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ENERGY VENTURES ANALYSIS

Wyoming Coal Study

Prepared for:

WYOMING ENERGY AUTHORITY

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1 Summary and Action Plans

The Wyoming Energy Authority (WEA) commissioned this study of the Wyoming coal industry. The goals of this study are to evaluate Wyoming's coal supply and demand outlook, identify issues affecting Wyoming coal, and recommend actions the state can take to improve the future of the coal industry and the state.

The Wyoming coal industry is at a crossroads. Coal production peaked at 466 million tons in 2008 but declined rapidly through 2024 to just 191 million tons, with a modest recovery to 211 million tons in 2025. The cause of the production decline was reduced coal demand for electric power generation, driven by new environmental regulations forcing the closure of coal-fired power plants and the displacement of coal generation by natural gas and new wind and solar power plants (which were subsidized by large federal tax credits).

The outlook for Wyoming coal could continue the downward trend in demand if federal policies remain that force the closure of coal power plants and subsidize new wind and solar power plants. Wyoming coal demand could even fall precipitously in the 2029 – 2032 period if the 2024 Greenhouse Gas (GHG) regulation were to be reinstated and mandate that all existing coal power plants reduce carbon dioxide emissions.

However, the outlook for Wyoming coal demand has improved over the past year. First, the current Administration has moved quickly to roll back the onerous federal environmental regulations that were forcing coal plant closures and has proposed reversing the Endangerment Finding that was the basis for regulating carbon dioxide emissions (this would make it difficult for future administrations to reinstate GHG regulations). Rescission of this finding will most likely be litigated through mid-2028. This timeframe will likely have a chilling effect on capital investment for coal reserves, power plants, and coal industry infrastructure.

The Administration has also used executive orders to prevent the imminent closure of some coal plants, allowing time for plant operators to reconsider long-term plans. Second, Congress acted to phase out subsidies for new wind and solar power plants that were displacing coal generation (although a future Congress could restore these subsidies). Finally, growth in power demand to supply industry (data centers) and increased public demand have raised concerns about adequate power supply and caused many coal plants to delay or reverse retirement plans. While construction of many new coal power plants is not likely in the near term, Wyoming coal demand could experience modest growth from increased utilization of the existing coal fleet, where utilization rates remain well below historical levels.

Export sales of Wyoming coal remain at very low levels. However, global coal demand continues to grow, led by new coal power plant construction in Asia. While the current economics are challenging, the primary obstacle to growth in Wyoming coal exports is the lack of coal port capacity on the U.S. West Coast, which would allow the efficient and low-cost shipment of Wyoming coal to the growing Asian market. The proposed new coal terminal in Oakland, California, is the best near-term prospect to spur new Wyoming coal exports.

Wyoming coal supply faces challenges in meeting demand for this coal. With demand declining over the past 15 years, there has been little reinvestment in coal mines in both the Powder River Basin (PRB) and the Green River Basin (GRB). There have been no significant additions to the recoverable coal reserves at these mines since 2012, and the existing reserve base is being depleted through mining. Even if Wyoming coal demand continues to decline, the existing mines will not be able to meet projected demand after 2035 without additional coal reserves. If Wyoming coal demand experiences a modest recovery to meet electricity load growth, existing leased Wyoming coal reserves would not be adequate to support coal demand after 2030.

As a result, much work needs to be done to assure the future of Wyoming coal. There have been many positive steps taken by the current Administration to reverse the decline in coal demand and facilitate increased coal supply. However, many of these actions are incomplete and will face challenges in court and from future administrations.

The work on this study was performed by Energy Ventures Analysis, Inc. (EVA), and its subcontractors WWC Engineering (WWC) and Energy Policy Network (EPN).

1.1 Prioritize Potential Markets for Wyoming Coal

The analyses in this study show that domestic electric power plants will remain the priority market for Wyoming PRB coal. In 2024, the domestic power market accounted for about 97% of total Wyoming PRB coal sales, with 2% industrial sales and about 1% in overseas exports. The state of Wyoming's primary objective should be to maintain or increase the domestic power market, which is threatened by federal environmental regulations and state laws mandating reductions in carbon dioxide emissions from coal combustion. The highest priority should be to prevent federal regulations that would force existing coal plants to reduce CO2 emissions or retire under the 2024 GHG Rule or a similar future regulation. The state of Wyoming's efforts should include working with the EPA, Congress, and/or pursuing court challenges to eliminate federal regulation of greenhouse gases from electric power plants.

The potential for increased sales of Wyoming coal to domestic power plants can come from higher utilization (capacity factors) of existing coal plants and possibly the construction of new coal power plants. As discussed in **Section 3** of this report, Wyoming PRB coal burn fell to about 186 million tons in 2024, due to power plant closures and a drop in the average annual capacity factor to 42% for the PRB plants. In 2025, Wyoming PRB coal burn is estimated to increase to about 216 million tons, with the average capacity factor rising to almost 50%. **Section 3** of this report shows that, under the Gray case (which assumes no future GHG regulations on existing coal plants), further increases to average 60% capacity factors are projected to boost Wyoming PRB coal burn to over 250 million tons by 2030 and maintain coal burn over 200 million tons per year throughout the 2050 forecast period.

The outlook for constructing new coal-fired power plants is less favorable than for maintaining existing coal-fired power plants. Construction of new coal plants faces many challenges, including the existing New Source Performance Standard for CO2 emissions, economic competition from new gas-fired CCGT plants, subsidized competition from new wind and solar power plants, permit delays due to political opposition, and financing limitations stemming from ESG considerations. If carbon capture and sequestration (CCS) is required for new coal plants, even the Section 45Q tax subsidy is unlikely to make new coal plant construction economically feasible.

Exports of Wyoming PRB coal to overseas markets are currently constrained by the lack of available deep-water port options on the West Coast of the United States, which are required to reach the growing Asian market. Existing West Coast coal terminals have limitations, including limited loading capacity at Westshore and the upcoming closure of the Richmond coal terminal. Coal terminals not located on the West Coast incur excessive transportation costs to access the Asian market, making delivered costs uncompetitive with supplies from countries in the Pacific (especially Indonesia). The proposed new coal terminal in Oakland could open access for up to 10 million tons per year of Wyoming PRB coal, which would be a modest addition to the Wyoming PRB coal market. A new coal terminal along the Columbia River, such as the former proposed Millennium coal terminal, would be needed to have a significant impact on Wyoming PRB coal demand. The state of Wyoming should continue its efforts to support a new coal terminal on the West Coast, such as the proposed Oakland terminal, through financing or long-term contracting for terminal capacity.

Because production costs for Wyoming GRB coal are much higher than for Wyoming PRB coal, the market is limited to local power plants and industrial consumers. (Distant coal consumers have found it more economical to purchase lower-cost PRB coal.) The local consumers (all in Southwest Wyoming) include two power plants (one of which is converting from coal to natural gas) and two large industrial consumers that mine trona and refine it into soda ash. The priority market for GRB coal is to keep these Wyoming customers burning coal rather than converting to natural gas or potentially nuclear. The local GRB coal mines need improved permitting of existing coal reserves and leasing of new coal reserves to assure these local customers that Wyoming GRB coal is the low-cost fuel supply for the long term.

1.2 Action Plans to Support Wyoming Coal Markets

This study identified specific actions that can be taken by the state of Wyoming policymakers to address the challenges facing Wyoming coal and improve its future for the benefit of the state.

1.2.1 Wyoming Coal Supply

There has been little investment in Wyoming coal supply since 2012. While no major mines have closed over this period (except for the underground mine at Bridger Coal Company), every mine has been scaled back and produced much less coal in 2025 than it did in 2012. Except for small lease modifications, there have been no new additions to the recoverable reserve base since 2012. Wyoming coal producers have not had the need to invest because demand has been declining steadily over this period.

While the decline in demand is likely to end due to favorable regulatory and market changes, changes will be required for Wyoming coal supply to keep pace with projected demand. Actions to support and increase Wyoming coal supply are discussed in detail in this report and are summarized below.

- **Coal Leasing:** Almost all Wyoming coal is leased from the federal government. Over time, the government has increased the barriers to coal producers leasing new reserves to extend the lives of their mines. Actions needed to increase the ability and reduce the cost of leasing federal coal include:
    - **End the consideration of GHG emissions in leasing federal coal.** Congress (led by the Wyoming Delegation) took a major step in this regard in 2025 by repealing the Buffalo RMP, which banned new Wyoming PRB coal leases due to the alleged environmental impact of GHG emissions by the future customers of Wyoming coal. The exclusion of consideration of downstream GHG emissions from coal leasing should become a permanent federal policy.
    - **Reform the Fair Market Value (FMV) determination process.** The Bureau of Land Management (BLM) sets a minimum FMV for each coal lease, the FMV process is not transparent, and the FMV is not disclosed until after the bids have been received. This discourages coal producers from applying for new coal leases, which is a costly and lengthy process, since coal producers do not know if their bid would be accepted.
    - **Increase the use of Lease by Modification (LBM) sales.** Since most coal producers do not need huge coal tracts to maintain their mine operations, BLM should accommodate the use of LBM sales for leasing new coal tracts up to 100 million tons. The LBM process is faster than the Lease by Application (LBA) process and provides more flexibility for future federal coal leasing.
    - **Extend the timing of Bonus Bid payments.** Under current policy, Lease Bonus Bids must be paid 20% at the time of award and 20% per year over the next 4 years. However, the time to permit and develop additional federal leases is much longer than this 4-year period, so coal producers must pay the cost to lease federal coal well in advance of mining and selling the coal. BLM should revise this policy so that lessees pay Bonus Bids at the rate of 10% per year over 10 years.
    - **Facilitate the reduction of Logical Mining Units (LMU).** Over time, coal producers have accreted additional federal coal leases to the LMU for each mine, even as older leases are mined out. This has the effect of increasing the amount of coal that must be mined from each LMU to satisfy the "continued operations" diligent development requirements, forcing producers to produce more coal than economic in the market. BLM should facilitate modifying the LMU to remove the mined-out areas and reduce the annual production (diligence) required for continued operations.
    - **End the Federal Lease Transaction Fee for federal coal leasing and production.** Under current law, the federal government takes 2.0% of all revenues received by the states for coal leasing, rents, and royalties for "administrative" purposes. This law reduces Wyoming's share of revenue below the 50% share

originally intended and bears no relation to the actual administrative costs for BLM's coal leasing program.

- **Coal Permitting:** There are multiple agencies whose approval is needed to obtain a permit for federal coal. These agencies perform duplicative environmental reviews that greatly extend the time required for permitting. The BLM first completes an Environmental Impact Statement (EIS) for the Resource Management Plan (RMP), then conducts a Programmatic EIS for an individual coal leasing action, and then the Office of Surface Mining and Reclamation (OSMRE) conducts a third EIS when approving a Federal Mine Plan (FMPA). The OSMRE NEPA review can add 5 – 7 years to the process of permitting a federal lease, even when a state like Wyoming has primacy for administering its mine and reclamation program. Actions needed to reform the permitting process:
    - **End duplicative NEPA review.** Environmental reviews should not be required by OSMRE where a state, like Wyoming, has primacy approved for its coal mine and reclamation program.
    - **Revise and reform the surnaming process:** The Assistant Secretary of Land and Minerals should propose new process rules and requirements to fix the extensive, unnecessary, and time-consuming surnaming requirements for a FMPA right of entry issuance.
- **Federal Excise Taxes:** Wyoming coal producers pay a grossly disproportionate share of federal revenues from leasing and producing coal. These revenues include lease bonus sales, rents, royalties, and excise taxes on coal production – the Abandoned Mine Lands (AML) fee and the Black Lung Excise Tax (BLET). These taxes are an unfair burden on Wyoming coal producers and have the effect of reducing economic activity in Wyoming. Actions needed to reform federal coal taxation include:
    - **Reduce Federal coal royalty rates:** Congress addressed this issue in the 2025 OBBBA budget bill, capping the royalty rate on federal coal at 7.0% (surface mine royalty rates were 12.5%) for a 10-year period. This action has provided a significant cost reduction for Wyoming coal producers and should be extended permanently.
    - **Reduce the AML Fee on Wyoming coal:** The AML Trust Fund is over-funded, and excess funds have been spent on projects other than mine reclamation or remain unappropriated. Wyoming coal producers pay about 57% of the total AML taxes collected by OSMRE. Wyoming is considered a certified state, and there are no abandoned post-SMCRA coal mine lands remaining in Wyoming.
    - **Reduce the BLET on Wyoming coal:** Wyoming coal miners receive very little benefit from the Black Lung Disability Trust Fund, which was established in 1972 to cover the workers compensation benefits of coal miners who were not paid by their last employers, yet Wyoming coal producers pay approximately 41% of the annual taxes (while lignite producer and exports are exempt from this tax). At a minimum, the BLET rates should be set at the pre-pandemic level of taxation.

1.2.2 Wyoming Coal Demand

Wyoming coal is primarily sold to domestic coal power plants, with small shares sold to industrial coal consumers and overseas exports. Coal demand at domestic power plants has been declining since 2008, despite the fact that Wyoming PRB coal is the lowest-cost fossil fuel for power generation.

Actions to support and increase Wyoming coal supply are discussed in detail in this report and are summarized below.

- **Federal environmental regulations on coal-fired power plants:** Federal environmental regulations on coal power plants have been the primary cause for reduced demand for Wyoming coal. Most of these actions by the Environmental Protection Agency (EPA) are outside of the control of Wyoming policy makers, but Wyoming can influence federal regulations and initiate or support court actions to limit or repeal excessive rules imposed by EPA. The current Administration has taken actions across the long list of regulations summarized below, but most of these actions will be challenged in court by environmental groups and other states, and it will be important for Wyoming to participate in the legal process.

- **End the regulation of GHG emissions from power plants.** The Administration has proposed to repeal the Endangerment Finding, which underpins EPA's efforts to regulate GHG emissions under the Clean Air Act, but this will be subject to court challenge. Further, this administration has repealed the 2024 GHG Rule requiring existing coal plants to reduce carbon dioxide emissions, which is not technically or economically feasible. EPA should also repeal the New Source Performance Standards (NSPS) for GHG emissions from new coal power plants, which remains a major barrier to building new coal plants.
- **Limit New Source Review (NSR) of maintenance projects at coal power plants.** EPA has brought NSR litigation against many coal power plant owners, claiming that maintenance projects should have triggered the application of NSPS for all environmental standards, which would be prohibitively expensive. EPA has used the threat of massive fines under the Clean Air Act (CAA) to force coal plants to settle lawsuits by agreeing to close some of their coal units. The definition of increased emissions after a maintenance project should be based on emission rates, not total emissions, as coal plants frequently run harder after maintenance projects, yet emit at lower rates. The fear of triggering NSR litigation has limited the willingness of companies to invest in coal power plant maintenance.
- **Repeal the 2024 Mercury and Air Toxics Standard (MATS).** The Administration has proposed to repeal EPA's 2024 rule that tightened MATS, which would force more coal plants to close. This repeal is under review by OMB prior to publication and will be challenged in court.
- **Repeal the 2024 Effluent Limitations Guidelines (ELG) for coal power plants.** This rule would force all coal plants to achieve zero liquid discharge of wastewater from coal plants (ash handling and scrubber wastewater) or stop burning coal. The Administration has published a rule extending the deadline to 2031 while litigation challenging the 2024 proceeds in court.
- **Allow Wyoming to administer its own Coal Combustion Residuals (CCR) program.** The Administration has proposed approval of Wyoming's CCR permit program, which would give the state the ability to regulate solid waste disposal from power plants in the state.
- **Revise and replace the "Good Neighbor" rule.** In 2023, the EPA denied the State Implementation Plan (SIP) for 21 states, including most major consumers of Wyoming coal, under the "Good Neighbor" Rule for emissions from states that affect compliance with ozone standards in downwind states. This rule was stayed by the Supreme Court in 2024, and the Administration has proposed to replace this rule.
- **Revise the Regional Haze Rule.** Previously, the EPA proposed that states must adopt the maximum technically feasible emission controls for power plants in states under the guise of achieving natural conditions of visibility in Class 1 areas (national parks) by 2064. The Administration has implemented a new national policy that state compliance plans satisfy statutory reasonable progress requirements, provided they have considered the four statutory factors: cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of sources.
- **Reconsider the Fine Particulate National Ambient Air Quality Standards (PM 2.5 NAAQS).** In 2024, the EPA lowered the PM 2.5 standard by 25%, and states will have to submit plans to comply with this new standard by 2032. The rule has been challenged in court, and the Administration has notified the court that it is reconsidering this rule, but has not yet published a revised rule.

- **Support local markets at customers located in Wyoming:** Customers located in Wyoming are the third-largest state for demand of Wyoming coal (after Texas and Missouri). For Wyoming GRB coal, power plants and industrial users located in Wyoming comprise the entire market for Wyoming coal. Wyoming policy makers can have significant influence over the use of Wyoming coal within the state, including:
  - **Support reinvestment in coal power plants owned by Wyoming utilities.** The largest Wyoming utility is PacifiCorp (aka Rocky Mountain Power), which owns 4 coal power stations located in Wyoming. PacifiCorp has converted units at the Jim Bridger plant from burning Wyoming coal to burning natural gas and has plans to convert additional coal units at the Naughton and Dave Johnston plants to natural gas by 2028.

These plants will require regulatory support and approval to make the investments needed to continue burning Wyoming coal.

  - **Support industrial plants that are major markets for Wyoming GRB coal.** The soda ash plants in southwest Wyoming, owned by WE Soda (Ciner) and Tata Chemicals, consume about 1.0 million tons per year of Wyoming GRB coal and are the only market for this coal other than the Jim Bridger power plant. The coal supply for these industrial plants is threatened by the announced plans to close the Kemmerer mine, and the state should support the extension of the Kemmerer mine or the development of a replacement local coal supply.
  - **Support development of new local coal power plants.** Growing power demand will require new power plants to maintain grid reliability. While it has been challenging to develop new coal power plants due to regulatory, financing, and political opposition, Wyoming would be the ideal location for a new coal power plant. The delivered cost of coal to the Dry Fork power plant, located in the Wyoming PRB, is the lowest cost in the nation, followed closely by the Dave Johnston, Laramie River, and Wyodak plants, also located nearby. The low cost of coal could make the development of a new coal plant in the Wyoming PRB the most economically viable option for Wyoming ratepayers.

- **Support development of a new coal terminal on the West Coast:** While overseas exports are currently a very small part of demand for Wyoming coal, the primary obstacle has been the lack of a large, efficient coal terminal located on the West Coast to handle exports to the huge and growing Asian coal market. The previous effort to develop a new coal terminal in the state of Washington (Millennium Terminal) was blocked by state opposition. Developers of a new coal terminal in Oakland have prevailed in court disputes with the city.
  - **Support development of the Oakland coal terminal.** After a series of favorable court rulings, the developer of a planned new terminal in Oakland, California, which could handle coal and other bulk commodities, has the legal ability to proceed. Wyoming should support the development of this project, with loans or contract commitments.

2 Wyoming Coal Supply

2.1 Objective

This section is an assessment of the outlook for Wyoming's coal supply, including the production outlook and mineable reserves for the existing and proposed coal mines. Coal produced in the State of Wyoming accounts for about 40% of the total annual production in the United States. In 2023, Wyoming coal production was 237.3 million tons out of U.S. total production of 577.7 million tons.[1] Further, coal produced in Wyoming is the lowest-cost source of coal in the U.S., with the 2023 average sales price of $15.24 per ton, compared to the national average of $54.04 per ton.[2] Thus, the outlook for Wyoming coal supply is critical to the availability of economic coal to support electric power generation and industrial customers (the primary markets for Wyoming coal).

The objective of this study is to collect and analyze data on Wyoming coal mine production plans and coal reserves available to support future Wyoming coal supply. This work involved reviewing all data sources to prepare a reliable assessment of future Wyoming coal production and the issues affecting future production, including mineable reserves, production plans, coal leasing, and permitting.

2.2 Approach

The analysis for this section was performed by Energy Ventures Analysis, Inc. ("EVA") and its subcontractor WWC Engineering ("WWC"). The primary data sources for the analysis were:

- State of Wyoming Department of Environmental Quality ("WYDEQ") permits for each coal mine.
- U.S. Department of the Interior, Bureau of Land Management ("BLM"), Resource Recovery and Protection Plans ("R2P2") for each coal mine.
- U.S. Energy Information Administration ("EIA"), Annual Coal Reports.
- U.S. Department of Labor, Mine Safety and Health Administration ("MSHA"), Mine Data Retrieval System.
- Securities and Exchange Commission ("SEC") filings of annual reports on Form 10-K by public coal companies.

Mine permits are public documents, which WWC obtained from the WYDEQ office. These permits provide information on coal production plans, permitted mine areas, and future strip ratios (bank cubic yards of overburden per ton of coal, a key measure of economic mineability).

BLM R2P2 reports are not public information, but they were reviewed by WWC with cooperation from Wyoming coal producers. The R2P2 report provides information on the coal lessees' plans for maximizing coal recovery on Federal coal leases. The vast majority of Wyoming coal is produced on minerals leased from the Federal government, with 2024 production of Federal coal equal to 178.2 million tons out of a total of 190.7 million tons of coal produced in Wyoming.

EIA performs an annual survey of coal production, reserves, and prices, which is summarized and published in the Annual Coal Report. These reports provide a long-term history of coal production in Wyoming and nationwide.

MSHA collects quarterly reports from all coal producers, including data on coal production, employment, and safety statistics. The MSHA data is the primary public source of coal production by mine.

Public coal companies file annual reports with the SEC and report their coal production and reserves.

EVA and WWC relied upon all these data sources, comparing the different reports and information to develop the most comprehensive and accurate picture of Wyoming coal supply.

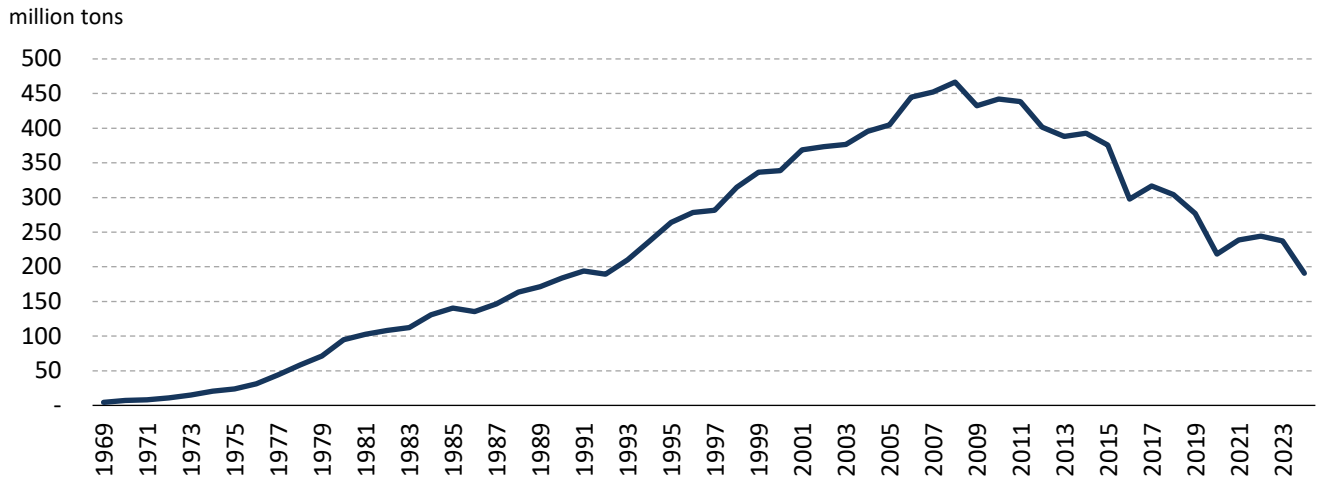
[1] EIA Annual Coal Report 2023. Table 1.
[2] EIA Annual Coal Report 2023. Table 28.

2.3 Historical Wyoming Coal Production and Reserves

Wyoming coal is produced in 2 coal basins – the majority of production is in the Powder River Basin ("PRB") in northeast Wyoming, and the remainder of the production is in the Green River Basin ("GRB") in southwest Wyoming. The Wyoming PRB is the largest coal-producing region in the United States, accounting for approximately 38% of total U.S. coal production over the last decade. The Wyoming PRB was first developed in the early 1970s, primarily to meet the significant growth in energy demand fueled by the construction of new coal power plants in the Western United States. Federal coal leases were issued to major mining and energy companies in the late 1960s, and new mine operations started in 1972 at the Belle Ayr mine.

In addition to new coal plant construction, the rapid growth of Wyoming coal production was fueled by the conversion of power plants in the Midwest to low-sulfur coal in response to the Clean Air Act of 1970 and the subsequent "acid rain" amendment in 1990. After the Union Pacific Railroad gained access to the Wyoming PRB Joint Line in 1984, many coal power plants converted from burning other types of coal due to the favorable economics of low-cost coal and competitive rail rates.

EXHIBIT 2-1: HISTORICAL WYOMING COAL PRODUCTION (MILLION TONS)[3]

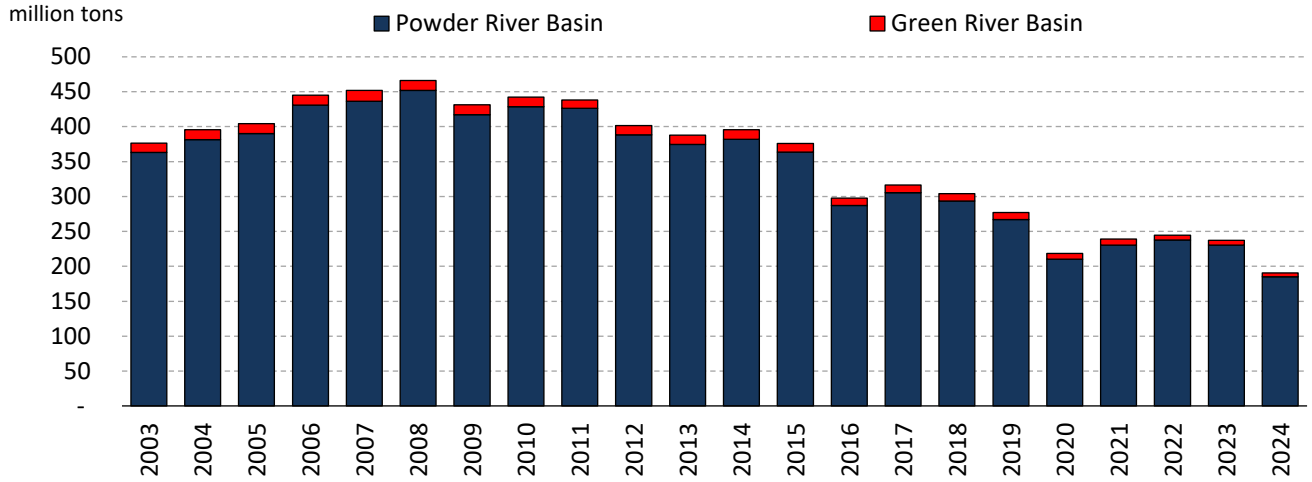


Source: State Inspector of Mines of Wyoming Annual Report 2024

Wyoming coal production peaked in 2008 at 466.3 million tons; national U.S. coal production reached its peak in the same year at 1.17 billion tons.

[3] State Inspector of Mines of Wyoming Annual Report 2024.

EXHIBIT 2-2: WYOMING COAL PRODUCTION BY COAL BASIN (MILLION TONS)[4]



Source: MSHA quarterly coal production data, analyzed by EVA

The long-term decline in PRB coal production since 2008 has been driven by the decline in coal demand from coal-fired power plants, as some coal plants have retired and the remaining coal fleet is operating at lower capacity factors, displaced by increased generation from natural gas, wind, solar power, and battery storage.

While total coal production has declined since the peak in 2008, none of the mines in the PRB and only one mine in the GRB have closed. Instead of closing, the mines have steadily reduced production to match demand.

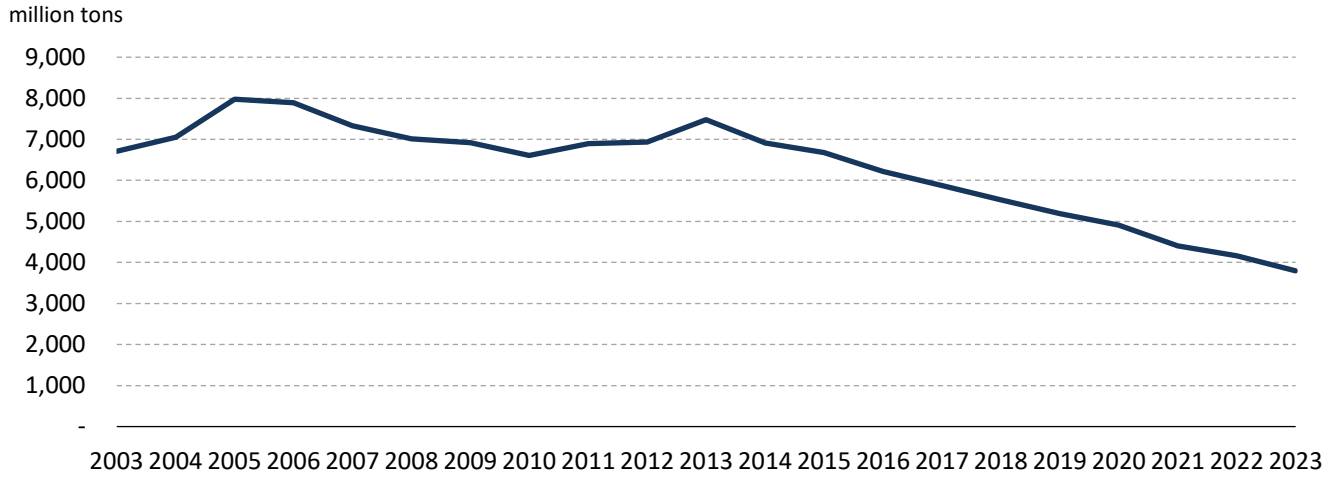
EXHIBIT 2-3: HISTORICAL WYOMING COAL PRODUCTION BY MINE (THOUSAND TONS)[5]

Company	Mine	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Eagle Summit	Belle Ayr	28,707	28,396	25,766	24,582	24,228	18,259	15,797	18,319	14,883	15,814	18,467	10,219	11,175	14,450	14,258	15,160	14,629
Eagle Summit	Eagle Butte	20,443	21,479	23,226	25,365	22,467	19,904	20,690	19,650	19,003	17,277	17,056	11,642	12,304	13,549	15,062	16,300	11,035
Core Nat. Res.	Black Thunder	130,730	110,257	116,227	104,958	93,083	100,688	101,017	99,451	67,890	70,513	71,135	71,977	50,189	59,360	62,182	60,568	44,481
Core Nat. Res.	Coal Creek	11,454	9,767	11,414	10,013	7,564	8,522	9,414	7,840	8,180	8,963	7,988	2,550	2,142	1,994	3,774	2,257	1,552
Kiewit	Buckskin	26,076	25,412	25,533	24,967	18,059	15,024	15,335	13,667	7,131	14,518	13,509	17,633	9,699	10,639	18,234	12,462	6,753
NTEC	Antelope	35,777	33,976	35,908	37,060	34,316	31,354	33,647	35,181	29,793	28,504	23,156	23,243	19,810	21,738	21,657	19,255	14,984
NTEC	Cordero	40,033	39,381	38,500	39,456	39,205	36,670	34,809	22,872	18,332	16,394	12,609	11,907	9,774	12,868	12,464	9,408	4,315
Peabody	Caballo	31,205	23,252	23,500	24,138	16,841	8,979	7,991	11,402	11,222	11,126	11,333	12,596	11,626	13,860	12,056	15,302	10,788
Peabody	NARM	97,578	98,279	105,756	109,064	107,639	111,006	117,966	109,344	92,864	101,595	98,316	85,341	66,112	62,799	60,390	62,019	59,793
Peabody	Rawhide	18,419	15,842	11,230	15,011	14,721	14,246	15,473	15,168	8,079	10,346	9,505	10,090	9,494	12,009	10,336	9,787	9,049
Western Fuels	Dry Fork	5,261	5,234	5,448	5,776	6,007	5,434	5,374	6,369	6,141	6,046	6,304	6,102	3,925	3,728	3,573	4,193	3,963
Wyodak	Wyodak	6,016	6,016	5,931	5,692	4,246	4,285	4,317	4,140	3,717	4,183	4,085	3,716	3,737	3,503	3,735	3,750	3,686
PRB Total		**451,701**	**417,292**	**428,438**	**426,082**	**388,376**	**374,372**	**381,830**	**363,403**	**287,235**	**305,278**	**293,463**	**267,017**	**209,985**	**230,498**	**237,720**	**230,459**	**185,029**
Lighthouse	Black Butte	3,687	3,877	3,129	3,275	2,872	3,728	4,018	2,735	2,160	2,556	2,500	2,308	2,216	1,771	2,514	1,602	434
Pacificorp	Bridger UG	3,501	3,472	3,819	3,043	4,637	4,443	3,370	3,090	1,542	1,716	2,210	2,194	2,424	3,195	-	-	-
Pacificorp	Jim Bridger	2,166	2,142	1,994	1,422	888	786	1,990	2,073	2,450	2,496	1,998	2,326	1,455	1,214	2,036	2,722	2,850
Kemmerer	Kemmerer	4,989	4,461	4,760	4,567	4,645	4,639	4,399	4,471	4,106	4,224	4,017	3,067	2,475	2,501	2,123	2,479	2,417
GRB Total		**14,343**	**13,952**	**13,703**	**12,307**	**13,041**	**13,596**	**13,777**	**12,370**	**10,258**	**10,992**	**10,725**	**9,895**	**8,570**	**8,682**	**6,673**	**6,803**	**5,702**
Wyoming Total		**466,044**	**431,244**	**442,140**	**438,389**	**401,417**	**387,968**	**395,607**	**375,773**	**297,493**	**316,270**	**304,188**	**276,912**	**218,556**	**239,180**	**244,393**	**237,261**	**190,731**

Recoverable coal reserves at existing mines have been steadily declining. There has been no significant leasing of Federal reserves since 2012 (only two minor lease modifications), so the coal mines have been steadily depleting their leased coal reserves. Recoverable coal reserves at Wyoming mines have fallen in half, from 7.5 billion tons at the end of 2013 to 3.8 billion tons at the end of 2023 (the most recent data). If annual coal production continued at the 2023 rate, the total recoverable coal reserves are projected to be mined out by 2039, without additional coal leasing.

[4] MSHA quarterly coal production data, analyzed by EVA.
[5] MSHA quarterly coal production data, analyzed by EVA.

EXHIBIT 2-4: RECOVERABLE COAL RESERVES AT WYOMING COAL MINES (MILLION TONS)[6]



Source: EIA Annual Coal Reports 2003 - 2023

2.4 Outlook for Wyoming Coal Production and Reserves

Based upon review of the WY DEQ mine plans, R2P2 filings, and other data from EIA and company reports, WWC and EVA prepared a comprehensive analysis of the outlook for Wyoming coal production. This outlook considered:

- **Mineable and recoverable coal reserves** as of December 31, 2024. These include coal in place under Federal, state, and private leases, adjusted for mineability and recoverability using engineering criteria. The analysis of recoverable coal reserves by mine was compared and confirmed with independent reports to the EIA and the SEC.
- **Annual production** is derived from mine plans filed with WY DEQ as well as historical data and company reports. Future production levels may vary from those presented in this analysis, depending on future demand and market conditions. The outlook for Wyoming coal production levels in this analysis is based on the maximum expected annual production, calculated using the reserves under control at the end of 2024, current production capability, and continued market demand.
- **Remaining mine life** is calculated from the annual production and the currently controlled coal reserves. Mine life could be extended by reduced coal production if coal demand declines. If demand increases, short-term production could increase (with increased equipment and labor), but would reduce the remaining mine life without the addition of new reserves.
- **Strip ratios,** the amount of bank (in place) cubic yards divided by the tons produced, are a primary measure of economic mineability as they directly affect the cost of production. Some leased in-place coal reserves were not considered to be mineable due to excessively high strip ratios.[7]

The tables in this section present the outlook for annual production and remaining coal reserves, analyzed by mine and summarized by coal basin.

2.4.1 Powder River Basin (PRB)

The Wyoming PRB covers Campbell, Converse, and Sheridan counties in Northeast Wyoming. Production has been about 200 million tons per year in recent years. Over 95% of the demand for this coal is met by coal-fired power plants, with the remainder serving industrial users and offshore exports. Based on 6 months of production data and company plans, EVA

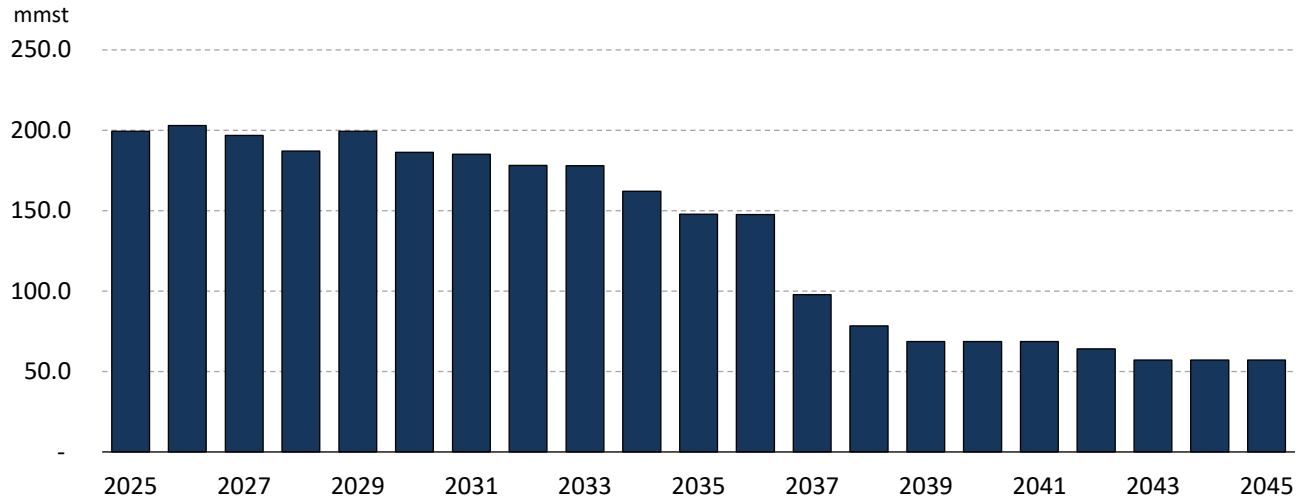
[6] EIA Annual Coal Reports 2003 - 2023.

[7] Coal producers must lease all coal within the reserve block defined by the BLM, however some of the reserves in the lease may not be economically recoverable due to surface infrastructure or high strip rations; thus, mineable reserves are usually less than the recoverable reserves defined in the coal lease.

estimates that 2025 Wyoming PRB production will be approximately 199 million tons, up from 185 million tons in 2024 due to increased demand from power plants.

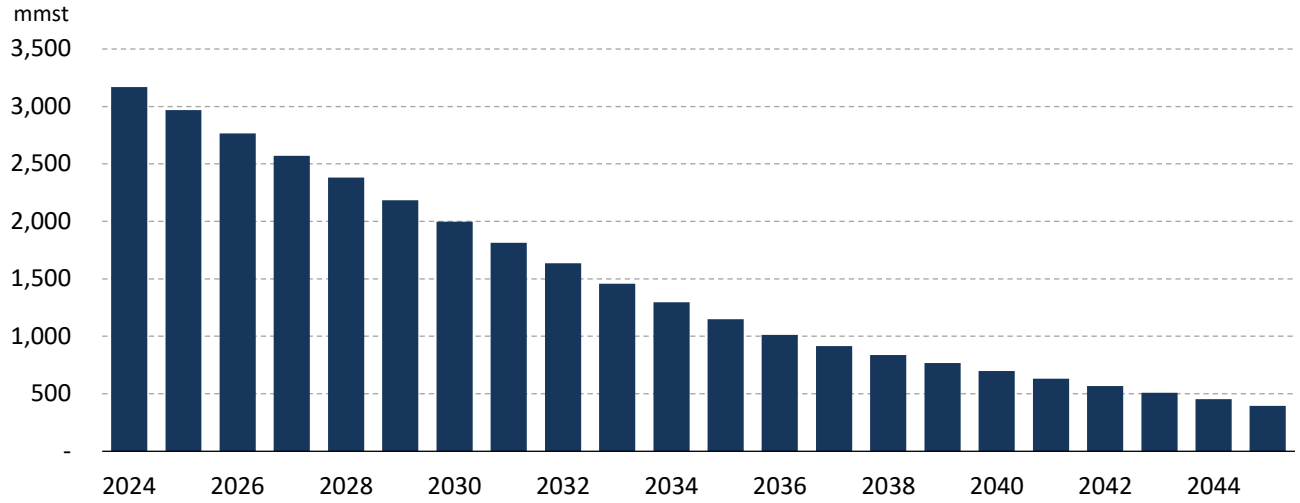
Based on the analysis by EVA and WWC, anticipated Wyoming PRB coal production is expected to be sustained at a range of 185 to 200 million tons per year through 2030; however, production is anticipated to decline significantly over the following decade. By 2035, Wyoming PRB coal production is expected to decline to under 150 million tons and fall rapidly to under 70 million tons per year by 2040.

EXHIBIT 2-5: WYOMING PRB COAL PRODUCTION OUTLOOK (MILLION TONS)



Wyoming PRB coal mines will be unable to sustain their current level of production due to the depletion of their existing coal leases. At the end of 2024, EVA and WWC estimate that the existing coal leases for the 12 Wyoming PRB coal mines have 3.2 billion tons of recoverable coal. While this seems substantial, at the current production rate of 200 million tons per year, the total reserve base will only last for 16 years and is expected to be depleted by 2040.

