interior to Better Ensure a Fair Return p 14 (GAO-14-50) (Dec. 2013).

percent) substantially higher than private rates. In the Northern and Central Appalachian regions, surface mine rates range from 4 percent to 8 percent; in Southern Appalachia 3 percent to 10 percent; and in the Illinois Basin 5 percent to 7 percent. Underground mine royalty rates in Northern, Central and Southern Appalachia range from 3 percent to 6 percent; and in the Illinois Basin 3 percent to 6 percent. Moreover, private lessees in these regions rarely if ever pay bonus bids or rentals under the lease terms. Federal coal also presents higher costs in terms of time and expense in obtaining and developing the lease through multiple federal and state environmental reviews for the lease sale, mine plan review and mining permit approval. Since 1991, the time between filing a lease application and the effective date of a lease has increased from two years to more than six years. [54]

Higher royalty rates will affect production and revenues in several ways. The higher costs will lower the return to producers on their investment which, in turn, will decrease production by making more coal uneconomic to mine. While raising the rate may increase short term royalty revenue per unit produced up to a certain point, royalties are paid when production occurs. If the rates were raised to 18.5 percent, the government would potentially increase its unit revenue by $0.60 per ton of PRB coal sold for $10.00. However, if that unit of coal is no longer economic to mine and sell, the government forfeits $1.25 of royalty revenue it would have received under the current 12.5 percent royalty.

The higher cost will also increase the risk premium producers require before bidding on a lease and will likely result in lower bids to compensate for that higher risk. It will also reduce taxes and other fees paid to federal and state governments as a result of lower production and decreased economic activity. [55]

In the absence of evidence that current royalty rates fail to provide a fair return—and in the face of data that shows federal rates are above market—proposals to increase rates would conflict with the statutory mandates that govern the Federal Coal Management

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[54] BLM, Powder River Basin Coal Leases by Application available at http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/lba_title.html . Effectively, these increased processing times for leases are denying the government the time value of potential bonus bids that are received two to four years later because of these delays.

[55] The lost revenue includes income, sales and payroll taxes from production and employment. Coal jobs pay twice the average industrial wages in the states and the related transportation, equipment and related jobs in the coal supply chain are similarly high wage jobs with generous benefits.

Program. Congress' purpose in enacting the Mineral Leasing Act is '[t]o promote the mining of coal . . . on the public domain."[56] The express Congressional policy is that it is "in the national interest to foster and encourage private enterprise in," among other endeavors, "the orderly and economic development of domestic mineral resources, reserves . . .to help assure satisfaction of industrial . . . needs."[57] Congress has instructed that "[i]t shall be the responsibility of the Secretary of the Interior to carry out this policy when exercising [her] authority under such programs as may be authorized by law."[58]

The purpose of FCLAA was to ensure the diligent development of coal and its maximum economic recovery in order to meet the nation's energy needs. Those amendments required, with some exceptions, production from the lease in commercial quantities within 10 years. It further required that lease tracts permit the mining of all coal which can be economically extracted and, to further maximize recovery, allows the consolidation of lease tracts (federal, private and state) in order to do so more efficiently. While setting higher royalty rates, FCLAA retained the royalty reduction mechanism to encourage the greatest recovery of coal and avoid bypassing coal otherwise uneconomical to mine under the higher rate.[59] Targeted amendments to the leasing laws were made by the Coal Leasing Amendments Act of 2005[60] in order to facilitate the continued development of federal coal by changing provisions of the MLA that impede the efficient development of the federal coal resources.[61] These changes included removing the 160-acre limitation on lease modifications, allowing the inclusion of additional leases in the formation of a logical mining unit and providing additional flexibility to allow payment of advanced royalties for a limited time in lieu of production in commercial quantities. [62] In sum, the overriding purpose of the MLA remains "to promote the mining of coal."[63]

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[56] Law of Feb. 25, 1920, c. 85, § 32, 41 Stat. 437.
[57] Mining & Minerals Policy Act of 1970, 30 U.S.C. § 21a.
[58] *Id*.
[59] 30 U.S.C. § 209.
[60] Energy Policy Act of 2005, Pub. L. 109-58 (Aug. 8, 2005), 119 Stat. 760-763. (Title IV, Subtitle D).
[61] H.R. 793 and H.R. 794 Legislative Hearing before the House Subcommittee on energy and Mineral Resources of the Committee on Resources, Serial No. 108-4, 108th Cong. 1st Sess., at 2-3 (March 3, 2003).
[62] 119 Stat. 760-761.
[63] Law of Feb. 25, 1920, c. 85, § 32, 41 Stat. 437.

The options for increasing royalty rates and their accompanying rationale all conflict with the purposes and intent of the governing laws. The "externality-adder" for a royalty would, by admission of its sponsors,[64] make federal coal uneconomic.[65] The same result is obtained by increasing coal royalties to the 18.75 percent rate set for offshore oil and gas. At a minimum such increases would conflict with the MLA's maximum economic recovery mandate by rendering substantial amounts of federal coal uneconomic. It would be surpassing strange to set higher royalty rates only to force lessees to avail themselves of the royalty reduction remedies of the MLA in order to bring them back down to levels sufficient to satisfy the law's maximum economic recovery requirement. At bottom, the purposes of the MLA and the collateral laws for minerals policy are to promote the mining of coal on the public domain.

None of the royalty options listed by BLM address the other purposes of the MLA—namely to provide for the nation's energy needs. The promotion of coal mining serves the public interest in the form of a stable and affordable supply of fuel for electricity generation. Coal has been the foundation of the U.S. power supply and federal coal has served an increasingly important role in supporting a diversified portfolio of U.S. power supply.

Engineering and economic analysis consistently confirm that a diversified portfolio of fuels and technologies produces the least-cost power production mix. Electricity generation costs change because of the fuel costs change over time. A diversified power supply portfolio is the most effective way available to manage this production cost risk. According to IHS Energy, the current diversified portfolio of U.S. power supply anchored by coal lowers the cost of generating electricity by more than $93 billion per year, and reduces the variability of monthly power bills by half.[66] Policies designed to disrupt the supply in terms of availability and higher costs rob the public of these direct benefits.

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[64] Krupnick, A. J., et al, *Putting a Carbon Charge on Federal Coal: Legal and Economic Issues,* Discussion Paper, RFF DP 15-13, Washington, D.C. Resources for the Future (2015).
[65] The authors also recognize that it would create market distortions and increase coal imports.
[66] IHS Energy, *The Value of US Power Supply Diversity*, p. 5 (July 2014).

VALUATION POINT FOR ROYALTY PAYMENTS

BACKGROUND

The valuation of the mineral for a federal royalty has long been determined on the value of the mineral produced at the mine.[67] The present federal regulation for coal identifies the mine as the valuation point by applying the royalty rate to the proceeds received by the lessee at the point of the first sale.[68] Most coal supply agreements are free on board (F.O.B.) mine (a/k/a F.O.B. place of shipment) which places responsibility on the producer to deliver the coal to the place of shipment (i.e., the carrier), not the destination. Under F.O.B. mine, the title and risk of loss pass to the buyer upon delivery to the carrier. [69]

Sales Price, Transportation Cost and Delivered Price

Several organizations argue that royalty payments should be based on a so-called "delivered price" at the point of consumption rather than the selling price at the mine. They claim royalties paid on the sale price at the mine result in underpaid royalties. For example, CAP asserts that "because royalties are assessed on the sale price of coal at the first point of sale—which is usually at the mine mouth and does not reflect the market price---taxpayers are losing out on additional royalty payments due to depressed prices that do not reflect the true value of federal coal on the market."[70] CAP provides no analysis to support the proposition that the mine sale price does not reflect market price for the commodity, nor does CAP engage in any examination of the structure of coal sales transactions.

Headwaters Economics makes an equally unavailing attempt to use the differential between mine sale prices and what it calls "delivered prices" at the utility as evidence that federal coal producers pay royalties on values that are below market prices. Like CAP, Headwaters uses the delivered costs to utilities but

[67] See S. Rep. No. 94-296 (1976) (royalty based upon "the gross value of the coal at the mine"); *United States v. Gen. Petroleum Corp. of Cal*., 73 F. Supp. 225, 258 (S.D. Cal. 1946 (royalty obligation is determined "at the mines, that is before it left the field.".) *aff'd sub. nom. Cont.'l Oil Co. v. United States*, 184 F.2d 802, 820 ((9th Cir. 1950); *Indep. Petroleum Ass'n of Am. V Armstrong*, 91 F. Supp. 2d 117,119 (D.D.C. 2000).

[68] 30 C.F.R. § 1206.257(b) (value of coal is gross proceeds accruing to lessee under an arms-length contract); see also id, at § 1206.257(b)(5) (value does not include payments received that were not part of the consideration paid for coal production).

[69] 1 Energy Law & Transactions § 23.05{2] (Matthew Bender & Co). See also U.C.C. § 2-509(1)(a).

[70] Thakar, *Modernizing the Federal Coal Program*, Center for American Progress, p 7 (Dec. 9, 2014).

coins a new derivative it misleadingly calls an "effective "royalty rate." Headwaters "effective royalty rate" is calculated by dividing the royalties paid by the coal producer by the ultimate cost to the utility which includes both the sale price for the coal at the mine plus the costs of transportation and handling from the mine to the power plant. [71]

Both CAP's and Headwaters' claims suffer from the same fatal flaw—what they refer to as "delivered price" is the sum of the sales price of the coal at the mine (commodity price) *and* the cost of transportation. The coal producer only realizes the proceeds from the mine sale price.