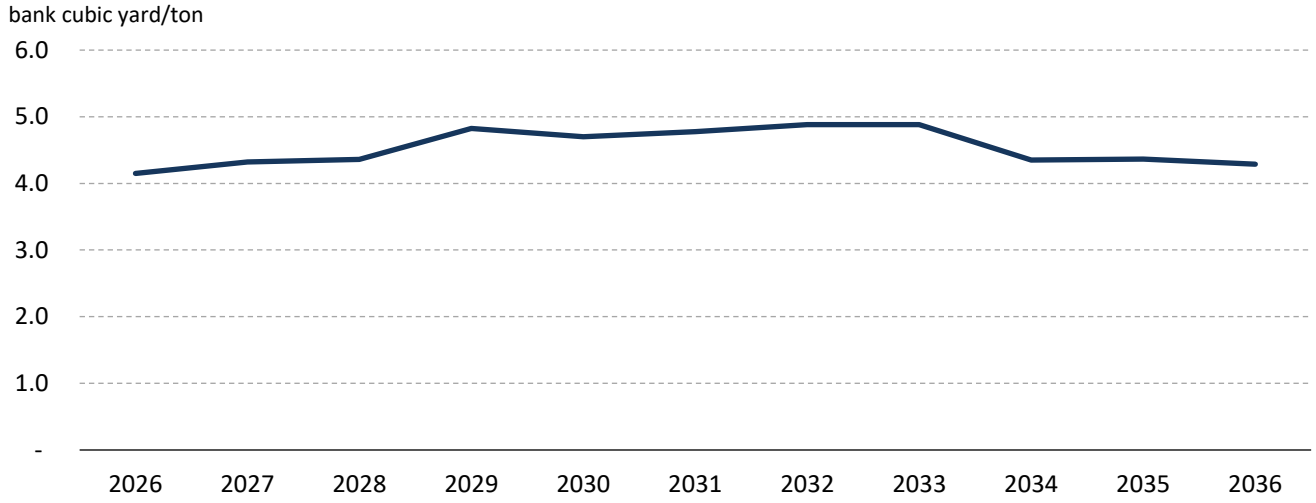
EXHIBIT 2-6: WYOMING PRB RECOVERABLE COAL RESERVES (MILLION TONS)



While some mines have substantial mine lives that will extend far beyond 2040, many mines will begin to exhaust their coal reserves within the next decade. By the end of 2035, we estimate that 6 of the 12 producing mines will have depleted their current reserves, without leasing additional new reserves from the Federal government.

The average strip ratio at Wyoming PRB mines is expected to increase through 2037, as existing mines develop higher-cost reserves.

EXHIBIT 2-7: WYOMING PRB EXPECTED AVERAGE STRIP RATIOS (BANK CUBIC YARDS PER TON)

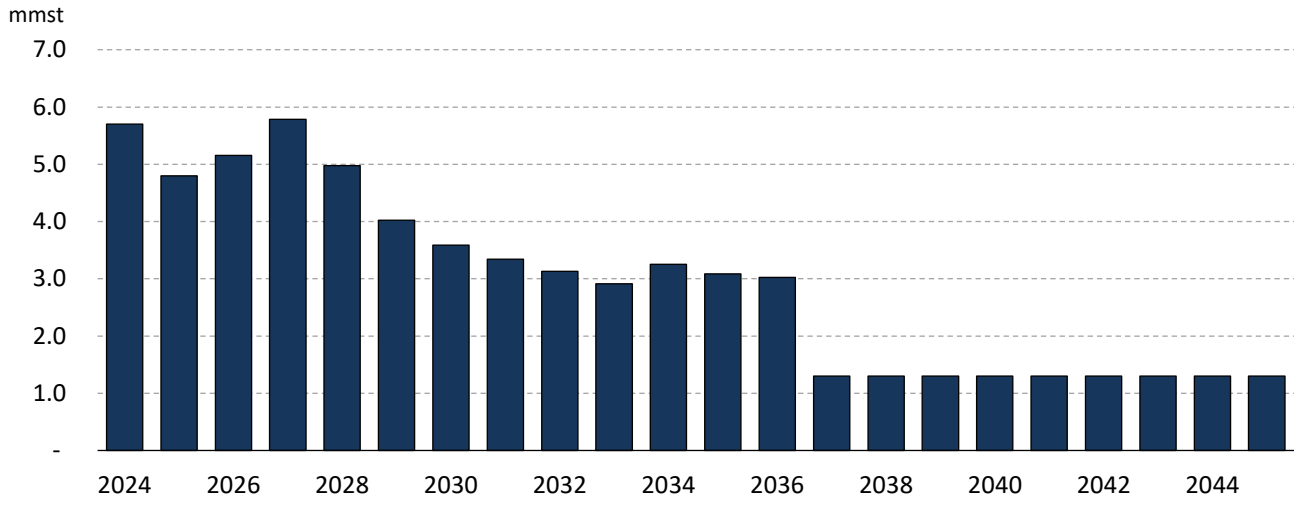


2.4.2 Green River Basin (GRB)

The Wyoming Green River Basin includes coal mines and reserves in Lincoln and Sweetwater counties in Southwest Wyoming. GRB coal production has declined from approximately 13 –14 million tons per year in the early 2010s to under 5 million tons by 2025. While this coal was once shipped to Eastern utilities, in recent years, demand has been limited to local coal power plants (Jim Bridger, Naughton, and North Valmy) and industrial boilers for soda ash processing from the local trona mines.

With the closure of the Bridger Underground mine in 2021, there are only 3 active mines in the GRB. The Jim Bridger surface mine is owned by Bridger Coal Company, a joint venture of PacifiCorp and Idaho Power, and supplies the adjacent Jim Bridger power plant by conveyor. A joint venture of Lighthouse Resources and Occidental Petroleum owns the Black Butte mine. Black Butte coal production has been scaled back in recent years and primarily supplies the Jim Bridger power plant but can also supply other power plants in the region. ECC Capital owns the Kemmerer mine and supplies the adjacent Naughton power plant by conveyor as well as the soda ash refining boilers by rail and truck.

EXHIBIT 2-8: WYOMING GRB COAL PRODUCTION OUTLOOK (MILLION TONS)



Based on the analysis by EVA and WWC, the expected Wyoming GRB coal production is expected to decline significantly in the next few years. By 2030, Wyoming GRB coal production is expected to be limited to 3-4 million tons per year. Several factors limit the production outlook.

Kemmerer: The Kemmerer mine plans to close at the end of 2027.[8] The mine life is limited by the remaining reserves accessible without relocating U.S. Highway 30. This project has been suspended, in part, due to the planned conversion of the Naughton power plant from coal to natural gas at the end of 2025.[9]

Black Butte: Coal mining has been limited by the lack of action by OSMRE to modify the mine plan to access the federal coal lease WYW-6266. On August 12, 2025, OSMRE announced its intention to prepare an Environmental Impact Statement (EIS) for the Black Butte Mine plan modification for Pit 10/15. The mine plan modification was approved on September 9, 2025.[10] This permit modification will enable the mining of 9.2 million tons of federal coal reserves, improving the economics of mining other private reserves. This federal action allows the mine to operate through at least 2040 at the expected production rate of 1.3 million tons per year. Without this permit modification, the mine was likely to close in the near term.

Jim Bridger: This surface mine is expected to produce 1.5 – 3.0 million tons per year to supply the adjacent power plant, and the reserves are estimated to support mining through 2036. Additional federal and private coal reserves could be accessed to support extended mine operations.

2.5 Status of Wyoming Coal Leasing

The vast majority of Wyoming coal reserves are owned by the Federal government and managed by BLM. The State of Wyoming owns 2 sections out of the 36 sections in every township (a section is one square mile, equal to 640 acres). The state sections are in a "checkerboard" pattern (typically sections 16 and 36), so an individual state section would not support a stand-alone mine; the state section would be integrated into a Logical Mining Unit ("LMU") with the Federal coal. In southwest Wyoming, there are some private coal reserves, originally awarded to the Union Pacific railroad in a checkerboard pattern, alternating on either side of the railroad.

The BLM administers a coal leasing program under the Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act of 1947, as well as the Federal Coal Leasing Amendments Act of 1976 (FCLAA). The FCLAA concluded the process of leasing preference rights and established a procedure for competitive bidding on new federal coal leases. Since 1990, all new federal coal leases have been issued pursuant to the Lease by Application (LBA) process or the Lease by Modification (LMA) process for small (under 160 acres), contiguous additions to existing leases.

Federal coal lease royalty income comes from three revenue categories:

- Lease bonus payments – New LBAs are subject to competitive bidding and are awarded to the highest bidder. If there is only one bidder, BLM sets a minimum fair market value and rejects the bid if the minimum value is not met. The lease bonus is paid 20% at the effective date and 20% annually for the next four years.
- Rents – Lessees pay an annual rental of $3 per acre for the life of the lease.
- Royalties – Lessees pay a production royalty equal to 12.5% of the sales price of the coal (with some exceptions). The recent budget bill ("OBBBA") reduced the maximum federal coal royalty to 7.0% for the next 10 years.

EXHIBIT 2-9 shows the total federal revenues from coal leasing (including lease bonus, rents, and royalties) for the entire country, as well as the revenues generated from leasing Wyoming coal. As shown, the state of Wyoming generates most

[8] ECC Capital Corporation Consolidation Financial Statements, Year Ended December 31, 2024, page 10.
[9] Cowboy State Daily, "Kemmerer Coal Mine Sold To Southern California Real Estate Company", September 13, 2024.
[10] Department of Interior, OSMRE, Black Butte Mine Expansion Approved, https://www.doi.gov/pressreleases/wyomings-black-butte-mine-expansion-approved-extending-operations-through-2039.

of the revenue earned from leasing federal coal. Between 2003 and 2024, federal revenues from Wyoming coal leases totaled $14.6 billion, accounting for 85% of the total federal coal revenues of $17.3 billion.

EXHIBIT 2-9: FEDERAL REVENUES FROM COAL LEASING AND PRODUCTION 2003 – 2024 ($MILLION)[11]

Revenue Source	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Royalties	$300.6	$330.2	$343.4	$412.9	$471.3	$ 563.9	$ 585.1	$617.7	$ 637.8	$ 623.8	$ 534.2	$ 574.9	$ 536.8	$397.1	$427.5	$402.6	$360.4	$299.5	$322.1	$413.1	$396.3	$319.3	$ 9,870.3
Bonus	$ 88.4	$117.5	$424.1	$415.9	$340.1	$ 426.7	$ 373.0	$ 96.8	$ 237.4	$ 544.4	$ 457.9	$ 448.1	$ 448.1	$307.9	$ -	$ 0.9	$ 0.9	$ 0.9	$ 0.9	$ 0.9	$ -	$ -	$ 4,730.7
Rents	$ 0.5	$ 0.6	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.6	$ 0.6	$ 0.6	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.5	$ 12.1
Other	$ 4.6	$ (0.9)	$ (1.9)	$ (4.5)	$ (4.1)	$ 0.2	$ (1.9)	$ 2.2	$ 3.3	$ 3.3	$ 3.6	$ 2.5	$ 5.4	$ (0.0)	$ 4.1	$ 0.2	$ (17.3)	$ (36.0)	$ (17.6)	$ 0.0	$ 0.1	$ 0.0	$ (54.8)
Wyoming Total	**$394.1**	**$447.3**	**$766.1**	**$824.7**	**$807.8**	**$ 991.4**	**$ 956.7**	**$717.1**	**$ 879.0**	**$1,172.1**	**$ 996.3**	**$1,026.1**	**$ 990.8**	**$705.5**	**$432.1**	**$404.2**	**$344.5**	**$265.0**	**$306.0**	**$414.6**	**$396.9**	**$319.8**	**$14,558.3**
Royalties	$397.2	$436.0	$453.3	$527.6	$588.4	$ 701.5	$ 686.0	$762.4	$ 786.4	$ 783.9	$ 667.7	$ 718.1	$ 671.5	$511.6	$543.5	$500.9	$447.0	$363.8	$388.3	$519.4	$466.3	$425.1	$12,346.1
Bonus	$103.4	$130.3	$433.1	$422.0	$350.7	$ 436.1	$ 381.6	$109.3	$ 246.4	$ 556.7	$ 459.9	$ 451.3	$ 453.3	$312.1	$ 10.2	$ 11.6	$ 12.9	$ 9.6	$ 9.7	$ 4.1	$ 3.2	$ 0.7	$ 4,908.1
Rents	$ 1.3	$ 1.3	$ 1.2	$ 1.3	$ 1.1	$ 1.3	$ 1.3	$ 1.4	$ 1.3	$ 1.4	$ 1.1	$ 1.3	$ 1.3	$ 1.3	$ 1.2	$ 1.3	$ 1.0	$ 1.2	$ 1.2	$ 1.2	$ 1.1	$ 1.1	$ 27.1
Other	$ 8.0	$ 4.2	$ 2.6	$ (1.2)	$ (1.9)	$ 2.6	$ 13.4	$ 3.9	$ 4.9	$ 6.0	$ 4.0	$ 3.6	$ 5.9	$ 3.2	$ 2.9	$ 0.4	$ (16.4)	$ (35.5)	$ (17.0)	$ 0.9	$ 3.9	$ 19.4	$ 17.9
Federal Total	**$509.9**	**$571.8**	**$890.2**	**$949.6**	**$938.3**	**$1,141.5**	**$1,082.3**	**$876.9**	**$1,039.1**	**$1,348.0**	**$1,132.8**	**$1,174.4**	**$1,131.9**	**$828.2**	**$557.8**	**$514.2**	**$444.5**	**$339.1**	**$382.2**	**$525.5**	**$474.5**	**$446.3**	**$17,299.1**

While most (two-thirds) of the total federal coal revenues over this period came from production royalties, lease bonus revenues were a significant source of federal revenue through 2016, and almost all federal revenue from lease bonuses came from Wyoming coal. Federal coal leasing in the PRB was very active from 1990 through 2012, using the LBA process. In this period, a total of 27 LBAs were issued for 68,208 acres covering 7.9 billion tons of recoverable coal reserves. The total federal lease bonus revenue from these LBA sales was $5.4 billion, an average rate of $0.68 per ton. Over this 23-year period, LBA sales averaged 343 million tons per year, sufficient to replace the average PRB coal production of 340 million tons per year. In addition to the LBAs, 11 small leases were awarded using the LMA process. These LMAs totaled 1,756 acres and covered 86.5 million tons, but only one LMA was awarded after 2012. Revenues from bonuses paid for new federal coal leases in Wyoming stopped after 2016 (the last year of payments for leases sold in 2012), due to the halt in Wyoming coal leasing imposed in 2016.

In January 2016, Secretary of the Interior Sally Jewell announced a moratorium on issuing new federal coal leases while DOI prepared a programmatic environmental impact statement ("PEIS") that would take into account the impact of federal coal leasing on climate change.[12] Under this Jewell Moratorium, no new federal coal leases were issued with limited exceptions. Although the Moratorium was revoked by Secretary Zinke in 2017, a federal district court ruled in 2019 that this action required an environmental review. In 2021, Secretary Haaland revoked the Zinke Order, and in 2023, BLM began a PEIS that considered the alternative of maintaining the Jewell Moratorium on coal leasing indefinitely.[13] On February 21, 2024, the U.S. Court of Appeals for the Ninth Circuit held that the legal challenge to the Zinke Order was moot, as Secretary Haaland had subsequently revoked it.

In May 2024, the Buffalo Field Office of the BLM issued a final supplemental EIS and Resource Management Plan that made coal resources in the Wyoming PRB unavailable for leasing. BLM estimated that coal production in the Wyoming PRB would continue until 2041 under existing coal leases, assuming no exhaustion.[14] In June 2025, the BLM moved to end the coal leasing moratorium and reopen the Wyoming PRB to coal leasing. BLM issued a Record of Decision for the West Antelope III LBA on September 25, 2025, and has scheduled the sale of this lease for October 8, 2025. This new lease, if sold, will add 365 million tons of recoverable coal (441 million tons of coal in place) to the Wyoming PRB reserve base.[15]

Because of the moratorium on coal leasing, the remaining reserve base in Wyoming has halved since 2013, as coal production was not replaced by new leases.

[11] US Department of Interior, Natural Resources Revenue Data, https://revenuedata.doi.gov/explore/?dataType=Production&period=Calendar+Year&mapLevel=State&offshoreRegions=false&location=NF%2CNA&year=2024&commodity=Coal+%28ton%29

[12] https://www.doi.gov/pressreleases/secretary-jewell-launches-comprehensive-review-federal-coal-program

[13] https://www.federalregister.gov/documents/2023/05/01/2023-08960/notice-of-intent-to-prepare-an-environmental-impact-statement-to-analyze-the-potential-environmental

[14] https://www.blm.gov/press-release/blm-proposes-amendment-buffalo-field-office-management-plan

[15] BLM to hold coal lease sale in Campbell and Converse counties | Bureau of Land Management

EXHIBIT 2-10: PRB COAL LEASE ACTIVITY SINCE 1990[16]

Type	Status	Tract Name	Tract Number	Current Company	Mine	Application Date	ROD Date	Sale Date	Acres	Tons	Successful Bid	$/ton	$/acre
LBA	Sold	Jacobs Ranch	WYW117924	Core NR	Black Thunder	10/10/1989		9/26/1991	1,708.62	161,216,000	$20,114,930	$0.12	$11,772.62
LBA	Sold	West Black Thunder	WYW118907	Core NR	Black Thunder	12/22/1989		8/12/1992	3,492.50	429,048,216	$71,909,283	$0.17	$20,589.66
LBA	Sold	North Antelope/Rochelle	WYW119554	Peabody	NARM	3/2/1990		9/28/1992	3,064.04	403,500,000	$86,987,765	$0.22	$28,389.89
LBA	Sold	West Rocky Butte	WYW122586	Peabody	Caballo	12/4/1990		1/7/1993	463.21	55,000,000	$16,500,000	$0.30	$35,621.38
LBA	Sold	Eagle Butte	WYW124783	Eagle Summit	Eagle Butte	7/25/1991	1/6/1995	4/5/1995	1,059.18	166,400,000	$18,470,400	$0.11	$17,438.48
LBA	Sold	Antelope	WYW128322	NTEC	Antelope	12/29/1992	7/10/1996	12/4/1996	617.20	60,364,000	$9,054,600	$0.15	$14,670.45
LBA	Sold	North Rochelle	WYW127721	Core NR	Black Thunder	7/22/1992	6/13/1997	9/25/1997	1,481.93	157,610,000	$30,576,340	$0.19	$20,632.78
LBA	Sold	Powder River	WYW136142	Peabody	NARM	3/23/1995	4/20/1989	6/30/1998	4,224.23	532,000,000	$109,596,500	$0.21	$25,944.76
LBA	Sold	Thundercloud	WYW136458	Core NR	Black Thunder	4/14/1995	7/30/1998	10/1/1998	3,545.50	412,000,000	$158,000,009	$0.38	$44,563.50
LBA	Sold	Horse Creek	WYW141435	NTEC	Antelope	2/14/1997	6/23/2000	9/7/2000	2,818.70	275,577,000	$91,220,121	$0.33	$32,362.54
LBA	Sold	North Jacobs Ranch	WYW146744	Core NR	Black Thunder	10/2/1998	11/28/2001	1/16/2002	4,982.24	537,542,000	$379,504,652	$0.71	$76,171.49
LBA	Sold	NARO South	WYW154001	Peabody	NARM	3/10/2000	5/6/2004	6/29/2004	2,956.70	297,469,000	$274,117,684	$0.92	$92,710.69
LBA	Sold	West Hay Creek	WYW151634	Kiewit	Buckskin	8/31/2000	10/1/2004	11/17/2004	921.00	142,698,000	$42,809,400	$0.30	$46,481.43
LBA	Sold	NARO North	WYW150210	Peabody	NARM	3/10/2000	7/16/2004	12/29/2004	2,369.40	324,627,000	$299,143,785	$0.92	$126,252.97
LBA	Sold	Little Thunder	WYW150318	Core NR	Black Thunder	3/23/2000	8/13/2004	9/22/2004	5,083.50	718,719,000	$610,999,950	$0.85	$120,192.77
LBA	Sold	West Antelope	WYW151643	NTEC	Antelope	9/12/2000	10/25/2004	11/15/2004	2,809.13	194,961,000	$146,311,000	$0.75	$52,084.10
LBA	Sold	West Roundup	WYW151134	Peabody	NARM	7/28/2000	9/9/2004	2/16/2005	2,812.51	327,186,000	$317,697,610	$0.97	$112,958.75
LBA	Sold	Eagle Butte West	WYW155132	Eagle Summit	Eagle Butte	12/28/2001	10/18/2007	2/20/2008	1,427.00	255,000,000	$180,540,000	$0.71	$126,517.17
LBA	Sold	Maysdorf South	WYW174407	NTEC	Cordero	9/20/2001	8/6/2007	4/22/2008	2,900.00	288,081,000	$250,800,000	$0.87	$86,482.76
LBA	Sold	Maysdorf North	WYW154432	NTEC	Cordero	9/20/2001	8/6/2007	1/29/2009	445.89	54,657,000	$48,098,424	$0.88	$107,870.60
LBA	Sold	West Antelope II North	WYW163340	NTEC	Antelope	4/6/2005	4/1/2010	5/11/2011	2,837.63	350,263,000	$297,723,228	$0.85	$104,919.68
LBA	Sold	West Antelope II South	WYW177903	NTEC	Antelope	4/6/2005	4/1/2010	6/15/2011	1,908.60	56,356,000	$49,311,500	$0.88	$25,836.48
LBA	Sold	Belle Ayr North	WYW161248	Eagle Summit	Belle Ayr	7/6/2004	7/30/2010	7/13/2011	1,671.03	221,734,800	$210,648,060	$0.95	$126,058.81
LBA	Sold	Caballo West	WYW172657	Peabody	Caballo	3/15/2006	7/28/2010	8/17/2011	1,023.99	130,196,000	$143,417,404	$1.10	$140,057.43
LBA	Sold	South Hilight Field	WYW174596	Core NR	Black Thunder	10/7/2005	3/1/2011	12/14/2011	1,976.69	222,676,000	$300,001,012	$1.35	$151,769.38
LBA	Sold	South Porcupine	WYW176095	Peabody	NARM	9/27/2006	8/10/2011	5/17/2012	3,243.03	401,830,508	$446,031,864	$1.11	$137,535.53
LBA	Sold	North Porcupine	WYW173408	Peabody	NARM	9/27/2006	10/17/2011	6/28/2012	6,364.28	721,150,000	$793,270,311	$1.10	$124,644.16
LBA	Pending	North Hilight	WYW164812	Core NR	Black Thunder	10/7/2005	2/1/2012		4,529.79	467,596,000			
LBA	Pending	West Antelope III	WYW180384	NTEC	Antelope	8/24/2015	9/25/2025	pending	3,508.31	365,000,000			
LBA	Rejected	West Coal Creek	WYW172585	Core NR	Coal Creek	2/10/2006			1,151.26	57,000,000			
LBA	Rejected	Hay Creek II	WYW173360	Kiewit	Buckskin	3/24/2006			1,253.27	149,700,000			
LBA	Rejected	Maysdorf II North	WYW173360	NTEC	Cordero	9/1/2006			1,338.37	148,565,000			
LBA	Withdrawn	West Hilight	WYW172388	Core NR	Black Thunder	1/17/2006			2,370.52	377,900,000			
LBA	Withdrawn	West Jacobs Ranch	WYW172685	Core NR	Black Thunder	3/24/2006			5,944.37	768,600,000			
LBA	Withdrawn	Maysdorf II South	WYW180711	NTEC	Cordero	9/1/2006			2,305.90	233,550,000			
LBA	Withdrawn	Belle Ayr West	WYW180238	Eagle Summit	Belle Ayr	8/3/2011			1,874.27	253,000,000			
LBA	Withdrawn	Antelope Ridge	WYW180384	Peabody	NARM	9/23/2011			8,261.93	1,000,900,000			
LMA	Pending	Hay Creek II	WYW078634	Kiewit	Buckskin				157.40				
LMA	Pending	Hay Creek II	WYW151634	Kiewit	Buckskin				155.90				
LMA	Sold	Wyodak Mine	WYW073289	Wyodak	Wyodak	10/5/1987		1/30/1990	160.00	18,051,749	$4,330,000	$0.24	$27,063.00
LMA	Sold	Wyodak Mine	WYW111833	Wyodak	Wyodak	10/5/1987		1/30/1990	40.00	4,263,779	$1,025,000	$0.24	$25,625.00
LMA	Sold	Wyodak Mine	WYW313666	Wyodak	Wyodak	10/5/1987		1/30/1990	160.00	12,039,309	$2,890,000	$0.24	$18,063.00
LMA	Sold	E. Black Thunder	WYW2313	Core NR	Black Thunder	6/18/1990		8/23/1991	102.76	5,000,000	$300,000	$0.06	$2,919.00
LMA	Sold	Scoria Bay - Black Thunde	WYW2313	Core NR	Black Thunder	9/28/1992		5/21/1993	10.21	1,030,537	$64,000	$0.06	$6,268.00
LMA	Sold	Caballo	WYW125698	Peabody	Caballo	10/2/1992		6/29/1994	20.23	908,000			
LMA	Sold	N. Rochelle	WYW71692	Core NR	Black Thunder	11/14/2002		1/30/2003	10.19	65,700	$5,000	$0.08	$491.00
LMA	Sold	Jacobs Ranch	WYW146744	Core NR	Black Thunder	4/21/2006		6/19/2006	40.36	8,000	$500	$0.06	$12.00
LMA	Sold	Rawhide Mine	WYW83395	Peabody	Caballo	10/13/2006		4/23/2008	315.18	31,400,000	$1,670,000	$0.06	$6,108.00
LMA	Sold	School Creek Mine	WYW172413	Peabody	NARM	12/11/2009		9/7/2012	40.80	104,623	$7,700	$0.07	$189.00
LMA	Sold	West Antelope II South	WYW177903	NTEC	Antelope	12/3/2012		2/28/2018	856.61	13,632,560	$2,592,000	$0.21	$3,350.00

[16] US Department of Interior, Bureau of Land Management, Coal Data, https://www.blm.gov/programs/energy-and-minerals/coal/coal-data

Even with the restoration of the ability to obtain new coal leases, the time required to lease, permit, and develop new coal leases jeopardizes the ability of Wyoming coal producers to maintain the current levels of production without leasing and permitting reforms. The steps required to lease and develop coal reserves include:

1. PRE-APPLICATION & RESOURCE PLANNING
    a. Resource Management Plan (RMP) Review & Amendment
        - Coal leasing must conform to the Bureau of Land Management (BLM)'s RMP.
        - Coal screening under 43 CFR 3461 applies 20 unsuitability criteria.
        - Tribal consultation, NEPA scoping, and public input occur during RMP planning.
    b. Identify Suitable Coal Tracts
        - Companies may identify coal tracts independently or in consultation with BLM.
        - Must avoid bypassing federal coal and demonstrate economic viability.

2. LEASE INITIATION PROCESS
    a. Step 1: Lease-by-Application (LBA) Submission
        - Submit a formal application to the BLM under 43 CFR 3425.
        - Requires geologic data, maps, tract configurations, and legal descriptions.
        - Enter into a cost-recovery agreement with BLM for processing costs.
    b. Step 2: Regional Coal Team (RCT) Review (PRB Only)
        - For Powder River Basin (PRB) leases, the RCT holds a public meeting to recommend whether the tract should proceed.

3. ENVIRONMENTAL REVIEW & COORDINATION
    a. Step 3: NEPA Environmental Analysis
        - BLM leads Environmental Impact Statement (EIS) or Environmental Assessment (EA).
        - Must analyze direct, indirect, and cumulative impacts, including only direct GHG emissions, i.e., those associated with on-site operations, transport during extraction, or land disturbance-related emissions, market demand, and alternatives.
        - Public comment period of 45 days minimum required.
        - Page limits: 150–300 pages, depending on complexity.
    b. Step 4: Agency Coordination
        - Key stakeholders:
            - BLM (leasing authority)
            - OSMRE (mining plan approvals)
            - EPA (Clean Air & Water Act permits)
            - WY DEQ (surface and subsurface permitting)
            - US Army Corps of Engineers (Section 404 for waters)
            - Tribal Governments (government-to-government consultations)

4. TRACT VALUATION & COMPETITIVE SALE
    a. Step 5: Tract Delineation
        - Finalize tract boundaries and configurations.
        - Amend land use plans if necessary.
    b. Step 6: Record of Decision
    c. Step 7: Fair Market Value (FMV) Determination
        - BLM calculates a confidential FMV using economic modeling.
        - Bidders must meet or exceed FMV in a sealed competitive sale.

d. Step 8: Lease Sale
   - Announced via Federal Register and local notices.
   - Public auction by sealed bid; the highest qualified bid over BLM established FMV wins.
   -Pay bonus bids, rental fees, and royalties
e. Step 9: Lease Issuance
   - Lease is awarded to the highest qualified bidder.
   - Lessee must:
   - Post performance and reclamation bonds
   - Begin diligent development within 10 years, or risk lease cancellation.

5. POST-LEASE: MINE PERMITTING AND OPERATIONS
   a. Step 10: State-Level Permitting
      - Wyoming DEQ issues:
      - Surface coal mining permits (max 5-year term)
      - Reclamation and water quality plans
      - Game and Fish reviews wildlife impacts.
   b. Step 11: Mining Plan Approval (OSMRE)
      - A separate NEPA review by OSMRE for the mine plan.
      - OSMRE recommends final approval to the Assistant Secretary for Land and Minerals Management.
      - Must conform with Surface Mining Control and Reclamation Act (SMCRA).
   c. Step 12: Clean Air & Water Act Permits/amendments (EPA & DEQ)
      - PSD (air quality) and NPDES (water discharge) permits may be required.
      - EPA may veto Section 404 dredge/fill permits if environmental harm is significant.

6. MINE DEVELOPMENT AND PRODUCTION
   a. Step 13: Construction and Operations
      - Begin site development: roads, facilities, and surface disturbance.
      - Initiate mining within 10 years to meet diligent development requirements.
   b. Step 14: Royalties and Reporting
      - Submit regular production and environmental compliance reports to BLM and OSMRE.

The time for applicants to obtain a coal lease under the LBA process between application and the sale date expanded from 2-3 years in the early 1990s to 5-7 years after 2000. After the lease is awarded, the coal mine operator must apply for permits from the WY DEQ, the federal Office of Surface Mining and Reclamation (OSMRE), and the EPA. Even with no opposition, the time to obtain the permits to begin mining is over 3 years after the lease is awarded.[17]

[17] This table does not include the pending sale of the West Antelope III tract in the PRB. The sale date has been set for October 8, 2025.

EXHIBIT 2-11: WYOMING PRB COAL LBA SALES SINCE 1990[18]

Type	Status	Tract Name	Tract Number	Application Date	ROD Date	Sale Date	Effective Date	Years to Sale
LBA	Sold	Jacobs Ranch	WYW117924	10/10/1989		9/26/1991	10/1/1992	2.0
LBA	Sold	West Black Thunder	WYW118907	12/22/1989		8/12/1992	10/1/1992	2.6
LBA	Sold	North Antelope/Rochelle	WYW119554	3/2/1990		9/28/1992	10/1/1992	2.6
LBA	Sold	West Rocky Butte	WYW122586	12/4/1990		1/7/1993	1/1/1993	2.1
LBA	Sold	Eagle Butte	WYW124783	7/25/1991	1/6/1995	4/5/1995	8/1/1995	3.7
LBA	Sold	North Rochelle	WYW127721	7/22/1992	6/13/1997	9/25/1997	1/1/1998	5.2
LBA	Sold	Antelope	WYW128322	12/29/1992	7/10/1996	12/4/1996	2/1/1997	3.9
LBA	Sold	Powder River	WYW136142	3/23/1995	4/20/1989	6/30/1998	9/1/1998	3.3
LBA	Sold	Thundercloud	WYW136458	4/14/1995	7/30/1998	10/1/1998	1/1/1999	3.5
LBA	Sold	Horse Creek	WYW141435	2/14/1997	6/23/2000	9/7/2000	12/1/2000	3.6
LBA	Sold	North Jacobs Ranch	WYW146744	10/2/1998	11/28/2001	1/16/2002	5/1/2002	3.3
LBA	Sold	NARO South	WYW154001	3/10/2000	5/6/2004	6/29/2004	9/1/2004	4.3
LBA	Sold	NARO North	WYW150210	3/10/2000	7/16/2004	12/29/2004	3/1/2005	4.8
LBA	Sold	Little Thunder	WYW150318	3/23/2000	8/13/2004	9/22/2004	3/1/2005	4.5
LBA	Sold	West Roundup	WYW151134	7/28/2000	9/9/2004	2/16/2005	5/1/2005	4.6
LBA	Sold	West Hay Creek	WYW151634	8/31/2000	10/1/2004	11/17/2004	1/1/2005	4.2
LBA	Sold	West Antelope	WYW151643	9/12/2000	10/25/2004	11/15/2004	3/1/2005	4.2
LBA	Sold	Maysdorf South	WYW174407	9/20/2001	8/6/2007	4/22/2008	8/1/2008	6.6
LBA	Sold	Maysdorf North	WYW154432	9/20/2001	8/6/2007	1/29/2009	5/1/2009	7.4
LBA	Sold	Eagle Butte West	WYW155132	12/28/2001	10/18/2007	2/20/2008	5/1/2008	6.2
LBA	Sold	Belle Ayr North	WYW161248	7/6/2004	7/30/2010	7/13/2011	11/1/2011	7.0
LBA	Sold	West Antelope II North	WYW163340	4/6/2005	4/1/2010	5/11/2011	7/1/2011	6.1
LBA	Sold	West Antelope II South	WYW177903	4/6/2005	4/1/2010	6/15/2011	9/1/2011	6.2
LBA	Sold	South Hilight Field	WYW174596	10/7/2005	3/1/2011	12/14/2011	5/1/2012	6.2
LBA	Sold	Caballo West	WYW172657	3/15/2006	7/28/2010	8/17/2011	11/1/2011	5.4
LBA	Sold	South Porcupine	WYW176095	9/27/2006	8/10/2011	5/17/2012	6/13/2012	5.6
LBA	Sold	North Porcupine	WYW173408	9/27/2006	10/17/2011	6/28/2012	10/1/2012	5.8

[18] US Department of Interior, Bureau of Land Management, Coal Data, https://www.blm.gov/programs/energy-and-minerals/coal/coal-data

2.6 Conclusions

While there are huge potentially mineable coal reserves in Wyoming, most are controlled by the federal government and have not been leased to coal producers and permitted for mining for a decade. The suspension of coal leasing after 2015 by BLM played a primary role in the 50% decline in the assigned coal reserves available for mining in Wyoming. At current demand levels, the depletion of reserves will cause coal production to decline after 2030, and coal production will drop precipitously after 2035.

There are multiple agencies whose approval is required to lease and permit coal reserves and mining activities. Each of these agencies performs independent environmental assessments of the impact of coal mining. The lead time for leasing and permitting coal reserves for mining has increased to 10 years or more.

Without immediate action to initiate coal leasing and expedite the review and approval process for leasing and mine permitting, it is projected that Wyoming's coal production will not be sufficient to sustain the current demand for Wyoming coal after 2030.

3 Domestic Demand Market Characterization

3.1 Executive Summary

3.1.1 Historical Demand for Wyoming Coal

Over the past decade, domestic Wyoming coal shipments have decreased by nearly 50%, from over 375 million tons in 2015 to 189 million tons in 2024. Wyoming coal is primarily used for power generation (184 million tons), with just 5 million tons burned in industrial boilers. Almost all the Wyoming coal is supplied from the Powder River Basin (PRB), with just 4 million tons from the Green River Basin (GRB).

The causes for the decline in demand for Wyoming coal are the retirement of existing coal-fired power plants and the lower utilization rate (capacity factor) for the remaining plants. The retirement of coal-fired power plants was primarily driven by the combination of new environmental regulations, which either directly forced plants to close or would require large capital investments to continue operations. The lower capacity factor (coal burn) at the remaining plants was caused by an increased supply of power from new wind and solar plants, funded by government subsidies, and increased generation from efficient natural gas combined cycle (CCGT) power plants, fueled by increased natural gas supply at lower prices.

3.1.2 Outlook for Demand for Wyoming Coal

This study prepared an analysis of the future demand for Wyoming coal. Because most Wyoming coal (nearly 90%) is used for power generation in the United States (Lower 48 states), and given the many uncertainties that affect future demand, EVA prepared three forecast cases for coal burn in domestic power markets. The **BLUE** case is closest to "business as usual", while the **GRAY** case is more favorable to future coal demand, and the **GREEN** case includes policies that phase out most coal generation. The input assumptions addressed the following issues:

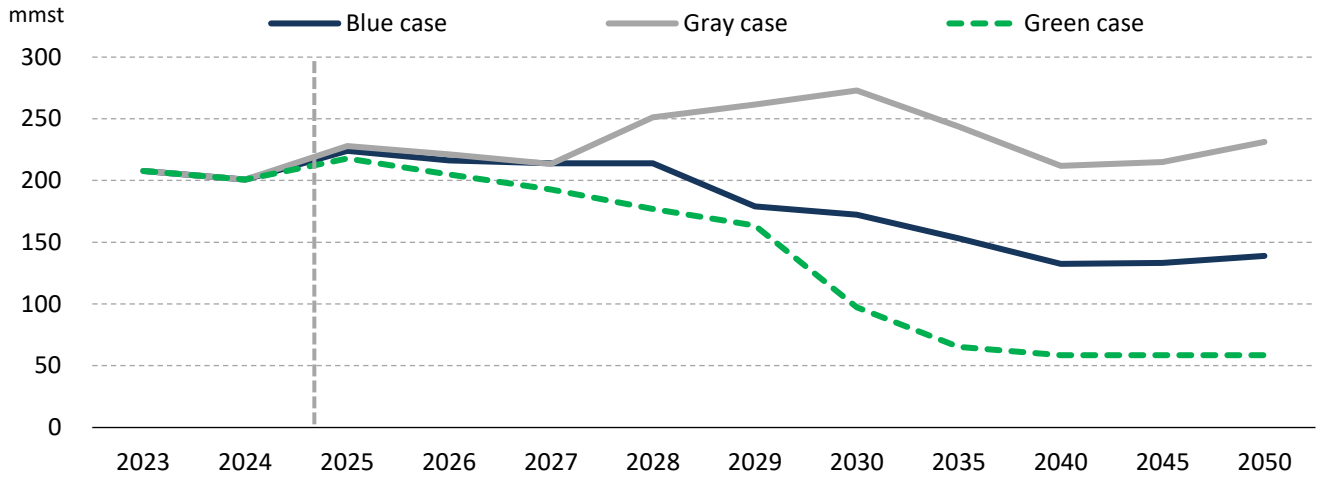
- **Electricity Demand.** Assumptions include growth from new data centers and from the continued electrification of vehicles and residential buildings.
- **Environmental Regulations for Existing Coal Plants.**
    - **The 2024 GHG Rule** would require existing coal units to either convert fully to natural gas by 2029, co-fire gas and continue operating, install CCS capable of 90 percent removal, or retire by 2031. EPA proposed repealing this rule in 2025.
    - **The 2024 ELG Rule** requires zero liquid discharge by the end of 2034, compared with the previous requirement to comply by 2025 or cease coal operations by 2028; EPA has also proposed repealing this rule in 2025.
    - **The 2024 MATS Rule** tightens particulate matter and mercury standards and removes startup exemptions, though EPA has proposed repealing this rule as well.
- **Environmental Regulations for New Coal Plants.** The 2015 NSPS requires new coal facilities to achieve 30 percent CO_2 removal using CCS. Under the 2024 GHG Rule, this threshold would increase to 90 percent.
- **Federal Tax Credits.** Subsidies for new wind and solar decline under the 2025 OBBBA budget reconciliation bill, which phases out remaining incentives.
- **State Policy Requirements.** Assumptions incorporate state-level net-zero mandates and Renewable Portfolio Standards.
- **Coal Retirement Timing.** Some announced retirements may be delayed by federal reliability actions.

The different input assumptions among these cases are summarized below.

Category	Blue Case	Gray Case	Green Case
Electricity demand	2–3 percent annual growth from data centers and electrification	More than 3 percent annual growth from data centers, partly offset by lower electrification	Less than 2 percent annual growth from data centers
Environmental regulations	Repeal 2024 GHG Rule; implement 2024 ELG Rule with 2-year delay; repeal 2024 MATS Rule; maintain 2015 NSPS at 30 percent removal	Repeal 2024 GHG, ELG, and MATS Rules and the 2015 NSPS	Implement 2024 GHG, ELG, and MATS Rules and the 2024 NSPS
Federal subsidies	Wind and solar subsidies only for projects starting by July 2026 and completed by end-2030 under OBBBA; other IRA subsidies phase out	Subsidies for all new plants limited to those starting by July 2026 and completed by end-2030 under OBBBA	IRA-level subsidies for wind and solar extended indefinitely
State laws	Net-zero standards delayed 5 years; RPS goals met	Net-zero standards delayed 10 years; RPS goals delayed	Net-zero standards met; RPS goals met
Coal retirements	Some retirements delayed due to ELG compliance extensions	Most retirements delayed past 2030	No retirement delays

The forecasted Powder River Basin (over 95% Wyoming coal) coal burn under each case is summarized in **EXHIBIT 3-1**. Under the **BLUE** case, PRB coal burn is forecast to be steady at 210 – 220 million tons per year through 2028, then resume its decline due to coal plant retirements, falling to 153 million tons in 2035, with long-term demand at 130 – 140 million tons per year. Under the **GRAY** case, PRB coal production recovers to over 250 million tons per year in 2028, with delayed retirements and increased dispatch and burn declines after 2035, reaching a long-term level of 210–240 million tons per year. Under the **GREEN** case, PRB coal burn is forecast to drop below 200 million tons by 2027 and decline below 100 million tons in 2030, due to the impact of the GHG Rule, with long-term demand expected to be only 50–60 million tons per year after 2035.

EXHIBIT 3-1: DOMESTIC PRB COAL DEMAND BY SCENARIO (MILLION TONS)



Source: EVA FUELCAST 2025 LT

3.1.3 State Laws Affecting Wyoming Coal Demand

This study also summarizes the impact of state laws on the Wyoming coal market, including Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES). While RPS and CES require utilities within a state to supply a certain percentage of their electric retail sales from alternative or non-fossil energy sources, respectively, some states have also set economy-wide (net) zero carbon (NZC) goals. Most state compliance deadlines typically fall between 2040 and 2050. Of the 30 states that used Wyoming coal in 2024, 14 have RPS or CES with future compliance goals or targets, while 10 states have economy-wide net-zero carbon goals or targets.

3.1.4 Non-Traditional Coal Demand

This study also considered the potential for future demand for Wyoming coal from non-traditional applications, including:

- Rare earth element production – High-valued rare earth elements have the potential to be co-produced with coal from the rock overburden, such as the new Brook Mine being developed by Ramaco Resources near Sheridan, Wyoming.
- Coal for synthetic natural gas production – The Great Plains Synfuels Plant in Beulah, North Dakota, has been producing 170 million cubic feet per day of pipeline-quality natural gas from 5 million tons per year of lignite since 1984. This plant also produces a range of by-product chemicals and captures approximately 50% of the CO2 produced, transporting it by pipeline to Saskatchewan, Canada, for injection in enhanced oil recovery. While this plant has been operating successfully for 40 years, no other major gasification project has been built in the United States since then.
- Coal liquefaction – Coal conversion to produce synthetic oil products is significantly more expensive and complex than coal gasification. Sasol has successfully produced approximately 160,000 barrels per day of oil products from 40 million tons of coal per year in Secunda, South Africa, since the early 1980s, utilizing indirect liquefaction (Lurgi gasification followed by Fischer-Tropsch liquefaction). Various projects have been considered in Wyoming, but no other company has achieved Sasol's level of success.
- Coal-to-chemicals – Eastman Chemicals operates a coal-to-chemical plant in Kingsport, Tennessee, to produce acetal chemicals since 1983, but this is the only such project currently operating in the United States. China has a substantial coal-to-chemicals industry, which consumes approximately 300 million tons of coal per year.

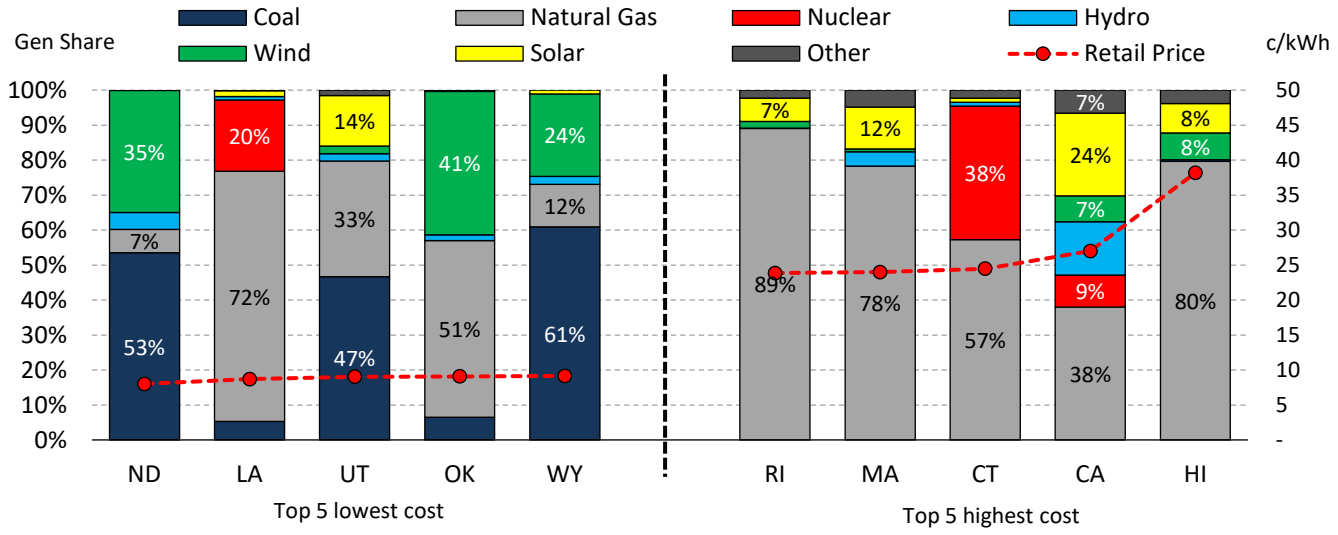
3.1.5 Impact of Coal Use on Retail Electricity Rates

Finally, this study examined the impact of coal use on retail electricity rates. A statistical analysis of the correlation between the percentage of coal generation by state and the retail electricity rates in each state. Controlling for other variables, a significant correlation exists between higher coal shares and lower retail rates by state. Notably, 4 of the 6 states with the lowest retail rates in 2024 (ND, UT, WY, NE) have a much higher share of coal generation (over 40%) than the national average (16%). However, ***none*** of the 13 states with the highest retail rates burn any significant amount of coal.

3.2 Impact of Coal Generation on Retail Power Rates by State

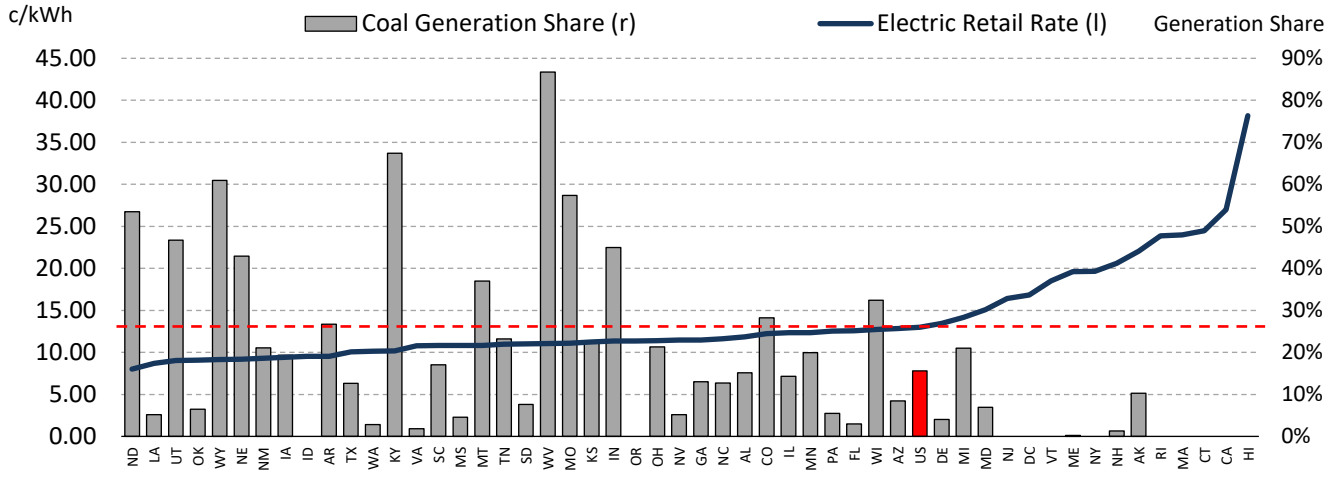
When analyzing the top and bottom 5 U.S. states by their average electric retail rate in 2024, one thing quickly becomes clear. Three of the top 5 (and seven of the top 10) have a coal generation share higher than the U.S. average, while none of the bottom 5 (and none of the bottom 10) have a coal generation share higher than the U.S. average. **EXHIBIT 3-2** displays the top and bottom five states by average electric retail rate, and their 2024 generation mix by fuel type.

EXHIBIT 3-2: 2024 TOP & BOTTOM 5 STATES BY AVG. RETAIL RATE AND GENERATION MIX



Furthermore, **EXHIBIT 3-3** shows each state's 2024 coal generation share compared to its average retail electric rate across all end-use customers. Of the 15 states with a higher average retail electric rate than the U.S. average, only one state (Michigan) had a higher coal generation share than the U.S. average (21% vs. 16%). Notably, all five states where coal accounted for more than 50% of total generation in 2024 are in the top half (Missouri is 21st out of 50 states + D.C.) in terms of the lowest retail electric rate.

EXHIBIT 3-3: 2024 AVERAGE RETAIL ELECTRIC RATE VS. IN-STATE COAL GENERATION SHARE[19]

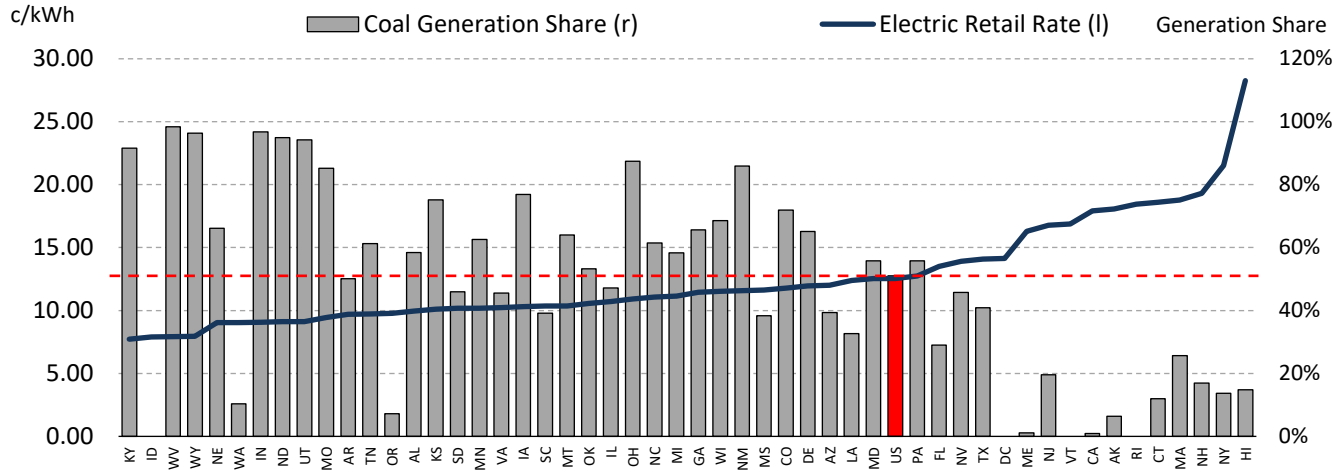


Source: EIA Electricity Data Browser

The same correlation can be observed in the average retail electric rate and in-state coal generation share two decades earlier, in 2005, as shown in **EXHIBIT 3-4**.

[19] Data source is the EIA Electricity Browser. The red bar is the average for the United States.

EXHIBIT 3-4: 2005 AVERAGE RETAIL ELECTRIC RATE VS. IN-STATE COAL GENERATION SHARE



Source: EIA Electricity Data Browser

Again, of the 16 states with higher average retail electric rates than the U.S. average in 2005, only one state (Pennsylvania) had a higher coal generation share than the U.S. average (56% vs. 51%). Additionally, among the top 10 lowest-cost states, only two (Idaho and Washington State) had a coal generation share of less than two-thirds (these two states have low retail electric rates because of the low-cost power provided by the federal hydroelectric dams on the Columbia River system), while seven of the top 10 had a coal generation share exceeding 85%.

Retail electric ratemaking in the U.S. varies significantly by state and depends on several factors, including the type and number of electric utilities in each state and the distribution of their customers by end-use (residential, commercial, and industrial). The reasons for differences in average retail electric rates among states can vary widely. However, some major factors can influence retail electric rates nationwide. These include the generation share by fuel type, the extent of market regulation, the state's involvement in regional CO2 emission markets, the amount of capital invested in environmental control retrofits at in-state coal-fired power plants, and applicable emission allowance prices within federal emissions markets like Acid Rain or the Cross-State Air Pollution Rule (CSAPR).

To further explore the impact of these major categories, the Project team conducted a correlation analysis using state-level data from the past 24 years. The resulting dataset included 1,224 data points across the 13 categories examined. Additionally, the study team analyzed the data separately for 2005 and 2024 to highlight any changes in correlation factors over time. The Pearson product-moment correlation coefficients for the three time periods and the 13 categories are displayed in **EXHIBIT 3-5**.

EXHIBIT 3-5: CORRELATION COEFFICIENTS WITH THE AVERAGE RETAIL ELECTRIC RATE - BY CATEGORY

	All Years	2005	2024
Gen Share - Natural Gas	0.51	0.70	0.38
Gen Share - Coal	-0.49	-0.64	-0.44
Elec. Deregulation	0.37	0.45	0.36
CO2 Markets	0.35	-	0.53
Gen Share - Other	0.30	0.49	0.45
Gen Share - Wind	-0.12	-0.16	-0.27
Gen Share - Nuclear	0.10	0.17	-0.01
Coal Retrofits	-0.10	-0.22	-0.09
Gen Share - Solar	0.08	0.19	0.17
Gen Share - Hydro	-0.08	-0.12	0.06
CSAPR SO2	-0.04	-	-0.29
CSAPR NOx	-0.03	-	-0.26

To review, the closer the correlation factor is to 1, the better the underlying variables correlate with each other (i.e., an increase in variable 1 would result in an increase in variable 2). A correlation factor closer to -1 indicates a strong inverse relationship between the two underlying variables (i.e., an increase in variable 1 would result in a decrease in variable 2).

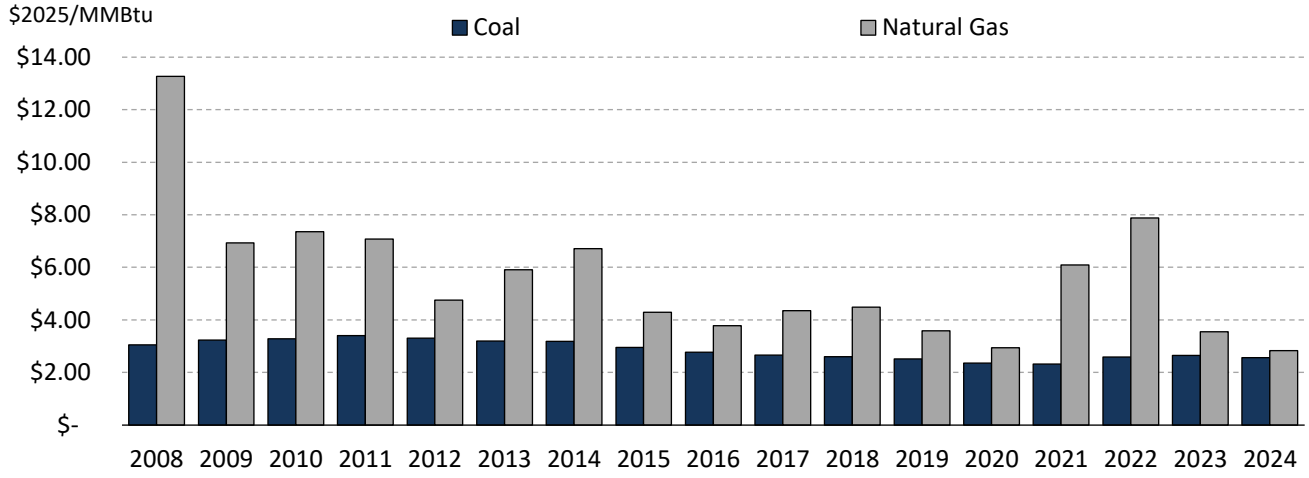
Based on a correlation analysis of state-level data for the past 24 years, a notable correlation exists between state-level inflation-adjusted average retail electric rates and in-state natural gas generation. Furthermore, the data also shows a decline in the correlation factor between 2005 (0.7) and 2024 (0.38). There are likely two main reasons for the high correlation between inflation-adjusted retail electric rates and in-state natural gas generation. Between 2001 and 2008, a year before the beginning of the U.S. “Shale Gas Revolution”, inflation-adjusted natural gas prices to the electric power sector averaged over $10/MMBtu, while averaging less than $5/MMBtu between 2020 and 2024. Since fuel costs are one of the components directly passed on to retail electric customers in most states, higher fuel prices correlate with higher retail electric power prices.

The second factor supporting the high correlation between in-state natural gas generation share and retail electric power prices is the substantial expansion in new natural gas-fired power plants following the dramatic decline in natural gas prices over the last decade. Since 2015, almost 100 GW of newly constructed natural gas-fired power-generating capacity has come online across the U.S. In most cases, the capital spent on new power projects is passed on to retail electric customers through rate increases.

Conversely, in-state coal generation share is the only major category analyzed that showed a significant negative correlation with retail electric rates (higher coal share correlates to lower retail power prices). Several factors likely contribute to the strong inverse relationship between the two variables. First, states with high in-state coal generation are often located near major coal supply regions. For example, the top three states in in-state coal generation share—West Virginia, Kentucky, and Wyoming—account for over 55% of all thermal coal produced in the U.S., providing a low-cost supply of local coal for power plants in those states. Second, states close to Wyoming also have access to low-cost coal due to the low production costs in the Powder River Basin. Nebraska, Iowa, and Arkansas all have some of the lowest retail electric rates while also using a significant amount of Wyoming coal for power generation.

Coal prices delivered to the U.S. power sector have remained remarkably stable over the past 15 years compared to natural gas, as shown in **EXHIBIT 3-6**. From 2015 to 2024, the average delivered coal price was $2.60 per MMBtu, while natural gas averaged $4.38 per MMBtu. However, coal prices varied only slightly during that time, ranging from $2.32 to $2.95 per MMBtu, whereas natural gas prices fluctuated more widely between $2.83 and $7.88 per MMBtu.

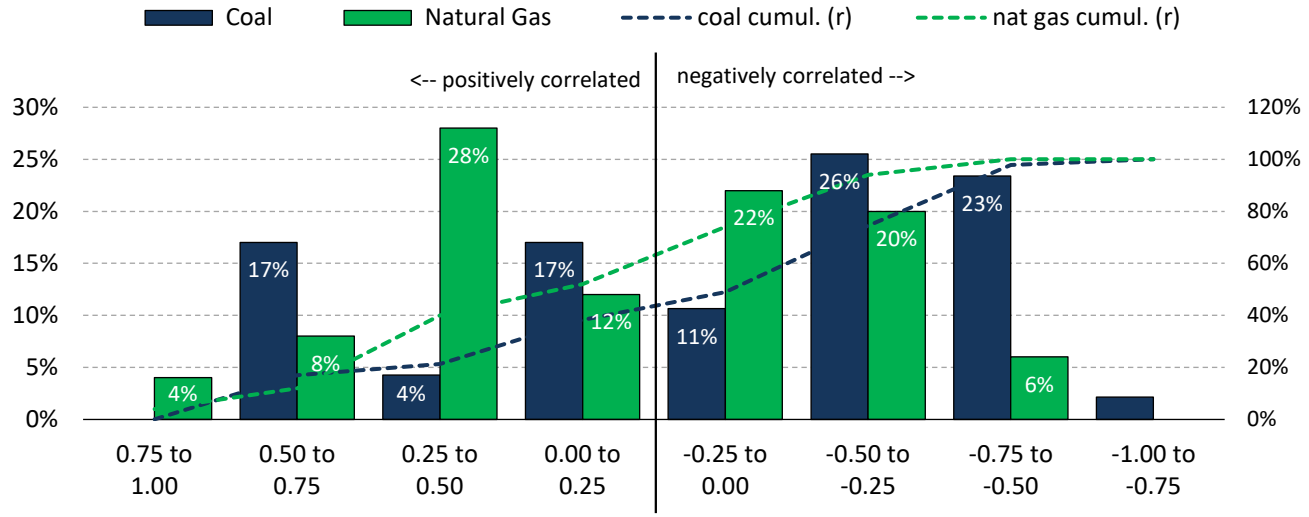
EXHIBIT 3-6: ANNUAL AVERAGE COAL & NATURAL GAS PRICES DELIVERED TO THE U.S. POWER SECTOR



Source: EIA Electricity Data Browser

Repeating the same correlation analysis for each state individually (24 years and 13 variables) yielded similar correlation factor values compared to the comprehensive analysis. **EXHIBIT 3-7** shows the distribution of states and their correlation factors between their coal and natural gas generation share and their inflation-adjusted average retail electric rate.

EXHIBIT 3-7: STATE DISTRIBUTION BY CORRELATION FACTOR BETWEEN COAL & NATURAL GAS GENERATION SHARE AND AVERAGE RETAIL ELECTRIC RATE



While some states have shown a positive correlation between their coal generation share and average retail electric rates, more than half the states have a correlation factor of -0.25 or less between their coal generation share and average retail electric rates, indicating a strong link between higher in-state coal generation and lower retail electric rates. Notably, most states with a strong positive correlation between their coal generation share and retail rates also exhibit a strong negative correlation between their natural gas generation share and retail rates, as they replace higher-cost coal deliveries from out-of-state with lower-cost local natural gas production. These states include Louisiana, Oklahoma, Pennsylvania, and Texas.

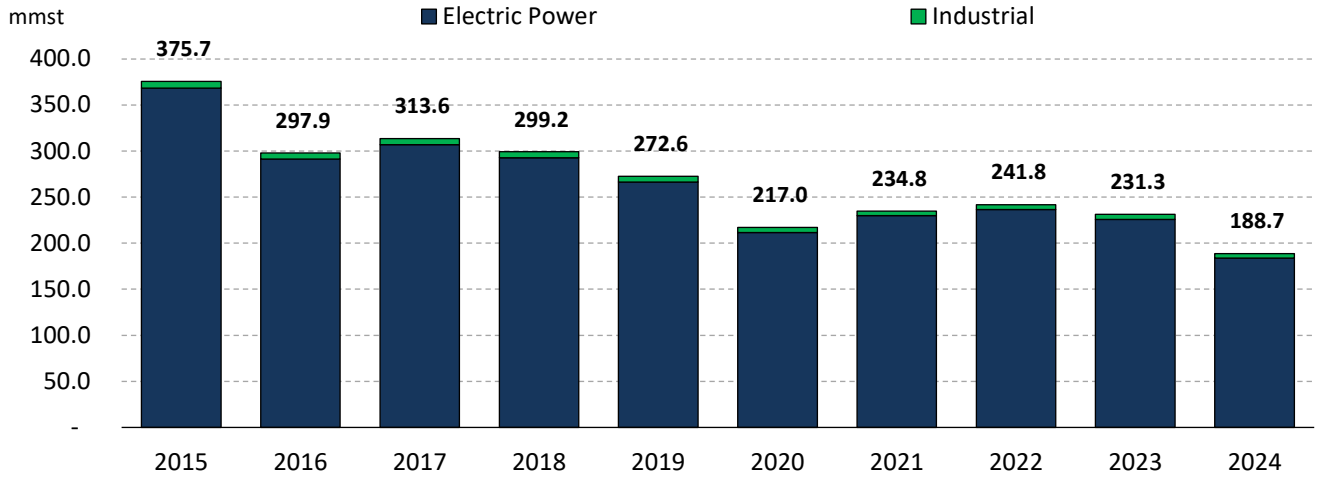
In conclusion, although many factors influence the final retail electric rates in each state, there is a strong correlation between higher shares of coal generation and lower average retail electric rates across the U.S., likely due to the low and relatively stable cost of the fuel supplied to U.S. power plants. Additionally, the inverse relationship between in-state coal

generation and retail electric rates has weakened over time, as coal generation nationwide has decreased and other factors have played a larger role in shaping retail electric rates.

3.3 Historical Domestic Demand for Wyoming Coal

Domestically, Wyoming coal is primarily used in the electric power and industrial sectors, with over 98% of Wyoming coal shipments consumed at U.S. coal-fired power plants. Over the past decade, domestic Wyoming coal shipments have decreased by nearly 50%, from over 375 million tons in 2015 to less than 190 million tons in 2024, as shown in **EXHIBIT 3-8**.

EXHIBIT 3-8: WYOMING COAL SHIPMENTS BY END-USE SECTOR (MILLION TONS)



Source: EIA Annual Coal Report

Wyoming coal mined in the Powder River Basin (PRB) makes up about 97% of all Wyoming coal shipments. Coal mined in the Green River Basin (GRB) accounts for the remaining 3%. However, because of their large industrial customers nearby in Southwestern Wyoming, GRB coal shipments represent roughly 20% of all Wyoming coal shipments to the industrial sector, as shown in **EXHIBIT 3-9**.

EXHIBIT 3-9: WYOMING COAL SHIPMENTS BY WY COAL BASIN (MILLION TONS)

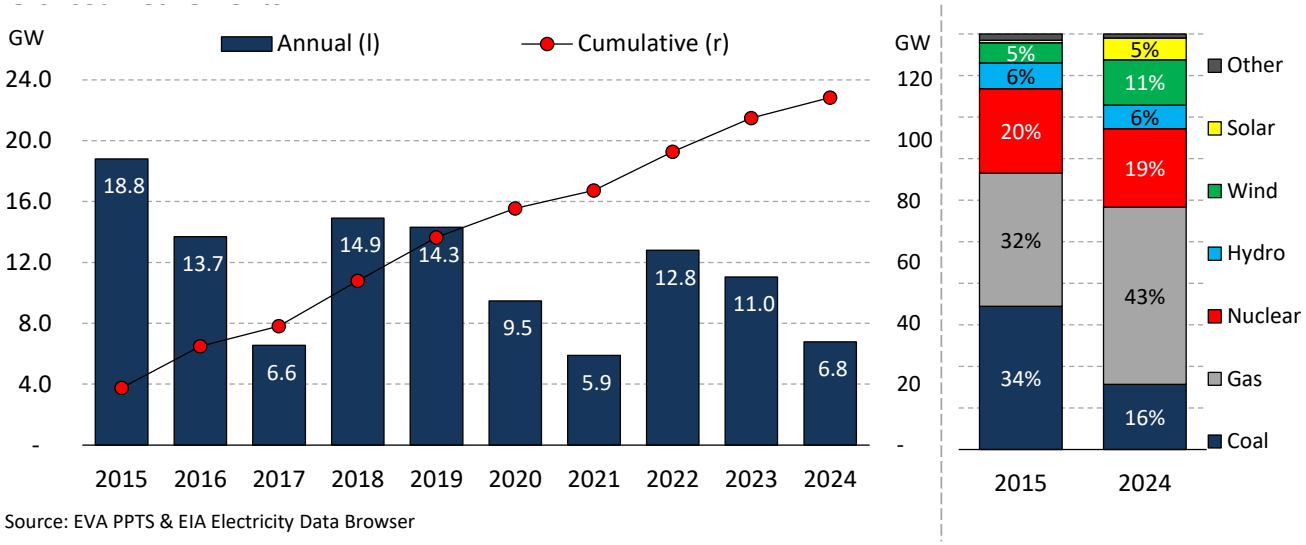
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PRB	356.5	282.4	297.4	283.7	258.0	204.1	223.5	229.2	218.7	179.9
GRB	11.9	9.0	9.4	8.9	8.4	7.5	6.3	7.2	6.9	3.8
Electric Power Total	**368.4**	**291.4**	**306.8**	**292.6**	**266.4**	**211.6**	**229.8**	**236.4**	**225.6**	**183.6**
PRB	5.8	4.9	5.3	5.1	4.7	4.2	3.8	4.1	4.5	4.1
GRB	1.6	1.6	1.6	1.6	1.5	1.2	1.2	1.3	1.2	0.9
Ind. & Comm. Total	**7.3**	**6.4**	**6.9**	**6.7**	**6.2**	**5.4**	**5.0**	**5.4**	**5.7**	**5.1**
PRB	362.2	287.3	302.7	288.8	262.7	208.3	227.3	233.4	223.2	184.0
GRB	13.5	10.6	11.0	10.4	9.9	8.7	7.5	8.5	8.1	4.7
Wyoming Coal - Total	**375.7**	**297.9**	**313.6**	**299.2**	**272.6**	**217.0**	**234.8**	**241.8**	**231.3**	**188.7**

3.3.1 Historical Power Sector Demand of Wyoming Coal

Over the past decade, the U.S. power sector has undergone a significant shift away from coal-fired power generation toward an increased use of natural gas and alternative energy sources (e.g. wind and solar). As shown in **EXHIBIT 3-10**, coal's share of generation across the U.S. has declined from about 34% in 2015 to just 16% in 2024. Conversely, natural gas's share of generation grew from 32% to 43% during the same period. Additionally, wind and solar generation increased

from roughly 5% in 2015 to over 16% a decade later. The decline in U.S. coal generation is primarily due to the large number of coal plant retirements, driven by increasingly more stringent federal and state environmental regulations. Coupled with lower wholesale power prices resulting from the construction of highly efficient new natural gas plants and alternative generation sources with low operating costs investing in costly environmental controls to meet these new regulations has become prohibitively expensive for many coal plants over the past decade. As a result, nearly 115 GW of coal-fired power plants have either closed or converted to burn natural gas, as shown in **EXHIBIT 3-10**. Additionally, the utilization of coal-fired power plants has also declined over the last decade, from nearly 55% average annual capacity factor in 2015 to just over 40% in 2024 as coal plants continue to be displaced by low-cost and highly efficient new natural gas power plants and subsidized new alternative energy sources.

EXHIBIT 3-10: U.S. COAL RETIREMENTS (LEFT) & GENERATION MIX BY FUEL TYPE (RIGHT)

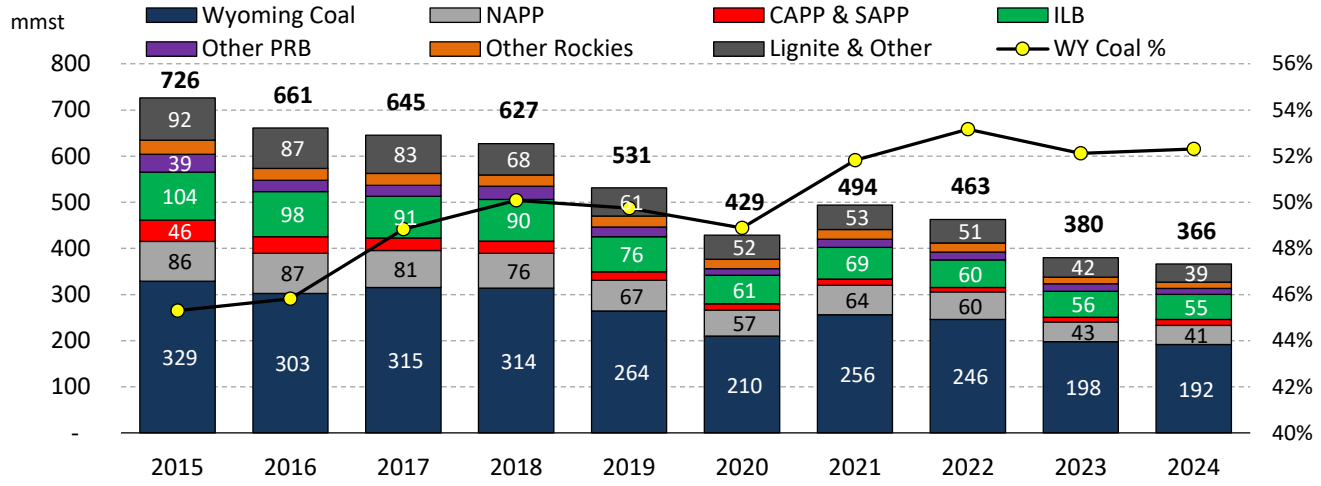


Source: EVA PPTS & EIA Electricity Data Browser

As a result of the substantial number of coal retirements and the reduced utilization of the remaining coal fleet, U.S. coal consumption in the power sector has declined by nearly 50% since 2015, from over 725 million tons to just 366 million tons in 2024. However, while overall U.S. coal generation has declined, the proportion of Wyoming coal used at U.S. coal-fired power plants has increased from 45% in 2015 to 52% in 2024, as plants burning Wyoming coal are often among the lowest-cost facilities in their respective markets due to their low fuel costs. Also, the low sulfur content of Wyoming coal has made the cost of compliance with new environmental regulations lower for Wyoming coal than for other coal basins.

EXHIBIT 3-11 highlights the U.S. power sector coal consumption by major coal basins and the share of Wyoming coal.

EXHIBIT 3-11: U.S. POWER SECTOR COAL CONSUMPTION - BY BASIN



Source: EIA Annual Coal Report

In 2024, Wyoming coal producers supplied coal to nearly 100 coal-fired power plants across 25 states. The top five states for Wyoming coal purchases in 2024 were Texas, Missouri, Wyoming, Illinois, and Wisconsin, collectively representing over half of all Wyoming coal deliveries to the U.S. power sector that year. Texas's 11 coal-fired power plants using Wyoming coal alone accounted for nearly 20% of all Wyoming coal shipments to the U.S. power sector in 2024, as shown in **EXHIBIT 3-12**.

EXHIBIT 3-12: WYOMING COAL SHIPMENTS TO POWER PLANTS BY DESTINATION STATE

State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Electric Power										
TX	55.1	43.5	56.4	47.4	45.6	36.3	40.8	40.5	40.2	33.6
MO	40.4	34.5	37.0	34.8	30.6	29.6	30.9	28.7	27.4	21.8
WY	26.6	25.2	23.2	22.4	21.1	20.8	19.5	19.4	20.3	17.5
IL	45.1	29.0	29.3	31.7	23.7	12.1	15.5	15.6	10.8	9.0
WI	21.3	17.5	18.9	17.8	14.0	12.8	13.8	11.8	12.4	10.0
AL	10.8	10.0	10.1	9.3	10.8	9.5	10.9	11.9	10.8	9.8
KS	17.6	14.2	11.9	12.3	11.2	11.1	12.5	13.2	12.4	9.1
MI	17.5	13.5	15.0	13.6	13.3	10.2	12.2	12.4	9.4	9.1
AR	14.7	12.7	14.2	16.7	14.0	9.7	11.4	12.6	11.1	8.7
NE	14.5	12.9	12.3	12.1	12.0	11.9	11.3	11.6	11.8	8.9
IA	20.2	15.9	13.1	13.1	13.7	10.8	9.6	10.5	11.0	7.8
KY	8.8	8.4	7.9	7.3	7.1	3.0	4.1	4.2	4.0	4.0
CO	10.8	9.5	10.6	10.0	9.0	6.6	7.9	6.8	7.8	5.5
MN	10.0	7.3	7.8	7.6	7.2	4.9	6.1	7.1	5.6	5.0
GA	11.3	9.4	9.5	8.9	8.7	4.0	4.3	5.0	5.3	4.6
AZ	7.0	4.2	5.0	4.3	4.1	3.6	3.4	4.1	4.5	3.4
OK	17.6	10.2	9.3	8.2	4.6	3.7	6.8	6.1	5.9	3.2
LA	7.1	4.0	5.8	5.6	4.3	2.7	3.0	4.9	4.7	2.9
TN	3.2	3.2	2.9	0.9	0.9	1.3	2.1	3.5	3.5	3.5
NV	1.1	0.5	0.7	1.1	1.1	0.6	0.6	1.1	1.0	1.1
SD	1.1	1.3	1.4	1.5	1.8	1.0	1.2	1.3	1.1	1.1
MS	0.7	0.7	0.7	1.2	1.2	1.2	1.4	1.6	1.1	0.8
WA	0.9	0.7	1.1	1.1	2.3	1.6	0.7	0.9	1.0	0.6
UT	-	-	-	-	-	-	-	-	0.3	0.5
IN	2.4	1.9	1.4	2.7	2.3	4.4	2.5	4.2	4.4	3.5
MD	0.3	0.1	0.1	0.0	-	-	-	-	-	-
MT	0.1	-	-	-	-	-	-	-	-	-
ND	0.1	0.2	0.1	-	-	-	-	-	-	-
NY	0.4	-	-	-	-	-	-	-	-	-
OH	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.1	-	-
OR	1.5	1.0	0.9	0.8	1.6	0.5	-	-	-	-
Electric Power Total	**368.4**	**291.4**	**306.8**	**292.6**	**266.4**	**214.0**	**232.8**	**238.8**	**227.9**	**185.2**

EXHIBIT 3-13 and **EXHIBIT 3-14** display the historical operating characteristics of coal-fired power plants that have used Wyoming coal over the past five years. In 2024 U.S. coal plants burning Wyoming coal made up almost 55% of coal generation. However, like the rest of the U.S. coal fleet, coal plants using Wyoming coal have also experienced a decline in utilization (i.e., capacity factor) over the last five years. After a brief increase to over 50% in 2021 and 2022, driven by higher natural gas prices and rebounding electricity demand following the COVID-19 pandemic, utilization rates fell by nearly 10 percentage points, reaching just 42% in 2024, as natural gas prices decreased significantly and new alternative energy resources connected to the grid and displaced coal-fired power generation.

EXHIBIT 3-13: OPERATING CHARACTERISTICS OF COAL PLANTS BURNING WY COAL - BY STATE (PART I)

ST	No. of	Capacity (GW)					Generation (TWh)					Capacity Factor (%)				
	Plants	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
TX	11	14.8	14.3	14.3	14.3	14.3	59.4	70.2	65.8	55.1	52.6	46%	56%	53%	44%	42%
MO	10	10.3	10.3	10.3	9.7	9.5	51.3	58.1	53.2	40.6	38.8	57%	65%	59%	48%	47%
WY	10	6.0	6.0	6.0	6.0	5.3	33.3	32.1	33.7	31.4	28.3	63%	61%	64%	60%	61%
WI	7	5.5	5.3	5.2	5.2	4.9	23.5	27.3	21.8	21.1	21.6	49%	58%	48%	46%	50%
AL	1	2.8	2.8	2.8	2.8	2.8	16.4	20.5	21.1	15.9	18.6	68%	85%	87%	65%	76%
KS	5	4.7	4.7	4.7	4.7	4.7	17.2	19.5	20.4	16.5	13.7	42%	48%	50%	40%	33%
MI	6	5.9	5.7	5.7	4.7	4.5	22.5	27.8	27.3	18.7	21.4	44%	56%	55%	45%	54%
IL	8	7.1	7.1	6.2	4.4	4.4	17.3	27.4	26.0	12.6	13.8	28%	44%	48%	33%	36%
NE	7	3.8	3.8	3.8	3.8	3.8	18.6	18.7	19.8	17.9	15.8	56%	56%	60%	54%	47%
AR	5	5.1	5.1	5.1	5.1	5.1	15.5	21.4	20.4	16.9	15.7	34%	48%	46%	38%	35%
IA	9	4.9	4.9	4.7	4.5	4.4	13.0	20.8	16.8	15.3	13.1	30%	49%	41%	39%	34%
CO	5	2.6	2.6	2.5	2.1	2.1	10.8	14.5	11.7	11.8	10.0	47%	63%	53%	65%	55%
MN	3	3.7	3.7	3.7	3.7	3.0	13.8	15.6	16.1	12.7	11.3	42%	48%	50%	39%	43%
GA	1	3.4	3.4	2.7	2.6	2.6	5.7	8.4	7.3	6.5	7.0	19%	28%	31%	29%	31%
KY	2	2.4	2.4	2.4	2.4	2.4	12.1	14.2	14.4	11.7	13.3	56%	66%	67%	55%	62%
TN	2	2.4	2.4	2.4	2.4	2.4	3.8	6.8	7.4	6.1	7.6	18%	33%	36%	29%	36%
IN	4	5.9	5.7	5.0	5.0	5.0	12.7	15.0	13.9	10.5	12.9	25%	30%	32%	24%	30%
AZ	3	2.6	2.6	2.6	2.6	2.6	12.1	13.4	11.9	11.3	10.2	54%	60%	53%	51%	45%
OK	6	3.7	3.7	3.7	3.7	3.7	7.3	12.0	10.3	6.3	8.8	22%	36%	31%	19%	27%
LA	3	3.0	3.0	3.0	3.0	3.0	7.6	11.2	12.0	6.8	4.5	29%	42%	45%	26%	17%
NV	2	0.7	0.7	0.7	0.7	0.7	2.0	2.8	2.7	2.1	2.3	30%	43%	42%	32%	36%
SD	1	0.5	0.5	0.5	0.5	0.5	1.7	1.6	1.9	1.6	1.6	40%	40%	45%	38%	38%
MS	1	1.0	1.0	1.0	1.0	1.0	2.3	2.8	2.8	1.5	1.5	26%	32%	31%	18%	17%
WA	1	1.3	0.7	0.7	0.7	0.7	5.1	3.1	3.6	4.1	2.8	44%	53%	61%	71%	48%
UT	1	1.8	1.8	1.8	1.8	1.8	6.8	7.6	5.5	4.5	5.7	43%	48%	35%	28%	36%
OH	1	0.6	0.6	0.2	-	-	0.2	0.8	0.5	-	-	5%	15%	36%	n/a	n/a
OR	1	0.5	-	-	-	-	1.6	-	-	-	-	38%	n/a	n/a	n/a	n/a
Total	**116**	**106.9**	**104.8**	**101.4**	**97.3**	**95.1**	**393.5**	**473.6**	**448.3**	**359.3**	**353.0**	**42%**	**52%**	**50%**	**42%**	**42%**

EXHIBIT 3-14: OPERATING CHARACTERISTICS OF COAL PLANTS BURNING WY COAL - BY STATE (PART II)

ST	No. of	Coal Burn (mmst)					Coal Purchases (mmst)					Wyoming Coal Purchases (mmst)				
	Plants	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
TX	11	39.4	45.6	42.4	36.2	34.6	39.3	42.9	40.5	40.2	33.6	36.3	40.8	40.5	40.2	33.6
MO	10	30.1	33.7	31.0	24.0	22.7	29.8	31.2	28.9	27.7	22.1	29.6	30.9	28.7	27.4	21.8
WY	10	20.9	20.0	20.8	19.9	16.1	20.8	19.5	19.4	20.3	17.5	20.8	19.5	19.4	20.3	17.5
WI	7	13.2	15.4	12.4	11.8	11.7	13.3	14.3	12.4	13.2	10.6	12.8	13.8	11.8	12.4	10.0
AL	1	9.3	11.5	12.1	9.3	10.7	9.5	10.9	11.9	10.8	9.8	9.5	10.9	11.9	10.8	9.8
KS	5	11.3	12.6	13.1	10.5	8.5	11.2	12.5	13.2	12.4	9.1	11.1	12.5	13.2	12.4	9.1
MI	6	12.4	15.1	15.5	9.7	11.8	12.0	14.4	14.6	10.7	10.8	10.2	12.2	12.4	9.4	9.1
IL	8	10.6	17.5	17.0	8.2	9.0	12.1	15.5	15.6	10.8	9.0	12.1	15.5	15.6	10.8	9.0
NE	7	11.4	11.6	11.9	10.7	9.4	11.9	11.3	11.6	11.8	8.9	11.9	11.3	11.6	11.8	8.9
AR	5	9.2	12.3	11.9	10.1	9.5	9.7	11.4	12.6	11.1	8.7	9.7	11.4	12.6	11.1	8.7
IA	9	8.2	13.0	10.5	9.3	8.1	10.8	9.6	10.5	11.0	7.8	10.8	9.6	10.5	11.0	7.8
CO	5	6.8	8.4	6.9	7.1	5.9	6.6	7.9	6.8	7.8	5.5	6.6	7.9	6.8	7.8	5.5
MN	3	8.3	9.3	9.6	7.5	6.7	7.8	8.1	10.0	8.7	6.6	4.9	6.1	7.1	5.6	5.0
GA	1	3.9	5.5	4.7	4.4	4.8	4.0	4.3	5.0	5.3	4.6	4.0	4.3	5.0	5.3	4.6
KY	2	6.2	7.4	7.6	6.3	7.1	6.3	6.9	7.2	6.7	7.1	3.0	4.1	4.2	4.0	4.0
TN	2	2.3	3.9	4.5	3.7	4.6	1.8	2.8	4.3	4.0	4.2	1.3	2.1	3.5	3.5	3.5
IN	4	7.0	8.4	7.5	5.7	7.0	8.3	5.3	8.5	8.5	7.1	4.4	2.5	4.2	4.4	3.5
AZ	3	6.4	7.4	6.8	6.3	5.2	6.6	6.1	7.0	7.3	5.6	3.6	3.4	4.1	4.5	3.4
OK	6	4.0	7.4	5.9	3.3	4.2	3.7	6.9	6.1	5.9	3.2	3.7	6.8	6.1	5.9	3.2
LA	3	3.3	6.1	6.5	3.5	2.6	4.4	4.8	6.4	5.3	3.2	2.7	3.0	4.9	4.7	2.9
NV	2	1.1	1.5	1.6	1.3	1.5	1.1	1.3	1.6	1.5	1.7	0.6	0.6	1.1	1.0	1.1
SD	1	1.1	1.1	1.2	1.1	1.1	1.0	1.2	1.3	1.1	1.1	1.0	1.2	1.3	1.1	1.1
MS	1	1.5	1.7	1.7	1.0	1.0	1.3	1.6	1.6	1.2	0.9	1.2	1.4	1.6	1.1	0.8
WA	1	3.5	2.1	2.4	2.8	2.0	3.5	1.8	2.4	2.6	1.6	1.6	0.7	0.9	1.0	0.6
UT	1	3.1	3.4	2.5	2.1	2.7	3.3	2.6	2.9	1.9	2.7	-	-	-	0.3	0.5
OH	1	0.1	0.4	0.3	-	-	0.2	0.4	0.1	-	-	0.1	0.2	0.1	-	-
OR	1	1.0	-	-	-	-	0.5	-	-	-	-	0.5	-	-	-	-
Total	**116**	**235.3**	**282.3**	**268.1**	**215.6**	**208.1**	**240.9**	**255.3**	**262.3**	**247.8**	**203.1**	**214.0**	**232.8**	**238.8**	**227.9**	**185.2**

EXHIBIT 3-15 and **EXHIBIT 3-16** display the Top 10 largest Wyoming coal-consuming power plants in the U.S. Together, these plants accounted for nearly 45% of all Wyoming coal purchases in 2024. The largest Wyoming coal-consuming power plant is Southern Company's 2.8 GW James H. Miller plant in Alabama. The Miller plant alone made up over 5% of Wyoming coal purchases in 2024. Additionally, four of the 10 largest Wyoming coal-consuming power plants are located in Texas (W.A. Parish, Martin Lake, Limestone, and the Fayette Power Project). Only one plant in the Top 10, Basin Electric's Laramie River Station, is located in Wyoming, illustrating the extensive reach of Wyoming coal in supplying the U.S. power sector.