A major component of the "delivered price" is transportation and handling costs utilities pay to the common carrier (railroad, barge and truck). The transportation arrangements in coal supply agreements are typically the coal buyer's responsibility. The buyer handles all dealings with the transportation company, including the negotiation of the transportation contracts, tariffs, scheduling and routing.[72]

Coal transportation costs are a significant component of the delivered cost of coal. According to the Energy Information Administration (EIA), the average cost of transporting coal by rail increased by almost 50 percent between 2001 and 2010.[73] On a national average, the transportation costs for coal by rail now comprise more than 46 percent of the delivered cost of coal. [74] In some cases the transportation cost for Powder River Coal, exceeds the sales price of coal at the mine.[75]

CAP and Headwaters *never* explain that their "delivered price" is the sum of the mine sale price paid by the buyer to the coal producer for the commodity plus the transportation costs paid by the buyer to the railroad (or other common carrier) for its delivery

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[71] Headwaters Economics, *An Assessment of U.S. Federal Coal Royalties* p. 11 (January 2015).

[72] 1 Energy Law & Transactions § 23.05{1]. Even if the transaction was based upon F.O.B. destinations with the seller assuming the responsibility and cost of transportation, those costs would need to be deducted to reach the commodity price for the coal.

[73] EIA, Cost of Transporting Coal to Power Plants Rose Almost 50 perecent in a Decade (Nov. 19, 20120 available at http://www.eia.gov/todayinenergy/detail.cfm?id=8830.

[74] EIA, Real Average Transportation and Delivered Costs of Coal, by Year and Primary Transportation Mode available at http://www.eia.gov/coal/transportationrates/pdf/table1.pdf .

[75] EIA, Real Average Transportation and Delivered Costs of Coal, by Year and Primary Transportation Mode and Supply Region available at http://www.eia.gov/coal/transportationrates/pdf/table2.pdf.

to the buyer's plant. In the simplest terms, CAP's and Headwaters' "delivered price" reflects two distinct transactions—one for the value of the commodity and the other for the value of services. Each transaction reflects the value of distinct items (commodity and services) negotiated often between different parties. In short, CAP's and Headwaters' "delivered price" is not the coal price, or value, received by the coal producer for the commodity. As a corollary, under CAP's proposal, the value of natural gas produced from federal leases would be valued at what is often referred to as the " burner tip" price –which includes the commodity price plus the cost of transporting and delivering it to the power plant.

The source of data CAP and Headwaters rely upon to propose a so-called "delivered price" make this distinction absolutely clear. The data is drawn from EIA reports compiling information reported by utilities on Form EIA-923. The instructions for EIA Form-923[76] collects information on "Total Delivered Costs" which includes "all cost incurred in the purchase and delivery of the fuel to the plant." [77] The commodity cost is reported separately as well the "*price paid for the fuel at the point of first loading"* exclusive of any charges relating to the movement of the fuel to the point of use." [78]

By failing to acknowledge these distinctions, CAP and Headwaters deceptively equate the "delivered cost" to the market price for coal produced.[79] Headwaters goes one step further to deploy a newly-minted term "gross market value," [80]to impute the transportation costs incurred by the buyer as part of the sale price paid to the coal producer. To fully capture this deception, one need only refer to CAP's assertion that when PRB producers sell coal based on the market price determined at the mine and pay royalties on that price, they in turn "reap huge profits" when the coal "is sold for more than triple the price downstream." [81] The Council of Economic Advisers apparently fell for this deception when it described Headwaters' "effective royalty rate" as reflecting the "delivered price *that sellers ultimately receive* for the coal sold

[76] Form EIA-923 Power Plant Operations Report Instructions, OMB No. 1905-0129 (Approval Expires 05/31/2017).
[77] The costs reported include transportation, maintenance and depreciation of rail cars owned by the utility, freeze proofing and dust suppressants for transportation.
[78] Id. at Schedule 2. Part A. *Contract Information, Purchases and Costs*. EIA instructs that for coal the commodity cost is F.O.B. mine, for natural gas it is F.O.B. the transmission pipeline.
[79] CAP (2014) p. 7.
[80] Headwaters, p. 16.
[81] CAP (2014) p. 7.

from federal leases." [82] This is patently incorrect. As explained, when the coal is sold F.O.B. mine, the coal producer receives the price for the commodity agreed to under a coal sale agreement; the buyer takes title; and the buyer contracts for the transportation of the coal to its plant. What CAP and Headwaters propose is for the royalty to be applied not only to the sales price of the coal but to the costs of transportation services reflected in the agreement between the buyer and common carrier (i.e., railroad, barge or truck). Essentially, CAP's and Headwaters' royalty is a hybrid of a production royalty and a tax on transportation services. This hybrid would no longer reflect the attributes or purpose of a royalty which is the compensation paid the mineral owner for the privilege to mine the commodity resource.

Applying CAP's and Headwater's valuation concepts to the meaning of royalty demonstrates why it is incorrect from both an economic and legal perspective. If the royalty payment were made in the form of a fractional share of production (i.e., 12.5 percent "in-kind"), the government would take its share of the coal at the mine and then be left to sell it. If the government's sale was F.O.B. mine then it would receive from a buyer, at best, the same proceeds as the coal producer would have paid in cash. If the government sold the coal F.O.B. destination assuming responsibility for transportation to the power plant, it would receive from the buyer both the commodity price and the cost of transportation; however, its net proceeds after deducting the expenses paid to the common carrier for transportation services to deliver the coal to the buyer. [83] In either case, the net-proceeds accruing to the government under an in-kind royalty would always be less than the current *ad valorem* cash royalty because the government would incur additional administrative costs to establish the same expertise and capability now performed by the coal producer for marketing, contract administration and inventory management, as well as the risks of loss from disputes in performance under coal supply agreements including delivery, quality and force majeure declarations by the customer.

[82] White House Council of Economic Advisers, "The Economics of Coal Leasing on Federal Lands," p. 8 (June 2016).

[83] One might postulate that the government could negotiate more favorable commodity sales price or transportation rates for its fractional in-kind share of the coal. However, its fractional share of production (12.5 percent or 8 percent) would be insufficient to give it pricing power in either case.

Nothing in the MLA suggests the federal royalty is different in character than its historic meaning as a share of production or revenue reflecting the value of commodity produced. Originally, federal coal royalties were a fixed amount of money for each unit of production (e.g., five cents per ton).[84] In changing the royalty to a fractional share of value (e.g., 12.5 percent), FCLAA did not change the nature of the royalty. In fact, FCLAA characterizes the payment as a "production royalty." [85] FCLAA's legislative history confirms that the royalty was a share of the "the value of the coal at the mine."[86]

In sum, movement of the valuation point from the sales price at the mine downstream to the total cost for the end user departs fundamentally from royalty principles for capturing the commodity value. Such proposals are motivated by the desire to make federal coal less competitive by taxing the costs of transportation services paid by the buyer. The proponents of such a scheme misuse data and invent new terms that are not reflective of the commodity value which is the fundamental tenet of a mineral royalty.

Coal Pricing

CAP attributes the lower prices for PRB coal to the longstanding valuation method of federal coal under DOI's regulations. According to CAP, "PRB coal sells at a severe discount when compared to other U.S. [ ] coal."[87] CAP's attempt to quantify the spread compares PRB mine prices of $13 per ton with a $63 per ton price for coal mined in Appalachia.[88] CAP never explains why a PRB coal producer would forgo $50 per ton coal if the company could command such a price in the market. Large PRB mines have high capital costs; can take a decade to come on line; and another decade to recover investment. The mine operator has every incentive to seek the highest price possible in the market to recover its investment sooner.

The lower prices for PRB coal as compared to coal produced in other regions is self-evident: substantially lower mining costs, economies of scale and lower heat content of the coal as compared

[84] Mineral Leasing Act of 1920 (41 Stat. 437) § 7.

[85] Federal Coal Leasing Amendments Act of 1976 (Pub. L. 94-377, § 6 amending MLA § 7 (30 U.S.C.§ 207).

[86] S. Rep. No. 296, 94th Cong. 1st Sess. 49 (1976).

[87] Center for American Progress, "Modernizing the Federal Coal Program," p. 2 (Dec. 9, 2014). See also Center for American Progress, "Federal Coal Leasing in the Powder River Basin," p. 2 (July, 29, 2014) (PRB coal "sells at a fraction of the cost of coal produced in other regions of the United States.").

[88] Id.

to other coal ranks and regions. The increase in demand for PRB coal arises from its low cost and lower-sulfur content. Electricity generators, the primary consumers of coal (>90 percent), strive to minimize their fuel cost which is a primary factor in the dispatch of their plants into power markets. In addition to fuel costs, electricity generators strive to minimize incurring additional capital investment in their plants. Lower sulfur coal allowed them to switch sources of coal without incurring larger capital costs than necessary to meet increasingly stringent air quality standards.

The price paid for coal in the thermal coal market reflects a range of factors:

- Demand for coal based upon expectations or forecasts of power generation and the availability and cost of competing generation sources in a region.
- The cost of mining a coal reserve.
- The heat content, or British thermal unit (Btu)s per pound, of the coal.
- The cost of removing sulfur, ash, mercury and other impurities to meet customers' specifications.
- The distance from the mine location to the end user.
- The modes of transportation available to a particular power plant. The coal handling and crushing systems at the various power plants.
- The boiler design of the power plant relative to the different types and characteristics of coal.
- Whether the power plant is outfitted with scrubbers and other emission control systems to comply with air quality standards.

The cost differential between Wyoming PRB and Appalachian coal is driven by several factors including:

- The mining method required to extract the coal
- The difference in the cost of those extraction methods
- The scale of the mining operation.

The federal coal leasing program does not contribute to lower Wyoming PRB coal prices relative to Appalachian coal prices. In fact, Wyoming PRB coal producers have a cost disadvantage due to the lease bonus and high royalty payments they make compared to coal produced on non-federal lands in other regions.

MINING METHODS AND COSTS

Mining methods and costs are driven by geology and are vastly different among coal regions especially between the PRB and Appalachia. The cost of extracting coal is a function of the thickness of the coal bed or seam and the amount of rock that overlies it, or overburden.

The geology of the PRB and its amenability to large scale surface mines using advanced mining technology provides a substantial productivity advantage over mines in other regions, especially those in Appalachia. The combination of extensive, thick, and more consistent coal beds is the major source of PRB's cost advantage as measured by productivity. PRB mine productivity is more than 10 times higher than Appalachian mines as measured by average production per employee hour. PRB productivity rates exceed those in every other coal region and are at least five times higher than the next productive coal producing region.[89] With these productivity advantages it is neither a coincidence nor a product of the federal coal valuation methods that nine of the top ten largest coal mines in the U.S. are located in the PRB.[90]

Coal in the PRB is extracted using surface mining methods because the coal is relatively close to the surface and lies in thick beds or seams, as much as 90 to 100 feet thick. The stripping ratio, the amount of overburden to be removed (measured in bank cubic yards) to extract one ton of coal, is very low, usually around 3 cubic yards of overburden to extract one ton of coal. In addition, the mining method in this region is characterized by highly mechanized and extremely large equipment allowing greater efficiency and productivity associated with economies of scale. This means that mining companies must invest hundreds of millions of dollars in equipment but realize lower labor and materials costs and higher production rates as a result.

By contrast, coal geology in the Appalachian region is characterized by much thinner seams, ranging from 4 to 12 feet thick and is under much deeper overburden. Both surface mining and underground mining methods are employed in this region depending on the geology. When surface mining methods are

[89] U.S. EIA, Annual Coal Report 2014, Table 21 Coal Productivity by State and Mine Type, 2014-2013 (March 2016).
[90] Id, at Table 9, Major U.S. Coal Mines 2014.

utilized, the stripping ratio is typically in the range of 15 to 20 cubic yards of overburden for every ton of coal extracted. Surface mining methods in Appalachia are characterized by much smaller less efficient equipment than PRB mines and the thinner seams result in lower production rates. Because the ratio of overburden to coal is so high, underground methods are the predominate method of extraction in this region. Underground mining in the Eastern U.S. is done by either the longwall method or room and pillar method, both of which are much more labor intensive than surface mining methods. For example, the 2013 tons produced per employee labor hour in the PRB was 30.05 compared to 2.44 in Appalachia. In addition to requiring more labor, underground mines incur significant costs to develop the mine to access the coal, to control the roof or overburden above the extracted coal seam, and to maintain the proper air flow in ventilating the mine.

A summary of typical mining costs by region is shown in Table 4.1 below. The eastern surface mining costs will vary based on whether it is a large surface mine or a small contour mine. The eastern underground costs will vary depending on whether it is a longwall mine or a room and pillar mine. These costs do not include indirect costs such as overhead and administration, insurance and property taxes, and production taxes and royalties. Federal royalties are substantially (40 percent to 65 percent) higher compared to private leases in the East.

Table 4.1 Typical Mining Cost per Ton by Region and Mining Method

Category	PRB Region	Eastern U.S. Surface Mine	Eastern U.S. Underground Mine ($/clean ton)
Labor and Benefits	$2.25	$12	$15
Materials and Supplies	$4.75	$18	$12
Outside Services	$0.15	$14	$24
Equipment and Facilities Depreciation	$1.55	$8	$4
Total Direct Mining Cost	**$8.70**	**$52**	**$55**

As can be seen in Table 4.1, the cost of extraction is a major factor in the selling price of coal in different regions. The heat content of the coal and the proximity of the coal deposit to the markets and also serve as important variables in the cost competitiveness of coal in different regions. The closer a coal deposit is to its market and the higher the heat content per ton, the more a utility can afford to pay for coal at the mine with transportation costs being the equalizer in total delivered fuel cost.

HEAT CONTENT

In general, utilities buy Btus, not tons. Other factors that influence demand for particular coals include sulfur dioxide content, ash content, handling characteristics, and boiler performance due to other impurities in the coal. But the heat content plays the biggest role in the comparison of the cost of various coal sources to an end user.

The heat content of PRB coal typically ranges from 8,400 to 8,800 Btus per pound compared to the approximately 12,000 Btus per pound for Appalachian coal. Because utilities buy Btus, they will pay more per ton for a coal with a higher heat content assuming the other coal characteristics will not impair boiler performance and emission limitations for a plant. On the basis of heat content alone, a utility would pay as much as 30 percent to 40 percent more per ton for Appalachian coal than PRB coal.

However, switching from Appalachian coal to PRB coal, even though it's less expensive, is not as simple as it may seem. Switching a plant to PRB coal from Appalachian coal means more tons have to be burned to generate the same amount of electricity. The coal handling and crushing systems as well as the boiler design are major factors in the analysis. They may not be capable of handling these additional tons which means the utility would need to spend millions of dollars to increase the capacity of these systems. The boilers may also require modifications to burn the lower heat content or they simply may not be able to generate as much electricity. All of these costs offset the lower fuel cost from switching to PRB coal. To penetrate these markets, PRB coal prices must be low enough to cover the cost of the additional tons and the cost of increasing the capacity of the handling and crushing systems and any boiler upgrades and/or de-rates.

Even coals in the same region will have price spreads based upon heat content. In the PRB for example, the spread between the spot price for 8,800 Btu per pound(/lb.) coal and 8,400 Btu/lb. coal ranges from $1.50-$2.50 a ton. [91]The price spread will fluctuate based upon the relative demand between the different quality coals. Mining costs will still play a prominent role. A lower 8,400 Btu/lb. coal will become more competitive with the higher heat coals in

[91] Platts, *The Barrel Blog*, "PRB 8,400 Coal Production Down But Not Out" (July 1, 2016).

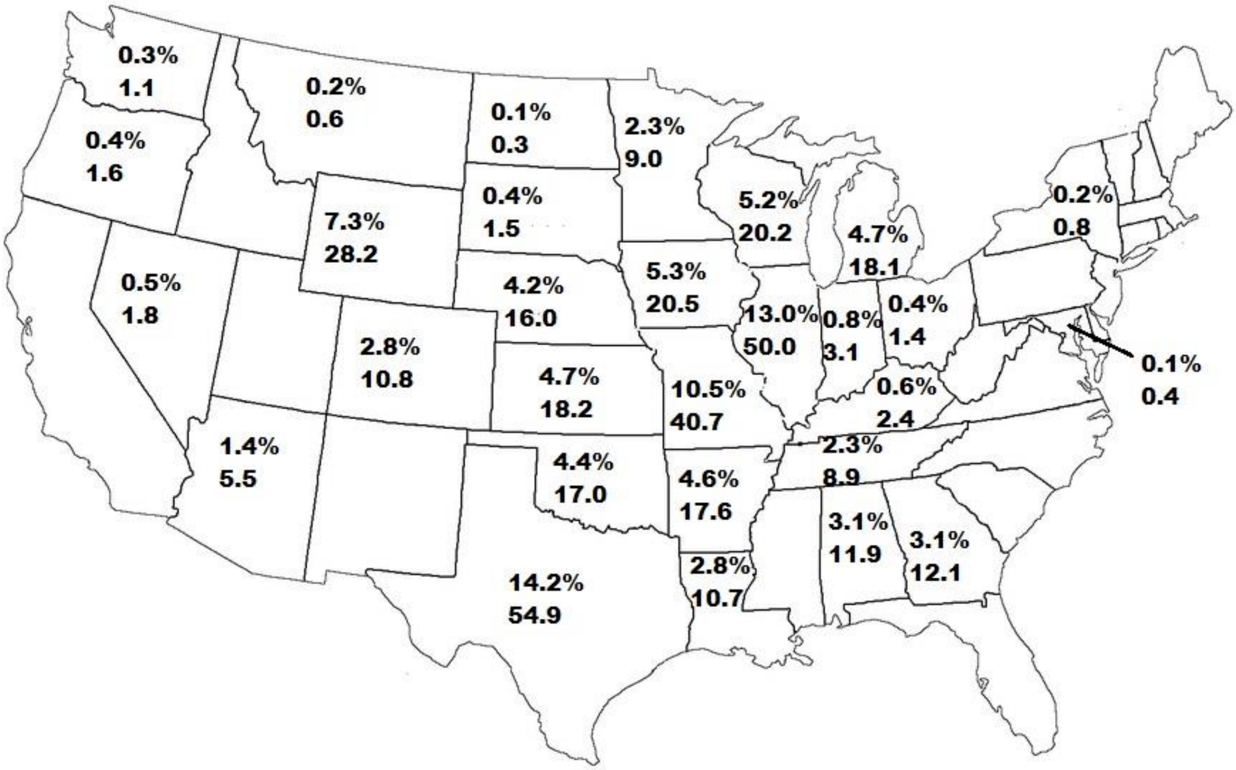
the PRB if the mine has lower mining costs due to lower stripping ratios.

TRANSPORTATION DISTANCE, RATES AND DELIVERED COST

Transportation costs have also influenced the competitiveness of coals from different regions. Transportation costs for all coal in the U.S. now comprise on average almost 40 percent of the delivered cost with coal delivered by rail exceeding 45 percent. However, the relative change in rates among regions of origin and destination can substantially influence demand and mine sales price for coal among different coals originating in different regions.