EXHIBIT 3-15: TOP 10 POWER PLANTS CONSUMING WYOMING COAL (PART I)

				Capacity (MW)					Generation (GWh)					Capacity Factor (%)				
Plant Name	Owner	Owner Type	ST	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
Miller	Southern Co	Utility	AL	2,770	2,770	2,770	2,770	2,770	16,445	20,534	21,070	15,850	18,597	68%	85%	87%	65%	76%
Labadie	Ameren	Utility	MO	2,372	2,372	2,372	2,372	2,372	16,484	16,608	16,446	15,782	14,402	79%	80%	79%	76%	69%
Parish	NRG Energy	Merchant	TX	2,499	2,499	2,499	2,499	2,499	9,989	13,180	11,605	9,520	10,087	46%	60%	53%	43%	46%
Martin Lake	Vistra	Merchant	TX	2,410	2,410	2,410	2,410	2,410	12,882	13,180	12,592	11,322	9,741	61%	62%	60%	54%	46%
Laramie River	Basin Electric	Coop	WY	1,710	1,710	1,710	1,710	1,710	8,017	8,315	9,859	9,465	6,794	53%	56%	66%	63%	45%
Monroe	Detroit Edison	Utility	MI	3,066	3,066	3,066	3,066	3,066	13,215	14,731	15,352	11,481	13,124	49%	55%	57%	43%	49%
Scherer	Southern Co	Utility	GA	3,440	3,440	2,652	2,580	2,580	5,682	8,387	7,316	6,484	7,050	19%	28%	31%	29%	31%
Jeffrey	Evergy	Utility	KS	2,189	2,189	2,189	2,189	2,189	6,672	8,340	8,981	5,879	5,432	35%	43%	47%	31%	28%
Baldwin	Vistra	Merchant	IL	1,157	1,157	1,157	1,157	1,157	4,061	6,885	5,923	5,899	6,487	40%	68%	58%	58%	64%
Limestone	NRG Energy	Merchant	TX	1,689	1,689	1,689	1,689	1,689	5,721	5,716	7,264	6,059	5,379	39%	39%	49%	41%	36%
Fayette	LCRA	State	TX	1,615	1,615	1,615	1,615	1,615	8,760	10,281	9,759	7,645	7,128	62%	73%	69%	54%	50%
Campbell	Consumers	Utility	MI	1,446	1,446	1,446	1,446	1,446	6,783	8,278	7,681	6,626	8,238	53%	65%	61%	52%	65%

EXHIBIT 3-16: TOP 10 POWER PLANTS CONSUMING WYOMING COAL (PART II)

		Coal Burn ('000 tons)					Coal Purchases ('000 tons)					Wyoming Purchases ('000 tons)				
Plant Name	ST	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
Miller	AL	9,291	11,460	12,083	9,263	10,665	9,496	10,899	11,882	10,847	9,804	9,496	10,899	11,882	10,847	9,804
Labadie	MO	9,754	9,788	9,852	9,567	8,512	9,517	8,626	9,035	9,748	8,891	9,517	8,626	9,035	9,748	8,891
Parish	TX	6,751	8,832	7,871	6,561	6,931	6,415	8,498	8,214	6,620	7,700	6,415	8,498	8,214	6,620	7,700
Martin Lake	TX	9,570	9,704	8,687	7,723	6,949	9,533	9,484	8,224	7,999	6,555	6,579	7,375	8,224	7,999	6,555
Laramie River	WY	4,900	5,195	5,994	5,906	4,377	4,810	4,602	5,322	6,648	5,443	4,810	4,602	5,322	6,648	5,443
Monroe	MI	7,024	7,543	8,513	5,569	7,113	6,479	7,648	7,710	6,267	7,076	4,674	5,582	5,547	4,880	5,368
Scherer	GA	3,914	5,512	4,683	4,357	4,793	3,968	4,270	4,951	5,330	4,608	3,968	4,270	4,951	5,330	4,608
Jeffrey	KS	4,735	5,599	5,917	3,844	3,510	4,841	4,820	6,198	5,245	4,365	4,841	4,820	6,198	5,245	4,365
Baldwin	IL	2,481	4,229	3,764	3,731	4,006	3,582	3,321	3,600	4,599	4,144	3,582	3,321	3,600	4,599	4,144
Limestone	TX	3,888	3,821	4,867	4,479	3,622	3,686	3,502	4,928	4,562	4,008	3,686	3,502	4,928	4,562	4,008
Fayette	TX	5,657	6,649	6,299	4,995	4,696	6,428	5,371	5,904	6,263	3,907	6,428	5,371	5,904	6,263	3,907
Campbell	MI	3,870	4,668	4,407	3,764	4,651	4,072	4,032	4,792	4,287	3,725	4,046	4,006	4,710	4,287	3,725

3.3.2 Historical Industrial Demand for Wyoming Coal

The demand for Wyoming coal at industrial plants has ranged from 5.0 to 5.5 million tons annually over the past five years. Most of this demand has come from large users in four states – Iowa, Illinois, Wyoming, and Nebraska.

EXHIBIT 3-17: WYOMING COAL PURCHASES BY INDUSTRIAL CUSTOMERS BY STATE[20]

State	2020	2021	2022	2023	2024
CA	-	-	-	23	230
CO	50	46	58	56	64
IA	1,780	1,745	2,098	2,007	1,944
IL	797	347	238	779	672
MI	28	15	7	87	13
MN	72	64	104	184	171
MT	49	49	52	62	49
ND	183	174	168	158	154
NE	860	983	959	674	551
OH	-	-	1	-	-
OK	33	31	65	130	19
SD	189	198	280	269	251
UT	-	-	13	69	39
WA	-	-	-	-	1
WI	186	128	106	74	7
WY	1,156	1,216	1,252	1,100	899
Total	**5,383**	**4,996**	**5,402**	**5,669**	**5,065**

The primary industrial users of Wyoming coal are focused on two main sectors: corn processing and soda ash processing. Other industries that utilize smaller amounts of Wyoming coal include pulp and paper mills, sugar beet processing, cement kilns, and lime kilns. Industrial demand for Wyoming coal from the pulp and paper oil seed processing, and sugar beet processing industries has declined as biomass and natural gas have replaced coal. Currently, industrial demand for Wyoming coal is centered around seven large boilers in the corn processing and soda ash processing industries.

EXHIBIT 3-18: WYOMING COAL BURN AT MAJOR INDUSTRIAL PLANTS[21]

Operator Name	Plant Name	State	Industry	Basin	2020	2021	2022	2023	2024
Searles Valley Minerals	Argus Cogen	CA	Soda ash	PRB	-	-	-	23	230
Archer Daniels Midland	Clinton	IA	Corn processing	PRB	980	94	1,000	926	950
Archer Daniels Midland	Des Moines	IA	Oil seed processing	PRB	73	72	73	23	-
Archer Daniels Midland	Cedar Rapids	IA	Corn processing	PRB	711	857	1,042	1,045	1,000
Archer Daniels Midland	Decatur	IL	Corn processing	PRB	651	347	238	750	672
Archer Daniels Midland	Mankato	MN	Oil seed processing	PRB	64	56	42	30	-
Archer Daniels Midland	Lincoln	NE	Oil seed processing	PRB	89	63	79	39	-
Archer Daniels Midland	Columbus	NE	Corn processing	PRB	417	550	617	547	576
Western Sugar Cooperative	Scottsbluff	NE	Sugar beet processing	PRB	115	123	114	10	-
Georgia-Pacific	Muskogee	OK	Pulp and paper mill	PRB	73	43	62	21	54
ND Paper	Biron Mill	WI	Pulp and paper mill	PRB	89	118	117	99	30
Verso Corporation	Wisconsin Rapids	WI	Pulp and paper mill	PRB	94	-	-	-	-
WE Soda	Westvaco	WY	Soda ash	GRB	441	593	633	528	469
Tata Chemicals Partners	General Chemical	WY	Soda ash	GRB	390	434	470	396	430
Total					**4,185**	**3,349**	**4,487**	**4,438**	**4,412**

Archer Daniels Midland ("ADM") is the largest grain processing company in the U.S., with plants in the Midwest that process corn into corn syrup and ethanol (for blending in gasoline), along with oilseed (soybean) processing plants. ADM

[20] Source: EIA Annual Coal Distribution Report

[21] Source: EIA Form 923 Data

powers these facilities using large boilers that cogenerate process steam and electricity. These boilers are mainly fueled by coal but can also burn natural gas. In recent years, ADM has switched the smaller boilers at its oilseed processing plants from coal to natural gas. However, its large corn processing plants in Clinton, Cedar Rapids, Decatur, and Columbus still primarily rely on Wyoming coal. The Decatur and Cedar Rapids plants burn both Wyoming PRB and Illinois coal. ADM has reduced its carbon dioxide emissions by converting its oilseed plants to natural gas and deploying carbon capture and sequestration at its flagship Decatur plant. Demand for Wyoming PRB coal is expected to remain between 3.0 and 3.5 million tons per year at these ADM corn processing facilities.

The other primary industrial market for Wyoming coal is for soda ash processing at two large plants in Southwest Wyoming. WE Soda and Tata Chemicals operate large coal boilers to produce process steam and co-generate electricity to power their facilities for producing soda ash from trona ore mined in the Green River area. Combined, these two plants burn about 1.0 million tons per year of Wyoming coal from local GRB mines. The local GRB coal supply from the Kemmerer mine may end after 2027, and these plants are evaluating alternative fuel sources, including other Wyoming GRB coal production, coal from other states, natural gas, and nuclear power. The Searles Valley, CA, soda ash plant consumes approximately 0.5 million tons of coal per year. Historically, this coal has been supplied from bituminous coal mines in Utah and Colorado, but in 2024, almost half of the coal supply came from Wyoming PRB mines.

Other industrial users of Wyoming coal consume approximately 1.0 million tons annually of PRB coal, primarily used in sugar beet processing, cement, and lime kilns, mainly in nearby states such as North Dakota, Minnesota, Colorado, South Dakota, and Wyoming.

3.4 Forecasted Domestic Demand for Wyoming Coal

To provide a range of possible outcomes for the future of domestic Wyoming coal consumption, the Project team utilized Energy Ventures Analysis' (EVA) 2025 FUELCAST outlook. EVA's FUELCAST publication is its flagship long-term North American energy market outlook, focused on forecasting supply, demand, and prices of major energy commodities in North America over the next 25 years. Due to the significant degree of uncertainty, EVA included three distinctly different scenarios. **EXHIBIT 3-19** presents a set of key modeling assumptions and the differences between the three scenarios (Grey Case, Blue Case, and Green Case).

EXHIBIT 3-19: KEY ASSUMPTIONS IN FUELCAST 2025 LT POWER SECTOR MODELING SCENARIOS

Category	Grey Case	Blue Case	Green Case
Load Growth from Data Centers	+	+/-	-
Load Growth from Electrification	-	+/-	+
EE/DG Deployment	-	+/-	+
New Coal Plant CCS Requirement	no	30% CCS (2015 NSPS)	90% CCS
45Q tax credit	OBBBA expansion & phase-out	OBBBA expansion & phase-out	IRA extended indefinitely
Utility-RE tax credits	OBBBA cut-off for all	OBBBA cut-off for wind & solar, all other IRA phase-out	IRA extended indefinitely
State CES/RPS goals	delayed	met	met
State NZC goals	delayed 10 years	delayed 5 years	met
2024 GHG Rule	out	out	in
2024 ELG	out	in	in
2024 MATS	out	out	in
ST Coal Retirements	Include delays for all 2020s coal retirements	include some delays due to ELG extensions	don't include delays

Key assumptions in the Gray Case included the removal of the 2024 EPA Greenhouse Gas (GHG) Effluent Limitation Guidelines and the Mercury and Air Toxics (MATS) rules. Additionally, the Gray case assumes a higher rate of data center deployment, partially offset by lower electrification rates in the Residential and Commercial heating sectors, as well as reduced energy efficiency (EE) and distributed generation (DG), such as rooftop solar, due to the lapse of federal tax credits and financial incentives. The case also assumes the full repeal of the 2009 Endangerment Finding and the elimination of the 2015 New Source Performance Standards (NSPS) for new coal-fired power plants, allowing for the future construction of coal plants without carbon capture and sequestration (CCS). Furthermore, the Gray case assumes the complete repeal of federal tax credits for all new utility-scale "clean energy" projects by 2027, including wind, solar, batteries, geothermal, biomass, and new nuclear energy resources. Lastly, it includes delays in most states' Clean Energy or Renewable Portfolio Standards (CES/RPS), economy-wide net-zero carbon (NZC) targets, and the postponement of nearly all announced coal retirements between 2026 and 2030.

Contrasting with the Gray case, the Green case presumes higher rates of Residential and Commercial heating and transportation sector electrification, increased EE and DG deployment, all partly offset by a slower growth in electricity demand from new data centers. It also assumes ongoing environmental regulations from 2024, such as the GHG, ELG, and MATS rules, along with a failed attempt to repeal the 2009 Endangerment Finding, and stricter NSPS for new coal-fired power plants, which would require 90% CCS to meet the 2024 GHG rule requirements. Additionally, the Green case considers federal tax credits from the 2022 Inflation Reduction Act (IRA) to be extended indefinitely, with states containing RPS, CES, or NZC targets expected to meet these goals on time. Lastly, it assumes there are no delays in retiring coal plants already announced to shut down by the end of the 2020s.

For many categories listed above, the Blue case combines assumptions from the Gray and Green cases and is, therefore, referred to as the Reference case for this analysis. The Blue case assumes moderate growth in electricity demand from data centers, Residential and Commercial heating, and transportation sector electrification, along with energy efficiency (EE) and distributed generation (DG) deployment. It includes the 2024 ELG rule and the 2015 NSPS for new coal-fired power plants but excludes the 2024 GHG and MATS rules. Additionally, the Blue case assumes the same federal tax credits and timelines as passed in the 2025 One Big Beautiful Bill Act (OBBA). It also presumes that states with mandatory RPS or CES targets meet those goals, while all net-zero carbon (NZC) goals are delayed by five years. Lastly, the Blue case assumes a delay of about half of the coal plants with announced retirements before the decade ends, mainly focusing on plants retiring due to the 2016/2020 ELG and Coal Combustion Residuals (CCR) rules.

EVA uses a highly customized version of Energy Exemplar's Aurora Electric Power Dispatch Model to model the impacts of these assumptions on the North American electric power market. At its core, the Aurora Model is a linear programming model that focuses on minimizing the overall system cost while meeting all external constraints, including electricity demand, reserve margins, and the operating characteristics of different power plants and energy resources, among others. During its modeling process, the Aurora model simulates every hour of every day for the 25-year modeling horizon, establishing an optimal energy resource mix through new resource additions, existing resource retirements, and the hourly operations (i.e., dispatch) of these resources during the modeling period. **EXHIBIT 3-20** highlights the resulting U.S. power sector generating capacity mix by fuel type for the Blue case and presents the differences between the Gray and Green cases and the Blue reference case.

EXHIBIT 3-20: U.S. POWER CAPACITY MIX - BY CASE & FUEL TYPE (GW)

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
BLUE										
Coal	176	170	167	162	153	142	99	84	77	75
Gas	501	502	498	496	504	511	573	657	712	810
Nuclear	97	98	98	98	99	99	101	103	107	108
Hydro	101	101	101	101	101	101	101	101	101	101
Wind	156	164	179	208	239	254	301	363	423	477
Solar	141	177	214	266	306	325	378	453	568	679
Batteries	35	55	76	106	117	131	171	181	202	223
Other	37	37	36	35	34	34	34	29	27	25
Total	**1,245**	**1,304**	**1,369**	**1,473**	**1,554**	**1,597**	**1,759**	**1,973**	**2,218**	**2,498**
GRAY minus BLUE										
Coal	3	10	13	17	26	36	54	53	53	62
Gas	(2)	(3)	(5)	(5)	(4)	(4)	(2)	(11)	(24)	(33)
Nuclear	-	-	-	-	-	-	1	2	0	1
Hydro	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	(16)	(41)	(45)	(32)	(27)	(17)	(5)
Solar	-	-	-	(14)	(39)	(47)	(19)	19	50	87
Batteries	-	-	-	(2)	(4)	(10)	(24)	(18)	(19)	(14)
Other	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(3)
Total	**1**	**6**	**7**	**(21)**	**(62)**	**(69)**	**(24)**	**19**	**43**	**94**
GREEN minus BLUE										
Coal	(0)	(2)	(2)	(9)	(19)	(56)	(65)	(54)	(47)	(44)
Gas	-	-	-	(2)	2	52	41	9	31	(11)
Nuclear	-	-	-	-	-	-	(2)	(0)	1	4
Hydro	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	1	(10)	4	78	89	81	49
Solar	-	-	-	(3)	(19)	(12)	90	145	218	242
Batteries	-	-	-	10	12	10	14	25	42	70
Other	-	-	-	-	-	-	0	0	(0)	(1)
Total	**(0)**	**(2)**	**(2)**	**(3)**	**(34)**	**(3)**	**156**	**214**	**326**	**310**

In the Blue case, total installed capacity in the U.S. power sector is projected to double between 2025 and 2050, driven primarily by robust electricity demand growth and the continued shift to new alternative resources such as wind and solar, which have lower reliability attributes during peak electricity demand periods than their dispatchable counterparts, such as natural gas, coal, and battery storage. U.S. coal capacity is projected to decline by over 100 GW, with no new coal-fired power plants expected to be built during the forecast period, due to the 2015 NSPS remaining in effect. Conversely, natural gas capacity increases by over 300 GW, while wind, solar, and battery storage capacity increase 2, 4, and 5-fold from their 2025 installed base over the forecast period.

The Gray case results in fewer coal plant retirements than the Blue case, but it also includes over 11 GW of newly built coal-fired power plants due to the repeal of the 2015 NSPS, strong growth in electricity demand, and fewer new alternative capacity additions. Since there are no federal tax credits for new renewable energy projects in this scenario, the total installed alternative capacity is significantly lower, especially through 2035, when federal tax credits are still available in the Blue case. Additionally, natural gas-fired capacity is reduced because more coal-fired power plants remain operational.

Conversely, the Green case includes significantly fewer operational coal plants compared to the Blue and Gray cases due to the implementation of the 2024 GHG rule. As part of compliance with the 2024 GHG rule, about a third of the remaining

127 GW of coal plants in 2029 choose to retire by 2031 instead of installing CCS equipment, converting to 100% natural gas, or co-firing 40% natural gas and retiring by 2038. According to EVA's modeling results, the most common compliance strategy is either fully or partially converting to natural gas, chosen by over 48 GW of coal plants. Although highly questionable in the real world, EVA's modeling also shows about 39 GW of coal-fired capacity installing CCS equipment, driven by favorable economics based on EPA's 2024 CCS equipment, CO2 transportation, and CO2 storage cost assumptions, as well as the indefinite extension of the 45Q federal tax credit of $85 per ton of CO2 utilized for EOR, or captured and sequestered. Lastly, alternative capacity installations also accelerate in the Green case due to the indefinite extension of federal tax credits as well as the inclusion of the 2024 GHG rule. Wind, solar, and battery storage capacity expand 2-, 5-, and 7-fold compared to their 2025 installed base.

EXHIBIT 3-21 illustrates the national power generation mix by fuel type under three different scenarios. In the Blue case, coal generation drops 37% from 2025 to 2050 as more coal plants are retired. However, the utilization rates of the remaining coal plants increase, as they are often the most efficient and, therefore, the lowest-cost dispatchable resources in their respective power markets. Overall, coal's generation share is projected to decline from 17% in 2025 to about 7% in 2050. Conversely, the share of wind and solar generation is projected to increase from 18% to nearly 40% over the same period.

Because there are more operational coal plants in the Gray case, along with higher electricity demand and reduced natural gas and renewable generation, coal generation in the Gray case rises slightly from 2025 to 2050, peaking at over 880 TWh in 2030 due to the significant number of coal retirement delays assumed in this scenario. In the Gray case, coal generation primarily displaces new and existing natural gas generation, as the share of wind and solar generation continues to rise to 39% by 2050, even without federal tax incentives.

In contrast, both coal and natural gas generation are heavily displaced by wind and solar in the Green case, where the combined share of wind and solar generation increases to over 45% by 2050. Meanwhile, the share of generation from coal from the approximately 30 GW of CCS-equipped coal-fired power plants drops to just 3% of total electric generation by mid-century. Total electric generation in 2050 is also higher in the Green case compared to the Blue case due to increased electrification assumptions in the Residential and Commercial heating and transportation sectors.

EXHIBIT 3-21: U.S. POWER GENERATION MIX - BY CASE & FUEL TYPE (TWH)

	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
BLUE										
Coal	727	722	704	698	656	630	526	461	446	456
Gas	1,685	1,661	1,633	1,552	1,512	1,536	1,847	2,124	2,308	2,574
Nuclear	780	790	792	795	800	797	817	837	869	876
Hydro	233	245	244	244	241	241	242	241	236	234
Wind	470	487	537	626	712	765	929	1,144	1,309	1,438
Solar	286	344	415	508	572	605	715	842	1,020	1,174
Other	44	32	29	22	21	18	12	6	(0)	(7)
Total	**4,225**	**4,280**	**4,353**	**4,445**	**4,513**	**4,593**	**5,090**	**5,656**	**6,189**	**6,746**
GRAY minus BLUE										
Coal	29	38	24	159	205	253	274	250	269	336
Gas	(0)	28	56	1	62	44	(41)	(93)	(210)	(354)
Nuclear	-	-	-	(0)	(0)	(0)	6	13	3	9
Hydro	(0)	(0)	(0)	0	2	2	1	(0)	(1)	(5)
Wind	(0)	0	0	(44)	(114)	(123)	(99)	(104)	(80)	(57)
Solar	0	0	0	(25)	(64)	(77)	(27)	38	89	113
Other	(0)	(1)	1	(1)	2	2	0	(1)	(6)	(10)
Total	**29**	**65**	**81**	**89**	**93**	**102**	**114**	**103**	**64**	**32**
GREEN minus BLUE										
Coal	(7)	(26)	(54)	(80)	(82)	(232)	(310)	(255)	(241)	(250)
Gas	1	5	33	49	95	186	(70)	(202)	(236)	(186)
Nuclear	-	-	-	-	-	-	(17)	(2)	4	29
Hydro	(0)	(0)	(0)	(1)	(0)	(1)	(5)	(5)	(5)	(5)
Wind	(0)	(0)	(0)	3	(22)	16	214	220	172	83
Solar	(0)	(0)	(1)	(10)	(35)	(22)	155	248	362	412
Other	0	(0)	0	(0)	(1)	(2)	(16)	(21)	(25)	(34)
Total	**(6)**	**(22)**	**(22)**	**(39)**	**(46)**	**(54)**	**(50)**	**(16)**	**32**	**49**

EXHIBIT 3-22 illustrates the resulting power sector coal consumption by major coal basins for the three analyzed scenarios. In the Blue case, power sector coal consumption drops almost 156 million tons between 2025 and 2050, a 39% reduction. PRB coal consumption is projected to decline by approximately 85 million tons, from 224 million tons in 2025 to less than 140 million tons by 2050.

In the Gray case, total coal consumption for power generation increases by over 10 million tons, or approximately 3%, between 2025 and 2050, peaking at just under 500 million tons in 2030 due to the large number of coal retirement delays assumed in this scenario. PRB coal consumption also increases slightly between 2025 and 2050, from 228 million tons to 231 million tons and peaking at just under 275 million tons in 2030.

Lastly, in the Green case, the most coal-adverse of the three modeled scenarios, power sector coal consumption drops by almost 250 million tons, or 64%, between 2025 and 2050. However, due to the lower efficiency of CCS-equipped coal-fired power plants compared to their non-CCS-equipped counterparts, the amount of coal consumed per megawatt-hour of electricity generated increases. In the Green case, the PRB coal basin shows the highest coal consumption loss potential, both in absolute and relative terms, compared to the other major coal basins, as a larger share of PRB-burning coal plants elect to retire or convert to natural gas, instead of installing costly CCS equipment.

EXHIBIT 3-22: U.S. POWER SECTOR COAL CONSUMPTION - BY CASE & BASIN

BLUE	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
NAPP	47.3	49.2	49.6	50.7	49.0	49.0	39.7	36.2	31.1	33.5
CAPP & SAPP	11.8	12.1	12.0	12.1	13.3	13.7	7.1	4.9	5.4	5.3
ILB	57.8	59.6	59.0	58.6	55.2	50.0	37.7	30.5	28.8	23.7
PRB	224.0	216.3	214.0	213.9	179.1	172.3	153.1	132.4	133.2	139.0
Rockies	15.9	12.5	13.7	12.6	10.6	9.2	9.7	9.8	9.0	9.4
Lignite and Other	41.5	41.2	41.2	40.6	39.9	35.1	31.7	31.5	31.5	31.5
Total	**398.3**	**390.8**	**389.4**	**388.5**	**347.1**	**329.2**	**279.0**	**245.3**	**239.1**	**242.5**
GRAY minus BLUE										
NAPP	1.1	2.3	(1.3)	8.9	13.7	14.2	16.1	13.6	16.7	24.9
CAPP & SAPP	0.2	1.6	(0.8)	5.6	5.4	6.0	5.3	5.0	5.0	4.7
ILB	0.6	0.4	(1.5)	9.0	14.2	19.8	19.8	18.0	19.8	21.2
PRB	3.8	5.0	(0.6)	37.4	82.4	100.6	90.6	79.5	81.8	92.3
Rockies	1.2	4.4	4.0	8.1	10.6	12.6	10.8	8.7	7.8	9.1
Lignite and Other	0.1	0.6	0.7	2.2	3.8	9.0	8.9	9.3	9.8	24.0
Total	**7.1**	**14.2**	**0.5**	**71.3**	**130.2**	**162.1**	**151.5**	**134.1**	**140.9**	**176.1**
GREEN minus BLUE										
NAPP	(1.8)	(0.9)	(6.6)	(7.4)	(9.2)	(24.0)	(20.0)	(16.5)	(11.4)	(13.8)
CAPP & SAPP	(0.5)	(0.2)	(0.8)	0.1	(2.6)	(5.2)	(2.3)	(0.2)	(0.9)	(0.9)
ILB	(1.5)	(4.8)	(6.2)	(9.5)	(9.6)	(13.6)	(20.5)	(13.1)	(11.4)	(6.2)
PRB	(6.0)	(11.3)	(21.3)	(37.0)	(15.6)	(74.9)	(87.9)	(73.8)	(74.8)	(80.4)
Rockies	(0.3)	(0.8)	(1.3)	(2.5)	(1.2)	0.1	1.8	1.8	2.6	2.2
Lignite and Other	(0.4)	0.0	0.1	(1.5)	(0.9)	4.6	(4.7)	(4.3)	(4.4)	(4.4)
Total	**(10.6)**	**(17.9)**	**(36.2)**	**(57.9)**	**(39.0)**	**(113.2)**	**(133.6)**	**(106.1)**	**(100.3)**	**(103.5)**

Coal consumption of Wyoming coal in the industrial sector is also projected to decline under the three scenarios, albeit at different rates. Higher natural gas prices and delayed state NZC compliance in the Gray and Blue cases results in a greater preservation of Wyoming coal consumption in the industrial sector compared to the Green case, where lower natural gas prices and the assumed on-time achievement of state NZC targets results in lower Wyoming coal consumption in the industrial sector.

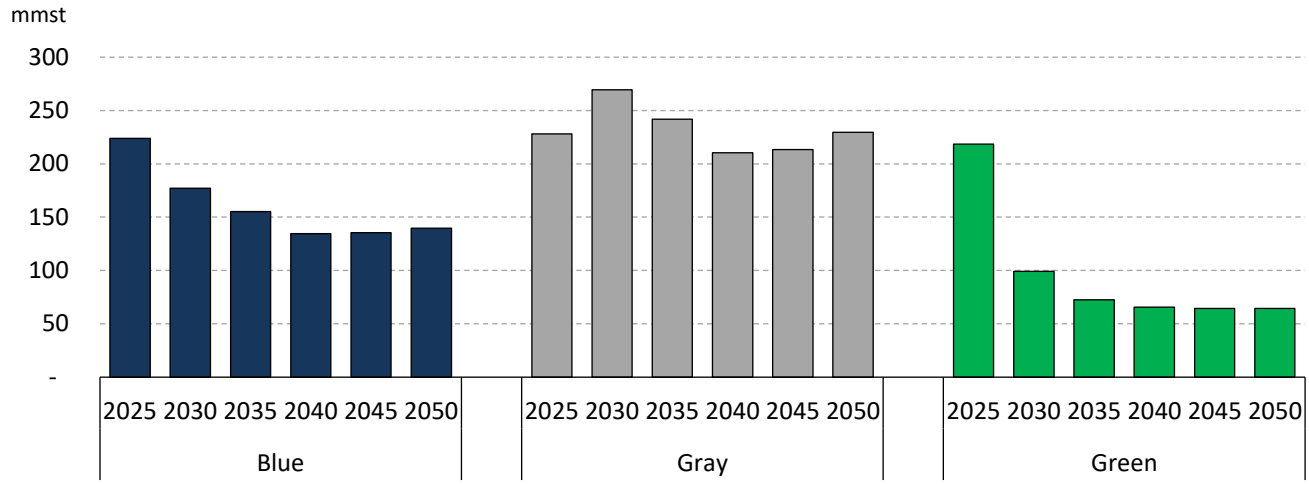
EXHIBIT 3-23 illustrates the resulting total Wyoming coal consumption levels in the U.S. electric power and industrial sectors in the three distinctly modeled scenarios.

In the Blue case, Wyoming coal consumption is projected to decline approximately 89 million tons between 2025 and 2040, a 40% reduction in consumption levels, before rising slightly to just under 140 million tons as coal generation increases with rising electricity demand.

In the Gray case, consumption of Wyoming coal is forecasted to remain largely stable through the forecast period, oscillating between 210 and 270 million tons due to fewer coal retirements in the absence of major federal environmental regulations and tax credits for new alternative energy projects.

Finally, in the Green case, consumption of Wyoming coal is estimated to drop by 70% or 153 million tons between 2025 and 2040 to just 66 million tons, continuing to decline slightly to 64 million tons of total consumption by 2050. As mentioned previously, the inclusion of the 2024 EPA GHG rule and the indefinite extension or federal tax credits for new alternative energy projects forces the majority of coal plants into early retirement and, thus, reducing overall power sector coal consumption.

EXHIBIT 3-23: WYOMING COAL CONSUMPTION - BY CASE



Source: EVA FUELCAST 2025 LT

3.5 Comparison of New Power Generation Technologies

The Project Team conducted a comprehensive comparative analysis of new power generation technologies to evaluate how different generation sources compare in terms of cost, environmental impact, and practicality for long-term energy planning. This analysis focuses on preserving and expanding market demand for Wyoming coal while understanding the competitive landscape across all major generation technologies.

3.5.1 Methodology and Technologies Evaluated

The comparison examines eleven distinct power generation and energy storage technologies across multiple attributes:

- Coal plants with high-efficiency, low-emission (HELE) technologies, both with and without carbon capture and sequestration (CCS)
- Nuclear technologies, including large-scale reactors (AP1000 design) and small modular reactors (AP300 SMR design)
- Natural gas-fired power plants in multiple configurations (simple cycle, 2x1 combined cycle (CC), and 1x1 single-shaft (SS) combined cycle with carbon capture and sequestration)
- Renewable technologies, including onshore wind, offshore wind, and solar photovoltaic systems
- Geothermal energy in geologically feasible regions
- Energy storage systems, including battery storage and pumped storage hydropower

For each technology, the analysis evaluated overnight capital costs, annual operating costs (fixed and variable operations and maintenance), capacity factors, effective load-carrying capability (ELCC), land use requirements, and annualized costs under standardized financing assumptions.

This analysis draws on multiple industry sources to assess the capital and operating costs of new power generation technologies. These sources include the U.S. Department of Energy's Energy Information Administration (EIA), the National Renewable Energy Laboratory (NREL), Lazard's 2025 LCOE Study update, and multiple electric utility integrated resource plans from the past three years.

Notably, the analysis excludes any currently available federal and state tax credits due to their uncertain future availability. The presented costs also exclude any grid connection costs or necessary upgrades, which can be substantial in certain circumstances. Lastly, the presented costs exclude any costs associated with the transportation and storage of captured CO_2 at coal- or natural gas-fired power plants equipped with CCS technology.

3.5.2 Economic Analysis: Capital and Operating Costs

EXHIBIT 3-24 presents a comprehensive economic comparison of the evaluated technologies.

EXHIBIT 3-24: CAPITAL AND OPERATING COSTS FOR NEW POWER GENERATION TECHNOLOGIES

Fuel Type	Technology	Overnight Capital Cost	Fixed O&M	Variable O&M	Heat Rate	Fuel Cost	CF	ELCC[1]	Annual Cost ($mill) to provide:[2]			
		$/kW	*$/kW-yr*	*$/MWh*	*Btu/kWh*	*$/MMBtu*	*%*	*%*	*2000 GWh*	*#*	*500 MW Peak Cap.*	*#*
Coal	*HELE w/o CCS*	$ 3,500	$ 62	$ 6.2	8,600	$ 1.50	75%	83%	$ 131.7	5	$ 260.6	7
	HELE w/ 95% CCS	$ 6,500	$ 94	$ 11.3	12,000	$ 1.50	75%	83%	$ 225.5	10	$ 446.2	10
Natural Gas	*Simple Cycle CT*	$ 1,300	$ 15	$ 4.5	9,800	$ 4.00	15%	61%	$ 249.1	11	$ 134.2	2
	2x1 H-Frame CC	$ 1,500	$ 20	$ 3.0	6,200	$ 4.00	80%	74%	$ 91.3	2	$ 216.1	5
	1x1 H-Frame SS CC w/CCS	$ 2,600	$ 50	$ 4.8	7,100	$ 4.00	80%	74%	$ 132.5	6	$ 313.7	8
Nuclear	*AP 1000*	$ 8,500	$ 159	$ 3.4	10,500	$ 0.85	95%	95%	$ 205.6	8	$ 450.3	11
	AP 300	$ 9,100	$ 129	$ 4.1	9,700	$ 0.85	95%	95%	$ 208.6	9	$ 456.9	12
Wind	*Onshore*	$ 1,700	$ 33	$ -	n/a	n/a	40%	41%	$ 86.5	1	$ 184.9	4
	Offshore, Fixed Bottom	$ 5,000	$ 80	$ -	n/a	n/a	50%	67%	$ 195.9	7	$ 320.1	9
Solar PV	*single axis tracking*	$ 1,400	$ 18	$ -	n/a	n/a	25%	8%	$ 105.9	3	$ 724.6	13
Geothermal	*Binary*	$ 4,700	$ 95	$ 0.5	n/a	n/a	90%	90%	$ 108.3	4	$ 237.2	6
Storage	*Pumped Storage*	$ 3,800	$ 20	$ 0.5	n/a	n/a	n/a	90%	n/a		$ 158.7	3
	4-hr Li-Ion Battery	$ 1,600	$ 38	$ -	n/a	n/a	n/a	58%	n/a		$ 129.1	1

Notes: Excludes all federal or state tax credits; Coal plants assume Wyoming PRB coal as fuel source; [1] ELCC = Effective load-carrying capability based on PJM's 2027/28 BRA documents; [2] Assumes weighted average cost of capital of 5.64% & 30-year financing

Coal-fired generation without CCS has competitive overnight capital costs of $3,500/kW, positioning it favorably against large nuclear ($8,500/kW) and offshore wind ($5,000/kW). However, coal with 95% carbon capture requires significantly higher capital investment at $6,500/kW, placing it in the upper tier alongside nuclear technologies. Among the evaluated technologies, natural gas simple-cycle plants have the lowest capital requirements at about $1,300/kW, while solar PV with tracking and battery storage systems also show relatively modest capital needs at approximately $1,400/kW.

Small modular reactors (SMRs) present an interesting contrast to traditional large nuclear plants. The AP300 SMR design requires $9,100/kW in overnight capital, about 7% higher than the AP1000 large reactor. This premium reflects current first-of-a-kind deployment costs, though advocates argue that factory fabrication and modular construction will drive costs down as the technology matures and achieves economies of scale.

Operating cost structures vary widely across technologies. Coal plants face substantial annual fixed operating and maintenance (O&M) costs comparable to those of offshore wind or new geothermal resources. Nuclear plants benefit from exceptionally low fuel costs ($0.85/MMBtu) despite having the highest fixed O&M requirements across technologies. Natural gas plants face the greatest fuel cost uncertainty, with prices assumed at $4.00/MMBtu, leaving them vulnerable to commodity price volatility.

Wind, solar, battery, and pumped storage technologies have zero fuel costs, fundamentally altering their economic profiles. However, their value must be assessed in the context of their capacity factors and ELCC ratings, which directly affect their ability to reliably serve load.

The capacity factor analysis shows stark differences in plant utilization. Nuclear technologies (both large and SMR) achieve 90-95% capacity factors, providing reliable baseload power with minimal downtime. New coal plants often operate above 70% capacity, also serving baseload needs, but with more planned and unplanned outages. In contrast, renewable

technologies have much lower capacity factors: solar PV at 25%, onshore wind at 40%, and offshore wind at 50%, constrained by natural resource limitations.

The Effective Load-Carrying Capability (ELCC)[22] metric provides additional insight into reliability. Nuclear maintains a 95% ELCC, essentially matching its nameplate capacity for planning purposes. Coal achieves 83% ELCC, which reflects its high reliability for peak demand events. However, renewable technologies show significantly lower ELCC values: solar at only 8% (meaning a 100 MW solar farm contributes only 8 MW toward peak planning reserves), onshore wind at 41%, and offshore wind at 67%. This disparity explains why renewable power generation requires substantial energy storage or backup base load capacity to ensure grid reliability.

Additionally, this analysis includes the annual cost to provide either 2,000 gigawatt-hours (GWh) or 500 MW of capacity during peak demand periods for each technology, using consistent financial assumptions (e.g., a weighted average cost of capital of 5.64% and 30-year financing). Wyoming coal without CCS has competitive total costs of $131.7 million per year to provide 2,000 GWh of electricity, or $260.6 million/yr to provide 500 MW of reliable capacity during peak demand. This positions new Wyoming coal power plants favorably against nuclear ($205.6 million/year and $450.3 million/year, respectively) and offshore wind ($195.9 million/year and $320 million/year, respectively).

Assuming favorable wind resources that would enable onshore wind to achieve a capacity factor of about 40%, new onshore wind would be the cheapest resource to provide 2,000 GWh of electricity at $86.5 million per year, followed by a natural gas combined cycle plant without CCS at $91.3 million per year. To provide 500 MW of reliable capacity during peak demand, battery storage has the lowest annual cost among the assessed technologies, at $129.1 million. However, this assumes surplus energy is available before the peak-demand event, since battery technology does not generate electricity. Simple-cycle natural gas combustion turbines have the second-lowest annual cost to provide reliable capacity during peak demand periods, at $134.2 million.

3.5.3 Land Use and Environmental Footprint

EXHIBIT 3-25 provides a detailed analysis of land disturbance requirements, distinguishing between direct land use (the physical plant footprint) and total land use, which includes indirect impacts and spacing requirements. This analysis reveals critical differences in how various technologies interact with land resources.[23]

[22] This analysis references PJM's latest ELCC analysis as used in its 2027/28 Base Residual Auction process: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf

[23] Data sources for the analysis of land disturbance include:

- Stanford University https://web.stanford.edu/group/efmh/jacobson/Articles/I/LandFossil.pdf
- National Institutes of Health https://pmc.ncbi.nlm.nih.gov/articles/PMC9258890/
- Nuclear Regulatory Commission https://www.nrc.gov/docs/ML2122/ML21225A754.pdf
- National Renewable Energy Laboratory https://docs.nrel.gov/docs/fy09osti/45834.pdf
- National Renewable Energy Laboratory https://docs.nlr.gov/docs/fy13osti/56290.pdf
- Department of Energy https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf
- Lawrence Berkeley National Laboratory https://eta-publications.lbl.gov/sites/default/files/land_requirements_for_utility-scale_pv.pdf
- New York State Energy Research Development Authority https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Energy-Storage-for-Your-Business/Types-of-Energy-Storage
- Washington State University https://www.energy.wsu.edu/documents/Pumped%20Storage%20Report%20FINAL%20DRAFT%2025-05-06.pdf

EXHIBIT 3-25: LAND USE REQUIREMENTS BY POWER GENERATION TECHNOLOGY

Power Plant Type	Direct Land Use *(acres/MW)*	Total Land Use Including Indirect/Spacing *(acres/MW)*	Notes
Wyoming PRB Coal	0.5 - 1.0	1.5 - 2.5	Includes coal mining, rail transport corridors, and waste storage. Assumes 50-ft coal seams at 1,800 tons/acre-ft.
Natural Gas - Combined-Cycle	0.2 - 0.4	5 - 15	Includes natural gas well pads (5 acres per multi-well pad), fracking operations, and pipeline rights-of-way. Gas wells produce for multiple plants, so per-MW allocation varies.
Natural Gas - Simple-Cycle	0.1 - 0.3	4 - 12	Similar to combined-cycle but optimized for peak power. Lower capacity factor means higher per-MW land allocation for upstream production.
Large Nuclear (Gen III/III+)	0.5 - 1.3	1 - 1.8	Includes uranium mining (mostly imported), fuel processing, waste storage sites, and cooling water reservoirs (can add 130,000+ acres nationally but varies by site).
Small Modular Reactor (SMR)	0.04 - 0.3	0.5 - 0.8	Compact footprint (e.g., NuScale 920 MW plant ~35 acres (0.04 acres/MW)), but similar indirect land use as large-scale nuclear due to fuel supply chain.
Offshore Wind	minimal	13 - 125	Onshore infrastructure minimal (<5 acres). Marine spacing for wake avoidance: 27-82 acres/MW (typical: 30-40 acres/MW). This marine area has competing uses, including shipping lanes, fishing grounds, and marine habitats.
Onshore Wind	0.7 - 3.0	30 - 100	Direct footprint: turbine pads, access roads, substations. Spacing: turbines must be separated to avoid wake effects. With spacing, land intensity increases to 30-125 acres/MW, but land between turbines often remains in agricultural use.
Solar PV (Utility-Scale)	5 - 10	7 - 10	Direct use: panels, inverters, access roads, substations. Actual panel coverage ~7.3 acres/MW. Total project area including spacing/buffers: 7-10 acres/MW. Does not include manufacturing supply chain.
Geothermal	1 - 8	1 - 8	Small direct footprint: power plant, well pads, pipelines. Most activity underground. Geothermal fields like The Geysers: 725 MW across 28,800 acres = ~40 acres/MW total field area, but plant sites much smaller.
Pumped Storage Hydropower	10 - 25 (per GWh storage)	10 - 25 (per GWh storage)	Two reservoirs at different elevations. Land use measured per GWh of energy storage capacity, not MW power capacity. Typical: 10 hectares/GWh = ~25 acres/GWh. Closed-loop systems minimize environmental impact.
Battery Storage (Lithium-Ion)	0.02 - 0.1	0.02 - 0.1	Very compact: 600-1,000 sq ft per MWh storage capacity = 0.01-0.02 acres/MWh. MISO standard: 0.1 acres/MW power capacity. Much smaller than generation sources. Often co-located with solar.

On a direct footprint basis, thermal generation technologies are remarkably land use efficient. Coal plants require only 0.5-1.0 acres/MW, natural gas plants 0.2-0.4 acres/MW, and large nuclear facilities 0.5-1.3 acres/MW. Small modular reactors are even more compact, at 0.04-0.3 acres/MW, with some designs, such as the NuScale 920 MW plant, occupying approximately 35 acres total (0.04 acres/MW).

Battery energy storage systems demonstrate the smallest direct footprint at 0.02-0.1 acres/MW, occupying only 600-1,000 square feet per MWh of storage capacity. This extreme compactness makes batteries ideal for urban deployment and co-location with renewable generation.

In contrast, renewable technologies require substantially more land per MW of capacity. Solar PV facilities need 5-10 acres/MW for the panels, inverters, access roads, and substations. Onshore wind shows a direct footprint of 0.7-3.0 acres/MW for turbine pads, access roads, and electrical infrastructure, though this understates the full land intensity when spacing requirements are considered.

When accounting for fuel supply chains and spacing requirements, the land use comparison changes dramatically for certain technologies:

- **Wyoming PRB Coal:** Total land use increases only modestly to 1.5 to 2.5 acres per MW due to the thick PRB coal seams and resulting energy density per acre of coal mined, making it one of the most efficient energy sources in the country and notably lower in total land use than natural gas.
- **Natural Gas:** Combined-cycle plants show 12-15 acres/MW of total land use, including natural gas well pads (5 acres per multi-well pad), hydraulic fracturing operations, and pipeline rights-of-way. Because gas wells typically serve multiple plants, the per-MW allocation varies with production efficiency and well lifespan.
- **Nuclear:** Large nuclear plants require only 1 to 2 acres per MW when including uranium mining (mostly imported), fuel processing facilities, waste storage sites, and cooling water reservoirs due to the high energy density of enriched uranium. However, cooling reservoirs can add over 130,000 acres nationally, depending on site selection. The indirect land use of small modular reactors also increases when the fuel cycle is considered, as they share the same uranium supply chain as large reactors.
- **Onshore Wind:** The most striking difference in land use is for wind generation. While direct turbine footprints total only 0.7-3.0 acres/MW, spacing requirements to avoid wake effects raise the total land intensity to 30-100 acres/MW. Importantly, the land between turbines often remains in agricultural use (grazing, row crops), making this a case of dual-purpose land use rather than complete displacement. The actual disturbed area remains small, but the project boundary is extensive.
- **Offshore Wind:** Onshore infrastructure is minimal (<5 acres for substations and cable landing points), but marine spacing for wake avoidance requires 13-125 acres/MW of ocean area (typically 30-40 acres/MW). This marine space has competing uses, including shipping lanes, commercial fishing grounds, and marine habitats. Unlike onshore wind, where land between turbines can support agriculture, the marine area cannot generally be dual-purposed, though some fishing activities may continue between turbines depending on project design and regulatory constraints.
- **Solar PV:** Utility-scale solar maintains a relatively modest 7-10 acres/MW total project area, including spacing and buffer zones. This footprint can often be sited on degraded lands, brownfields, or integrated with agriculture (agrivoltaics).

3.5.4 Implications for Wyoming Coal

This comprehensive analysis reveals both challenges and opportunities for Wyoming coal in the evolving electricity generation landscape:

Economic Competitiveness: Coal without CCS is economically competitive, with an annual cost of $131.7 million to provide 2,000 GWh of electricity or $260.6 million to provide 500 MW of reliable peak capacity. However, coal faces strong competition from natural gas combined-cycle plants ($91.3 million/yr for 2,000 GWh) and onshore wind in favorable wind resource areas ($86.5 million/yr for 2,000 GWh). For peak capacity provision, battery storage ($129.1 million for 500 MW) and simple-cycle natural gas turbines ($134.2 million for 500 MW) offer lower-cost alternatives, though batteries require surplus energy to charge and do not generate electricity themselves.

Coal with 95% CCS faces substantially higher costs, with annual expenditures of $225.5 million for 2,000 GWh or $446.2 million for 500 MW peak capacity. This positions CCS-equipped coal above nearly all alternatives, raising questions about market viability in the absence of robust federal incentives. It is important to note that these cost estimates exclude currently available federal and state tax credits, grid connection costs, and expenses associated with CO_2 transportation and storage infrastructure, which could materially affect the comparative economics.

Reliability Advantage: New Wyoming coal power will typically operate at a 75% capacity factor and 83% ELCC, providing dispatchable power that can respond to system needs. This reliability premium becomes increasingly valuable as grids integrate more variable renewable power generation. Nuclear offers superior reliability metrics (90-95% CF, 95% ELCC) but at substantially higher annual costs ($205.6 million for 2,000 GWh, $450.3 million for 500 MW peak capacity) and

longer construction timelines. Coal's ability to provide firm capacity at moderate cost represents a strategic advantage in an electricity system that must balance energy provision with reliability and affordability.

Land Use Profile: Coal's direct footprint of 0.5-1.0 acres/MW is highly efficient, comparable to other thermal generation technologies. Additionally, due to the high energy density of Wyoming PRB coal, coal's total land use increases only marginally to 1.5 to 2.5 acres/MW over the life of a typical PRB coal plant, comparable to nuclear power plants, which show similarly small total land use numbers due to the energy density of enriched uranium. Additionally, Wyoming PRB coal's 1.5-2.5 acres/MW total footprint is significantly smaller than natural gas's (5-15 acres/MW) when the full fuel cycle is included, and it is also smaller than onshore wind's (30-141 acres/MW) when turbine spacing is considered.

Competing Technologies and Market Context: Natural gas combined-cycle plants present the most direct economic competition for energy provision, offering the second-lowest annual costs (after onshore wind in favorable locations), lower capital requirements, and flexibility to follow load. However, natural gas faces commodity price volatility and competing end-use demands from residential, commercial, and industrial sectors, as well as substantial growth in U.S. liquefied natural gas exports.

Wind and solar power technologies with storage offer zero-fuel-cost operations, making them increasingly competitive for energy generation. However, their low ELCC ratings (solar: 8%, onshore wind: 41%, offshore wind: 67%) mean they require substantial overbuilding or complementary dispatchable capacity to provide equivalent firm capacity. A 100 MW solar farm contributes only 8 MW toward peak planning reserves, requiring either 12.5 times the nameplate capacity or backup generation/storage to match coal's 83% ELCC contribution.

Battery storage offers the lowest cost for peak capacity provision ($129.1 million for 500 MW) but does not generate electricity and therefore requires surplus energy from other sources to be charged before peak-demand events. This complementary relationship between renewables and storage creates a different competitive dynamic than traditional dispatchable generation.

Strategic Position: Wyoming coal occupies a middle ground in the landscape of generation technologies. It is higher cost than natural gas combined cycle for energy costs. However, Wyoming coal power offers a balanced value proposition: competitive (though not lowest) costs for both energy and capacity provision, high reliability with 83% ELCC, proven technology with established supply chains, and the ability to provide dispatchable power that responds to system needs.

The key strategic challenge is that coal's competitive position depends heavily on federal and state policy choices—carbon pricing, emissions regulations, tax credits, and infrastructure investment—whose future trajectory remains uncertain. The analysis excludes federal and state tax credits that currently favor wind and solar power generation and storage, grid connection costs that can be substantial for remote wind and solar power generation, and CO_2 transportation and storage infrastructure costs required for CCS deployment. Depending on how these policies and cost factors evolve, coal's relative competitiveness could improve or deteriorate significantly.

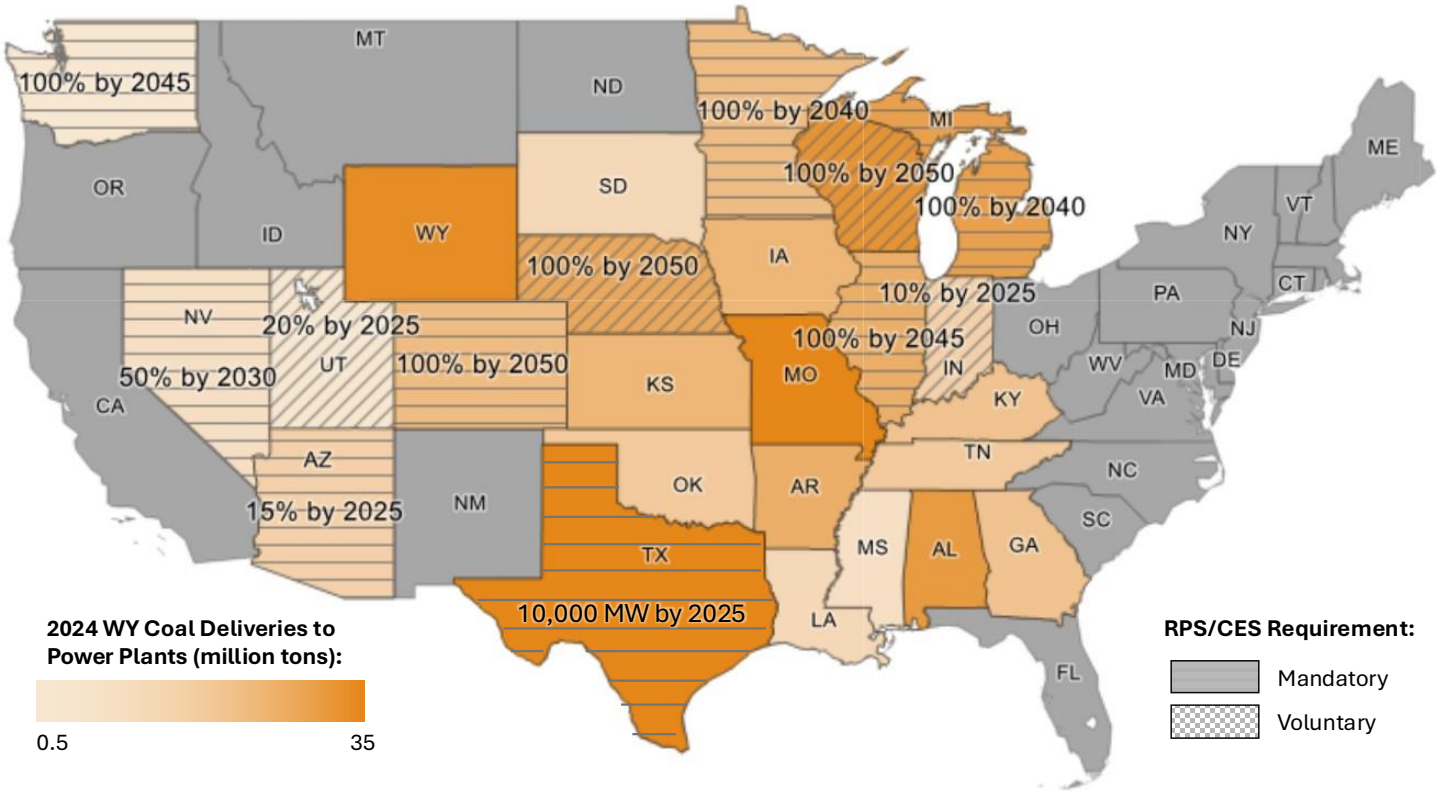
For Wyoming coal to maintain and expand market share, strategies must focus on: (1) emphasizing reliability advantages as grids face increasing challenges from variable wind and solar power generation, (2) highlighting competitive economics for balanced energy and capacity provision compared to alternatives requiring massive overbuilding (wind and solar) or higher capital costs (nuclear), (3) demonstrating land use efficiency relative to the extensive footprints required by wind generation, and (4) advancing CCS technologies to reduce the current cost penalty while positioning for potential future carbon regulations.

3.6 State Laws Affecting the Wyoming Coal Market

The negative impact of state laws on the Wyoming coal market can be attributed to two main requirements: Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES). While RPS and CES set requirements for utilities within a state to supply a certain percentage of their electric retail sales from alternative or non-fossil energy sources, respectively, some states have also established economy-wide (net) zero carbon (NZC) goals. Most state compliance deadlines are usually set between 2040 and 2050.

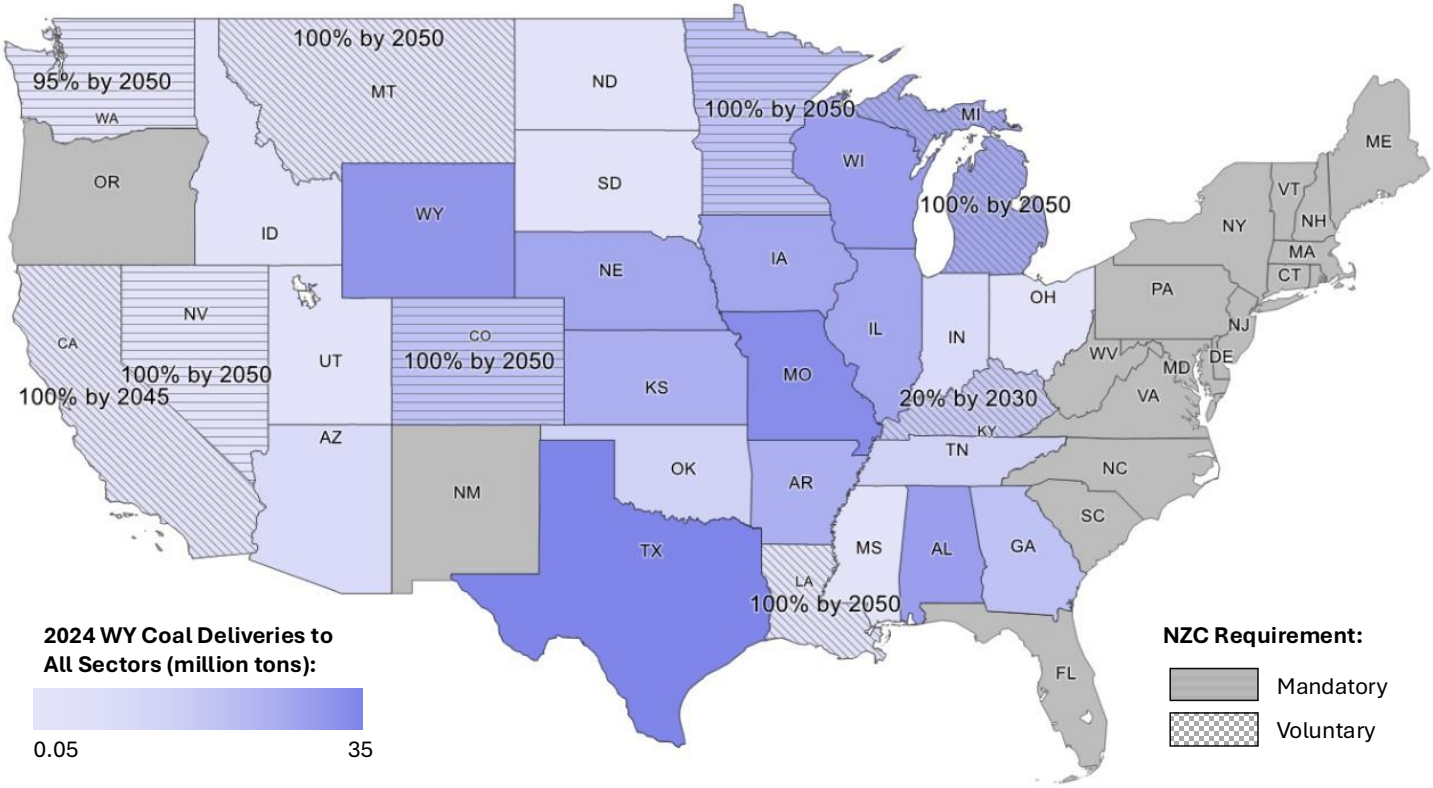
Of the 30 states that consume Wyoming coal in 2024, 14 have RPS or CES with future compliance goals or targets, while 10 states have economy-wide net-zero carbon goals or targets. **EXHIBIT 3-26** and **EXHIBIT 3-27** show the states with mandatory or voluntary RPS/CES and NZC targets, respectively, with the color intensity indicating the relative amount of Wyoming coal delivered to each state in 2024.

EXHIBIT 3-26: WYOMING COAL DELIVERIES TO POWER PLANTS & STATES WITH RPS/CES TARGETS



Note: Nebraska does not have a state-wide Clean Energy Standard. However, since all electric generation is publicly owned and operated by either the Nebraska Public Power District or the Omaha Public Power District, and both NPPD and OPPD have voted in favor of net-zero carbon standards, Nebraska was included. Additionally, Nevada has a mandatory CES of 50% by 2030 and a voluntary goal of 100% CES by 2050. Only the mandatory target is shown on the map.

EXHIBIT 3-27: WYOMING COAL DELIVERIES TO ALL SECTORS & STATES WITH NZC TARGETS



Of the 11 states with either a 100% CES or an economy-wide NZC, five states (California, Louisiana, Montana, Nevada, and Washington) collectively accounted for less than 2.5% of Wyoming's total coal sales in 2024. For this reason, they were not individually analyzed in this study. Additionally, although Nebraska's two utilities technically have NZCs, of the seven coal power plants operating in the state, only one (North Omaha) has announced its closure. North Omaha represents only 7% of the coal purchased by Nebraska utilities from Wyoming and only 0.3% of total Wyoming coal sales in 2024. Therefore, Nebraska is not currently considered a significant threat to the Wyoming coal market.

The remaining five states (CO, IL, MI, MN, WI) are the primary concerns for the future marketing of Wyoming coal. Collectively, these states have nineteen coal power plants, which purchased 39.4 million tons of Wyoming coal, with an additional 1.6 million tons consumed by industrial customers.

3.6.1 Individual State 'Adverse' Laws Impact

Each of the states listed below has a different RPS mandate, a different timeline for reaching net-zero carbon, and individual power plant closure dates. Therefore, the analysis looked at both the individual impact of each state and the overall impact of all five states on the Wyoming coal market. Analysis of the five primary states using Wyoming coal that have adopted strict net-zero or clean energy standards suggests Wyoming might lose over 30 million tons of thermal coal sales to electric power plants by 2031. This accounts for roughly 15 to 20% of Wyoming's thermal coal sales.

3.6.1.1 Colorado

Colorado mandates a 100% reduction in greenhouse gas emissions from 2005 levels by 2050, provided it is both technically and economically feasible. There are also interim requirements that mandate:

- by 2025, a reduction of GHG emissions by 26%
- by 2030, a 50% reduction in GHG
- by 2035, a reduction of 65%
- by 2040, a 75% reduction in GHG

- by 2045, a 90% reduction and
- by 2050, a reduction of 100% compared to 2005

Colorado has six active coal-fired power plants, as shown in **EXHIBIT 3-28**. These six power plants consumed 6 million tons of Wyoming coal in 2024. Currently, all six have announced closures by 2031, with several of the units scheduled to close in 2025-2026, resulting in approximately 6 million tons of at-risk Wyoming coal being lost over the next six years.

EXHIBIT 3-28: COLORADO COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Comanche 2	Xcel Energy	Utility	CO	335	-	Dec-25	1,085	1,085
Craig 1	Salt River Project	Coop	CO	427	-	Dec-25	956	-
Pawnee 1	Xcel Energy	Utility	CO	505	C-NG	Dec-26	1,506	1,506
Hayden 2	Xcel Energy	Utility	CO	262	-	Dec-27	616	-
Craig 2	Salt River Project	Coop	CO	410	-	Sep-28	926	-
Hayden 1	Xcel Energy	Utility	CO	179	-	Dec-28	410	-
Craig 3	Salt River Project	Coop	CO	448	-	Dec-29	740	-
Rawhide 1	Platte River Power Authority	Polit	CO	280	-	Dec-29	684	684
Ray D Nixon 1	Colorado Springs Utilities	Muni	CO	208	-	Dec-29	615	615
Comanche 3	Xcel Energy	Utility	CO	750	-	Dec-30	2,060	2,060
			CO - Total	**3,804**			**9,598**	**5,950**

3.6.1.2 Illinois

Illinois aims to achieve 100% clean energy by 2050, with interim targets of 40% by 2030 and 50% by 2040. This standard is based on 2005 GHG levels. The law also mandates the sale of specific amounts of alternative energy.

- 40% of electric sales must come from renewable energy by 2030.
- 50% of electric sales must come from renewable energy by 2040.

The four Illinois coal plants powered by coal consumed 9 million tons of Wyoming coal in 2024, as shown in **EXHIBIT 3-29**. All four coal plants have announced retirement dates before 2029.

EXHIBIT 3-29: ILLINOIS COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Newton 3	Vistra	Merchant	IL	595	-	Dec-27	1,771	1,771
Kincaid 1	Vistra	Merchant	IL	554	-	Dec-27	739	739
Kincaid 2	Vistra	Merchant	IL	554	-	Dec-27	730	730
Baldwin 1	Vistra	Merchant	IL	576	-	Dec-27	2,053	2,053
Baldwin 2	Vistra	Merchant	IL	581	-	Dec-27	1,953	1,953
Powerton 5	NRG Energy	Merchant	IL	769	-	Dec-28	898	898
Powerton 6	NRG Energy	Merchant	IL	769	-	Dec-28	855	855
Prairie State 1	Multiple Owners	Muni	IL	815	-	Dec-45	3,345	-
Prairie State 2	Multiple Owners	Muni	IL	815	-	Dec-45	3,000	-
Dallman 4	City of Springfield - (IL)	Muni	IL	209	-	Dec-45	317	-
Marion 1	Southern Illinois Power Coop	Coop	IL	40	-	Dec-99	136	-
Marion 2	Southern Illinois Power Coop	Coop	IL	40	-	Dec-99	138	-
Marion 3	Southern Illinois Power Coop	Coop	IL	40	-	Dec-99	140	-
			IL - Total	**6,357**			**16,075**	**8,999**

3.6.1.3 Michigan

In 2023, the Michigan legislature revised its RPS targets to reach 15% by 2029, 50% by 2030, 60% by 2035, and 80% "clean energy"—including nuclear, hydrogen, and carbon capture and storage—by 2035, with the goal of achieving 100% clean energy by 2040. These reductions are measured against 2005 emissions levels. It is essential to note that the commission has the authority to modify this standard if it determines that it would significantly increase electricity costs or compromise reliability.

There are only three coal-fueled power plants in the state, but all three are large scale plants that consumed over 10 million tons of Wyoming coal in 2024.

EXHIBIT 3-30: MICHIGAN COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
J H Campbell 1	CMS Energy Corporation	Utility	MI	260	-	Oct-25	902	902
J H Campbell 2	CMS Energy Corporation	Utility	MI	356	-	Oct-25	657	657
J H Campbell 3	CMS Energy Corporation	Utility	MI	785	-	Oct-25	3,092	3,092
Belle River 1	DTE Energy Company	Utility	MI	635	C-NG	Dec-25	1,805	-
Belle River 2	DTE Energy Company	Utility	MI	635	C-NG	Dec-26	1,443	-
Monroe 3	DTE Energy Company	Utility	MI	773	-	Dec-28	1,668	1,273
Monroe 4	DTE Energy Company	Utility	MI	762	-	Dec-28	1,651	1,261
Monroe 1	DTE Energy Company	Utility	MI	758	-	Dec-32	2,028	1,548
Monroe 2	DTE Energy Company	Utility	MI	773	-	Dec-32	1,765	1,348
			MI - Total	**5,736**			**15,012**	**10,081**

Due to the potential for a power shortage during the summer of 2025, the U.S. Department of Energy (DOE) issued an emergency operating order for the J H Campbell plant under its Federal Power Act 202 (c) authority to extend its operation for 90 days, and this order has been extended twice to continue operations through at least February 2026. The Belle River Power plant is currently undergoing a conversion to natural gas, with completion scheduled for 2026. The largest of the three is the Monroe Power Plant, which is scheduled to close by the end of 2032.

3.6.1.4 Minnesota

Minnesota requires electric utilities to obtain 100% of the electricity they sell from carbon-free sources by 2040, including alternative energy, nuclear power, and carbon capture from fossil fuel generation. There are interim targets of 80% carbon-free power in 2030 and 90% in 2035. This reduction is based on 2005 GHG emissions. In addition, Minnesota implemented a Renewable Portfolio Standard of:

- 25% by 2025
- 55% by 2035.

Minnesota has three coal-fueled plants, which generate over 3,000 MW of capacity, as shown in **EXHIBIT 3-31**.

EXHIBIT 3-31: MINNESOTA COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Sherburne County 1	Xcel Energy	Utility	MN	680	-	Dec-26	1,596	1,384
Allen S King 1	Xcel Energy	Utility	MN	511	-	Jan-28	342	342
Clay Boswell 3	ALLETE, Inc.	Utility	MN	352	C-NG	Dec-30	868	503
Sherburne County 3	Xcel Energy	Utility	MN	876	-	Dec-34	2,117	1,835
Clay Boswell 4	ALLETE, Inc.	Utility	MN	585	C-NG	Dec-35	1,794	1,039
			MN - Total	**3,004**			**6,718**	**5,103**

3.6.1.5 Wisconsin

Wisconsin Governor Tony Evers issued an executive order (EO#38) calling for Net-Zero Carbon by 2050. This target is based on 2005 levels of GHG emissions. A Clean Energy Roadmap was developed by the state utility commission in cooperation with electric utilities. Although Wisconsin is shifting away from fossil fuels, the EO is not as strict as the laws passed in the four previous states (CO, IL, MI, MN) as it is a voluntary standard.

The state has six coal-fueled power plants; two have announced closure, and three have announced the switch to natural gas by 2031. The one remaining is a small plant owned by Dairyland Cooperative. **EXHIBIT 3-32** provides an overview of the Wisconsin coal units.

EXHIBIT 3-32: WISCONSIN COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
South Oak Creek 7	WEC Energy	Utility	WI	304	-	Dec-26	540	540
South Oak Creek 8	WEC Energy	Utility	WI	311	-	Dec-26	588	588
Edgewater 5	Alliant Energy	Utility	WI	409	C-NG	Dec-28	1,297	1,297
Columbia 1	Alliant Energy	Utility	WI	579	-	Dec-29	1,462	1,462
Columbia 2	Alliant Energy	Utility	WI	569	-	Dec-29	1,518	1,518
Elm Road 1	WEC Energy	Utility	WI	636	C-NG	Dec-31	1,871	1,476
Elm Road 2	WEC Energy	Utility	WI	635	C-NG	Dec-31	1,336	1,054
Weston 3	WEC Energy	Utility	WI	335	-	Dec-31	465	465
Weston 4	WEC Energy	Utility	WI	553	C-NG	Dec-31	1,734	1,734
Manitowoc 9	Manitowoc Public Utilities	Muni	WI	58	-	Dec-99	2	-
John P Madgett 1	Dairyland Power Cooperative	Coop	WI	390	-	Dec-99	632	632
			WI - Total	**4,780**			**11,445**	**10,765**

Over the next five years, Wyoming is projected to lose 9.5 million tons out of the 10 million tons it currently supplies to Wisconsin.

3.6.2 Individual State 'Beneficial' Laws Impact

State and local policies have evolved significantly in recent years as lawmakers work to manage the complex challenges of societal electrification, supply chain disruptions, rapid economic expansion, prolonged blackouts resulting from winter storms Uri and Elliott, and alerts from federal electric reliability agencies, such as FERC and NERC. In the past three years, eight states (Arkansas, Indiana, Kansas, Kentucky, Missouri, Texas, Utah, and Wyoming) have passed a total of 23 bills aimed at enhancing "electric reliability." These laws differ significantly across states, with no two being identical. Many of these bills focus on six main themes:

1) Prohibits shutting down dispatchable generation until an equal or greater amount of dispatchable generation is available. (AR, KY, MO, UT, WY)

2) Establishes a 'presumption' that existing dispatchable generation should not shut down early unless the electric utility can adequately rebut this presumption. "Rebuttable Presumption" (AR, KY, UT, WV, WY)

3) Restrictions are imposed on electric utilities when they reach settlement agreements with third parties to close a power plant prematurely. (AR, MO, UT, WV)

4) Power plants scheduled for closure may remain open for electric reliability reasons, such as extreme weather events. The electric utility might include the costs of maintaining and fueling the plant in its rate base if it is considered prudent. (KS, MO)

5) Before shutting down a dispatchable power plant, the electric utility must offer the option to sell the plant at a 'fair market value' to a third party. (UT, WY)

6) New intermittent power generation must be supported by dispatchable generation. (TX)

3.6.2.1 Arkansas

Arkansas has enacted four bills that discourage the early shutdown of coal-fired power plants (SB 65 & HB 1665 in 2021, SB 463 & SB 596 in 2025). The new laws require:

- SB 65 is designed to restrict any federal EPA CO2 regulations. It requires approval from both legislative chambers before the state environmental agency can submit a state plan regarding carbon dioxide. It also calls for rate impact studies and economic analyses of any federal CO2 mandate.[24]
- HB 1655 mandates the continued use of existing generation to the greatest extent feasible. It encourages electric utilities to invest in existing facilities to extend their operational life. The PSC is required to perform a rate impact analysis, a cost-benefit analysis, and a reliability/resilience study. The PSC must thoroughly examine these factors and report findings to the legislature before approving the closure of any existing generation.[25]
- SB 463 requires public utilities in Arkansas to obtain approval from the Arkansas Public Service Commission (APSC) for any settlement agreements related to the closure, deactivation, or decommissioning of electric generation units.[26]
- The bill details the state's energy policy to ensure sufficient, affordable, reliable, and resilient electric generation. It requires PSC approval before shutting down a plant. It establishes a rebuttable presumption that the utility can only close a plant after replacing it with an equal or greater amount of dispatchable generation. The replacement must happen before the existing plant is closed.[27]

Although these provisions help preserve much of the existing fleet in Arkansas, they do not prevent the closure of two large plants, White Bluff and Independence, by 2030. These two plants consume nearly half (4.6 million tons) of the Wyoming coal sent to Arkansas. Out of the total 9.5 million tons of Wyoming coal shipped to Arkansas, 4.9 million tons are expected to remain in the state well into the next decade.

EXHIBIT 3-33: ARKANSAS COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
White Bluff 1	Entergy	Utility	AR	817	-	Dec-27	371	371
White Bluff 2	Entergy	Utility	AR	821	-	Dec-28	971	971
Independence 1	Entergy	Utility	AR	821	-	Dec-30	1,503	1,503
Independence 2	Entergy	Utility	AR	826	-	Dec-30	1,800	1,800
Turk 1	AEP	Utility	AR	650	-	n/a	1,505	1,505
Plum Point 1	Multiple Owners	Mercha	AR	680	-	n/a	1,824	1,824
Flint Creek 1	AEP	Utility	AR	494	-	n/a	1,478	1,478
			AR - Total	**5,109**			**9,453**	**9,453**

[24] https://arkleg.state.ar.us/Bills/Detail?id=SB65&ddBienniumSession=2021%2F2021R
[25] https://arkleg.state.ar.us/Bills/Detail?id=HB1665&ddBienniumSession=2021%2F2021R
[26] https://arkleg.state.ar.us/Bills/Detail?id=SB463&ddBienniumSession=2025%2F2025R
[27] https://arkleg.state.ar.us/Bills/Detail?id=SB596&ddBienniumSession=2025%2F2025R

3.6.2.2 Indiana

The primary objective of the two Indiana laws was to ensure that reliability and resource adequacy were at the forefront of the IRUC's decisions. HB 1007 and HB 1520 accomplished this goal.

- HB 1007 - Decisions on Indiana's electric generation mix, energy infrastructure, and electric service must consider key attributes such as reliability, affordability, resiliency, stability, and environmental sustainability. It also requires utilities to demonstrate enough capacity to meet planning reserve margin requirements and other federal reliability standards.[28]
- HB 1520 – The bill requires utilities to submit a forward-looking three-year resource adequacy report annually to the Indiana Utilities Regulatory Commission, demonstrating the availability of unforced capacity to meet the utilities' peak winter and summer demands. It also limits the amount of UCAP that can be purchased from capacity markets to 30%. The bill grants the IURC the power to reject the plan, which would require the utility to acquire the necessary capacity to address the IURC's concerns.[29]

The two coal-fueled plants that consume Wyoming coal (Rockport/Michigan City) are scheduled to close in 2028. Given the legal obligations behind these closure agreements, the laws passed will help preserve other Indiana coal plants, although they will not prolong the closure of these two plants. Wyoming is expected to lose 3.4 million tons of coal sales to Indiana over the next five years.

EXHIBIT 3-34: INDIANA COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
AES Petersburg 3	AES	Utility	IN	528	C-NG	Dec-25	818	-
AES Petersburg 4	AES	Utility	IN	530	C-NG	Dec-25	758	-
R M Schahfer 17	NiSource Inc.	Utility	IN	361	-	Dec-25	487	-
R M Schahfer 18	NiSource Inc.	Utility	IN	361	-	Dec-25	429	-
F B Culley 2	CenterPoint Energy	Utility	IN	90	-	Dec-25	147	-
F B Culley 3	CenterPoint Energy	Utility	IN	270	C-NG	Dec-27	732	-
Michigan City 12	NiSource Inc.	Utility	IN	455	-	May-28	541	460
Rockport 1	AEP	Utility	IN	1,300	-	Dec-28	1,703	1,650
Rockport 2	AEP	Utility	IN	1,300	-	Dec-28	1,349	1,307
Cayuga 1	Duke Energy	Utility	IN	500	-	Dec-29	779	-
Gibson 5	Duke Energy	Utility	IN	620	-	Dec-29	683	-
Cayuga 2	Duke Energy	Utility	IN	495	-	Dec-30	1,035	-
Gibson 3	Duke Energy	Utility	IN	630	-	Dec-31	984	-
Gibson 4	Duke Energy	Utility	IN	622	-	Dec-31	952	-
Gibson 1	Duke Energy	Utility	IN	630	-	Dec-38	1,322	-
Gibson 2	Duke Energy	Utility	IN	630	-	Dec-38	1,005	-
Clifty Creek 1	AEP	Utility	IN	196	-	Dec-40	420	-
Clifty Creek 2	AEP	Utility	IN	196	-	Dec-40	498	-
Clifty Creek 3	AEP	Utility	IN	196	-	Dec-40	432	-
Clifty Creek 4	AEP	Utility	IN	196	-	Dec-40	372	-
Clifty Creek 5	AEP	Utility	IN	196	-	Dec-40	473	-
Clifty Creek 6	AEP	Utility	IN	196	-	Dec-40	266	-
Merom 1	Hallador Energy	Coop	IN	488	-	Dec-99	909	-
Merom 2	Hallador Energy	Coop	IN	489	-	Dec-99	963	-
			IN - Total	**11,471**			**18,057**	**3,417**

[28] https://iga.in.gov/legislative/2025/bills/house/1007/details
[29] https://iga.in.gov/legislative/2021/bills/house/1520/details

3.6.2.3 Kansas

As a fallout of winter storm Uri, in 2024, the state passed HB 2527[30], allowing a coal plant to remain online (even if idled) in an effort to ensure adequate power during extreme weather events.

The electric utility is permitted to recover expenses related to operating such facilities that remain in service to ensure reliable availability of generating capacity to provide essential service to customers, including during extreme weather events, and recover any portion of the utility's rate base and prudently incurred expenses necessary for those facilities:

a) To operate at a low-capacity factor; or
b) that operate offline during normal conditions and supply capacity only.

Although not directly related, this legislation has positively affected the lifespan of coal-fired plants in the state. The Lawrence coal plant was scheduled to close in 2028 but has been extended to 2033. The closure date of one coal unit at the Jeffrey Energy Center was also moved from 2030 to 2031. Kansas's five coal-fired plants consumed 8.5 million tons of Wyoming coal in 2024, as shown in **EXHIBIT 3-35**. Of these, only one unit (Jeffery 2) is scheduled to close in 2031. The other eight coal units are planned to stay open past 2031.

EXHIBIT 3-35: KANSAS COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Jeffrey 2	Evergy, Inc.	Utility	KS	664	-	Dec-31	1,331	1,331
Lawrence 4	Evergy, Inc.	Utility	KS	111	-	Dec-33	142	142
Lawrence 5	Evergy, Inc.	Utility	KS	374	C-NG	Dec-33	330	330
La Cygne 1	Evergy, Inc.	Utility	KS	758	-	Dec-33	1,336	1,328
La Cygne 2	Evergy, Inc.	Utility	KS	668	-	Dec-38	1,996	1,984
Jeffrey 1	Evergy, Inc.	Utility	KS	671	-	Dec-38	451	451
Jeffrey 3	Evergy, Inc.	Utility	KS	673	-	Dec-38	1,728	1,728
Holcomb 1	Sunflower Coop	Coop	KS	359	-	n/a	741	741
Nearman Creek 1	City of Kansas City - (KS)	Muni	KS	243	-	n/a	424	424
			KS - Total	**4,521**			**8,480**	**8,459**

3.6.2.4 Kentucky

Although only two plants in Kentucky purchase Wyoming coal, the laws passed by this state are significant. The Shawnee and Trimble County plants used 4.3 million tons of Wyoming coal in 2024. Neither is scheduled to close within the next five years.

A big reason why is SB 4[31] and SB 349[32]:

- SB 4 – *"There shall be a rebuttable presumption against retiring a fossil fuel-fired electric generating unit. The commission shall not approve the retirement of an electric generating unit, nor authorize a surcharge for decommissioning it, nor take any other action that allows for recovery of costs related to its retirement. The decision to retire the fossil fuel-fired electric generating unit is not based on any financial incentives or benefits offered by any federal agency."*
- SB 349 – *"The utility shall not start retiring or decommissioning the electric generating unit until the replacement generating capacity that meets the requirements of paragraph (a) of this subsection is fully built, permitted, and*

[30] https://www.kslegislature.gov/li_2024/b2023_24/measures/hb2527/
[31] https://apps.legislature.ky.gov/record/23rs/sb4.html
[32] https://apps.legislature.ky.gov/record/24rs/sb349.html

operational, unless the utility can show that it is necessary under the circumstances to begin retiring or decommissioning the existing unit earlier."

The passage of these two bills has slowed the early closure of coal-fueled plants in this state.

EXHIBIT 3-36: KENTUCKY COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Mill Creek 2	LG&E/KU	Utility	KY	297	-	Jun-31	765	-
Shawnee 1	TVA	Fed	KY	134	-	Dec-33	439	439
Shawnee 2	TVA	Fed	KY	134	-	Dec-33	451	451
Shawnee 3	TVA	Fed	KY	134	-	Dec-33	375	375
Shawnee 4	TVA	Fed	KY	134	-	Dec-33	373	373
Shawnee 5	TVA	Fed	KY	134	-	Dec-33	470	470
Shawnee 6	TVA	Fed	KY	134	-	Dec-33	398	398
Shawnee 7	TVA	Fed	KY	134	-	Dec-33	428	428
Shawnee 8	TVA	Fed	KY	134	-	Dec-33	424	424
Shawnee 9	TVA	Fed	KY	134	-	Dec-33	383	383
Ghent 1	LG&E/KU	Utility	KY	474	-	Dec-34	1,312	-
Ghent 2	LG&E/KU	Utility	KY	495	-	Dec-34	1,130	-
East Bend 2	Duke Energy	Utility	KY	600	-	Dec-34	1,087	-
Trimble County 1	LG&E/KU	Utility	KY	511	-	n/a	1,623	272
Trimble County 2	LG&E/KU	Utility	KY	732	-	n/a	1,758	294
E W Brown 3	LG&E/KU	Utility	KY	412	-	n/a	693	-
Ghent 3	LG&E/KU	Utility	KY	485	-	n/a	1,281	-
Ghent 4	LG&E/KU	Utility	KY	465	-	n/a	1,047	-
Mill Creek 3	LG&E/KU	Utility	KY	391	-	n/a	770	-
Mill Creek 4	LG&E/KU	Utility	KY	477	-	n/a	1,175	-
Cooper 1	EKPC	Coop	KY	116	-	n/a	57	-
Cooper 2	EKPC	Coop	KY	225	-	n/a	152	-
H L Spurlock 1	EKPC	Coop	KY	300	-	n/a	838	-
H L Spurlock 2	EKPC	Coop	KY	510	-	n/a	1,249	-
H L Spurlock 3	EKPC	Coop	KY	268	-	n/a	712	-
H L Spurlock 4	EKPC	Coop	KY	268	-	n/a	759	-
D B Wilson 1	Big Rivers	Coop	KY	417	-	n/a	1,178	-
			KY - Total	**8,649**			**21,327**	**4,306**

3.6.2.5 Missouri

Missouri is the second-largest customer of Wyoming coal. With eight coal-fired plants consuming nearly 22 million tons of Wyoming coal, Missouri remains a major customer of Wyoming coal. **EXHIBIT 3-37** shows all currently operating coal units in Missouri.