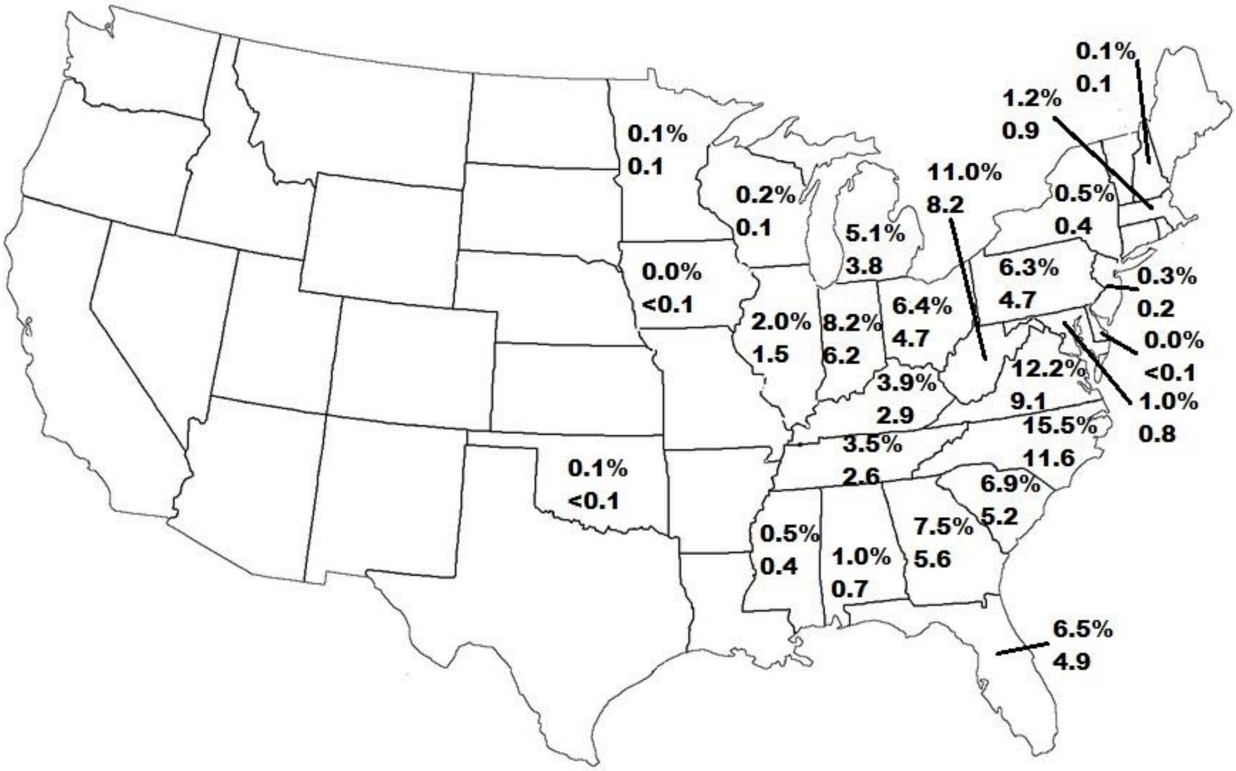
The majority of PRB coal must travel hundreds of miles to its markets. Most Wyoming coal is sold in Texas, Missouri, Illinois, Kansas, Nebraska, Arkansas, Wisconsin, and Michigan. Lesser amounts are sold as far east as Alabama and Georgia. The biggest markets are Texas, Missouri, and Illinois, accounting for 39 percent of Wyoming coal shipments in 2013 (Figure 4.1). Approximate distances to markets are 1,200 miles to Texas, 800 miles to Missouri and 1,150 miles to Illinois. For long distances such as these, the cost of rail transportation ranges from $0.02 to $0.025 per ton mile. This means that transportation costs of PRB coal to Illinois can cost from $23 to $29 per ton.

Figure 4.1 2013 Coal Shipments from Wyoming (%, M Tons)



In contrast, most Appalachian coal is sold in the Eastern U.S. much closer to the end user. For example, coal produced in the Central Appalachian Region (CAPP) of Kentucky and West Virginia is generally consumed in the same area (Figure 4.2). The higher sulfur coal from Northern Appalachia (NAPP) is not shown in Figure 4.1; however, its distribution range is even smaller than CAPP because it serves mostly local power plants and it competes with coal from the Illinois Basin. Approximately 66 percent of coal produced in this region is consumed in Pennsylvania, Ohio, West Virginia, Virginia, North Carolina, South Carolina, and Georgia. Very little coal from this region is shipped west of these states due to the competition from the PRB (Figure 4.1) and from the Illinois Basin (not shown in this report). Domestic transportation distances for coal from most Appalachian mines to their markets can range from a few miles to over 700 miles, but more typically falls within a radius of approximately 200 miles or less.

Figure 4.2 2013 Coal Shipments from Central Appalachia (%, M tons)



Transportation costs for coal mined in the East vary greatly due to the availability of multiple transportation modes (rail, barge and truck) and the requirements of the specific power plant. Shorter rail distances in this region typically incur a higher rate per ton mile than the longer distances from the PRB. These rates can range from \$0.05 to \$0.11 per ton mile. At distances around 75 miles or less, trucking becomes competitive with rail with rates in the range of \$0.12 to \$0.15 per ton mile. In addition to rail transportation, much Eastern and Midwestern utility coal is delivered by barge, particularly to those plants located along the Ohio River. For example, in West Virginia the breakdown of shipment methods in 2014 was 51 percent by rail, 25 percent by truck, 18 percent by barge, and 6 percent by conveyor belt. In Kentucky, the transportation modes for Eastern Kentucky coal in 2013 (part of Central Appalachia) were 88 percent by rail, 7 percent by truck, and 5 percent by barge, while the Western Kentucky coal (Illinois Basin) consisted of 66 percent by barge, 30 percent by rail, and 4 percent by truck.

Shipping distance adds to the delivered cost of coal, but also affects rail rates. After Congress passed the Staggers Act in 1980, rail rates were no longer linked to regulated tariffs set by the Interstate Commerce Commission. Railroads now charge their own tariffs and compete with each other for more business by setting competitive rates. Rail rates steadily dropped in most regions from 1980 through 2000, but began to increase thereafter, and at higher rates for other regions as compared to PRB coals.[92] The decline in rates between 1980 and 2000 was greatest from long haul distances of 1000 miles or more. The increase in rail rates since 2000 has been highest for short haul shipments of less than 500 miles.[93]

PRB mines add to their overall productivity with larger and more efficient on-site storage and loading capacity with tracks for unit trains.[94] The coal can be loaded from overhead silos with storage capacity as high as 48,000 tons for loading into gondola cars that move along a track loop that can accommodate multiple unit trains at once. As loaded trains move onto the trunk line empty cars arrive and the system serves much like a conveyor belt. Mines in the PRB can hold four to fifteen unit trains on site.[95]

SUMMARY OF DELIVERED COAL PRICE ANALYSIS

The effect of mining costs, heat content and transportation costs on total delivered fuel cost per ton and fuel cost per million Btus are summarized in Table 4.2 and Table 4.3. These tables show the delivered cost per ton and per million Btus by state of origin and representative destinations for 2014. It only includes low sulfur coal from Wyoming, Kentucky and West Virginia. Several states, most notably Texas and Illinois, have numerous unregulated power plants for which delivered cost data is not available. These tables only include regulated utilities.

Table 4.2 2014 Delivered Fuel Cost per Ton – Low Sulfur Coal

Origin	NE	IA	MO	IL	IN	AL	GA	KY	WV
WY	23.65	29.27	33.42	35.67	41.64	33.25	43.89	34.34	n/a
East KY	n/a	n/a	n/a	n/a	69.86	83.43	102.52	71.31	72.87
Southern WV	n/a	n/a	n/a	n/a	71.86	n/a	87.30	54.82	66.59

[92] Considine, T., "Powder River Basin Coal: Powering America," 4 Natural Resources 514, 521, Figure 4 (2013).
[93] Mintz, M., Saricks, C., Anant, V., Argonne National Laboratory, Coal-by-Rail: A Business-as-Usual Reference Case, p. 15 (Feb. 2015).
[94] A standard 120-car unit train with single cars with a 120-ton capacity can carry more than 14 thousand tons of coal.
[95] BNSF Railway, Guide to Coal Mines (June 12, 2013).

Table 4.3 2014 Delivered Fuel Cost per MMBtu – Low Sulfur Coal

Origin	NE	IA	MO	IL	IN	AL	GA	KY	WV
WY	1.39	1.69	1.89	2.03	2.36	1.89	2.55	1.94	n/a
East KY	n/a	n/a	n/a	n/a	2.89	3.34	4.22	2.94	2.99
Southern WV	n/a	n/a	n/a	n/a	2.93	n/a	3.68	2.54	2.74

The wide range in mining costs and transportation distances across the coal fields create significant variation in the impact of transportation rates on the delivered cost. The disadvantages faced by PRB coal of lower heat content, higher royalty rates and longer distance to customer's coal are offset by substantially lower production costs and lower transportation rates per mile charged by railroads.

Notwithstanding these differences, transportation cost comprises a substantially larger percentage of the total delivered cost to customers. According to EIA, in 2010, rail transportation costs for Appalachian and Illinois basin coals as a percent of total delivered cost was in the low 20 percent range. For PRB coal, transportation costs averaged almost 60 percent of the total delivered cost.[96]

In sum, the transportation costs are primarily determined by the distance and rates charged for the move from the mine to the destination. Those costs do not have any effect on mining cost. Those costs may indirectly influence the coal sale price at the mine agreed to between the coal producer and buyer. The mining costs are within the control of the coal company; the transportation costs are a product of the rates charged by the common carrier. A coal producer's profit or loss is determined by the cost of coal production and the price of the coal sold at the mine, not the delivered cost to the power plant. There is simply no support for the proposition advanced by CAP and others that the delivered cost represents the "market price" or "true value" of the commodity. The valuation of coal at the mine represents the commodity price for purposes of the royalty. The royalty imposed under the MLA is a" production royalty," not a levy on the post-production costs incurred by the buyer.

[96] EIA, Cost of Transporting Coal to Power Plants Rose Almost 50 percent in a Decade (Nov. 19, 20120 available at http://www.eia.gov/todayinenergy/detail.cfm?id=8830.

Coal Exports

CAP's claim that the current leasing and royalty valuation regulations do not capture the true value of coal exports suffers from the same fundamental error as its arguments for using the total delivered cost to domestic consumers as the market price of the commodity. CAP asserts that PRB coal sells for five times more than it does domestically.[97]

Like its omission of discussion on delivered costs for domestic consumers, CAP misleadingly includes in its so-called "export price" the transportation and logistics costs beyond the F.O.B. mine price. These costs are more substantial than those associated with delivered costs to domestic electricity generators. The cost of transporting the coal to the terminal and having it loaded on a vessel can be more than six times the mining cost for PRB coal.

The cost of shipping coal for export includes transportation to the port, terminal fees for unloading, storage and loading on to the vessel, demurrage charges and in some cases the cost of chartering the vessel to deliver the coal to the customer's discharge destination. There are also heightened risks associated with export transactions including: take-or-pay obligations to the port for reserving capacity; and, counter-party risks (credit and default risks).

The "export price" CAP advocates for valuing leases for bonus bids and royalties reflect the cost of coal delivered to a site remote from the mine in a form and at a quantity that can be readily loaded into a seaborne vessel.[98] In sum, CAP would have the royalty obligation assessed not only on the sale price of the commodity but also on the transportation and logistics services that form the separate supply chain.

The increase in U.S. coal exports from 2008-2012 was the product of increased global demand, global productive capacity that did not

[97] See CAP, Federal Coal Leasing in the Powder River Basin, at 3 (July 29, 2014) (opining that "[i]n China, for example, Powder River Basin coal fetches $69 per short ton"). We could not find in the report referenced by CAP any statement that PRB coal was selling at $69 per ton in China. Rather, the report cited by CAP reviews costs of delivered costs of coal from other coal exporting nations to the Southeast China coast and reasons that PRB 8,800 Btu/lb. coal could compete with other exports at a total delivered cost of $69.11 per ton. Power and Power, "The Impact of Powder River Basin Coal Exports on Global Greenhouse Gas Emissions," p. 20, Table 1 (2013).

[98] Most, but not all, of these components of the delivered cost of coal for export are reflected in the report referenced by CAP, yet CAP chose to ignore them when making a apples-to-oranges comparison of FOB mine price with total delivered cost.

keep pace with demand and favorable exchange rates (weaker U.S. dollar as compared to Australia). Since 2012, all three of those factors have reversed –slower demand growth, oversupply with the addition of new global coal capacity and strengthening of the U.S. dollar.[99]

U.S. coal exports have ranged from 4 percent to 10 percent of total domestic production between 2001 and 2011.[100] Coal exports have never comprised a significant share of coal production from western states with federal coal lands. During the zenith of U.S. coal exports, exports from Colorado, Montana, Utah and Wyoming were 4 percent of the total production in those states.[101] Between 2001 and 2012, coal exported from western coal producing states totaled approximately 139 million tons.

In general, Western U.S. coal is at a significant disadvantage in the seaborne steam coal market. The four largest importers of coal, China, Japan, India, and Korea are substantially closer to the two largest exporters of coal, Australia and Indonesia with low mining costs. Currently, the vast majority of exports of Western coal must go through Canadian, U.S. Gulf Coast or Great Lakes ports which represent significant transportation and logistics costs, placing the Western mines at a competitive disadvantage. Transportation distance from the PRB to the Canadian ports is slightly less than 2,000 miles, and the distance to the majority of the proposed U.S. ports is approximately 1,200 miles. Transportation to the U.S. Gulf Coast is comparable to the Canadian ports.

Future Western coal exports are dependent on the development of port capacity on the U.S. West Coast. Current port capacity on the U.S. West Coast is approximately 6 million tons annually. Port capacity in Western Canada is 83 million tons assuming the planned expansions are completed, much of which has been dedicated to Canadian producers. Proposed U.S. West Coast port projects could handle approximately 81 million tons annually--about 20 percent of PRB output.

Finally, the role of exchange rates cannot be overstated for the competitiveness of U.S. coal exports. The surge in coal exports between 2009 and 2013 was largely fueled by a weakened U.S.

[99] Global seaborne coal trade is U.S. dollar-denominated making the relative strength of the U.S. dollar a major factor in the competitiveness of U.S. coal exports.
[100] Ernst & Young, U.S. Coal Exports: National and State Economic Contributions, p. 2, Figure 1 (May 2013).
[101] Id. at 3, Table 1.

dollar. Until the Australian dollar strengthens against the U.S. dollar on a sustained basis, global coal prices will remain low and U.S. coals will face steep challenges competing.

The relatively small portion of western coal exported precludes potential exports as serving as a basis to value new coal leases. The value of increased coal exports would be captured in the royalty which is based upon the price of the coal sold at the mine. Charging federal royalties on the total cost of exporting coal (i.e., commodity price F.O.B. mine plus transportation and logistics costs) as CAP and others advocate will shift exports to private coal where royalties are paid on the basis of F.O.B. mine price.

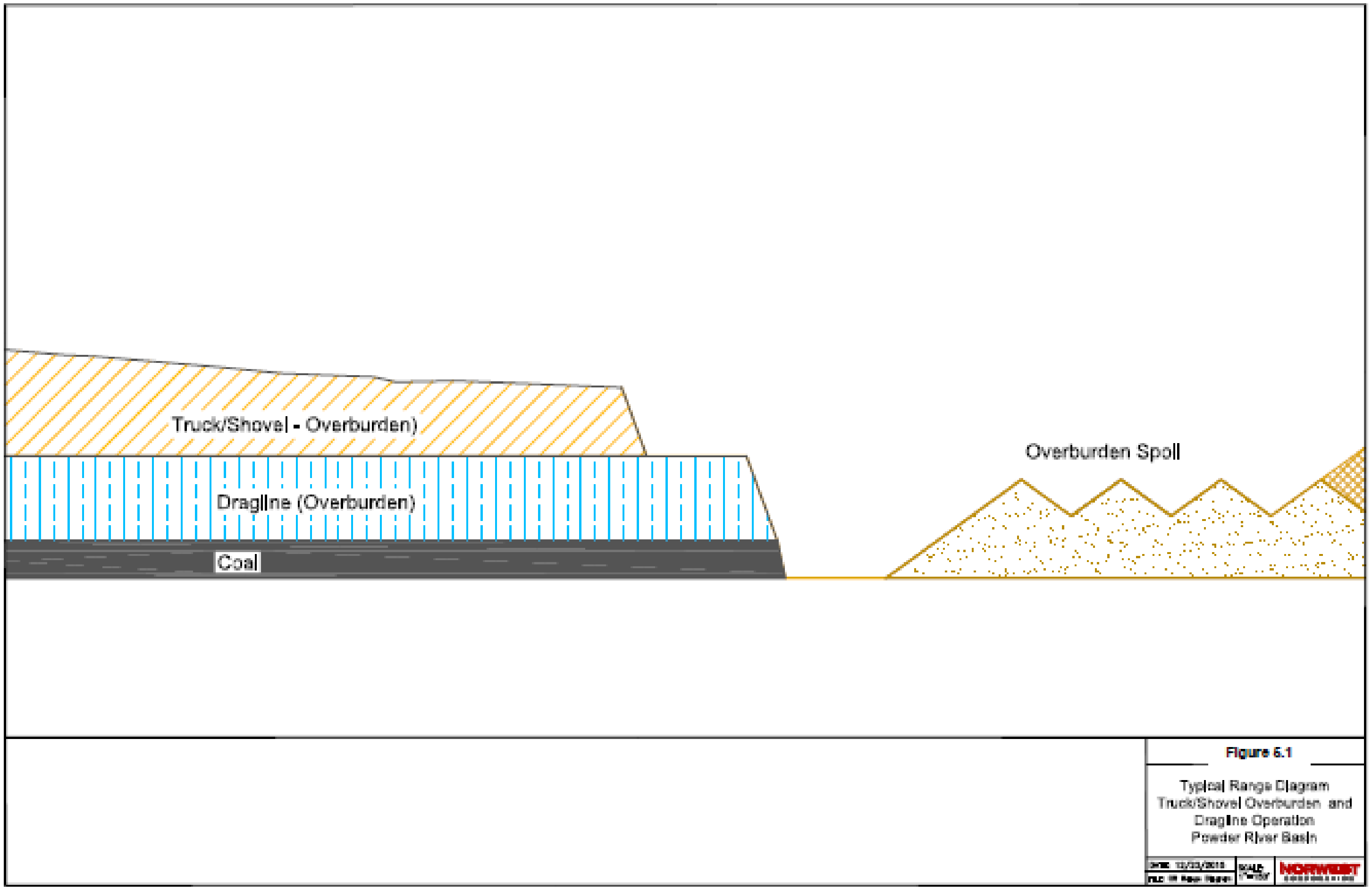
EFFECT OF HIGHER MINING COSTS

Federal coal already confronts disadvantages due to higher royalty rates, geographical distance from markets and in many cases lower energy content of the coal. At $11 per ton for PRB 8,800 Btu/lb. coal, the total burden of royalties, bonus bids, taxes and fees comprise 38 percent of the sale price. At lower sales prices the burden, as measured by the share of price, increase due to the fixed amounts of certain taxes such as AML and Black Lung. For example, a $10 per ton sales price would carry a 40 percent burden from royalties, taxes and fees.

Moving the valuation point for royalties, increasing royalty rates, adding higher fees or other charges will impair the competitiveness and sale of federal coal. If coal producers determine that they do not want to lose market share due to higher prices, they will have to absorb the higher costs. This will ultimately reduce their operating margins impairing the amount of federal coal that is mined.

Due to the geology in the PRB, the amount of overburden that must be removed per ton of coal mined is continually increasing. As the overburden quantity increases, the cost of mining increases. In this case, the selling price of coal at the mine is essentially fixed. If a higher portion of the revenue goes to cover higher royalty payments, there is less to go towards mining costs. With less money to go towards mining costs, the ability to mine coal with a higher overburden ratio without losing money is diminished. That means each successive ton costs more than the last one. If there is no money available to cover the increasing mining costs, those tons will simply not be mined. Figure 5.1 depicts the geology of the PRB with its increasing overburden.