Over the past two years, the state has passed SB 4[33] and SB 202[34], both aimed at addressing electric reliability concerns.

- SB 4 – "*Prior to closing dispatchable generation, the PSC shall first certify that such utility company has secured and placed on the electric grid an equal or greater amount of dispatchable electric generation. To identify potential capital projects that are expected to result in the extension of the retirement date of*

[33] https://www.senate.mo.gov/25info/bts_web/Bill.aspx?SessionType=R&BillID=66
[34] https://www.senate.mo.gov/21info/BTS_Web/Bill.aspx?SessionType=R&BillID=54105488

each generating unit. Electrical corporations shall not enter into such a settlement to meet pollution reduction or other corporate or societal goals beyond those required by law."

- SB 202 – "*If determined by the commission to be just, reasonable, and necessary for the provision of safe and adequate service, the electrical corporation may be permitted to retain coal-fired generating assets in rate base and recover costs associated with operating the coal-fired assets that remain in service to provide greater certainty that generating capacity will be available to provide essential service to customers, including during extreme weather events, and the commission shall not disallow any portion of such cost recovery on the basis that such coal-fired generating assets operate at a low capacity factor, or are off-line and providing capacity only, during normal operating conditions."*

Of the eight coal-fired plants, only one (Sioux) is scheduled to close in the next five years. The plant, set for closure in 2028, would result in a reduction of approximately 1.5 million tons in sales. However, due to the increasing demand for electricity in the state and the passage of SB 4, it is expected that the Sioux plant's closure may be postponed by several years.

EXHIBIT 3-37: MISSOURI COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Sioux 1	Ameren	Utility	MO	487	-	Dec-31	851	710
Sioux 2	Ameren	Utility	MO	487	-	Dec-31	1,004	838
Labadie 1	Ameren	Utility	MO	593	-	Dec-36	2,417	2,417
Labadie 2	Ameren	Utility	MO	593	-	Dec-36	2,308	2,308
Iatan 1	Evergy	Utility	MO	703	-	Dec-39	1,009	1,009
Labadie 3	Ameren	Utility	MO	593	-	Dec-42	1,663	1,663
Labadie 4	Ameren	Utility	MO	593	-	Dec-42	2,123	2,123
Hawthorn 5	Evergy	Utility	MO	562	-	n/a	1,067	1,067
New Madrid 1	AECI	Coop	MO	575	-	n/a	1,656	1,656
New Madrid 2	AECI	Coop	MO	566	-	n/a	1,453	1,453
Thomas Hill 1	AECI	Coop	MO	165	-	n/a	638	638
Thomas Hill 2	AECI	Coop	MO	268	-	n/a	270	270
Thomas Hill 3	AECI	Coop	MO	698	-	n/a	2,268	2,268
Iatan 2	Evergy	Utility	MO	897	-	n/a	1,415	1,415
John Twitty Energy Center 1	City Utilities of Springfield - (MO)	Muni	MO	184	-	n/a	494	494
John Twitty Energy Center 2	City Utilities of Springfield - (MO)	Muni	MO	275	-	n/a	758	758
Sikeston 1	City of Sikeston - (MO)	Muni	MO	240	-	n/a	909	909
			MO - Total	**8,478**			**22,304**	**21,996**

3.6.2.6 Texas

Although the Wyoming coal market has declined over the past decade, Texas remains the largest customer of Wyoming coal, accounting for 33.4 million tons. With nine coal-fired power plants, the state is the single largest consumer of coal in the country.

After Winter Storm Uri in 2021, Texas enacted SB 3[35] to improve reliability. Key provisions of SB 3 include:

- Require ERCOT to develop appropriate qualification and performance requirements for providing such ancillary or reliability services, including suitable penalties for failure to deliver the services.
- Size the services procured to prevent prolonged rotating outages caused by net load variability in high-demand and low-supply scenarios; and

[35] https://legiscan.com/TX/bill/SB3/2021

- Ensure services are dispatchable and capable of meeting continuous operating requirements for the season in which they are procured; and
- Ensure winter resource capability qualifications are met, including on-site fuel storage, dual fuel capability, or fuel supply arrangements to guarantee winter performance for several days.

This is in addition to SB 1281[36], which supports thermal generation in Texas by requiring ERCOT's reliability assessments to consider "thermal generation availability" under extreme conditions and by easing specific permitting requirements for new short transmission lines—thereby supporting grid reliability claims that can favor the continued use of thermal plants. The beneficial legislation enacted in Texas resulted from Winter Storm Uri, multiple warnings by ERCOT during summer peak times, and the state's rapid economic growth. However, it is essential to note that Texas is a deregulated state, where generation primarily depends on competitive pricing. Due to the significant resource advantage of wind and solar in the state, coal-fired plants will continue to face challenges as more natural gas plants come online.

EXHIBIT 3-38: TEXAS COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Welsh 3	AEP	Utility	TX	500	C-NG	Dec-27	1,385	1,385
Coleto Creek 1	Vistra	Utility	TX	655	-	Dec-27	1,633	1,633
San Miguel 1	San Miguel Electric Coop	Coop	TX	391	-	Dec-27	1,653	-
Welsh 1	AEP	Utility	TX	500	C-NG	Dec-28	1,534	1,534
Tolk 1	Xcel Energy	Utility	TX	532	-	Dec-28	500	500
Tolk 2	Xcel Energy	Utility	TX	535	-	Dec-28	590	590
J K Spruce 2	CPS	Muni	TX	785	C-NG	Dec-28	2,021	2,021
J K Spruce 1	CPS	Muni	TX	560	-	Dec-28	1,617	1,617
Limestone 1	NRG Energy	Merchant	TX	831	-	n/a	1,941	1,941
Limestone 2	NRG Energy	Merchant	TX	858	-	n/a	1,681	1,681
W A Parish 5	NRG Energy	Merchant	TX	664	-	n/a	1,845	1,845
W A Parish 6	NRG Energy	Merchant	TX	663	-	n/a	1,382	1,382
W A Parish 7	NRG Energy	Merchant	TX	577	-	n/a	1,677	1,677
W A Parish 8	NRG Energy	Merchant	TX	610	-	n/a	2,027	2,027
Sandy Creek 1	LS Power	Merchant	TX	933	-	n/a	1,734	1,734
Martin Lake 1	Vistra	Merchant	TX	800	-	n/a	2,314	2,314
Martin Lake 2	Vistra	Merchant	TX	805	-	n/a	2,010	2,010
Martin Lake 3	Vistra	Merchant	TX	805	-	n/a	2,625	2,625
Fayette Power Project 1	LCRA	State	TX	590	-	n/a	1,700	1,700
Fayette Power Project 2	LCRA	State	TX	590	-	n/a	1,192	1,192
Fayette Power Project 3	LCRA	State	TX	435	-	n/a	1,805	1,805
Oak Grove 1	Vistra	Merchant	TX	855	-	n/a	4,623	-
Oak Grove 2	Vistra	Merchant	TX	855	-	n/a	4,214	-
Twin Oaks 1	Armadillo Power LLC	Merchant	TX	152	-	n/a	932	-
Twin Oaks 2	Armadillo Power LLC	Merchant	TX	153	-	n/a	875	-
			TX - Total	**15,634**			**45,508**	**33,212**

[36] https://legiscan.com/TX/text/SB1281/2021

3.6.2.7 Utah

Utah joined Wyoming, West Virginia, and Kentucky in passing the most aggressive laws to support the continued operation of coal-fired plants. Over the past three years, the state has passed four major laws (HB 70[37], HB 191[38], HB 374[39], SB 161[40]), all of which are aimed at retaining coal-fueled generation in the state. Some of the legislative highlights include:

- Authorizes the state to establish a public/private partnership and find a buyer or operator for the Intermountain Power Plant. Sets a fair market value and targets energy demand customers and data centers to contract with the IPP.
- Requires the PSC to make decisions based on clear and convincing evidence before approving the early retirement of an electrical generation facility. These decisions must ensure that such retirements do not negatively impact the availability of affordable, reliable, dispatchable, and secure electricity, worsen electricity shortages, impose unnecessary costs on ratepayers, or result from federal financial incentives.
- There is a presumption against prematurely retiring an electric generation plant. (b) A qualified utility can overcome the presumption described in Subsection (6)(a) by providing evidence of a firm commitment and ability to have a replacement resource ready before retiring the current facility.
- Before closing a dispatchable power plant, the utility must offer the facility for sale. The Office of Energy Development shall determine the fair market value of the plant.

Although Utah power plants consume 9.4 million tons of coal, only 0.5 million tons are sourced from Wyoming, mainly due to supply shortages in the Utah coal basin.

EXHIBIT 3-39: UTAH COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Intermountain 1	IPA	Muni	UT	900	-	Sep-25	1,373	249
Intermountain 2	IPA	Muni	UT	900	-	Nov-25	1,278	231
Bonanza	Desert Power	Coop	UT	458	-	Dec-41	1,705	-
Sunnyside Cogen GEN1	Sunnysude Cogen	Merchant	UT	51	-	n/a	392	-
Hunter 1	PacifiCorp	Utility	UT	446	-	n/a	802	-
Hunter 2	PacifiCorp	Utility	UT	446	-	n/a	778	-
Hunter 3	PacifiCorp	Utility	UT	471	-	n/a	511	-
Huntington	PacifiCorp	Utility	UT	459	-	n/a	657	-
Huntington	PacifiCorp	Utility	UT	450	-	n/a	611	-
			UT - Total	**4,581**			**8,106**	**480**

However, without laws mandating the sale of existing dispatchable generation, the Intermountain Power Plant (IPP) likely would have already shut down. As demonstrated over the past few years, if supply shortages persist, Intermountain could remain a key customer for Wyoming coal.

3.6.2.8 Wyoming

Over the last six years, Wyoming has enacted five major bills that have significantly contributed to the ongoing operation of coal-fired power plants in the state. Just a few years ago, PacificCorp planned to shut down three of its four coal-fired plants in Wyoming. Now, only the Naughton plant and two of the four Dave Johnston coal units are switching to natural gas. The closures of the remaining Jim Bridger and Dave Johnson coal units have been postponed.

[37] https://le.utah.gov/~2025/bills/static/HB0070.html
[38] https://le.utah.gov/~2024/bills/static/HB0191.html
[39] https://le.utah.gov/~2024/bills/static/HB0374.html
[40] https://le.utah.gov/~2024/bills/static/SB0161.html

Highlights of the five major bills include:

- **Mandatory sale attempt before retirement:** Wyoming's 2019 SF 159[41] requires an investor-owned utility to make a good-faith effort to sell a coal unit before retiring it and exempts a buyer from public-utility regulation. It also stipulates that electricity from a purchased unit must be taken under specified terms, including avoided-cost-style purchases for eligible customers. These provisions create a pathway for third-party ownership to maintain units.
- **Purchaser rights and commission oversight**: SF 21[42] (2020) amends Public Service Commission authority and clarifies rights for buyers of retiring coal units, reinforcing the SF 159 sale pathway and PSC consideration of such transactions.
- **Presumption against retirement with rate-recovery consequences:** HB 166[43] (2021) establishes a rebuttable presumption that coal and gas plants should remain in service. To retire a unit, a utility must prove customer cost savings, adequate, reliable, and dispatchable capacity after retirement, and no adverse effect on service. If a utility retires without rebutting the presumption, recovery and earnings on certain replacement capital costs can be limited. The PSC must also weigh reliability impacts before approving a retirement.
- **Litigation funding to defend coal markets and operations:** HB 207[44] (2021) appropriated $1.2 million for the Governor and Attorney General to sue other states whose laws impede Wyoming coal exports or contribute to early coal-plant retirements. HB 69[45] (2023) continued and updated this litigation funding authority. These measures seek to preserve markets that underpin the continued operation of Wyoming coal plants.

EXHIBIT 3-40: WYOMING COAL UNITS

Plant & Unit Name	Owner	Owner Type	Plant State	Capacity (MW)	Fuel Switch?	Announced Retire/Fuel Switch	2024 Total Coal Consumption ('000 tons)	2024 WY Coal Consumption ('000 tons)
Naughton 1	PacifiCorp	Utility	WY	156	C-NG	Dec-25	388	388
Naughton 2	PacifiCorp	Utility	WY	201	C-NG	Dec-25	523	523
Neil Simpson 2	Black Hills	Utility	WY	80	C-NG	Dec-25	491	491
Dave Johnston 1	PacifiCorp	Utility	WY	93	C-NG	Dec-28	353	353
Dave Johnston 2	PacifiCorp	Utility	WY	102	C-NG	Dec-28	397	397
Dave Johnston 3	PacifiCorp	Utility	WY	220	-	Dec-27	848	848
Dave Johnston 4	PacifiCorp	Utility	WY	330	-	n/a	1,127	1,127
Wygen 1	Black Hills	Utility	WY	85	-	n/a	425	425
Wygen 2	Black Hills	Utility	WY	90	-	n/a	462	462
Wygen 3	Black Hills	Utility	WY	100	-	n/a	498	498
Dry Fork	Basin Electric	Coop	WY	390	-	n/a	1,883	1,883
Wyodak	PacifiCorp	Utility	WY	332	-	n/a	1,501	1,501
Laramie River 1	Basin Electric	Coop	WY	560	-	n/a	1,141	1,141
Laramie River 2	Basin Electric	Coop	WY	570	-	n/a	1,793	1,793
Laramie River 3	Basin Electric	Coop	WY	570	-	n/a	1,444	1,444
Jim Bridger 3	PacifiCorp	Utility	WY	523	-	n/a	1,368	1,368
Jim Bridger 4	PacifiCorp	Utility	WY	526	-	n/a	1,504	1,504
			WY - Total	**4,928**			**16,144**	**16,144**

[41] https://www.wyoleg.gov/Legislation/2019/sf0159
[42] https://wyoleg.gov/Legislation/2020/SF0021
[43] https://www.wyoleg.gov/Legislation/2021/HB0166
[44] https://wyoleg.gov/2021/Introduced/HB0207
[45] https://wyoleg.gov/Legislation/2023/HB0069

3.7 Potential for Non-Thermal Demand for Wyoming Coal

3.7.1 Rare Earth Element Extraction from Coal and Related Resources in Wyoming

Wyoming has drawn growing interest in rare earth elements (REEs) and other critical minerals as part of a broader effort to diversify the state's coal value chain beyond combustion. Several initiatives are exploring REE recovery from coal, coal-associated strata, and hard-rock deposits, though all remain at relatively early stages of commercial development. To date, Wyoming's most tangible progress has been in advancing processing technologies rather than establishing large, high-grade, mine-permitted REE resources.

One of the most visible coal-related efforts is underway at the Brook Mine[46] near Sheridan, Wyoming, by Ramaco Resources. The project is notable for its unconventional geology, in which REEs occur in coal, carbonaceous shale, and friable clays rather than in traditional hard-rock minerals such as bastnaesite or monazite. Ramaco refers to this material as "carbon ore." The company has published a Preliminary Economic Assessment[47] prepared by Fluor Corporation, outlining a conceptual operation processing roughly two million tons of material per year. However, the Brook Mine resource has an average REE grade of approximately 450 parts per million, which is lower than grades at established or advanced hard-rock projects. As a result, project economics are highly sensitive to recovery efficiency, reagent consumption, and product mix.

Importantly, the Brook Mine PEA relies heavily on scandium revenues, which account for roughly 58 percent of projected critical mineral revenue. While scandium is strategically valuable, global demand remains limited, and the pricing assumptions in the PEA have been viewed by some analysts as optimistic. In contrast, neodymium and praseodymium oxides, which form the economic backbone of most REE projects globally, play a comparatively smaller role in the Brook Mine revenue case. This reliance on niche markets introduces additional commercial risk beyond the already significant technical challenges of scaling a novel extraction process.

From a technology standpoint, Ramaco's proprietary SolvEx process is a multi-stage leaching system that reportedly uses less acid than conventional REE extraction techniques and aims for high recovery rates. While bench-scale results have been encouraging, the process has yet to be demonstrated on a pilot or commercial scale. Key uncertainties include impurity management, waste handling, potential radioactive byproducts, and permitting requirements for tailings disposal.

Wyoming's coal-based REE efforts contrast with the state's hard-rock REE prospects, which offer substantially higher grades but face their own development hurdles. The Bear Lodge Project[48], located in northeast Wyoming and developed by Rare Element Resources, hosts REE grades of 30,000 ppm and has long been considered one of the more significant undeveloped REE resources in the United States. Similarly, the Halleck Creek Project[49], advanced by American Rare Earths, reports even higher grades approaching 90,000 ppm. Despite their geological advantages, neither project currently holds a complete state mine permit, and both remain subject to extended timelines related to permitting, financing, and downstream processing integration.

Wyoming's comparative advantage may lie less in near-term REE production and more in advancing processing technologies applicable to low-grade or unconventional resources. The Wyoming Energy Authority, the University of Wyoming School of Energy Resources, and the State of Wyoming have been supportive of research and development aimed at improving REE recovery from coal and coal-related materials, recognizing that breakthroughs in processing efficiency could broaden the range of economically viable domestic resources. While commercial success remains

[46] https://ramacoresources.com/brook-mine-faqs/
[47] https://ramacoresources.com/wp-content/uploads/2025/07/Ramaco-PEA-Report-Jul-2025.pdf
[48] https://www.rareelementresources.com/bear-lodge-project/
[49] https://www.americanree.com/projects/halleck-creek/

uncertain, these efforts align with state and federal objectives to strengthen U.S. critical mineral supply chains and reduce reliance on foreign sources.

3.7.2 Coal-to-Gas and Synthetic Natural Gas

Coal-to-gas conversion has an established history in the United States, with the Great Plains Synfuels Plant in Beulah, North Dakota, being the most notable example. Operated by Dakota Gasification Company, this facility has been producing pipeline-quality synthetic natural gas since the 1980s using fixed-bed Lurgi gasifiers fueled by lignite coal. Its production is approximately 170 million cubic feet per day, and the plant also produces a range of co-products, including ammonia, ammonium sulfate, phenol, and naphtha. Significantly, the facility has incorporated carbon capture and sequestration. Initially, captured CO_2 was piped north to the Weyburn oil field in Saskatchewan for enhanced oil recovery. More recently, Dakota Gas has launched its own on-site sequestration project into the Broom Creek formation, with a capacity exceeding two million metric tons annually.

The Great Plains experience highlights both the opportunities and limitations of coal-to-gas in the U.S. Wyoming's sub-bituminous Powder River Basin coal is of a higher rank and has less moisture than North Dakota lignite, which could enhance gasification efficiency. The state also has promising geological storage formations and has secured primacy for Class VI CO_2 injection wells, making it a relatively attractive jurisdiction for integrating carbon capture and storage. However, the economics of synthetic natural gas are complex when competing with abundant and inexpensive conventional natural gas. Unless Wyoming projects can achieve premium pricing for low-carbon gas, incorporate high-value co-products, or benefit from federal incentives, profit margins may be thin. The scale of capital investment is also a challenge, though modular gasification concepts could enable more flexible and staged deployment.

3.7.3 Coal-to-Liquids

Coal-to-liquids (CTL) technologies utilize either indirect or direct liquefaction methods. Indirect liquefaction involves gasifying coal into syngas and then converting it through Fischer–Tropsch (FT) synthesis to produce liquid fuels, such as diesel and kerosene. Direct liquefaction aims to hydrogenate coal directly into liquid hydrocarbons under high pressure and temperature. Both methods require significant capital investment and generate high carbon emissions, but indirect FT synthesis has the most established operational history.

The global benchmark is Sasol's Secunda complex in South Africa, the world's largest coal-to-liquids facility. Secunda produces approximately 150,000 barrels per day of liquid fuels, but it is also one of the most significant sources of CO_2 emissions worldwide. Sasol has announced plans to lower the carbon intensity of Secunda by co-feeding natural gas and boosting process efficiency, but the core emissions profile of CTL remains a concern. China has also invested in large CTL projects, including the Shenhua plant in Ningxia, but enthusiasm has diminished due to water shortages and environmental concerns.

For Wyoming, CTL presents significant challenges. The technology can produce valuable, energy-dense fuels that align with U.S. transportation markets. Still, the capital cost per barrel is very high, and lifecycle CO_2 emissions surpass those of conventional petroleum unless paired with very high capture rates. Incorporating biomass or low-carbon hydrogen could help lower the carbon intensity; however, these options also add additional cost and complexity. Given the policy environment, CTL in the United States is only feasible if established as a niche or demonstration project with strong carbon capture capabilities and access to IRA credits, such as 45Q or 45Z.

3.7.4 Coal-to-Chemicals

A more promising use of Wyoming coal could be as feedstock for chemicals, a path that has historically yielded higher margins per ton than fuels. The well-known example is Eastman Chemical's Kingsport complex in Tennessee. Eastman has operated slurry gasifiers at this site for decades, converting coal into syngas and then directing the intermediates into an acetyl chemicals chain. The facility produces acetic acid and acetic anhydride on a large scale, supplying both Eastman's

internal needs and external markets. This demonstrates that, with proper process integration and market positioning, coal can be a viable chemical feedstock.

China has actively promoted this concept by investing heavily in coal-to-methanol, methanol-to-olefins, and coal-to-urea projects on a large scale. In 2024 alone, Chinese facilities used nearly 300 million tons of coal for chemical and gas conversion projects, and current project pipelines could double this capacity within a few years. These facilities operate on a global scale and demonstrate technical feasibility, but they also face increasing pressure from water shortages, local pollution, and carbon emissions.

The U.S. context differs, as natural gas remains a cheaper feedstock for most chemical production. However, coal-to-chemicals could have potential in Wyoming if strategically positioned. Chemicals such as methanol, acetic acid, and olefins can yield a higher unit value than synthetic fuels, and the syngas intermediates are relatively well-suited for efficient CO_2 capture. With Wyoming's CO_2 storage capacity and permitting environment, an integrated coal-to-chemicals plant could be combined with sequestration to lower emissions. The main challenge is economics: competing with natural-gas-based chemical production and establishing a stable market for coal-derived products.

3.7.5 Comparative Perspective

Taken together, these pathways reveal a range of opportunities for Wyoming's coal. Rare earth extraction is the most immediate and aligns with federal policy priorities on critical minerals, though technical and market risks still exist. Coal-to-gas has proven viable at scale but is hindered by low natural gas prices, making it only practical if co-product revenues and carbon incentives are substantial. Coal-to-liquids has achieved global success, but it involves high capital costs and significant carbon emissions in the U.S. context. Coal-to-chemicals seems to offer the best balance of technical feasibility and potential economic benefit, especially when combined with carbon capture and storage.

In Wyoming, the key takeaway is that non-combustion uses of coal are technically possible and, in some cases, already proven. However, their viability depends on pairing technology choices with strong policy support, carbon management, and careful alignment with market opportunities. A potential near-term approach may be to advance the Brook Mine REE, the Peabody project, or similar projects while also evaluating integrated coal-to-chemicals concepts that leverage Wyoming's coal, geological storage, and existing infrastructure. CTL and CTG can remain as longer-term options or niche demonstrations, depending on future policy and technological developments.

4 Regulatory Constraints on Wyoming Coal Supply and Demand

4.1 Executive Summary

Wyoming coal is affected by many federal and state regulations that govern coal production and consumption. This report is a review of these regulations and their impact on Wyoming coal, along with recommendations for actions by Wyoming policy makers that would improve the outlook for Wyoming coal.

4.1.1 Regulatory Constraints on Wyoming Coal Supply

Over the last 40 years, the regulatory landscape that any producer must navigate to develop and operate coal mines in Wyoming has become increasingly cumbersome, slow, and expensive. New and revised federal regulations have been used to slow and prevent leasing, permitting, and development of Wyoming coal. The increased time and cost of developing new and extending existing coal mine operations pose a threat to the ability of Wyoming to maintain current levels of production without significant reforms to the process.

This report reviews the constraints to Wyoming coal development and production, including the following areas:

- Leasing federal coal reserves, which comprise most of the mineable coal in the state of Wyoming. New leases will be required to extend the lives of existing coal mines as they approach depletion of their existing reserve base over the next 5 – 15 years.
- Permitting new mining areas at existing coal mines, in addition to potentially developing new coal mines. Permits and approvals are required from multiple state and federal agencies before mining can commence. The lead time for obtaining permits is typically 2 to 4 years and often takes more than a decade when federal lands are involved.
- Federal coal excise taxes are disproportionately assessed on Wyoming coal production, far in excess of the funding that the state of Wyoming receives from the federal trust funds.

This report includes recommendations for reform of leasing, permitting, and federal taxation that would improve market certainty and significantly increase the ability of Wyoming coal producers to maintain and facilitate future production and contribute to employment and tax revenues for the state.

4.1.2 Regulatory Constraints on Wyoming Coal Demand

As discussed in **Section 3** of this report, the primary market for Wyoming coal is at domestic power plants, accounting for about 97% of total demand in 2024. Wyoming coal use at power plants has fallen dramatically since its peak in 2008 and this is the reason that Wyoming coal production has fallen from 466 million tons in 2008 to just 191 million tons in 2024 (Wyoming coal production was on track to rebound slightly to 210 million tons in 2025). Demand for Wyoming coal for power generation has fallen over this period because many coal plants have stopped burning coal (retired or converted to burning natural gas), and remaining coal plants are running at reduced rates (capacity factors). For Wyoming PRB coal, power plants that have now stopped burning coal had purchased about 134 million tons in 2008, 30% of total PRB coal production. Further, coal power plants that have announced plans to stop burning coal by the end of 2030 purchased almost 66 million tons of Wyoming coal in 2024 (35% of 2024 demand).

The primary reasons for the closure of coal power plants since 2011 (and the announced plans to stop burning coal) are regulatory constraints imposed on coal power plants, primarily new federal environmental regulations. These regulations include restrictions on flue gas emissions, wastewater discharges, and solid waste disposal. Most of these federal regulations require major capital investments for compliance. As a result, power plant owners have decided to stop burning coal rather than invest in cost-prohibitive compliance technologies.

Under the Biden Administration, the Environmental Protection Agency (“EPA”) promulgated a long list of major new and modified regulations that would force most, if not all, coal plants to stop burning coal by 2032. Under the Trump

Administration, EPA has proposed to modify or repeal many of these new rules. This report is a review of the status of these regulations affecting Wyoming coal demand and the issues to be considered by Wyoming state officials to improve the outlook for Wyoming coal. The regulations and issues addressed in this report include:

- 2024 Greenhouse Gas Rule, also known as the Clean Power Plan 2.0, which would force all coal plants to either install technology for carbon capture and sequestration or stop burning coal.
- Mercury and Air Toxics Standard ("MATS"), which would force coal plants to upgrade emission control technology to remove mercury, chlorine, and other "air toxics".
- Effluent Limitation Guidelines ("ELG"), which would force all coal plants to achieve zero wastewater discharge from coal ash handling and scrubber wastewater.
- Coal Combustion Residuals Rule ("CCR"), which would force coal plants to cease operation of all coal ash and scrubber waste landfills and ponds without expensive liners.
- Cross-State Air Pollution Rule ("Good Neighbor"), which has been interpreted by EPA to force coal plants to install expensive emission control technology or close based on modeling that emissions could have a small impact on air quality in downwind states.
- Regional Haze rule, which EPA interprets to require continuing reductions in emissions of sulfur dioxide and nitrogen oxides and EPA has used its disapproval of state implementation plans to force coal power plants to close.
- New Source Review ("NSR") litigation by EPA, which has been used to prevent coal power plants from investing in major maintenance projects without complying with the same standards as new power plants, including carbon capture and sequestration.
- Fine Particulate Matter ("PM 2.5") National Ambient Air Quality Standards, which would further limit all emissions of sulfur dioxide and nitrogen oxides from coal power plants.
- Greenhouse Gas Reporting Rule, which requires data collection and reporting on greenhouse gas emissions from all fossil fuel facilities, including Wyoming coal mines.
- Public Lands rule, which the Department of Interior Bureau of Land Management has used to prevent development of public lands, including federal coal reserves in Wyoming.
- Federal Energy Incentives, which has provided huge federal subsidies to develop wind and solar power plants that have displaced generation from existing coal power plants.

4.2 Regulatory Impacts on Wyoming Coal Supply

4.2.1 Objective

This task assesses the regulations and agency policies that restrict the ability of producers to lease, timely permit, and develop Wyoming coal. The work was performed by Energy Ventures Analysis, Inc. (EVA) and its subcontractor WWC Engineering.

4.2.2 Federal Coal Leasing

The federal government owns about 94% of the coal reserves in the Wyoming PRB, while the state of Wyoming owns about 5%, and private lands comprise less than 1% of the coal reserves. The state-owned sections are interspersed among the federal coal, so the state sections are unable to support economic coal mining operations without control of the adjacent federal coal. In the Wyoming GRB, most of the mineable coal reserves lie within the area of the Union Pacific Railroad Land Grant, where the federal reserve ownership alternates in a "checkerboard" fashion with the private reserves (now owned by the private land company Wildcat Coal LLC). As a result, the federal government controls almost 50% of the mineable coal reserves in the GRB, while the private reserves comprise 50% of the coal. Again, because of the alternating control, a coal producer needs to lease the federal coal to combine with the private coal to have an economic reserve and mine plan.

Federal coal leasing is under the jurisdiction of the Bureau of Land Management (BLM), within the Department of Interior (DOI). BLM administers the coal leasing program under the Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act of 1947, as well as the Federal Coal Leasing Amendments Act of 1976 (FCLAA). The FCLAA concluded the process of leasing preference rights and established a procedure for competitive bidding on new federal coal leases. Since 1990, all new federal coal leases have been issued pursuant to the Lease by Application (LBA) process or the Lease by Modification (LMA) process for small (under 160 acres), contiguous additions to existing leases.

4.2.2.1 Overview of the Leasing Process

As discussed in **Section 2** of this report, federal coal leasing has been subject to increasing delays and complexities imposed by changing federal policies with different presidential administrations. Under recent administrations of Presidents Obama and Biden, BLM sought to prevent federal coal leasing, using the National Environmental Policy Act (NEPA) process to include concerns of the impact of coal consumption on global climate change that effectively stopped federal leasing of Wyoming coal for a decade.

In January 2016, Secretary of the Interior Sally Jewell announced a moratorium on issuing new federal coal leases while DOI prepared a Programmatic Environmental Impact Statement ("PEIS") that would consider the impact of federal coal leasing on climate change.[50] Under this Jewell Moratorium, no new federal coal leases were issued with limited exceptions. Although the Moratorium was revoked by Secretary Zinke in 2017, a federal district court ruled in 2019 that this revocation required an environmental review. In 2021, Secretary Haaland revoked the Zinke Order, and in 2023, BLM began a PEIS that considered the alternative of maintaining the Jewell Moratorium on coal leasing indefinitely.[51] On February 21, 2024, the U.S. Court of Appeals for the Ninth Circuit held that the legal challenge to the Zinke Order was moot, as Secretary Haaland had subsequently revoked it.

In May 2024, the Buffalo Field Office of the BLM issued a final Supplemental SEIS and Resource Management Plan (RMP) that made coal resources in the Wyoming PRB defined coal resource boundary (Coal Potential Development Area) unavailable for leasing. BLM estimated that coal production in the Wyoming PRB would continue until 2041 under existing coal leases, assuming no exhaustion.[52] However, in June 2025, the BLM moved to end the coal leasing moratorium and reopen the Wyoming PRB to coal leasing. In November 2025, using the Congressional Review Act, Congress passed a joint resolution (H.J. Res. 130. Repealing the Biden-era 'Buffalo Field Office Resource Management Plan Amendment') that permanently repealed the 2024 Buffalo RMP and reopened leasing in the PRB.

As discussed in **Section 2** of this report, even with the restored ability to obtain new coal leases, the time required to lease, permit, and develop new coal leases jeopardizes the ability of Wyoming coal producers to maintain the current level of production without leasing and permitting reforms. The steps required to lease and develop coal reserves include:

1. PRE-APPLICATION & RESOURCE PLANNING
    1. Resource Management Plan (RMP) Review & Amendment
    2. Identification of Suitable Coal Tracts

2. LEASE INITIATION PROCESS
    1. Step 1: Lease-by-Application (LBA) Submission
    2. Step 2: Regional Coal Team (RCT) Review (PRB Only)

3. ENVIRONMENTAL REVIEW & COORDINATION
    1. Step 3: NEPA Environmental Analysis

[50] https://www.doi.gov/pressreleases/secretary-jewell-launches-comprehensive-review-federal-coal-program

[51] https://www.federalregister.gov/documents/2023/05/01/2023-08960/notice-of-intent-to-prepare-an-environmental-impact-statement-to-analyze-the-potential-environmental

[52] https://www.blm.gov/press-release/blm-proposes-amendment-buffalo-field-office-management-plan

2. Step 4: Agency Coordination

4. TRACT VALUATION & COMPETITIVE SALE
    1. Step 5: Tract Delineation
    2. Step 6: Record of Decision
    3. Step 7: Fair Market Value (FMV) Determination
    4. Step 8: Lease Sale
    5. Step 9: Lease Issuance

5. POST-LEASE: MINE PERMITTING AND OPERATIONS
    1. Step 10: State-Level Permitting
    2. Step 11: Federal Mine Plan Approval (OSMRE)
    3. Step 12: Clean Air & Water Act Permits/amendments (EPA & DEQ)

6. MINE DEVELOPMENT AND PRODUCTION
    1. Step 13: Construction and Operations
    2. Step 14: Royalties and Reporting

The time required for applicants to obtain a new coal lease under the LBA process (application to sale date) expanded from 2-3 years in the early 1990s to 5-7 years after 2000. After the lease is awarded, the coal mine operator must apply for permits from the WY DEQ (WDEQ is required to have certification of mineral ownership prior to permitting), the federal Office of Surface Mining and Reclamation (OSMRE), and the EPA. Even with no opposition or litigation, the time required to obtain these permits is over 3 years after the lease is awarded.

4.2.2.2 Cost of Leasing Federal Coal

The cost to lease federal coal includes:

- Lease bonus payments – New LBAs are subject to competitive bidding and are awarded to the highest bidder. If there is only one bidder, BLM sets a minimum Fair Market Value and rejects the bid if the minimum value is not met. The lease bonus is paid 20% on the effective date and 20% annually for the next four years.
- Rents – Lessees pay an annual rental of $3 per acre for the life of the lease.
- Royalties – Lessees pay a production royalty equal to 12.5% of the sales price of the coal (with some exceptions). The recent 2025 budget bill (OBBBA) reduced the maximum federal coal royalty to 7.0% for the next 10 years.
- NEPA Environmental Impact Statement development costs.

The lease bidding and bonus process has been a significant barrier to leasing and developing new federal coal reserves. BLM does not disclose the Fair Market Value (FMV) prior to the lease sale. All the federal leasing since 1990 has been under the LBA process with only one bidder (with one exception). The lease applicant bid is only accepted if it exceeds the confidential FMV established internally and set by BLM. With the decline in coal demand and lease value since 2011, and the lack of transparency in the FMV calculation, applicants are uncertain whether a lease bid will be accepted by BLM until after the bid process has closed. This uncertainty has discouraged coal producers from applying for new LBAs and pursuing the expensive front-loaded cost provisions of the application process.

The timing of the lease bonus payments has discouraged the sale of new federal coal leases. The bonus payments are made in five installments, with 20% due at the time of the lease award and 20% each year for the next 4 years. However, the extensive timeline for permitting and developing the lease after award delays mining coal for approximately 7 - 10 years. This means that companies must finance as a sunk cost the bonus payments long before revenue is generated from the sale of new leased coal.

4.2.2.3 Logical Mining Units (LMU) and Diligent Development

A logical mining unit (LMU) is an administrative grouping that allows the lessee or operator to consolidate the diligent development and continued operations requirements for all the federal leases and other coal tracts within the permitted boundaries of the mine. An LMU provides continuity in management of the coal resource whenever the geologic characteristics of a coal seam cross property boundaries. LMU's have been defined as an area of land in which the coal can be developed in an efficient, economical, and orderly manner as a unit, with due regard for conservation (maximizing coal resource recovery) of the coal and other resources. The BLM establishes Logical Mining Units for each permitted mine and each new lease is aggregated with the existing leases, steadily expanding the acreage and original coal reserves included within the LMU.

Federal coal leases require "diligent development" of the reserve after the lease award. The diligent development requirement means that commercial quantities of coal must be produced from the lease within 10 years of lease issuance. The term "commercial quantities of coal" has been defined by regulation to be 1% of the coal that potentially could be mined, including any coal that has already been mined. Failure to meet this requirement will result in termination of the lease. Further, coal operators are required to maintain "continued operation", which is defined as annual production at least 1% of the total original coal reserves under the LMU.

Under current provisions, each time a new lease is added to an LMU, the amount of due diligence production required for continuous operation is increased. When mines are increasing production and expanding, the continuous operation production requirement is not an economic burden. However, in a flat or contracting market, this requirement quickly becomes problematic, as operators are potentially unable to reduce production without violating the annual minimum tonnage. Under current provisions, adding resources to the LMU designation is straightforward. However, removing mined out tonnage from the LMU and reducing the due diligence requirement is not a simple or straightforward process. As a result, mines are economically penalized when reducing production due to declining coal demand.

4.2.2.4 Policy Recommendations

Wyoming policymakers should seek to improve the process for federal coal leasing and management to sustain Wyoming PRB production, employment, tax revenue to the state and federal interest. Potential policy changes include:

- **Fair Market Value (FMV) process:** BLM should establish a transparent process for determining the FMV for a coal lease and disclose the FMV prior to the lease sale. Under the current policy, potential lessees have no clarity as to either the process used by BLM to establish the FMV or the amount of a bid that would be accepted by BLM. The secrecy, lack of investment capital clarity, and uncertainty of success discourage coal producers from applying for a new LBA. BLM should initiate a public rulemaking process to reform the FMV methodology so that the FMV amount is determined by a transparent formula that benefits both the public and industry. Further, BLM should disclose the FMV for an LBA at the time of the lease delineation prior to bidding. This will increase interest among coal producers initiating the LBA process and purchasing federal coal reserves.
- **Lease Bonus Bid timing:** Recognizing the time required to permit federal coal reserves after the lease award, BLM should revise the timing for lease bonus payments to better match the development, sale, and revenue generation from a coal leasing action. Instead of lease bonus payments of 20% annually spread over five years (the current process), BLM should consider spreading the lease bonus payments over 10 years, at 10% annually.
- **Logical Mining Unit (LMU) reduction:** BLM should reform the process of removing mined-out coal leases from the LMU, so the annual diligence continued operation requirement does not include the mined-out coal reserves in the minimum annual (due diligence) production tonnage. Lessees should not be forced to mine their remaining reserves at a rate higher than supported by the market simply because they have responsibility to meet the resource recovery requirements of mined out coal leases.
- **Lease Modifications:** BLM should increase the use of Lease by Modification (LBM) to allow coal producers to add smaller maintenance tracts (up to 100 million tons) of coal reserves without the expensive and slow LBA process.

This change would maximize the public benefit by recovering adjacent coal reserves already under lease that might otherwise be bypassed in the mining process, and provide improved flexibility in future coal leasing.

- **Federal Lease Transaction Fees:** In 2013, Congress codified a 2% federal deduction from lease bonus, rents and royalty payments to the states as an "administrative fee". This fee bears no relation to the administrative costs to BLM for managing the federal coal lease program. This transaction fee shifts the revenues from the state's share of federal coal (originally intended to be 50%) to the federal government. It is recommended that the Wyoming congressional delegation renew the effort to remove this requirement on state fund shares.
- **Policy Stability:** BLM policies to federal coal leasing change significantly with presidential administrations. This uncertainty discourages investment in coal production and mining federal coal leases, and reduces Wyoming coal employment and revenues. It is recommended that congress continue to codify common sense legislation to create a more stable federal coal leasing process which excludes consideration of greenhouse gas emissions from downstream consumers of Wyoming coal (consistent with the unanimous decision of the Supreme Court in *Seven County Infrastructure Coalition v. Eagle County* on May 29, 2025).

4.2.3 Federal Coal Permitting

While Wyoming's Powder River Basin (PRB) and Green River Basin (GRB) host the largest reserves of low-sulfur thermal coal in the United States, the length and complexity of federal coal leasing and permitting processes present a significant barrier to investment in coal supply and power generation facilities.

One of the major obstacles to the timely processing and issuance of permits for federal coal is the review under the National Environmental Policy Act (NEPA) by the Office of Surface Mining Reclamation and Enforcement (OSMRE). This review requires OSMRE to prepare an Environmental Assessment (EA) or Environmental Impact Statement (EIS) prior to issuing a Federal Mine Plan Approval (FMPA). OSMRE began requiring a NEPA analysis of any FMPA in 2007, following litigation involving the Colowyo Mine. The prior 31 years of OSMRE oversight review did not require NEPA review of an FMPA in Wyoming, which has had coal program primacy since 1982. Under current policy, a federal coal lease and mine plan are required to have a BLM Resource Management Plan (RMP) EIS, an individual Mineral Leasing Action EIS, and an OSMRE FMPA Right of Entry EA or EIS. The inefficiency and redundancy of triple jeopardy NEPA reviews to obtain approval to mine a single ton of federal coal exemplifies the need to eliminate the redundant OSMRE FMPA NEPA review.

The OSMRE NEPA review process can add as much as 5 - 7 years to the process of leasing and permitting federal coal reserves. **EXHIBIT 4-1** shows the timeline for the steps required to lease and permit federal coal under current policy.

EXHIBIT 4-1: FEDERAL COAL PERMIT TIMELINE WITH NEPA REVIEW

4.2.3.1 Case Study of NEPA Delays – Black Butte Coal Mine

The Black Butte Coal Mine (BBCM), located in Sweetwater County, Wyoming, is an example of the excessive delays caused by the redundant OSMRE NEPA review process. BBCM has been operating since 1977. BBCM is a large surface mine, which is permitted to produce up to 5.0 million tons per year, but production was limited by demand below 2.0 million tons since 2023. The mine was temporarily idled in 2024 and 2025, primarily due to the delay in obtaining a FMPA from OSMRE. The primary customer for BBCM is the nearby Jim Bridger power plant, and this coal is an essential part of the long-term coal supply to maintain power plant operations.

According to the EIS prepared by OSMRE in 2025:[53]

> "BBCC sought approval from OSMRE of the Federal mining plan modification to extract Federal coal resources within 450 acres of Federal Coal Lease WYW-6266. The expansion would allow Maximum Economic Recovery (MER) of the Federal coal resources and is a logical progression of the northern portion of the BBCM. The Federal coal resources

[53] Office of Surface Mining Reclamation and Enforcement, Western Region, "Black Butte Coal Company, Federal Coal Lease WYW-6266, Mining Plan Modification, Environmental Impact Statement, September 2025, https://www.osmre.gov/laws-and-regulations/nepa/projects.

are needed by the BBCM to maintain mine operations and provide high-quality, low-cost fuel in support of electrical generation at the Jim Bridger Power Plant.

The Federal mining plan modification area consists of 450 acres of the WYW-6266 Federal coal lease tract (as approved by BLM in 2017) that extends to the north and south of the current Pit 10 area of the BBCM. Approval of the Federal mining plan modification would facilitate an extension of Pit 10 in its southeast corner of 50 acres and a Pit 15 north of Pit 10 on 400 acres. Each area is within the existing 43,384-acre BBCM permit boundary (WDEQ Permit PT467) (WDEQ 2021a). Approximately 68 acres, or 15 percent of the Federal mining plan modification area, was previously disturbed by mining activities under a separate existing BLM right-of-way (ROW) agreement. BBCC's goal was to mine approximately 9.2 M tons of mineable coal in Pit 10 and Pit 15 for continued operation of the BBCM.

OSMRE is required under current policy to conduct a thorough analysis of the environmental effects of the proposed Federal mining plan modification to inform its recommendation to the Assistant Secretary of Land and Minerals (ASLM). The ASLM will consider OSMRE's recommendation when deciding whether the Federal mining plan modification is approved, disapproved, or approved with conditions. OSMRE's recommendation will be based, at a minimum, on the following:

- The permit application package (PAP), including the resource recovery and protection plan (R2P2);
- Information prepared in compliance with NEPA, including this EIS;
- Documentation assuring compliance with the applicable requirements of Federal laws, regulations, and EOs other than NEPA;
- Comments and recommendations or concurrence of other Federal agencies and the public;
- Findings and recommendations of the BLM, who is a cooperating agency, with respect to the R2P2, Federal lease requirements, and the MLA;
- Findings and recommendations of the WDEQ, who is a cooperating agency, with respect to the BBCM permit application and the Wyoming State program; and
- The findings and recommendation of the OSMRE with respect to the additional requirements of 30 CFR Chapter VII, Subchapter D.

Pursuant to section 503 of SMCRA, the Wyoming Department of Environmental Quality (WDEQ) developed, and, in November 1980, the Secretary of the Interior approved, a program authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on non-Federal lands within the State of Wyoming. In January 1987, pursuant to section 523(c) of SMCRA, WDEQ entered into a State-Federal cooperative agreement with the Secretary of the Interior authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on Federal lands within the State of Wyoming. Pursuant to this agreement, Federal coal lease holders in Wyoming must submit PAPs to OSMRE and WDEQ for proposed mining and reclamation operations on Federal lands in Wyoming. The WDEQ reviews the PAP to ensure that it complies with the permitting requirements and that the coal mining operation will meet the performance standards of the approved Wyoming State program.

The WDEQ is the primary enforcement agency ensuring the performance standards and permit requirements for mining and reclamation are met during a mine's operation, and it has primary authority in environmental emergencies. OSMRE retains oversight responsibility to ensure that the standards and requirements are enforced according to Wyoming's State program.

The BLM approved the BBCM Federal coal lease modification in 2017 to include the requested additional acreage, and the WDEQ approved the permit amendment in 2021. Pursuant to the section 7(c) of the MLA, (30 USC § 207(c)), BBCC needs to obtain approval of the Federal mining plan modification before it can mine the Federal coal."

OSMRE delayed action on the EIS and mine plan approval, despite the facts that:

- This application was for a small modification of 450 acres to an existing mine plan where the permit encompassed 43,384 acres for a mine that had been operating for over 40 years.
- BLM had approved the modification of the existing coal lease in 2017.
- The new coal lease modification was within the existing permitted mine plan area.
- WDEQ, the state agency which had primacy to regulate surface mining operations, approved the mine plan modification in 2021.

The five-year delay by OSMRE caused the BBCM to be idled in 2024, 7 years after the federal coal lease had been awarded. It was not until an Executive Order under the current administration in January 2025 that OSMRE accelerated the EIS review, as stated in the EIS:[54]

> "Executive Order (EO) 14154, *Unleashing American Energy* (Jan. 20, 2025), and the Presidential Memorandum, *Ending Illegal Discrimination and Restoring Merit-Based Opportunity* (Jan. 21, 2025) (Memorandum), require the DOI to strictly adhere to NEPA, 42 United States Code (USC) §§ 4321-4370. Further, EO 14154 and the Memorandum repealed EOs 12898 (February 11, 1994) and 14096 (Apr. 21, 2023). On April 23, 2025, the Council on Environmental Quality (CEQ) authorized the DOI to use alternative arrangements for projects that respond to the national energy emergency declared in EO 14156, *Declaring a National Energy Emergency* (Jan. 20, 2025), and the DOI subsequently adopted alternative arrangements for qualifying projects to comply with NEPA. *See* "Alternative Arrangements for Compliance with the National Environmental Policy Act amid the National Energy Emergency," April 23, 2025 (DOI 2025b).
>
> To expedite the review and approval, if appropriate, of projects related to the identification, leasing, siting, production, transportation, refining, or generation of energy within the United States (U.S.), these measures allow for more concise documents and a compressed timeline. Projects requiring an EIS under DOI's Alternative Arrangements for NEPA Compliance will be published approximately 28 days after publication of the Notice of Intent on a public website.
>
> The Alternative Arrangements for NEPA Compliance apply to actions relating to a wide range of energy sources, including coal (DOI 2025b). On May 12, 2025, BBCC submitted an application to OSMRE to use the alternative arrangements to expedite the NEPA, National Historic Preservation Act (NHPA), and Endangered Species Act (ESA) compliance processes and complete OSMRE's review of the proposed Federal mining plan modification as quickly as possible in light of the national energy emergency. The ASLM approved BBCC's application with respect to NEPA and ESA compliance on August 8, 2025. The request to accelerate the NHPA compliance was not granted because the section 106 analysis was already complete. Although the ASLM also granted BBCC's request to use DOI's Alternative Procedures for Informal Section 7 Consultation, after further analysis, those procedures were not necessary as the project would have no effect on all listed species; thus, no consultation with the United States Fish and Wildlife Services (USFWS) was required."

OSMRE finally issued the EIS on September 9, 2025 and approved the Mine Plan Modification 8 years after BLM had issued the federal coal lease modification.

4.2.3.2 Policy Recommendations

OSMRE should return to its former policy where it does not require a NEPA review for a FMPA when the NEPA review has already been performed by another federal agency. To the extent that OSMRE performs a NEPA review, it should set a firm time limit for an FMPA review of a primacy state action, like Wyoming. A 12-month review and approval time limit would be appropriate, as OSMRE is simply conducting oversight of the approved state-level primacy program decision. In the event the 12-month time limit for an FMPA is missed by OSMRE, then the state approval decision should be automatic

[54] Ibid.

and final. This could be established through a Memorandum Of Understanding (MOU) with a state agency primacy program and OSMRE. In addition, revising and reforming the surnaming process would also reduce the extensive, unnecessary, and time-consuming requirements for a FMPA right of entry issuance.

4.2.4 Federal Excise Taxes on Wyoming Coal

In the 1970's, the federal government passed major legislation to address problems associated with historic coal mining, including reclamation of pre-law (1977) mined lands and compensation for miners with black lung disease. Both laws required coal operators to fund the liabilities that they created (reclaiming mine permits and compensating black lung victims) and also created national programs to pay for the liabilities not covered by the responsible coal operators (liabilities created prior to the legislation or liabilities defaulted by bankrupt operators).

4.2.4.1 AML Fees

The Surface Mine Reclamation and Control Act of 1977 (SMCRA) created the Abandoned Mine Reclamation Fund (AML) Title IV program. The AML Fund is financed by excise taxes on coal producers, and the funds are allocated by OSMRE to state agencies to support reclamation of coal mine lands not performed by post-1977 SMCRA permit holders (coal operators). The original amounts for the AML fees were set at:

- $0.35 per ton for surface coal mines (no greater than 10 percent of the sales price)
- $0.15 per ton for underground coal mines (no greater than 10 percent of the sales price)
- $0.10 per ton for lignite mines (no greater than 2 percent of the sales price)

The fees were set at these levels because abandoned surface mines were deemed to have created much greater reclamation liabilities than underground mines, and few lignite mines were abandoned prior to passage of SMCRA – thus most of the burden for financing the AML program was placed on surface coal mines.

The AML fees were originally scheduled to expire in 1992, but Congress has extended these fees eight times since their inception, most recently by The Infrastructure Investment and Jobs Act P.L. 117-58, enacted on November 15, 2021. This enacted legislation extended the Title IV AML reclamation fee through September 30, 2034. AML fee rates for all coal sold, transferred, or used on or after October 1, 2021, are:

- Surface-mined coal (except lignite) – 22.4 cents per ton
- Underground-mined coal (except lignite) – 9.6 cents per ton
- Lignite – 6.4 cents per ton
- The alternative Ad-Valorem rate of 10 percent for surface or underground and 2 percent of the value for lignite, continues to be in effect.

The AML program is currently a 100% funded program based on current inventory needs. As of September 30, 2025, the AML Fund has collected $14,233 billion, including interest earned on the unappropriated balance. The AML Fund has distributed only $6.569 billion in grants to state and tribal agencies for reclamation programs. Another $2.432 billion has been used for OSMRE operating expenses and emergencies. $2.302 billion has been distributed to the United Mine Workers of America Health and Retirement Funds, unrelated to mine reclamation activities. Finally, $2.931 billion remains unappropriated.[55]

Wyoming coal producers pay a disproportionate share of the total AML taxes collected by OSMRE because the AML tax rates are heavily weighted toward surface coal mining (except for lignite) and Wyoming accounts for about 72% of the total annual surface coal production in the United States. According to the OSMRE Fiscal Year 2026 Fee-based Grant

[55] https://www.osmre.gov/programs/reclaiming-abandoned-mine-lands, Status of the AML Funds

Distribution, Wyoming coal producers paid $46.3 million in AML taxes – 57% of the total annual AML taxes collected by OSMRE.[56]

However, Wyoming does not have any historic (Pre-1977 SMCRA) abandoned mine lands remaining and is considered a certified state, so it receives none of the AML funds appropriated for the reclamation of historic lands. Pursuant to the OSMRE distribution process, Wyoming should receive 50% of the annual AML fee collections from Wyoming coal production.

4.2.4.2 Black Lung Excise Taxes

In 1969, Congress passed the Federal Coal Mine Health and Safety Act to require coal operators to pay workers compensation benefits to former coal miners who contract black lung disease. These benefits were extended to miners whose former employers did not pay under the Black Lung Benefits Act of 1972. The benefits are paid from the Black Lung Disability Trust Fund, established by the Black Lung Revenue Act in 1977, which is financed by the Black Lung Excise Tax (BLET) on coal operators. The tax rates were permanently extended by the Inflation Reduction Act of 2022 at:

- $0.55 per ton for surface coal mines (no greater than 4.4 percent of the sales price)
- $1.10 per ton for underground coal mines (no greater than 4.4 percent of the sales price)

Producers of lignite do not pay the BLET, and the tax is not applied to coal exports, which account for close to half of all Eastern coal production (the tax on coal exports was found to be unconstitutional by the Supreme Court in 1998). Since little Wyoming coal is exported, Wyoming coal producers pay a disproportionate share of the Black Lung Excise Tax. In Fiscal Year 2024, the BLET tax receipts totaled $256.66 million, with over half ($130.67 million) from surface mines. Wyoming surface coal production was 191 million tons in 2024, so Wyoming coal producers paid about $105 million in Black Lung Excise Taxes, about 41% of the total tax receipts.[57]

Because Wyoming coal production was small prior to the 1969 Coal Mine Health and Safety Act and because the incidence of black lung disease is much lower for surface coal miners than underground miners, Wyoming coal miners receive very little benefits from the Black Lung Disability Trust Fund, while Wyoming coal producers finance a large share of the costs.

4.2.4.3 Policy Recommendations

The federal policies for the excise taxes are set by Congress under federal law, so the state of Wyoming cannot change these taxes without an act of Congress. It is recommended that the Wyoming congressional delegation continue to make reform of these taxes a priority, as they are excessively discriminatory to Wyoming coal producers.

4.3 Regulatory Impacts on Wyoming Coal Demand

4.3.1 Objective

This task assesses the critical federal regulatory landscape affecting demand for Wyoming coal. The report analyzes key regulations from the Environmental Protection Agency (EPA), Department of Energy (DOE), Federal Energy Regulatory Commission (FERC), and Department of the Interior (DOI) to identify their direct and indirect impacts on coal-fired electricity generation and industrial demand. The objective of the report is to provide a clear, actionable understanding of these rules, focusing on their legal underpinnings, regulatory requirements, current implementation status, and practical effects on the coal market.

The approach involves a detailed review of specific regulatory actions, major litigation, and policy debates impacting coal demand. The analysis for this task was performed by Energy Ventures Analysis, Inc. (“EVA”) and its subcontractor Energy Policy Network (“EPN”). This includes: (1) an examination of EPA regulations, such as the Clean Power Plan 2.0; (2) an analysis of the Endangerment Finding on CO_2 and related court decisions; (3) an assessment of the impacts of the Social

[56] Ibid.

[57] https://revenuedata.onrr.gov/how-revenue-works/coal-excise-tax/

Cost of Carbon; (4) a review of taxation on power generation, including the effects of production tax credits on thermal coal; and (5) an identification of regulatory requirements and policies necessary to preserve and extend the life of coal-fired power plants, covering areas like emission capture technologies and permitting.

4.3.2 Executive Summary

This report provides a critical analysis of the current federal regulatory landscape affecting demand for Wyoming coal. The Biden administration's aggressive environmental policies, particularly the so-called Clean Power Plan 2.0, threatened to dismantle the nation's baseload coal generation, jeopardizing grid reliability, affordability, and the economic security of Wyoming's coal communities. However, a significant shift in the regulatory environment brought on by the new administration is poised to deliver much-needed regulatory relief. At a high-level, this administration is taking bold action to deregulate GHG emissions economy-wide, including a repeal of the 2009 Endangerment Finding alongside repeal of Clean Power Plan 2.0 due to the lack of significant contribution from U.S. power plants relative to global emissions.

Similarly, the proposed repeal of the 2024 amendments to the Mercury and Air Toxics Standards (MATS) offers substantial regulatory relief, recognizing that existing standards already protect public health and that further costly mandates are disproportionate and technically unjustified. This move will bring needed regulatory certainty to support future coal-fired electricity generation. Furthermore, the extension of compliance deadlines for Effluent Limitation Guidelines (ELG) alleviates immediate retirement pressures, safeguarding operational flexibility for coal plants and supporting continued demand for Wyoming coal.

Collectively, these actions signal a return to common sense, data-driven regulation and a commitment to reining in an overreaching administrative state. This shift will help to ensure the continued viability of Wyoming's coal industry, bolstering national energy security, promoting grid reliability, and securing thousands of jobs and economic prosperity for the state. A similar sensible approach should be considered for other administrative burdens, including the Greenhouse Gas Reporting Program (GHGRP), to further streamline compliance and reduce costs for energy producers.

4.3.3 Clean Power Plan 2.0 ("CPP")

The Biden administration's 2024 Carbon Pollution Standards—commonly known as Clean Power Plan 2.0—threatened to shut down virtually the entire U.S. coal fleet by mandating the installation of 90 percent carbon capture and sequestration (CCS) technology by January 1, 2032, a requirement that is neither technologically proven nor economically viable at commercial scale. For Wyoming, the nation's leading coal producer, this rule represented an existential threat to the state's coal mining industry, the power plants that utilize Wyoming coal, and the thousands of jobs and billions in economic activity tied to coal production and export.

On June 17, 2025, EPA Administrator Lee Zeldin published a proposed rule to completely repeal Clean Power Plan 2.0. The proposal advances two alternative and severable legal arguments: first, that greenhouse gas (GHG) emissions from U.S. power plants do not "contribute significantly" to dangerous air pollution under the Clean Air Act (CAA) because they represent only three percent of global emissions; and second, that even if EPA has authority to regulate, the technologies mandated by the 2024 rule—90 percent CCS for coal plants and 40 percent natural gas co-firing—fail the statutory test because they are not adequately demonstrated, are unreasonably costly, and cannot be deployed within the rule's compliance deadlines. The agency initiated this repeal process in February 2026.

The repeal of the 2024 Carbon Pollution Standards is critical for Wyoming's energy economy. Removing the federal mandate will help to preserve baseload coal generation that is essential for grid reliability and affordability, protect Wyoming coal mining jobs and tax revenues, and restore rational planning certainty to utilities that purchase Wyoming coal. The finalization of this repeal represents the single most important federal regulatory action for securing the future of Wyoming's coal sector.

4.3.3.1 Regulatory History

- **October 23, 2015:** EPA finalizes the Clean Power Plan, setting state-specific carbon emission targets requiring generation shifting from coal to gas and renewables, and publishes 2015 New Source Performance Standards (NSPS) for new fossil fuel-fired power plants.
- **February 9, 2016:** Supreme Court stays the Clean Power Plan pending judicial review—first time the Court had ever stayed a regulation before appellate review.
- **July 8, 2019:** EPA finalizes the Affordable Clean Energy (ACE) Rule, repealing the Clean Power Plan and replacing it with state-led heat-rate efficiency improvements for existing coal plants.
- **June 30, 2022:** Supreme Court decides *West Virginia v. EPA*, striking down the original Clean Power Plan and holding that EPA cannot use CAA Section 111 to force generation shifting away from coal.
- **May 9, 2024:** EPA publishes final Carbon Pollution Standards (Clean Power Plan 2.0), mandating 90 percent CCS by 2032 for existing coal plants or retirement, plus standards for new gas turbines; rule becomes effective July 8, 2024.
- **June 17, 2025**: EPA publishes proposed rule to repeal the 2024 Carbon Pollution Standards in their entirety, citing lack of "significant contribution" and best system of emission reduction (BSER) failures.

4.3.3.2 Recent Developments

On June 11, 2025, EPA Administrator Zeldin signed a notice of proposed rulemaking titled "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units," which was published in the *Federal Register* on June 17, 2025. This proposal would eliminate all GHG standards for the power sector established under CAA Section 111, including the 2024 Carbon Pollution Standards and the 2015 NSPS. EPA opened the public docket under ID number EPA-HQ-OAR-2025-0124, held a virtual public hearing on July 8, 2025, and accepted written comments through August 7, 2025. The agency is currently reviewing comments and has publicly committed to issuing a final rule by the end of 2025.

The proposed repeal involves a dual-track legal strategy designed to maximize the probability of surviving judicial review. The primary argument presents a foundational challenge to EPA's regulatory authority: the agency now interprets CAA Section 111(b)(1)(A) to require a finding that emissions from a specific source category "contribute significantly" to dangerous air pollution before regulation is permitted. Applying this test, EPA proposes to find that GHG emissions from U.S. power plants—which accounted for approximately three percent of global GHG emissions in 2022, down from 5.5 percent in 2005—do not meet this "significant contribution" threshold. Because U.S. power sector emissions are a small and declining share of global totals, EPA concludes that any achievable reductions would have no meaningful impact on global atmospheric concentrations or public health and welfare, and therefore the statutory predicate for regulation is not satisfied. EPA notes that while the U.S. reduces coal use, China and India are adding more than 530,000 megawatts of new coal-fired generation—roughly three times the existing U.S. coal fleet of 179,000 megawatts—further demonstrating that U.S. power sector reductions cannot meaningfully affect global climate conditions.

As a separate and severable rationale, EPA's alternative proposal accepts regulatory authority but concludes that the specific technologies mandated in the 2024 rule fail the statutory Best System of Emission Reduction (BSER) test on factual grounds. The agency proposes that 90 percent CCS is not "adequately demonstrated" because real-world performance at the only two commercial-scale projects—Boundary Dam Unit 3 in Saskatchewan and the Petra Nova facility in Texas—has consistently fallen far short of design targets. Boundary Dam achieved total carbon capture rates of only 68 percent in its best calendar year (2021) despite multiple design modifications, and Petra Nova closed in 2020 after just three years due to chronic operational problems and unsustainable costs. EPA further concludes that the costs of compliance are "unreasonably costly," estimating avoided compliance costs of $1.2 billion per year or $19 billion in present value over two decades. Additionally, the necessary infrastructure—thousands of miles of high-pressure carbon dioxide pipelines and

massive permanent geologic storage sites—does not exist and cannot be permitted and constructed within the rule's 2032 compliance deadline, rendering the degree of emission limitation "not achievable."

Under this alternative rationale, EPA proposes to repeal the 2024 Carbon Pollution Standards, but would leave in place the 2015 New Source Performance Standards for new coal-fired units, which require partial CCS, and certain efficiency standards for new gas-fired EGUs. This is because EPA's rationale under the alternative proposal is focused on finding that 90% CCS is unachievable and that natural gas co-firing mandates fuel-switching, which is foreclosed by *West Virginia v. EPA*.

For Wyoming coal producers and the utilities that burn Wyoming coal, the repeal removes the most severe federal threat to coal-fired generation. The 2024 rule would have forced existing coal plants to choose among three options: install unproven 90 percent CCS technology by 2032 at costs exceeding hundreds of millions of dollars per plant; convert to co-firing with 40 percent natural gas by 2030 and commit to retire by 2039; or simply retire before 2032. EPA's own modeling projected that the rule would result in coal plant retirements of 5 gigawatts (GW) by 2030, an additional 21 GW by 2035, and another 14 GW by 2040 relative to a baseline without the rule. These closures would have directly reduced demand for Wyoming coal, eliminated mining jobs, and devastated coal-dependent communities and tax bases across the State.

The repeal also addresses critical electric grid reliability concerns that have been amplified by unprecedented growth in electricity demand. The North American Electric Reliability Corporation (NERC) has warned repeatedly about the erosion of grid stability caused by premature retirement of dispatchable, fuel-secure coal generation, and estimates that electricity demand will grow by 149,000 megawatts over the next ten years driven by artificial intelligence (AI) data centers, advanced manufacturing reshoring, and broader public electrification. Coal plants maintain an average on-site fuel stockpile equivalent to over 76 days of normal operation, providing essential reliability attributes that cannot be replicated by natural gas plants dependent on just-in-time pipeline delivery or by weather-dependent wind and solar resources. Winning the AI race is critical for national security reasons and having ample and dependable, affordable, and dispatchable supplies of electricity are necessary to promote national security. By preserving the existing coal fleet, the repeal directly supports national energy security and grid resilience.

EPA is pursuing this repeal as part of a broader coordinated regulatory relief strategy. On the same day the repeal proposal was published, EPA also announced a separate proposal to rescind the 2024 amendments to the Mercury and Air Toxics Standards (MATS), another regulation that placed significant cost pressures on the coal fleet (discussed further below). Even more fundamentally, on August 1, 2025, EPA proposed to rescind the 2009 Endangerment Finding, which is the foundational legal predicate for all GHG regulation under the Clean Air Act. If finalized, that action would eliminate EPA's legal authority to regulate greenhouse gases from any source category—power plants, vehicles, or industrial facilities. A future Administration seeking to regulate GHGs under the Clean Air Act would need to issue a new finding.

4.3.3.3 What's Next

EPA is currently reviewing public comments submitted by August 7, 2025, comment deadline and has publicly stated its intention to issue a final repeal rule by early January 2026. The agency's ability to finalize this action on schedule is strategically critical because litigation over the 2024 Carbon Pollution Standards is currently held in abeyance in the U.S. Court of Appeals for the D.C. Circuit. On February 19, 2025, the court granted the new administration's motion to pause the lawsuit challenging the 2024 rule while EPA pursues administrative repeal. If EPA successfully finalizes the repeal before the court lifts the abeyance, these challenges to the 2024 Clean Power Plan 2.0 would be mooted.

However, the finalization of the repeal will trigger new litigation. Environmental organizations and a coalition of states led by California, New York, and Massachusetts are certain to file lawsuits challenging the repeal when it is finalized. These challengers will argue that EPA has unlawfully abdicated its statutory duty to regulate greenhouse gases and that the agency's "significant contribution" finding and BSER analysis represent arbitrary and capricious reversals of scientific

findings and longstanding agency precedent. This litigation will proceed through the D.C. Circuit and is virtually certain to be appealed to the U.S. Supreme Court, with a final resolution not expected until 2027 or later.

The Supreme Court's prior signals strongly favor the repeal's ultimate survival. In October 2024, when the Court denied an emergency stay of the 2024 rule, Justices Kavanaugh and Gorsuch issued a statement indicating that challengers had "shown a strong likelihood of success on the merits" against the rule, signaling the Court's skepticism toward EPA's regulatory approach. The Court's 2022 decision in *West Virginia v. EPA*, which invoked the major questions doctrine to reject generation shifting as a permissible basis for regulation, established that agencies cannot undertake transformative economic policy without clear congressional authorization—a principle that provides strong legal support for EPA's repeal.

Recommendations: Wyoming policymakers should actively support the federal repeal through multiple channels. State leadership should maintain coordinated public advocacy for the repeal and oppose any legislative efforts to undermine it through Congressional Review Act resolutions. The state Attorney General should be prepared to file a motion to intervene in defense of the final repeal rule as soon as litigation is filed, which typically must occur within 30 days of the lawsuit being filed; this requires advance preparation now, before the final rule is published. It is essential that Wyoming work for an expedited briefing schedule for the review of the finalized repeal in the D.C. Circuit, as there is an opportunity to secure legal durability by ensuring that the Supreme Court has an opportunity to hear the case and render an opinion by 2028.

At the state level, it is recommended that Wyoming reinforce its commitment to grid reliability and fuel diversity through legislation that explicitly prioritizes resource adequacy and ensures that the reliability attributes of coal generation are properly valued in utility planning processes. Wyoming should also coordinate closely with other major coal-producing states—Montana, North Dakota, West Virginia, Pennsylvania, and Kentucky—to present a unified multi-state legal and political defense.

Finally, Wyoming should closely monitor EPA's separate August 1, 2025, proposal to rescind the 2009 Endangerment Finding for greenhouse gases, a foundational legal proceeding that will determine whether any future administration has the authority to regulate climate change under the Clean Air Act. The outcome of that rulemaking will ultimately determine the durability of any success achieved through this power plant repeal and represents an even more consequential regulatory battle for Wyoming's long-term coal interests.

4.3.4 Mercury & Air Toxics Standards ("MATS")

EPA has proposed to repeal the Biden administration's costly 2024 MATS rule for coal-fired power plants, delivering critical regulatory relief to Wyoming's coal industry. The June 17, 2025 proposal would eliminate three burdensome requirements imposed by this rule: a stricter particulate matter limit that would have cost the industry up to one billion dollars, a 70 percent reduction in mercury standards for lignite plants, and a universal mandate forcing all coal plants to install expensive continuous monitoring equipment. If finalized, this repeal would restore the 2012 standards and remove a major threat to coal plant viability that was driving premature retirements and threatening demand for Powder River Basin coal.

For Wyoming, this represents a fundamental shift toward common-sense regulation that respects the enormous progress the coal fleet has already made. The industry invested over $18 billion in mercury controls since 2012 and achieved a 90 percent reduction in mercury emissions. The 2024 MATS rule demanded another billion dollars in costs despite finding that residual health risks are negligible—only 0.3-in-1 million, far below the agency's own safety threshold. The Trump administration now correctly recognizes that these excessive costs are not justified. The repeal would preserve dispatchable baseload generation capacity essential for grid reliability, maintain long-term demand for Wyoming coal, and provide regulatory certainty for utilities making capital planning decisions—while maintaining the 2012 mercury emission standards that are protective of public health.

The proposal's technical justification directly incorporates arguments advanced by the coal industry. EPA now acknowledges that the 2024 particulate matter standard carried cost-effectiveness ratios—exceeding $16 million per ton

at the Colstrip Power Plant in Montana (which currently burns Montana coal but is a potential future market for Wyoming PRB coal)—that the agency has rejected as unreasonable in other sectors. The agency also concedes that the tightened mercury limit for lignite plants was based on insufficient data from a single unrepresentative facility and failed to account for the day-to-day variability in mercury content that characterizes lower-rank coals. This recognition establishes important precedent limiting EPA's ability to impose across-the-board standard reductions without rigorously demonstrating achievability across diverse coal types and boiler configurations.

4.3.4.1 Regulatory History

- **February 16, 2012:** EPA promulgates original Mercury and Air Toxics Standards, establishing first federal limits on mercury, acid gases, and toxic metals from coal and oil plants. The compliance deadline was April 15, 2015, with a one-year extension available upon application. Many coal power plants elected to retire, rather than invest the capital to comply with the MATS rule – almost 56,000 megawatts of coal capacity closed in the period 2012 – 2016, almost 20% of the existing coal fleet.
- **May 22, 2020:** EPA completes residual risk and technology review, finding existing MATS standards provide ample margin of safety and no revisions are necessary; simultaneously rescinds "appropriate and necessary" finding while maintaining emission standards.
- **February 15, 2023:** EPA revokes Trump administration's 2020 determination and reinstates "appropriate and necessary" finding for regulating power plant air toxics.
- **April 24, 2023:** EPA proposes to strengthen MATS standards based on technology review.
- **May 7, 2024:** EPA finalizes strengthened MATS rule, imposing stricter particulate matter limit (0.030 to 0.010 lbs./MMBtu), tighter lignite mercury limit (4.0 to 1.2 lbs./TBtu), and mandatory continuous monitoring; sets a July 8, 2027 compliance deadline.
- **May 8, 2024:** North Dakota, West Virginia, and 21 other states file lawsuit challenging the 2024 MATS rule in the D.C. Circuit Court of Appeals (Case No. 24-1119).
- **April 8, 2025:** Presidential proclamation grants two-year compliance relief (until July 8, 2029) to 68 specified coal plants under Clean Air Act authority.
- **June 17, 2025:** EPA proposes to repeal the 2024 MATS amendments (particulate matter standard, lignite mercury standard, and mandatory continuous monitoring requirement), restoring the 2012 standards.

4.3.4.2 Recent Developments

EPA's June 17, 2025 proposal would eliminate the three core components of last year's regulatory overreach: the tightened particulate matter standard, the 70 percent reduction in lignite mercury limits, and the mandate that all plants install continuous monitoring systems. This reversal is grounded by three arguments: (1) the existing standards were already protective of public health; (2) the 2024 standards impose costs grossly disproportionate to benefits; and (3) the revised mercury limit was not demonstrated to be technically achievable across the diversity of coal types and plant configurations.

The agency's own 2020 analysis—which the Biden administration did not reopen—found maximum cancer risk from coal plant air toxics at only 0.3-in-1 million, more than 300 times below EPA's 100-in-1 million acceptable risk threshold. The question appropriately challenges whether billion-dollar compliance burdens can be justified when health risks are already negligible and the industry has invested massively in proven controls.

The cost-effectiveness analysis exposes the 2024 rule's fundamental flaw. EPA determined that the revised particulate matter standard—which serves as a surrogate for controlling toxic metals like arsenic and chromium—carried fleet-wide costs exceeding $3.8 million per ton of pollutant removed. At the Colstrip Power Plant in Montana, the only facility that

would have required major new pollution controls, the ratio reached $16 million per ton. The agency now correctly recognizes this is inconsistent with its own cost-benefit determinations in other industries; in 2020, EPA declined to impose taconite facility controls costing $16 million per ton, concluding they were not cost-effective. The proposal properly applies this same cost-reasonableness standard to the power sector, finding that despite acknowledged pollution control technology improvements, the costs of mandatory implementation are too high to be considered necessary under the Clean Air Act.

The technical justification for repealing the lignite mercury standard addresses feasibility concerns related to issues with lignite. EPA acknowledges the 2024 rule reduced the lignite limit from 4.0 to 1.2 pounds per trillion Btu based on inadequate data from a single Texas facility—Twin Oaks—using circulating fluidized bed technology, which is not representative of conventional coal plants, which use pulverized coal technology. The agency also failed to account for substantial mercury content variability in lower-rank coals. Industry data demonstrated that lignite seams can exhibit mercury concentrations as high as 34 pounds per trillion Btu, requiring sustained control efficiencies exceeding 96 percent—a level never proven achievable across variable fuel quality and conventional boiler designs.

The proposal also eliminates the mandatory continuous monitoring requirement and restores compliance flexibility, allowing plant operators to choose quarterly stack testing, parametric monitoring of control equipment, or continuous emissions monitors based on site-specific circumstances. EPA estimates this saves $2.8 million annually in direct costs, but the real value is eliminating capital expenditure uncertainty for utilities evaluating coal plant life extension. Plants with existing mercury controls and pollution equipment sufficient for 2012 MATS compliance gain certainty that no additional retrofits are required, fundamentally altering the economics of continued coal operation.

For Wyoming's coal market, the proposal's most significant impact is removing the July 8, 2027 compliance deadline that created urgent pressure on utility retirement decisions. An April 2025 presidential proclamation extended the compliance deadline to July 8, 2029, providing immediate relief, but a future administration could rescind that proclamation and set an earlier compliance deadline. A durable repeal of the 2024 MATS rule is urgently needed. Coal industry comments consistently argued that the 2024 rule—combined with other pending regulations—would accelerate closure of dispatchable baseload generation precisely when electricity demand is surging. The Department of Energy's July 2025 Resource Adequacy Report concluded that continued plant retirements amid rising demand could increase blackout risk by a factor of 100 by 2030. Multiple utilities have already delayed planned coal retirements responding to grid reliability warnings, and this MATS repeal removes a significant regulatory driver of premature closures that would have reduced Wyoming coal demand.

4.3.4.3 What's Next

The comment period closed 60 days after Federal Register publication in August 2025. EPA scheduled a virtual public hearing roughly 15 days after publication to receive stakeholder testimony. Wyoming agencies submitted comments documenting market impacts, quantifying compliance cost relief the repeal provides, and supplying technical data on Powder River Basin coal variability that supports EPA's feasibility concerns. On December 23, 2025, EPA submitted a draft of the final action to the Office of Management and Budget (OMB) for interagency review under Executive Order 12866. Following completion of the OMB interagency review process, EPA expects that the Administrator will finalize the action in early 2026.

If EPA finalizes the repeal before the July 8, 2027 compliance deadline, utilities gain immediate certainty that no additional investments beyond the 2012 baseline are required—the industry has already achieved those standards. However, legal challenges will create timing uncertainty. The North Dakota v. EPA lawsuit challenging the 2024 rule remains active, with merits briefing underway in the D.C. Circuit; if that court strikes down the 2024 amendments before EPA finalizes the repeal, the administrative action may become unnecessary. Environmental groups filed Air Alliance Houston v. Trump in June 2025 challenging the presidential exemption and have signaled intent to challenge any final repeal as arbitrary agency

reversal. That case is held in abeyance until March 3, 2026, pending this rulemaking outcome but will likely resume if EPA finalizes the repeal.

Any final repeal will face judicial scrutiny under administrative law standards requiring agencies to provide reasoned explanation for policy reversals beyond simple change in administration. The proposal's reliance on cross-sector, cost-effectiveness comparisons and technical feasibility concerns provides stronger legal footing than mere policy preference. Grid reliability evidence and Department of Energy resource adequacy warnings strengthen the defense. Wyoming stakeholders should monitor three parallel tracks: the comment process concluding mid-August, D.C. Circuit litigation over the 2024 rule extending into fall 2025, and potential future litigation over any final repeal likely filed within 60 days of publication. The most probable near-term outcome is a final repeal, published in early 2026, which would then face legal stay motions creating continued uncertainty. Wyoming should consider intervening in this litigation in support of the proposed repeal and consider advocating for an expedited briefing schedule for the review of the finalized repeal in the D.C. Circuit. As with the proposed repeal of the Clean Power Plan 2.0, there is an opportunity to secure legal durability by ensuring that the Supreme Court has an opportunity to hear the case and render an opinion by 2028.

Wyoming coal producers should engage directly with utility customers to understand plant-specific compliance postures and capital planning assumptions under each scenario. Individual plant economics vary dramatically based on remaining useful life, existing pollution controls, power purchase agreements, state cost recovery mechanisms, and regional grid value. A relatively modern plant with existing fabric filters and activated carbon injection may already comply with 2024 standards at minimal incremental cost, limiting the financial stake in repeal. Conversely, older plants with electrostatic precipitators requiring fabric filter retrofits to meet the 0.010 lbs./MMBtu particulate limit face major capital expenditures which the repeal would eliminate. Understanding these plant-specific dynamics is essential for accurately assessing Wyoming coal demand at risk under different regulatory scenarios and targeting advocacy resources toward highest-value utility relationships.

4.3.5 Effluent Limitation Guidelines ("ELG")

The Biden administration's May 2024 power plant wastewater rule imposed costly zero-discharge requirements on coal-fired power plants that forces plant owners to choose between investing hundreds of millions of dollars in unproven treatment technologies or committing to retire by 2034. With a December 31, 2025, deadline for plants to make that irreversible decision, the rule created immediate retirement pressure on facilities that are major purchasers of Wyoming Powder River Basin coal, directly threatening demand for Wyoming coal production and the jobs and revenue it supports.

Following litigation challenging the 2024 rule, EPA Administrator Lee Zeldin announced in March 2025 that the agency would reconsider the rule. On October 2, 2025, EPA formally proposed extending the most critical compliance deadlines by five to six years and would push the retirement decision deadline from December 31, 2025, to December 31, 2031. This six-year extension would eliminate the immediate threat of forcing coal plant owners into premature retirement commitments and preserves operational flexibility for the facilities that constitute Wyoming's coal customer base.

EPA justified the extensions citing surging electricity demand from artificial intelligence, data centers, domestic manufacturing, and increasing public demand. The agency explicitly stated the action removes "regulatory pressure for the premature closure of reliable, affordable base-load power" and supports grid reliability and American energy security. For Wyoming, this represents a major regulatory victory that sustains coal plant operations, preserves coal market demand, and buys time for a broader reconsideration expected to weaken or eliminate the Biden-era zero-discharge mandates entirely. The agency has signaled that a subsequent rulemaking will revisit the underlying technology requirements, with industry groups already advocating for a return to the less stringent standards based on the cost and lack of fleet-wide feasibility of the technologies previously mandated.

4.3.5.1 Regulatory History

- **November 3, 2015:** Obama Administration EPA finalizes first numeric limits on toxic metals (arsenic, mercury, selenium, nitrogen) in power plant wastewater discharges and establishes zero-discharge standard for fly ash transport water; represents major tightening of 1982 baseline requirements.
- **October 13, 2020:** Trump Administration EPA finalizes reconsideration rule creating multiple compliance subcategories (low utilization units, high flow facilities, units retiring by 2028) while adding regulatory flexibility for wastewater treatment requirements.
- **May 9, 2024:** EPA publishes Supplemental Effluent Limitations Guidelines Final Rule establishing zero-discharge standards for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate based on membrane filtration and thermal evaporation technologies; rule effective July 8, 2024; compliance deadline for direct dischargers set at December 31, 2029; creates early adopter subcategory allowing plants committing to cease coal combustion by December 31, 2034, to avoid zero-discharge requirements and instead comply with less stringent 2020 standards.
- **June 2024:** Industry coalition (Southwestern Electric Power Co., Edison Electric Institute, Utility Water Act Group) and 22 states file petitions for judicial review in multiple federal appellate courts; cases consolidated in U.S. Court of Appeals for the Eighth Circuit.
- **March 12, 2025:** EPA Administrator Lee Zeldin announces reconsideration of 2024 rule in response to industry administrative petitions; litigation held in abeyance to allow agency review.
- **June 30, 2025:** EPA announces plan to propose compliance deadline extensions by end of summer and states it will explore "immediate relief" from combustion residual leachate requirements and "other flexibilities" to support coal-fired generation.
- **August 11, 2025:** EPA files motion in U.S. Court of Appeals for the Eighth Circuit requesting continued hold on litigation until December 15, 2025, to allow agency reconsideration; indicates substantive revisions to technology standards will follow deadline extensions.
- **October 2, 2025:** EPA publishes proposed rule and direct final rule extending key compliance deadlines by five to six years; cites AI-driven electricity demand growth, data center expansion, and manufacturing resurgence as justification for delaying Biden-era zero-discharge requirements.

4.3.5.2 Recent Developments

On October 2, 2025, EPA published a proposed rule and a companion direct final rule that would extend the most consequential compliance deadlines in the 2024 effluent limitation guidelines for steam electric power plants. The proposal extends the final deadline for achieving zero-discharge standards (the "best available technology economically achievable" or BAT) for three major waste streams—flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate—from December 31, 2029, to December 31, 2034, a five-year extension. More immediately critical for Wyoming coal interests, the direct final rule extends the deadline for power plant owners to submit a Notice of Planned Participation ("NOPP") in the early adopter retirement subcategory from December 31, 2025, to December 31, 2031, a six-year extension and allows facilities to transfer in and out of the subcategory. The direct final rule was published by EPA in December 2025.

The December 31, 2025, NOPP deadline was the most immediate threat to Wyoming coal demand. Under the 2024 rule's structure, plant owners facing that year-end deadline had to choose between two paths: commit to permanently ceasing coal combustion by December 31, 2034, and thereby avoid unreasonably costly zero-discharge technology requirements, or proceed toward compliance with those requirements by installing treatment systems costing hundreds of millions of dollars per facility. For older, smaller, or economically marginal coal plants—many of which purchase Wyoming coal—the

capital cost of zero-discharge compliance would exceed the plants' remaining economic value, making the retirement option the rational business decision. The six-year extension of this decision point removes immediate pressure and allows plant owners to maintain operational flexibility while EPA conducts a broader reconsideration that is expected to weaken or eliminate the zero-discharge mandate entirely.

EPA's justification for the extensions represents a pivot from the Biden administration's environmental and public health rationale to a focus on energy security, grid reliability, and economic competitiveness. The agency cited extraordinary increases in projected electricity demand driven by artificial intelligence infrastructure, data center expansion, and a domestic manufacturing resurgence, and stated that the extensions are necessary to prevent premature retirement of reliable, affordable baseload generation capacity. Administrator Zeldin characterized the action as eliminating "regulatory pressure for the premature closure" of coal plants and supporting the administration's commitment to "unleash American energy responsibly" while maintaining grid stability during unprecedented demand growth. The proposal also solicits public comment on new pilot study data, actual cost information, and engineering analyses bearing on the technical availability and economic achievability of the membrane filtration and thermal evaporation systems that formed the basis of the 2024 rule's zero-discharge determination, signaling EPA's intent to revisit and likely weaken those underlying technology standards in a subsequent rulemaking.