Figure 5.1 Conceptual Geology of PRB



In their consulting practice, Norwest routinely conducts this analysis on both existing mining operations and mines being considered for development. The objective of the analysis is to determine how many tons can be mined from a deposit with increasing overburden removal costs given a limit on the price at which the coal can be sold. To demonstrate this concept, Norwest prepared an illustrative analysis showing the effect of increased mining costs on the number of tons that can ultimately be mined. This analysis is based on the same labor and benefits rates, equipment costs, explosives costs, production taxes and royalties as we have recently used in similar mining studies. The results of this analysis are shown below in Table 5.1

Table 5.1 Illustrative Mine Costs – Existing Tax and Royalty Structure

Strip Ratio	3.0 : 1	3.5 : 1	4.0 : 1	4.5 : 1	5.0 : 1
Tons Mined (000's)	15,000	15,000	15,000	15,000	15,000
Overburden Removed (000's)	45,000	52,500	60,000	67,500	75,000
Coal Sales Price at the Mine	$11.00	$11.00	$11.00	$11.00	$11.00
Federal Production Royalties	1.38	1.38	1.38	1.38	1.38
Federal Lease Bonus	1.06	1.06	1.06	1.06	1.06
Wyoming Severance Tax	0.56	0.56	0.56	0.56	0.56
County Ad Valorem Tax	0.48	.48	0.48	0.48	0.48
Federal Black Lung Excise Tax	0.46	0.46	0.46	0.46	0.46
Federal Abandoned Mines Reclamation Fee	0.28	0.28	0.28	0.28	0.28
Total Royalties and Taxes	4.22	4.22	4.22	4.22	4.22
Royalties and Taxes as Percent of Sales Price	38%	38%	38%	38%	38%
Net Revenue to the Mine	$6.78	$6.78	$6.78	$6.78	$6.78
Operating Expenses					
Overburden Removal	3.30	3.85	4.40	4.95	5.50
Coal Mining, Handling and Loading	1.32	1.32	.32	1.32	1.32
Final Reclamation Cost	0.50	0.50	0.50	0.50	0.50
Equipment and Facilities Depreciation	1.55	1.55	1.55	1.55	1.55
Mine Administration and Operations Support Costs	0.35	0.35	0.35	0.35	0.35
Total Direct Production Costs	7.02	7.57	8.12	8.67	9.22
Operating Margin	$(0.24)	$(0.79)	$(1.34)	$(1.89)	$(2.44)

For this analysis, a recent sales price of Wyoming coal of $11 per ton was used. The production taxes and royalties are based on actual rates and calculation methodology currently employed in Wyoming. Operating expenses were modeled based on a mine with a capacity of 15M tons per year. Cost per material unit moved was developed with a detailed approach using a mine plan and an equipment fleet of large shovels and trucks. Costs were derived by calculating equipment operating hours based on productivity rates, equipment operating costs per hour, detailed manpower schedules and labor and benefits costs, and estimates of supplies and contract services. The unit cost of moving material was then applied to the overburden and coal production for each strip ratio scenario. Depreciation is taken from the capital required to develop such a mine and amortized over its useful life. Mine Administration and Operations Support includes labor and benefits and supplies costs related to mine management, engineering, procurement, human resources, accounting, and safety departments.

The operating margin is simply the revenue less the production taxes and royalties and the direct operating costs. It does not include all costs incurred by a mining company such as interest, income taxes, corporate overhead and some selling expenses. The intent of this analysis is not to predict net income but to illustrate the effect of increased mining costs on the tons that can ultimately be mined from a particular deposit.

Table 5.1 shows that at an $11 selling price, coal resources with a stripping ratio above 3.0:1 could not be mined and still have a positive operating margin.

Table 5.2 below shows the impact of valuing coal at a Midwest destination as suggested by CAP in their December 14, 2014, paper. The royalty was calculated using the $37 delivered price in CAP’s paper. This raised the royalty from $1.38 per ton to $3.63 per ton. All other costs and assumptions are the same as in Table 5.1.

As can be seen in Table 5.2 the effect of the $2.25 per ton increase in royalty costs makes it economically infeasible to mine coal above a 3.0:1 strip ratio.

In this example, a loss of over $146 million in federal royalties and lease bonuses would result from the tons above a 3.0:1 stripping ratio not being mined. The federal, state and county governments would lose more than $107 million in taxes and fees. The results of such polices are contrary to the mandates and purposes of the MLA, SMCRA and other laws to maximize recovery of the coal resource while ensuring the public receives fair market value.

Table 5.2 Illustrative Mine Costs – Royalties Based on Midwest Destination

Strip Ratio	3.0 : 1	3.5 : 1	4.0 : 1	4.5 : 1	5.0 : 1
Tons Mined (000's)	15,000	15,000	15,000	15,000	15,000
Overburden Removed (000's)	45,000	52,500	60,000	67,500	75,000
Coal Sales Price at the Mine	$11.00	$11.00	$11.00	$11.00	$11.00
Federal Production Royalties	3.63	3.63	3.63	3.63	3.63
Federal Lease Bonus	1.06	1.06	1.06	1.06	1.06
Wyoming Severance Tax	0.43	0.43	.43	.43	0.43
County Ad Valorem Tax	0.37	0.37	.37	0.37	0.37
Federal Black Lung Excise Tax	0.46	0.46	0.46	0.46	0.46
Federal Abandoned Mines Reclamation Fee	0.28	0.28	0.28	0.28	0.28
Total Royalties and Taxes	6.24	6.24	6.24	6.24	6.24
Royalties and Taxes as Percent of Sales Price	57%	57%	57%	57%	57%
Net Revenue to the Mine	$4.76	$4.76	$4.76	$4.76	$4.76
Operating Expenses					
Overburden Removal	3.30	3.85	4.40	4.95	5.50
Coal Mining, Handling and Loading	1.32	1.32	1.32	1.32	1.32
Final Reclamation Cost	0.50	0.50	0.50	0.50	0.50
Equipment and Facilities Depreciation	1.55	1.55	1.55	1.55	1.55
Mine Administration and Operations Support Costs	0.35	0.35	0.35	0.35	0.35
Total Direct Production Costs	7.02	7.57	8.12	8.67	9.22
Operating Margin	($2.26)	($2.81)	($3.36)	($3.91)	($4.46)

AFFILIATE SALES

BACKGROUND

In two advocacy papers, CAP claims that current regulations contain a "loophole" that allow federal coal producers to avoid paying royalties on the market value of coal.[102] According to CAP, a coal company selling coal to an affiliated organization can avoid paying the royalty on a higher sales price if the affiliate resells the coal at a higher price. Neither paper provides any analysis to support such a claim. The 2014 paper simply makes the statement. The 2015 paper glosses over the lack of analysis by simply listing coal company affiliates and subsidiaries without identifying whether these affiliates are engaged in coal sales, mine operations, services or land holding entities. It should be unremarkable that enterprises are organized around separate corporate entities to expand their business through acquisitions, allocate risk, raise capital and engage in different lines of business. CAP never examines the applicable coal valuation regulations which provide extensive reporting and auditing requirements to assure royalty is paid on the proceeds that should be received under an arm's length sale.

SALES TO AFFILIATE COMPANIES

The formation and use of different subsidiaries or affiliates to perform distinct business activities is a standard practice in many industries. Typically, many coal customers such as electric utilities perform the logistics and transportation function for the coal they purchase at the mine, others will use third party brokers, trading companies and logistics firms to perform this function and assume certain risks. This is often the case for smaller customers (e.g., industrial) and coal exports.

Some coal companies decided to diversify and vertically integrate their business by forming separate corporate entities to compete with third party brokers and logistics firms in providing these non-mining services. Given their experience, expertise and customer relationships, they believe they can perform those services more efficiently and extend their market reach. [103]

[102] CAP, "Modernizing the Federal Coal Program" (Dec. 9, 2014); CAP, "Cutting Subsidies and Closing Loopholes in the U.S. Department of Interior's Coal Program," (Jan. 6, 2015).
[103] In many ways, this diversification is the flip side of the backward vertical integration prevalent in the 1960s and 1970s with electric utilities and steel companies acquiring and operating mines to secure reliable fuel supplies for their businesses. In 1976, seven of the top 15 coal producers were affiliates of utilities or steel companies

There is nothing perfunctory about the logistics business. It carries separate and significant commercial risks and costs including: the cost of transportation arrangements to deliver coal to designated destinations; the fees paid for reserving and using terminal capacity; demurrage charges and “take-or-pay’ obligations under long term contracts with rail and terminal providers. This separate business segment also carries commercial risks of non-performance by those contracted for the services as well as non-payment by the coal buyer.

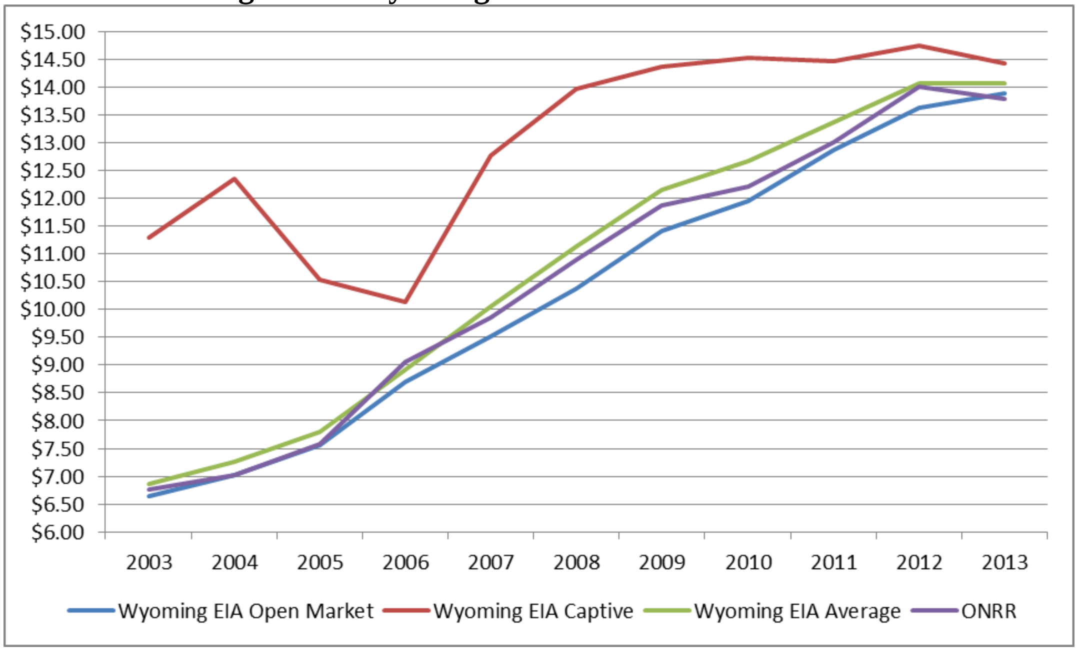
Independent brokers, logistics and trading firms are not subject to federal royalties for the reselling of federal coal they purchase from a mine, and, for good reason: the services they perform are not coal production. There is no legal, economic or legitimate policy justification to treat vertically integrated enterprises engaged in these separate functions differently.

The claim that coal producers are selling coal to affiliates to avoid royalty obligations is contradicted by the available data. The sales price reported to the Office of Natural Resources Revenue (ONRR) for federal coal produced in Wyoming is on average higher than the price reported to EIA for Wyoming open market (i.e., non-captive) sales (Figure 6.1). The reported prices to ONRR also track closely with the price reported for *all* coal sales reported to EIA—both captive and open market. [104] In short, the data does not support CAP’s speculative claim that coal companies are “cloaking” sales to affiliates as “arms-length” transactions in order to reduce royalty payments.

accounting for close to 20 percent of all coal production. See EIA, *The Changing Structure of the U.S. Coal Industry 1976-1986* (DOE/EIA-0513) (June 1988). Today only one of the top 15 coal producers is an affiliate of a coal consumer.

[104] The quantity and revenue for open market and Captive Sales are reported to EIA on Form 7A. Captive market sales include both sales and transfers to a parent or subsidiary company Form EIA 7-A Part 5 Item 7.

Figure 6.1 Wyoming Coal Prices



Sources: U.S. Energy Information Administration
U.S. Department of the Interior, Office of Natural Resources Revenue

ROYALTY VALUATION PROCEDURES

More important than whether coal was sold to an affiliate or subsidiary is how the sales are valued for royalty purposes. The ONRR has procedures in place to ensure proper valuation of coal sold to affiliates or subsidiaries under non-arms-length transactions.

The regulations at 30 § CFR 1206.257 (c) include five benchmarks applied sequentially to establish the value for royalty purposes. The first benchmark uses comparable sales with the conditions that the non-arms-length value is never based on anything less than gross proceeds and the value is based on coal in marketable condition. The five benchmarks in order are:

1. The prices are comparable to other arms-length transactions where neither the buyer nor seller is affiliated with the lessee and the coal and contract terms are similar. In other words, the prevailing market for similar coal in the same area.
2. The price is accepted or approved by a public utility commission for inclusion in the rates charged to electric power customers

3. The price of coal reported to the DOE, U.S. Energy Information Administration
4. Determine the value using spot prices and other relevant matters including circumstances unique to the mine
5. A net back or any other reasonable method determined in consultation with ONRR

Under all benchmarks ONRR has the last word on the value of coal in non-arm-length sales and the benchmarks are applied in the order noted above. These benchmarks provide ONRR with several tools to ensure that the value of coal sold in non-arm's-length transactions is comparable to what the value if the coal was sold in an arm's-length transaction. Since most of the coal is sold at a mine occurs under arm's-length transactions to third parties, ample transactions are available to compare the sales prices under arms-length and non-arm's-length transactions from the same mine.

CAP and others claiming companies are using sales to affiliates to avoid higher royalties never discuss the regulatory valuation framework. There is a system of checks and balances in place to ensure that the coal sold under non arm's-length transactions is properly valued. Coal producers are required to provide copies of coal contracts to ONRR and to report production and sales information to ONRR each month. These transactions are not "cloaked" in any way; they are openly reported to ONRR and are subject to review, audit and adjustment by ONRR.

THE COUNCIL OF ECONOMIC ADVISERS ANALYSIS

Recently, the Council of Economic Advisers (CEA) added its own perspectives on the question of whether the current federal coal leasing program delivers a fair return.[105] The CEA largely outsources its analysis by resting on the observations made in third-party advocacy papers previously discussed in this report. CEA's analysis also discloses a lack of familiarity with energy markets, transactions and the federal coal leasing program. As a general matter, the policy discussion evinces a disdain for markets and the benefits accruing to consumers. CEA is quick to suggest either market or policy failures as the reasons for federal coal's growth when the answer lies with fundamental economic realities of economies of scale and higher productivity. The result is a series of market distorting policies designed to neutralize the economic advantages arising from these factors.

INCORRECT ASSUMPTIONS

CEA begins with the uncritical acceptance of several undocumented observations gleaned from several advocacy papers: (1) lease sales result in bonus bids below FMV due to fewer bidders; (2) the federal government is operating in an environment of asymmetric information precluding the it from estimating FMV; and (3) royalties based on ad valorem rates incentivize companies to reduce reported prices from coal sales.

<u>Thin Bidding Pools for Lease Sales</u>: As previously discussed, the experience under the regional lease and LBA methods demonstrates no material difference in the number of bidders. Moreover, it is well documented that since leasing shifted to the LBA method, bonus bids have steadily increased with the most recent bids in the PRB 700 percent higher than before the LBA process.

The thin bidding pool is a consequence of the advanced development of the coal regions and changes in the industry structure. The development of the federal coal regions produces a higher hurdle for new entrants facing substantially more capital costs to build a new mine infrastructure to compete with existing

[105] Council of Economic Advisers, "The Economics of Coal Leasing on Federal Lands: Ensuring a Fair Return to Taxpayers," (June 2016).

operations. A thinner bidding pool is also the result of significant industry restructuring. When coal prices increased through the 1970s, the number of coal companies and mines increased. As prices declined thereafter, the number of firms and mines decreased as the smaller marginal mines became less profitable and closed. Coal production increased with fewer mines and the larger more efficient mines (> 1 million tons/yr.) accounted for more than 75 percent of all coal production in 1997 as compared to 44 percent a decade earlier.[106]

The pool of potential bidders has not only thinned with the substantial decrease in the number of coal companies participating in the industry, but there are now even fewer companies with the financial capacity and specialization necessary to build and operate long-lived assets typical in the western coal fields. In 1976, approximately 52 percent of all major U.S. coal producers (> 3 million tons/yr.) were owned by oil and gas companies, electric utilities or steel companies. Only a few major producers are affiliated with such firms today. Moreover, many major producers today have demonstrated a preference to focus on specific coal regions, specific mining method (e.g., underground coal mining), or both.

<u>Asymmetric Information</u>: The foundation of CEA's analysis is the assumption that DOI lacks sufficient information to accurately determine FMV. This assumption is just one example where CEA's economic theory crashes into reality. To begin with, DOI is in possession of the greatest store of information related to coal quantity and quality. The United States Geological Survey (USGS) has been performing coal and mineral geological surveys for well over a century.[107] FCLAA added provisions directing the USGS to conduct a comprehensive coal exploratory program to obtain sufficient information on the extent, location and potential for developing recoverable coal resources on federal lands.[108] The purpose of this program was, among others, to "improve[e] the information regarding *the value of public resources and revenue* which should be expected from leasing." [109] Companies conducting coal exploration under an exploration license are

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[106] See EIA, *The U.S. Coal Industry, 1970-1990: Two Decades of Change, p 20* (DOE/EIA-0559) (Nov. 1992); EIA, *The U.S. Coal Industry in the 1990's: Low Prices and Record Production*, p.2 (DOE/EIA-0631) (Oct. 1999).
[107] See USGS, *Records and History of the United States. Geological Survey*, Circular 1179 (2000).
[108] 30 U.S.C. § 208-1(a).
[109] *Id*. at § 208-1(a)(2).

required to furnish DOI copies of "all data (including but not limited to, geological, geophysical and core drilling analyses) obtained during such exploration."[110] DOI is also in possession, and approves, all mine plans for operations on federal lands. In sum, the DOI has direct access to useful information for existing operations on nearby lease tracts that are included in a LBA.

As for the other information CEA suggests is less observable, DOI has ample and contemporaneous information from comparable coal sales from the same and nearby leases. DOI is also capable of accessing various published index prices (a/k/a price assessments) for coal from different regions delivered by different transportation modes (i.e., rail, barge). These indices are reliable and used widely for indexation of long term contracts, spot contracts, derivatives transactions, internal transfer pricing and market analysis.

In sum, DOI has access to the foundational information needed for estimating FMV. The coal leasing program is anything but a setting with asymmetric information.

CEA also trips on the myth perpetuated in the CAP and Headwater papers when suggesting that transportation costs are "self-reported" and incentivize inflating the transportation costs. There are no transportation deductions allowed for "in-mine" transportation to the loading point. [111] Coal is sold typically F.O.B. mine and the transportation costs are incurred by the customer not the coal producer. There is nothing to "self-report." The coal producer has no influence over the rates charged the coal buyer by the common carrier for delivery. There are no options for coal producers, as CEA apparently thinks, to more efficiently transport coal. The options for transportation are limited—the common carrier railroad controls the rates and movement of trains from the mine to the buyer's designated destination. In any event, DOI may review sales agreements between the coal producer and buyers for any transaction DOI believes the gross proceeds reported for the sale of coal is less than all the consideration paid to the coal company for the coal.[112]
As for washing allowances, it should be of little moment in view of the fact that few coal preparation plants exist at western mines on

[110] 30 U.S.C.§ 201(b)(4).
[111] 30 C.F.R. § 1206.261(a)(2).
[112] As explained earlier in the discussion of affiliate sales, ONRR regulations provide several tools to determine the value of coal for royalty purposes including review of documents to establish any deductions.

federal lands. Only nine coal preparation plants operate in the six major federal coal producing states in the west and none of them are located in the PRB which accounts for most of the coal produced from federal leases.[113] Even Headwaters implicitly admits that questions about allowable cost deductions are a red herring amounting to 0.3 percent of the sales price of coal from federal leases over thirteen years.

In view of the information available to the DOI, CEA's analogy that the current system is akin to allowing homeowners to declare the value of their homes for tax purposes is grossly inapt. CEA admits that the public property assessor uses "comparable sales" to determine the value of the property. This is precisely the method used by DOI in making FMV determinations. Moreover, unlike a public property assessor, DOI has more robust and timely information to guide its determination of FMV for bonus bids and coal valuation for royalties. DOI's regulations are detailed in setting forth the revenues included in the gross proceeds for applying the royalty as well as the limits and documentation of any allowances. This information is subject to review and audit. In short, public property assessors are not allowed "into the home," but ONRR does have access to verify.

<u>Royalties Based on Rates Incentivize Reporting Reduced Sale Prices</u>: CEA suggests the combination of imperfect information and use of ad valorem royalties lends itself to manipulation of the market value. CEA offers no documentation for speculating that any manipulation does or can occur under the program. As discussed, DOI has the tools and has access to a wealth of information to verify the accuracy of sales prices and any allowances.

CEA's premise rests on the Headwater's deceptive construct—the "effective royalty rate." There are several fundamental flaws in this construct. First, Headwaters includes in its "effective royalty rate" leases that received royalty rate reductions; and, for purposes of its calculation, assumes the coal from those leases would have been mined and sold without the rate reductions. Those rate reductions were granted after a demonstration the coal would be bypassed because of higher mining costs or the lease tract would not be economic because the royalty rate was uncompetitive as compared to lower rates prevailing in that region. Neither

[113] See Coal Age, *2015 U.S. Prep Plant Census* (Oct. 2015).

Headwaters nor CEA provide any analysis that the coal would be mined without the reductions. As the data in the Headwaters report discloses, the royalty rate reductions are mostly in states where federal coal is a lower proportion of production, so rate reductions would be expected in order to place federal coal on a competitive par with non-federal coal.

Second, the most glaring flaw in CEA's acceptance of Headwaters' "effective royalty rate" is revealed in CEA's mistaken belief that that the total delivered cost—what Headwaters calls "gross market price"--reflects the "price that sellers ultimately receive for the coal sold from Federal leases."[114] As explained earlier, this is fundamentally incorrect.

Headwaters' "effective royalty rate" calculation is comprised of metrics it creates called "gross market value" and "gross market price." Each adds to the coal sales price the transportation costs incurred by the buyers for the delivery of the coal. By dividing the royalties paid on the *actual* sales price received by the coal producer into the larger total delivered cost (i.e., coal sales price + cost transportation incurred by buyers) Headwaters derived by design an artificially low "effective royalty rate" to create the impression that coal producers pay royalties below the statutory rates.

The Headwaters' terms "gross market price" and "gross market value" are artificially created to advance policies for converting the production royalty into a new federal tax on the entire coal supply chain.

GLARING OMISSION OF EXECUTIVE POLICIES ON MARKETS

CEA suggests that downward pressure on coal prices exerted by lower cost PRB coal is a likely contributor to the "sharper decline in coal production in the Appalachian and interior coal producing regions *over the past few years*." Actually, the steep decline in Central Appalachian coal production over the "past few years" is closely correlated with a series of recent policies and regulations that have had an outsized impact on Central Appalachian coal mines.

[114] Council of Economic Advisers, p. 8.

The 1990 Clean Air Act Amendments imposing more stringent air quality standards combined with the lower sulfur and lower cost coal in the PRB introduced increased competition in markets served by mines in other coal basins with higher sulfur and higher cost coals. However, the immediate and most significant impact was on Illinois Basin production which experienced a 40 percent drop in production from 1990 through 2000 when a substantial portion of its core market switched to PRB coal. Contrary to CEA's statement about decreases in Illinois Basin production, over the past several years Illinois Basin production has steadily increased with its markets migrating outside its historically core markets to customers formerly served by Central Appalachian coal mines.[115]

More recently, the sharp decline (62 percent) in Central Appalachian coal production corresponds to several key executive policy actions.

1. Moratorium on Central Appalachian Mine Permits (2009): A de-facto moratorium imposed by the Environmental Protection Agency (EPA) in March 2009 on new coal mining permits in Kentucky, Virginia and West Virginia. This moratorium occurred when 235 Clean Water Act § 404 permit applications were pending with the Army Corps of Engineers. As the backlog grew, more than half those applications for new or expanded mines were withdrawn as coal companies grew increasingly frustrated with delays and new guidance that was never properly adopted by EPA. Coal production dropped steeply (45 percent) in just five years from 234 million tons in 2008 to 127 million tons in 2013. EIA estimated that the moratorium and guidelines imposed by EPA decreased Central Appalachian mine productivity by 20 percent.[116]
2. Cross State Air Pollution Rule (CSAPR) (2011): Imposed an increasingly stringent two-phased emission reduction budget for power plants in most of the eastern states, with many of the plants affected using Central Appalachian coal.
3. Mercury and Air Toxic Standards (MATS) (2012): Forced the closure of hundreds of coal-fired power plants—more than half were plants using Appalachian coal. EPA projected the rule would close only 4,500 megawatts (MW) of power plant

[115] Since 2000, Illinois Basin coal production has grown from 87 million tons to 137 million tons in 2014.
[116] EIA, Annual Energy Outlook-2011, Legislation and Regulations: *Representing impacts of U.S. EPA's interim permit review guidelines for surface coal mining operations,* Rep. No. DOE/EIA 0383 (April 26, 2011).

> capacity. In one year alone, MATS forced the closure of ten times the capacity of capacity (42,000 MW) EPA estimated would occur over the life of the rule. [117] Even by EPA's own estimates, the annual costs of the rule would be $9 billion annually in return for a meager $6 million in benefits. To make matters worse, almost half the compliance costs are related to imposing standards on emissions EPA concedes do not pose any threat to public health. From 2012 when EPA issued the final MATS rule through its 2015 compliance deadline, Central Appalachian coal production declined by 40 percent.

Neither PRB coal nor the federal coal leasing program are the reasons for the sharp decline in Appalachian coal production over the past several years as CEA postulates in its paper. Rather, Central Appalachia has experienced an outsized impact from executive actions impairing the productivity of the mines and the closing of a substantial portion of its market.[118]

MARKET DISTORTING POLICIES

Building upon the discredited notion that the price paid for coal at the mine does not reflect the true commodity value, CEA pivots to policy changes designed to capture revenue unrelated to the production of coal by either moving the valuation point beyond the mine or raising the royalty rates to achieve the same purpose. CEA does not dispute that fundamental economic factors—higher productivity, low heat value—explain the difference between the lower prices received for PRB coal as compared to coal produced in other regions. Yet, CEA appears unsatisfied with the answer as well as the results: higher sales volumes, more royalty revenue and lower electricity prices.

CEA suggests several changes to coal valuation; all entailing the government establishing "adjusted" market prices. These include: adjustments for heat content, quality and location of the coal.[119]

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[117] EIA, Annual Energy Outlook 2016 (Early Release May 17, 2016) (noting that compliance with MATS drives coal plant retirements in the near terms, with 40,000-45,000 MW of coal retirements in 2016 alone).

[118] CEA's theory appears strikingly similar to the fictional narrative sponsored by the Center for American Progress which attempts to steer blame for the steep drop in Central Appalachian coal production away from executive actions and attribute them to the federal coal leasing program. See Center for American Progress, "Revitalizing Appalachia" (Feb. 2015).

[119] CEA goes so far to suggest using nation-wide prices to determine the starting point for royalty valuation subject to deductions for transportation costs. While one might derive an average coal price by combining all coal prices from different regions—the different coal qualities and cost structures preclude deriving an actual market price for all coal. The suggestion appears to be grounded in an assumption that one can derive a more uniform price for all coals akin to natural gas which has a substantially lower variance in fuel composition and properties than coal.

CEA never explains how the current market does not already reflect those differences or why government-derived “Btu-adders” and adjustments for sulfur content or other characteristics would be more efficient than the market place in pricing those differences. At bottom, all of these suggestions are market distorting policies designed to increase the cost of federal coal in the service of politically-favored substitute sources of electricity generation. Greater transparency in revealing the true motivations for these policy changes may not make them more credible measures for seeking fair return, but it would fuse them with a greater sense of intellectual honesty.

CONCLUSION

The federal coal leasing moratorium rests upon contrived reasons that are the product of the deceptive use of data and disdain for market principles. The real motivations are disclosed in most of the reports relied upon in the Secretarial Order and BLM Scoping Notice which hijack the banner of seeking fair return to the public in the service of an objective to suppress the use of the nation's vast hydrocarbon resources for the benefits of Americans.

Short on facts and devoid of analytical rigor, the reports enlisted by the Secretary go long on rhetoric with purely fictional claims that "loopholes" are embedded in the leasing program. The root cause of their concern is the success of coal producers on federal lands in overcoming above-market royalty rates and geographical disadvantages to deliver a reliable and cost-effective source of energy that benefits consumers and businesses.

Paradoxically, the market distorting policies advocated by these organizations will yield less revenue for the public and increase domestic energy costs by keeping coal in the ground. Moreover, these same policy prescriptions for distorting valuation, increasing royalty rates and adding new government exactions in the guise of externality charges would by logical and legal extension require similar policy changes for all energy sources developed on federal lands.

The combination of the rise in consumption of federal coal and the $111 billion investment in emission controls has reduced the emissions of coal-fired power plants by 92 percent per unit of electricity generated. States that, on average, generate 70 percent of their electricity from coal pay an average of 13 percent less than the national average price for electricity. Those states that generate, on average, less than 8 percent of their electricity from coal pay 24 percent more than the national average.

The current diversified portfolio of U.S. power supply, anchored by coal baseload power plants, lowers the cost of generating electricity by $93 billion annually and reduces the variability of monthly power bills by half. Studies and actual experience document that reducing the diversity of the power supply mix produces negative economic impacts similar to an economic downturn—reduced GDP, lost jobs, lower disposable income and diversion of capital from more productive applications.

The "honest and open conversation" the Secretary of the Interior called for prior to announcing the federal coal leasing moratorium must begin with the facts, scrutiny of the rhetoric that served as the catalyst for the Secretarial Order and consideration of the vast benefits accruing to the public in the form of steady revenues and lower energy costs.