For Wyoming coal producers and the state's broader coal economy, the proposed extensions directly reduce financial and operational pressure on the coal-fired power plant customer base. The 2024 rule's structure functioned as a powerful retirement-forcing mechanism: the stark choice between extremely high compliance costs and a subsidized retirement pathway, combined with a short decision timeline, incentivized plant closures that would have contracted Wyoming coal demand. The six-year extension of the Notice of Planned Participation deadline removes that immediate forcing event, preserves coal generation capacity that would otherwise have committed to retirement, and aligns federal environmental regulation with the state's economic interest in sustaining coal production, supporting utility ratepayers, and maintaining grid reliability during a period of rising electricity load.

4.3.5.3 What's Next

The public comment period on the proposed extension closed on November 3, 2025. EPA is expected to finalize the compliance deadline extensions in the first quarter of 2026, finalizing the six-year extension and flexibility with respect to providing Notice of Planned Participation.

The timeline for EPA's broader substantive reconsideration of the 2024 rule's underlying zero-discharge technology standards is less certain and will unfold on a longer track. The agency has stated it intends to issue a second rulemaking to revise the technology basis for the BAT limitations and potentially eliminate or modify requirements for unmanaged combustion residual leachate, but no formal Notice of Proposed Rulemaking has been published for this effort. Based on typical regulatory development timelines and references in the Office of Management and Budget's most recent Unified Agenda, a proposed rule for the substantive reconsideration is anticipated in 2026, with a final revised rule issued in 2027 or 2028. Industry groups, including the Cross-Cutting Issues Group and the Utility Solid Waste Activities Group, have already submitted detailed white papers to EPA recommending that the agency revert to chemical precipitation and advanced biological treatment ("ABT") as the technology basis for wastewater standards—the approach used in the 2015 and 2020 rules—rather than the membrane filtration and thermal evaporation systems that underpin the 2024 zero-discharge ("ZLD") mandate. Additional industry comments from early adopters of ABT flag that even those standards are not adequately demonstrated in practice to assume fleetwide feasibility. These industry recommendations provide a preview of the likely direction and scope of EPA's substantive revisions.

Importantly, EPA has not just signaled that the next phase of regulatory activity will make less stringent controversial ZLD and ABT mandates, they explicitly requested comment on the legality of certain aspects of the 2024 Rule which created unit retirement as an explicit compliance option. This could signal a reversal of course and the ultimate removal of retirement incentives originating from this area of regulation.

The litigation challenging the 2024 rule remains held in abeyance in the U.S. Court of Appeals for the Eighth Circuit pending the completion of EPA's reconsideration process. Once the agency finalizes a revised rule, the existing petitions for review will likely be dismissed as moot because the challenged rule will have been superseded. However, a new round of litigation is virtually certain to follow. Industry and state petitioners will challenge any revised rule that they view as retaining overly stringent or costly requirements, while environmental groups will challenge any weakening of the 2024 standards as arbitrary, capricious, or contrary to the Clean Water Act. The ultimate legally durable effluent standards for coal-fired power plants will therefore be determined through this next litigation cycle, which could extend into 2028 or beyond, depending on the pace of judicial review and any potential appeals to the U.S. Supreme Court.

Wyoming policymakers should anticipate that the regulatory environment could shift again following the 2028 presidential election. If a future Democratic administration takes office, it could attempt to reinstate more stringent wastewater limits, potentially as soon as 2029 or 2030, depending on the status of the current reconsideration and any intervening litigation. For long-term planning purposes, the state should therefore treat the current favorable regulatory trajectory as contingent on continued alignment between federal policy and Wyoming's coal production interests. At the same time, a more durable regulatory framework is needed for EGU wastewater—this may require congressional intervention. Of course, like CPP 2.0 and MATS, expedited action on this rule will make it more realistic to reach the Supreme Court on many of the key legal issues associated with this rule before the end of the current administration, thereby providing more regulatory certainty than has existed after prior administrative changes.

4.3.6 Coal Combustion Residuals ("CCR")

EPA regulates coal ash disposal through the CCR program established in 2015 and subsequently amended. Core requirements for closure of non-compliant impoundments, groundwater monitoring and corrective action, and limits on continued disposal remain the principal drivers of coal plant retirement decisions. The 2024 CCRMU and Legacy CCR rules did not create new retirement triggers, but they expanded the scope of regulated units and imposed additional monitoring, documentation, and closure expectations on older or previously unregulated features. These expansions are widely viewed as unnecessary and poorly calibrated to actual environmental risk, and they introduce uncertainty about the scope of regulated units, the extent of corrective obligations, and the applicable technical standards. Although they do not independently force retirements, the CCRMU and Legacy rules increase compliance exposure and administrative burden, and they compound the cost and operational pressures created by the underlying CCR program. For policymakers, this means CCR policy continues to shape the viability of the remaining fleet, even though earlier retirements were driven by the original CCR requirements. On July 22, 2025, EPA proposed a rule that would, if finalized, extend compliance deadlines for CCR Management Units and provide additional flexibility with respect to submission of Facility Evaluation Reports. EPA later withdrew the direct final version of the rule, so existing compliance deadlines remain in place unless and until EPA finalizes the proposed revisions. The proposed rule remains active, and the comment period has been extended, leaving owners and operators without near-term clarity. These revisions, if finalized, would help address the regulatory uncertainty and near-term compliance pressures associated with the new CCRMU requirements, which stem from the 2024 Legacy CCR Rule and extend the CCR program into inactive or historically managed areas that often present limited current risks. These requirements have introduced obligations that are difficult for owners and regulators to apply consistently, and additional time and flexibility would reduce immediate compliance strain while EPA considers broader implementation issues

At the same time, EPA has prioritized state applications for primacy for state-level CCR regulation. EPA has advanced Wyoming's application for state primacy over coal ash permitting, with Administrator Lee Zeldin traveling to Wyoming in August 2025 to announce the proposed approval alongside Governor Mark Gordon. This proposal would transfer regulatory authority from federal EPA to the Wyoming Department of Environmental Quality, restoring state control and reducing one-size-fits-all federal mandates. Other states are following suit by pursuing primacy of CCR regulation programs, including North Dakota.

For Wyoming policymakers and coal producers, these developments provide meaningful near-term regulatory stability. The proposed extensions, if finalized, would reduce immediate operational pressure on coal-fired units that rely on Wyoming coal. State primacy over coal ash regulation ensures that future CCR permitting and compliance decisions reflect Wyoming's geology, hydrogeology, and regulatory framework rather than uniform federal interpretations that are often unclear, inflexible, or misaligned with site-specific risk. Even with earlier retirements shaped by the original CCR program, the combination of federal extensions and state primacy remains critical to preserving the viability of the remaining fleet and sustaining Wyoming coal demand.

4.3.6.1 Regulatory History

- **April 2015:** Obama Administration EPA issues the first federal CCR disposal regulations under RCRA, establishing nationwide requirements for CCR units.
- **December 2016:** Congress enacts the Water Infrastructure Improvements for the Nation Act (the "WIIN Act"), creating the process for EPA to approve a state-administered CCR permit program in place of the federal self-implementing requirements.
- **August 2018:** The D.C. Circuit Court vacates several exemptions in the 2015 CCR Rule and directs EPA to regulate legacy CCR surface impoundments and strengthen closure and groundwater provisions, prompting a series of amendments.
- **2017–2020:** EPA issues amendments to the CCR Rule to address the Court's remand, revise closure and groundwater requirements, and clarify compliance pathways for inactive and historically managed CCR areas.
- **May 8, 2024:** Biden EPA finalizes legacy CCR rule tightening closure requirements for coal ash surface impoundments and establishing new standards for CCR management units.
- **March 12, 2025:** EPA Administrator Zeldin commits to prioritizing state CCR permit program approvals as part of broader deregulatory agenda.
- **July 22, 2025:** EPA issues both a direct final rule and a parallel proposed rule to extend certain Legacy CCR and CCR Management Unit compliance deadlines and modify Facility Evaluation Report requirements. EPA later withdraws the direct final rule, leaving the proposed rule in place and existing deadlines unchanged pending final action.
- **August 28, 2025:** EPA proposes approval of Wyoming's partial CCR permit program, fulfilling Administrator Zeldin's March commitment to expedite state primacy applications.

4.3.6.2 Recent Developments

Congress enacted the Water Infrastructure Improvements for the Nation Act in 2016 (the "WIIN Act"), which amended RCRA to create a process for EPA to approve a state-administered CCR permit program in place of the federal self-implementing requirements. The WIIN Act preserves EPA's enforcement authority but requires EPA to notify the state and give the state an opportunity to address alleged violations before EPA pursues federal enforcement. This framework gives the states a primary role in day-to-day permitting and compliance decisions for CCR units once a program is approved, while still allowing EPA to act if a state does not address an alleged violation or if an imminent and substantial endangerment arises. Although the WIIN Act approval cannot fully insulate facilities from future federal involvement, it ensures that Wyoming DEQ is consulted first and has the opportunity to resolve compliance issues before any federal action proceeds.

Wyoming sought approval of its CCR permit program under this framework, but EPA did not act on the application within the statutory 180-day deadline. After several years without a decision, Wyoming sued the Biden EPA in October 2023 in the U.S. District Court for the District of Wyoming to compel EPA to act. EPA has now advanced Wyoming's long-pending

application for state primacy over coal ash permitting. On August 28, 2025, the agency proposed approval of Wyoming's partial CCR permit program, which would transfer regulatory authority from federal EPA to the Wyoming Department of Environmental Quality for coal ash disposal facilities covered by the state program. Administrator Zeldin personally traveled to Wyoming to announce the proposed approval in a ceremony with Governor Mark Gordon, underscoring the administration's political commitment to cooperative federalism and state regulatory control over natural resources. Once finalized, this approval will replace inflexible federal self-implementing regulations with a state-designed permit program tailored to Wyoming's unique geology, hydrology, and existing state regulatory framework, reducing compliance costs and administrative burden while ensuring environmental protections appropriate to local conditions.

EPA's proposed approval fulfills the statutory process established by the WIIN Act and provides a clearer, more predictable compliance structure for owners and operators. While EPA retains backstop enforcement authority, the state-first requirement and the shift to a permit-based program gives Wyoming meaningful control over interpretation, enforcement timing, and the resolution of alleged violations. For regulated entities, this represents a significant improvement over the federal self-implementing rule, which can create uncertainty and inconsistent federal oversight. State primacy therefore offers practical and durable benefits even though it does not eliminate the possibility of future EPA involvement entirely.

4.3.6.3 What's Next

EPA is expected to finalize approval of Wyoming's partial CCR permit program in 2026, following review of public comments. Once effective, this approval will shift primary day-to-day regulatory authority from federal EPA to Wyoming Department of Environmental Quality for coal ash disposal units covered by the state program. Wyoming should monitor whether EPA modifies the scope of approval in response to potential adverse comments from environmental groups, who have criticized partial program approvals in other states as creating confusing patchwork jurisdiction between state and federal requirements. EPA has separately committed to finalizing a standalone federal CCR permit program to govern facilities in states without approved programs, expected in 2026, which could establish baseline expectations that indirectly constrain state program design.

The overarching uncertainty is political durability. The regulatory trajectory of both wastewater and coal ash rules has proven sensitive to presidential election cycles, with each administration systematically reversing its predecessor's approach. The current reconsideration represents yet another pendulum swing. For Wyoming coal interests, this pattern indicates that achieving durable, coal-friendly regulatory outcomes requires not merely favorable EPA actions in the near term, but sustained political engagement and advocacy to ensure those outcomes survive potential future administration changes after the 2028 election cycle.

4.3.7 "Good Neighbor" / Cross-State Air Pollution Rule

The Environmental Protection Agency's Federal Good Neighbor Plan for the 2015 ozone National Ambient Air Quality Standards also puts pressure on Wyoming coal markets. Finalized in June 2023, the rule took the form of a mass denial of State Implementation Plans and the imposition of a Federal Implementation Plan (FIP) across 23 states. The FIP imposed strict nitrogen oxide emissions limits on coal-fired power plants across twenty-three states—key customers for Wyoming coal—through a cap-and-trade program paired with daily emissions limits that effectively curtailed coal plant operations during peak summer months when these facilities generate the majority of their annual revenue. The rule is currently stayed nationwide following a Supreme Court decision in June 2024, and EPA announced in September 2025 a two-phase process to replace it. EPA proposed the Phase One revised rule in January 2026.[58]

The economic stakes for Wyoming are substantial. EPA's own analysis projected the rule would eliminate demand for thirty-two million tons of coal annually by 2030—a fifteen percent reduction from baseline projections. Real-world data from the rule's brief 2023 implementation in ten states showed an immediate twenty-four percent drop in coal plant operations during the ozone season. For Wyoming coal producers whose markets depend heavily on power plants in the

[58] https://www.epa.gov/newsreleases/epa-advances-cooperative-federalism-improve-air-quality-taking-important-step.

Midwest and Great Plains states covered by this rule, this forced operational curtailment translates directly to lost production volumes, reduced state coal lease royalties, and diminished severance tax revenues.

The Supreme Court halted the rule based on a critical procedural failure—EPA's inability to explain how the rule's stringent requirements remained justified after federal courts removed twelve states from the program. EPA's announced two-phase replacement process creates an immediate window for Wyoming to influence the rule's future and protect the state's coal economy from a reinstated federal mandate that would accelerate displacement of coal-fired generation.

4.3.7.1 Regulatory History

- **2015** – EPA sets ozone NAAQS at seventy parts per billion, triggering Clean Air Act Good Neighbor obligations for upwind states to control emissions that significantly contribute to downwind nonattainment
- **February 2023** – EPA disapproves twenty-one state implementation plans and proposes federal implementation plan to address interstate ozone transport
- **June 5, 2023** – EPA finalizes Federal Good Neighbor Plan for 2015 Ozone NAAQS, establishing CSAPR NOx Ozone Season Group Three Trading Program for electric generating units in twenty-two states with declining emissions budgets and unit-specific daily emissions rate limits for large coal-fired units backed by three-for-one allowance penalties
- **July–September 2023** – Multiple circuit courts (Fourth, Fifth, Sixth, Eighth, Ninth, Tenth, Eleventh Circuits) grant stays of EPA's state implementation plan disapprovals for twelve states (Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, West Virginia); EPA issues interim final rules administratively staying Good Neighbor Plan requirements in those states
- **June 27, 2024** – U.S. Supreme Court stays Good Neighbor Plan nationwide in *Ohio v. EPA*, finding EPA likely acted arbitrarily by failing to explain how rule's cost-benefit analysis remained valid after twelve states were judicially removed from the program
- **March 2025** – EPA announces formal reconsideration of Good Neighbor Plan, citing burdens on domestic energy production and commitment to cooperative federalism; D.C. Circuit places merits litigation in abeyance pending agency review
- **September 2025** – EPA announces two-step process to replace Good Neighbor Plan; Phase One proposed rule on January 30, 2026; the Phase Two proposal is expected later in 2026

4.3.7.2 Recent Developments

The Good Neighbor Plan has been legally unenforceable since the Supreme Court's June 27, 2024 decision in *Ohio v. EPA*. The Court granted a nationwide stay after finding that EPA likely violated the Administrative Procedure Act by failing to adequately explain how the rule's stringent requirements remained justified after the program's scope was cut by more than half due to judicial stays of underlying state plan disapprovals. The Court's five-to-four decision emphasized that EPA's original cost-benefit analysis was premised on a complex, integrated twenty-three-state program, and the agency provided only a cursory assertion of "severability" rather than a reasoned explanation for why the same emissions budgets and compliance costs made sense for sources in the remaining eleven states when the broader regional air quality benefits were no longer achievable.

The design of the original rule was particularly damaging to coal economics. Beyond the cap-and-trade emissions allowance system, EPA imposed unit-specific daily nitrogen oxide emissions rate limits on large coal plants backed by a three-for-one allowance penalty if a unit exceeded its daily limit by more than fifty tons. This dual-mechanism approach eliminated the operational flexibility fundamental to coal plants' business model—the ability to ramp up generation during high-demand, high-price summer periods. By creating enormous financial risk for operating during peak demand, the rule

effectively forced plant operators to either severely curtail summer operations or face catastrophic compliance costs, directly threatening the baseload coal generation that drives demand for Wyoming production.

EPA's Regulatory Impact Analysis projected the rule would reduce national coal demand by thirty-two million tons annually by 2030 when accounting for Inflation Reduction Act incentives for non-fossil generation—a fifteen percent reduction from baseline. These are not abstract projections. During the 2023 ozone season when the rule was briefly in effect in ten states, nitrogen oxide emissions dropped eighteen percent compared to 2022, but a significant portion of that reduction came simply from running coal plants less. Coal unit operations fell twenty-four percent across the affected region during the very summer months when these plants typically earn the majority of their annual revenue.

In September 2025, EPA announced its replacement strategy by announcing a two-phase approach. The agency stated it would propose a Phase One rule in the near future with finalization expected by year-end 2025, followed by a Phase Two proposal in October 2025 with a final rule expected in summer 2026. EPA indicated this approach would "invoke the principles of cooperative federalism while accomplishing EPA's core mission of protecting the environment," signaling potential openness to state-led solutions rather than a uniform federal implementation plan. The D.C. Circuit litigation challenging the original rule (*State of Utah v. EPA*) remains in abeyance pending completion of EPA's reconsideration process.

4.3.7.3 What's Next

EPA's announced timeline creates two critical engagement windows for Wyoming. The Phase One rule, proposed on January 30, 2026, addresses the Biden EPA's disapproval of multiple state plans for meeting the 2015 ozone NAAQS reversing those findings and approving at least some plans. The proposed rule also proposes to establish a 1 ppb significant contribution threshold for upwind states. This may provide temporary relief and additional time to develop a more comprehensive policy. The Phase Two rule, expected later in 2026 will likely establish the substantive emissions requirements that directly impact coal-fired generation and therefore Wyoming coal markets.

The specific content and stringency of these replacement rules remain uncertain and depend heavily on EPA's interpretation of its cooperative federalism commitment. The agency's September 2025 announcement provided no detail on whether Phase One or Phase Two will reimpose the unit-specific daily emissions limits and three-for-one penalties that proved so damaging during the 2023 ozone season, or whether the replacement will rely more heavily on state implementation plans that could provide greater operational flexibility for coal plants. EPA has not yet published formal proposals or opened public comment periods for either phase.

Wyoming has narrow but critical windows to shape outcomes. The Supreme Court's *Ohio* decision established that any future iteration of this rule must be legally defensible on a state-by-state basis and cannot rely on a fragile multi-state cost-benefit analysis that collapses if individual states are removed. This creates a higher evidentiary burden for EPA and a stronger foundation for state-specific arguments about economic harm and grid reliability. Immediate strategic actions should include monitoring for Phase One and Phase Two proposals issued in January 2026 and later in 2026, respectively; preparing detailed comments for any forthcoming comment periods that document state-specific economic impacts on coal production, royalties, and employment; and coordinating with the coalition of states that successfully obtained judicial stays in 2023 to present unified opposition to reinstatement of the original rule's stringent requirements. The legal victory in *Ohio* provides both a temporary reprieve and a powerful procedural precedent, but sustained engagement will be necessary to ensure replacement rules do not replicate the original program's economic damage to Wyoming coal under a different procedural structure.

4.3.8 Regional Haze Rule

The Environmental Protection Agency is implementing fundamental reforms to the Regional Haze Rule that significantly reduce federal pressure on Wyoming's coal industry while strengthening state authority over air quality decisions. On October 2, 2025, EPA published an Advance Notice of Proposed Rulemaking proposing that signaled the agency's intent

to extend the program's 2064 visibility restoration deadline, establish clearer criteria for when states have satisfied their obligations, and create a "preservation" status eliminating further control requirements for areas achieving sufficient improvement. These changes follow Administrator Lee Zeldin's commitment to end what he described as misuse of the haze program to impose excessive burdens on coal-fired power plants.

For Wyoming, the immediate impact is favorable. EPA's new approach allows states meeting visibility improvement benchmarks to avoid costly pollution control installations on coal plants, provided they demonstrate reasonable consideration of compliance costs and energy impacts. Wyoming can expect reduced federal micromanagement of emission control decisions in states that utilize Wyoming coal and greater flexibility to balance visibility goals against economic and grid reliability concerns.

However, environmental groups filed suit on September 4, 2025 challenging EPA's new framework as an unlawful abandonment of Clean Air Act requirements. The litigation creates uncertainty about whether the reforms will survive judicial review, particularly under the Supreme Court's recent rulings limiting deference to agency interpretations of underlying statutes. Wyoming should navigate this transitional period by supporting state plan approvals under current favorable policies while preparing for potential future regulatory shifts.

4.3.8.1 Regulatory History

- **September 11, 2018:** EPA issued Regional Haze Reform Roadmap establishing principles of state leadership, leveraging co-benefits from other programs, and streamlining state plan requirements.
- **August 2019:** EPA issued guidance providing states broad flexibility in second implementation period plans, allowing credit for emission reductions from other Clean Air Act programs.
- **March 12, 2025**: Administrator Zeldin announced comprehensive deregulatory initiative including restructuring of Regional Haze Program to reduce power generation sector burdens.
- **July 7, 2025:** EPA finalized approval of West Virginia's regional haze plan, announcing new national policy allowing states meeting Uniform Rate of Progress to satisfy reasonable progress requirements.
- **July 16, 2025:** EPA proposed partial disapproval of Colorado's regional haze plan, rejecting enforceable coal plant closure provisions based on grid reliability concerns and potential Takings Clause violations.
- **September 4, 2025:** National Parks Conservation Association and Sierra Club filed Fourth Circuit lawsuit challenging EPA's approval of West Virginia's regional haze plan as violating statutory requirements.
- **October 2, 2025:** EPA published Advance Notice of Proposed Rulemaking proposing major Regional Haze Rule restructuring, including potential extension of 2064 target, establishment of regulatory safe harbor, and creation of "preservation" status.

4.3.8.2 Recent Developments

EPA's July 7, 2025 approval of West Virginia's regional haze State Implementation Plan establishes a new national policy fundamentally changing how EPA evaluates state compliance. The agency announced that states demonstrating visibility improvement consistent with the Uniform Rate of Progress glidepath toward 2064 natural conditions will be presumed to satisfy statutory reasonable progress requirements, provided they have considered the four statutory factors: cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life of sources. This transforms the URP from a tracking metric into a regulatory standard that protects state decisions from federal second-guessing.

The policy directly benefits Wyoming by eliminating pressure to impose maximum technically feasible controls on coal plants when visibility is already improving at an acceptable rate. Under the prior administration's approach, EPA routinely disapproved state plans that balanced environmental benefits against economic costs, effectively mandating installation

of expensive pollution controls regardless of cost-effectiveness. The new framework restores proper balance by recognizing that "reasonable progress" permits states to weigh energy security and economic impacts alongside visibility gains.

EPA reinforced its commitment to grid reliability on July 16, 2025 by proposing partial disapproval of Colorado's regional haze plan. While approving most of Colorado's submission, EPA rejected provisions imposing enforceable coal and gas plant closure deadlines, finding that Colorado failed to adequately assess grid reliability impacts and did not provide assurances that forced closures would comply with the Takings Clause prohibition on uncompensated property seizures. EPA explicitly stated that the energy impacts analysis did not satisfy requirements to consider "grid reliability and electrical demand" in a manner consistent with executive orders prioritizing energy generation. This establishes important precedent that EPA will not approve plans threatening reliable electricity supply or imposing unconstitutional regulatory takings.

Wyoming has already benefited from the administration's state empowerment priorities. On August 28, 2025, EPA proposed approval of Wyoming's application to operate a partial coal combustion residuals permit program in lieu of federal requirements, ending Wyoming's litigation against the Biden EPA for unlawfully delaying action on the application. The approval transfers state authority over significant portions of federal CCR requirements while EPA retains jurisdiction over legacy surface impoundments and certain groundwater standards added after December 2020. This represents the second state CCR program authorized under the current administration and demonstrates EPA's commitment to transferring oversight to states with proven regulatory capability.

The October 2, 2025 ANPRM signals EPA's intent to codify these policies through formal rulemaking. The notice explores extending the 2064 visibility restoration target to a later date, establishing an explicit regulatory safe harbor for states meeting progress metrics, creating a "preservation" category for areas achieving sufficient improvement, and establishing numerical thresholds for when visibility impairment from U.S. sources becomes de minimis and requires no further action. The ANPRM also examines extending state plan revision cycles from 10 years to 15 years or replacing automatic deadlines with as-needed triggers based on actual visibility conditions.

Environmental organizations are mounting legal challenges to block these reforms. The September 4, 2025 Fourth Circuit lawsuit argues that EPA's URP-based approval framework unlawfully allows states to bypass the statutory requirement to analyze pollution controls using the four factors. Additional litigation is expected as EPA applies the policy to other state plans. The Supreme Court's 2024 decision in *Loper Bright Enterprises v. Raimondo*, which eliminated judicial deference to agency statutory interpretations, creates additional uncertainty because courts will now independently determine whether EPA's approach represents the best reading of the Clean Air Act. Environmental groups argue that the URP is merely a regulatory tracking metric that cannot override explicit statutory analysis requirements.

4.3.8.3 What's Next

The public comment period for the October 2, 2025 ANPRM runs through December 1, 2025. Based on typical rulemaking timelines and EPA's regulatory agenda, a proposed rule could appear in 2026, with final action potentially in 2027, though these projections remain uncertain and dependent on agency priorities and resource allocation.

The Fourth Circuit litigation over the West Virginia plan approval will proceed on a schedule set by the court, likely with briefing complete in early to mid-2026 and oral argument following several months later. Environmental groups are expected to file similar challenges to other plan approvals in multiple circuits, potentially creating conflicting decisions that could require Supreme Court resolution of whether EPA can approve plans meeting URP benchmarks without requiring states to impose all cost-effective controls identified through four-factor analysis. Wyoming has direct interests in these cases and should consider amicus participation defending EPA's interpretation of state authority and the legitimacy of weighing costs and energy impacts against marginal visibility improvements.

The Biden EPA's disapproval of Wyoming's own regional haze plan remains under reconsideration by the Trump EPA. Based on the agency's approval pattern for other western states and explicit commitment to state deference, Wyoming can reasonably expect reversal of the prior disapproval and approval of the state's plan, likely with only technical modifications. However, timing remains uncertain and depends on EPA's prioritization of the backlog of second-period plan reviews subject to consent decree deadlines from environmental group litigation. It is recommended that Wyoming maintain contact with EPA Region 8 staff to monitor progress and ensure the state's positions are clearly understood as the agency prepares its action.

The primary risk to Wyoming is potential invalidation of the URP policy through adverse court rulings or future administrative policy reversals. If courts determine that the URP framework violates the Clean Air Act's explicit four-factor analysis requirement, EPA could be forced to reopen approved plans and require states to conduct new source-specific evaluations potentially mandating additional controls. It is recommended that Wyoming pursue a defensive strategy documenting thorough consideration of all four statutory factors for significant sources in its administrative record, even while arguing that URP compliance provides independent grounds for approval. This approach preserves benefits of current flexible policies while providing protection against judicial invalidation or future policy changes, ensuring Wyoming's coal industry has maximum regulatory certainty for long-term planning.

4.3.9 New Source Review (NSR) Developments

In September 2025, the Environmental Protection Agency issued three coordinated guidance memoranda that signal an intent to reform the Clean Air Act's New Source Review program, which governs preconstruction permitting for major industrial facilities. These changes ease the regulatory burden for building new facilities, modifying existing coal-fired power plants, and restarting mothballed units—all without triggering the lengthy federal permitting reviews that have historically constrained coal plant operations and life-extension investments. For Wyoming's coal industry, which exports approximately 85 to 90 percent of its production to out-of-state power plants, these regulatory shifts create the most favorable operating environment for coal-fired generation in over a decade and could extend demand for Wyoming coal by making it economically viable to reactivate idled plants and upgrade aging facilities.

The most consequential change is EPA's September 18, 2025 elimination of the "reactivation policy," which had created a near-insurmountable barrier to restarting coal plants idled for two years or more by treating any restart as construction of a new source requiring installation of modern pollution controls costing hundreds of millions of dollars. With that obstacle removed, utilities can now bring mothballed coal units back online as peaking or reserve capacity without federal preconstruction permits, provided the restart does not involve separate major physical modifications. EPA has also reinstated its policy of deferring to industry projections when determining whether efficiency upgrades trigger permitting requirements, removing regulatory disincentives for capital investments that extend coal plant operational lives. The third change allows developers to begin foundational construction work—including for coal-handling facilities and rail infrastructure—before obtaining final air permits, potentially compressing project timelines by 12 to 24 months.

These policies are currently implemented through non-binding guidance that could be reversed by a future administration. However, EPA has announced plans to codify the most significant change through formal rulemaking, with a proposed rule expected in early 2026 and a final rule targeted for September 2026. Legal challenges from environmental organizations are virtually certain but unlikely to halt implementation in the near term.

4.3.9.1 Regulatory history

- **1991**: U.S. Court of Appeals for the Seventh Circuit rules in *Wisconsin Energy Corp. v. Reilly* that life-extending repairs not altering a facility's original design constitute routine maintenance exempt from NSR.
- **2007**: U.S. Supreme Court rules unanimously in *Environmental Defense v. Duke Energy* that NSR applies when modifications increase actual annual emissions, even if maximum hourly pollution rates remain unchanged.

- **2017**: EPA Administrator Scott Pruitt issues "no second-guessing" memorandum establishing that EPA will defer to industry emissions projections unless there is clear procedural error.
- **2020**: First Trump administration issues Project Emissions Accounting rule allowing existing facilities to count emissions decreases alongside increases when determining whether modifications trigger NSR.
- **2022**: Biden EPA rescinds the 2017 "no second-guessing" policy from the first Trump administration, requiring the agency to challenge questionable industry emissions projections upfront.
- **July 2023**: U.S. Court of Appeals for the Third Circuit rules in *Port Hamilton Refining v. EPA* that the Clean Air Act does not authorize EPA to require NSR permits for merely restarting an idled facility, rejecting the legal basis for the reactivation policy.
- **July 2025**: EPA withdraws Biden administration proposal that would have tightened the 2020 Project Emissions Accounting rule and restricted industry's ability to avoid NSR review.
- **September 2, 2025**: EPA issues interpretive letter to Maricopa County Air Quality Department establishing that developers may construct foundations, building shells, and non-emitting infrastructure before obtaining NSR permits.
- **September 15, 2025**: EPA reinstates the "no second-guessing" policy directing the agency to defer to facility operators' projections of post-modification emissions and pursue enforcement only based on five to ten years of actual operational data.
- **September 18, 2025**: EPA Administrator Lee Zeldin issues memorandum rescinding the nationwide "reactivation policy," eliminating the presumption that facilities idled for two or more years require new NSR permits to restart.

4.3.9.2 Recent Developments

EPA's September 2025 guidance package represents a deliberate effort to reduce regulatory barriers imposed by the NSR program. The three memoranda work together to create new flexibility for industrial sources, with particularly significant implications for coal-fired power generation.

The reactivation policy rescission has immediate economic implications for Wyoming coal markets. Under the policy established in the 1970s and formalized through decades of EPA practice, any major stationary source that ceased operations for two or more years was presumed permanently shut down. Restarting such a facility was treated as constructing an entirely new source, automatically triggering NSR requirements including installation of best available control technology in attainment areas or lowest achievable emission rate controls in nonattainment areas—equipment investments typically costing hundreds of millions of dollars that rendered virtually all restart scenarios economically unviable regardless of electricity market conditions. The September 18 memorandum eliminates this regulatory barrier entirely, responding directly to the Third Circuit's July 2023 ruling in *Port Hamilton Refining* that found the policy inconsistent with Clean Air Act statutory language limiting NSR to "construction" of new sources and "modification" of existing ones.

Coal-fired units across the country that were mothballed during periods of low natural gas prices, weak electricity demand, or unfavorable regulatory conditions can now be brought back online without preconstruction review, as long as the restart itself does not involve a separate physical or operational change qualifying as a "major modification" under existing regulations. This creates a pathway for utilities to use dormant coal capacity as dispatchable reserve generation to meet surging electricity demand from data centers, artificial intelligence infrastructure, and transportation electrification—all without navigating multi-year federal permitting processes. For Wyoming, this means coal units that were idled but not yet demolished can re-enter service and resume purchasing Wyoming coal, potentially extending demand that would otherwise have shifted permanently to natural gas or renewable generation. However, Wyoming policymakers must

recognize that permitting requirements are only one factor affecting restart economics. Many units idled for extended periods have experienced equipment deterioration, removal of components for use as spare parts at operating facilities, or termination of coal supply contracts and rail transportation agreements. Capital costs for restoring units to operational condition can range from tens of millions to hundreds of millions of dollars depending on idleness duration and equipment degradation. Industry analysis suggests the policy change will most likely affect units mothballed for two to five years that retain intact equipment, rather than facilities shut down for a decade or more.

The "no second-guessing" policy removes longstanding regulatory disincentives for efficiency investments at operating coal plants. When a utility undertakes projects to improve a coal plant's heat rate—such as upgrading turbines, boilers, or auxiliary equipment—the facility becomes more thermally efficient and economical to operate. This improved efficiency can allow the plant to run more hours per year at lower operating costs, improving its competitive position against natural gas combined-cycle units. However, under traditional NSR analysis, increased operating hours could lead to higher total annual emissions even if the pollution rate per unit of electricity remains unchanged or improves. If annual emissions increase crosses regulatory significance thresholds, the project would trigger NSR review requiring installation of expensive pollution controls. This regulatory risk has historically discouraged utilities from making efficiency-improving capital investments at aging coal plants, accelerating their path toward retirement rather than life extension.

The September 15 memorandum reinstates 2017 guidance altering this risk calculation. EPA now directs permitting authorities to accept a facility operator's projection that it will manage post-modification operations to ensure no significant emissions increase occurs, without challenging the assumptions, calculation methodologies, or operational commitments underlying that projection. The operator essentially provides a projection stating that despite efficiency improvements, it will limit run-hours or make other operational adjustments to stay below significance thresholds, and the permitting authority defers to that projection. The agency will not pursue upfront enforcement based on perceived flaws in the projection. Instead, EPA will wait five to ten years (the specific period depends on whether the facility is subject to more stringent monitoring requirements) for actual post-modification emissions data to accumulate, and only initiate enforcement if real-world operational data ultimately shows a significant increase occurred. This approach shifts the burden of proof from the facility operator (to demonstrate the project is minor) to the regulatory agency (to prove the projection was violated), and moves the enforcement timeframe from pre-construction to years after project completion. The policy creates regulatory space for capital investments that extend coal plant operational lives and improve their market competitiveness, potentially sustaining long-term demand for Wyoming coal from facilities that might otherwise proceed to retirement rather than risk triggering costly permitting obligations.

The "begin actual construction" guidance accelerates project development timelines for new coal-related infrastructure. The Clean Air Act requires facilities to obtain NSR permits before they "begin actual construction," but the statute does not define that critical trigger phrase. For decades, EPA interpreted the prohibition broadly based on a 1986 memorandum (the "Reich Memo") understood to bar construction of any structures intended to accommodate emissions units, even if those structures themselves generate no pollution. The September 2 guidance explicitly rejects this precedent, establishing that the construction prohibition applies only to physical on-site work on an emissions-generating unit itself. Developers may now pour concrete foundations, install structural supports, erect building shells, and construct coal storage facilities, rail connections, and materials handling infrastructure before obtaining final NSR permit approval, provided this preparatory work is not on emissions equipment such as boilers, turbines, or pollution control devices.

This "parallel-tracking" approach allows permitting and construction to proceed simultaneously rather than sequentially, potentially compressing project development schedules by 12 to 24 months for large coal-fueled generation projects and associated infrastructure. However, EPA emphasizes that all pre-permit construction is undertaken entirely at the developer's financial risk. The time and capital invested in foundational work—so-called "equity in the ground"—cannot be used to influence the permitting authority's final decision. If the permit is ultimately denied, conditioned on design changes requiring different foundations, or delayed indefinitely, the developer must bear all demolition, redesign, and delay costs without any regulatory credit or consideration. EPA has stated this policy is intended to "expedite construction

of essential power generation, data centers, and manufacturing projects" to support national objectives including U.S. leadership in artificial intelligence and semiconductor production, but the framework applies equally to coal-fired generation and coal-handling facilities.

These three policies were implemented through interpretive guidance memoranda rather than formal notice-and-comment regulations. Guidance represents an agency's interpretation of its existing statutory and regulatory authority but is not legally binding on the public and can be modified or rescinded by a future administration through simple policy directive without requiring a new rulemaking process. Because Wyoming operates its own NSR permitting program under an EPA-approved State Implementation Plan, the state has discretion in how—and whether—to incorporate these federal interpretive changes into state permitting decisions. Wyoming is not legally required to adopt the guidance, but federal NSR regulations establish a floor which state programs must meet. The guidance establishes what EPA now considers an acceptable interpretation of federal baseline requirements, creating a safe harbor for state decisions that align with the federal approach.

4.3.9.3 What's Next

EPA has committed to proposing a formal regulation codifying the "begin actual construction" interpretation and potentially other NSR-related policy changes by January 2026 according to the OMB Unified Regulatory Agenda, with a final rule targeted for September 2026. Wyoming and other coal-producing states will have the opportunity to submit detailed technical and legal comments supporting the rule's finalization and potentially urging EPA to extend similar regulatory certainty to the reactivation and "no second-guessing" policies through future rulemakings—and to raise additional reforms to the NSR program. Once established through formal regulation rather than guidance, these policies will require a subsequent notice-and-comment rulemaking to reverse, creating substantially greater durability and certainty for long-term capital investment decisions by utilities and coal producers. However, the window between anticipated finalization in late 2026 and the next presidential transition in January 2029 is relatively narrow, and the possibility of yet another regulatory reversal remains a material consideration for decade-long coal supply contracts and plant life-extension investments.

Legal challenges to the September 2025 guidance and any resulting regulations are virtually certain and likely to be filed by environmental organizations within 60 days of the proposed rule's publication in early 2026 or within 60 days of the final rule's effective date in late 2026. Environmental groups have already initiated litigation in the D.C. Circuit Court of Appeals challenging EPA's July 2025 withdrawal of the related Biden-era Project Emissions Accounting proposal, establishing a clear pattern of immediate legal challenges to NSR policy changes. Litigation will likely argue that the new interpretations constitute arbitrary and capricious reversals of decades of agency practice undertaken without sufficient justification, violate the protective intent and plain language of the Clean Air Act, and will allow significant increases in harmful air pollution without required review and installation of modern controls. Court resolution typically requires at least 18 months from the date of filing, meaning final judicial clarity on the "begin actual construction" regulation may not arrive until mid-to-late 2028 or later. However, unless a court issues a preliminary injunction, the policies will remain in effect and shape permitting decisions throughout the litigation period.

Wyoming policymakers plan to engage in this rulemaking, emphasizing how regulatory certainty for coal infrastructure development supports grid reliability, energy security, and economic development objectives that serve the national interest. It is recommended that the state coordinate advocacy efforts with other major coal-producing states including Montana, North Dakota, and West Virginia to develop multi-state comment submissions and intervention and amicus brief strategies for anticipated litigation. Wyoming could also engage directly with major coal-purchasing utilities to ensure their management teams, regulatory affairs departments, and integrated resource planning processes fully understand the new permitting flexibilities and assess whether these changes affect long-term generation planning decisions and coal procurement strategies. Because Wyoming exports most of its coal production to other states, the ultimate market impact depends entirely on whether out-of-state utilities take actual operational decisions to reactivate idled units, invest in

efficiency upgrades at existing plants, or construct new coal-fired capacity. These are decisions Wyoming does not directly control but can significantly influence through strategic engagement during this critical 18-month window before policies are finalized and potential legal challenges are resolved.

4.3.10 Particulate Matter (PM2.5) NAAQS

The Biden administration's February 2024 decision to lower the annual fine particulate matter standard from 12.0 to 9.0 micrograms per cubic meter threatens Wyoming's coal industry by accelerating coal-fired power plant retirements nationwide. This tightening of allowable ambient PM2.5 concentrations will reduce demand for Wyoming coal by making it costlier for power plants to operate and nearly impossible to permit new coal capacity or major plant modifications. The rule became legally effective on May 6, 2024, immediately constraining industrial permitting, though full implementation through mandatory state compliance plans extends through a 2032 attainment deadline.

The Trump administration is pursuing a reconsideration to reverse the Biden standard and restore the prior 12.0 µg/m³ level, with EPA targeting a final reconsidered rule by February 2026. Twenty-six states are challenging the Biden rule in federal court, with litigation currently paused pending EPA's reconsideration outcome. The stricter standard's survival depends on whether EPA can successfully defend a rollback against environmental group litigation and whether courts accept industry arguments that the Biden rule exceeded EPA's statutory authority.

The tighter ambient air quality ceiling would compel states to impose new emission limits on existing coal plants and make life-extension projects economically prohibitive for aging facilities, reducing Wyoming coal markets even before any direct mandates on specific facilities.

4.3.10.1 Regulatory History

- **2012**: EPA last strengthened annual PM2.5 standard, lowering it from 15.0 to 12.0 µg/m³ based on epidemiological evidence linking chronic fine particulate exposure to premature mortality.
- **2020**: Trump EPA completed statutory five-year NAAQS review and retained 12.0 µg/m³ annual PM2.5 standard despite Clean Air Scientific Advisory Committee recommendations for tightening.
- **January 20, 2021**: President Biden issued Executive Order 13990 directing EPA to reconsider Trump administration's 2020 decision to retain 12.0 µg/m³ annual PM2.5 standard.
- **February 7, 2024**: EPA finalized rule lowering primary annual PM2.5 standard from 12.0 to 9.0 µg/m³; retained 24-hour standard at 35 µg/m³ and PM10 standards unchanged.
- **March 6, 2024**: Coalition of 26 states led by Kentucky and Texas filed consolidated petitions for review in U.S. Court of Appeals for D.C. Circuit (Case No. 24-01050); 16 states led by California and New York intervened to defend EPA rule.
- **May 6, 2024**: Revised PM2.5 NAAQS became legally effective, immediately applying new 9.0 µg/m³ benchmark to New Source Review permitting for major industrial facilities and modifications.
- **August 2025**: D.C. Circuit grants abeyance in consolidated litigation challenging Biden rule; EPA notifies court it targets February 2026 for final reconsidered rule restoring 12.0 µg/m³ standard.
- **September 2025**: EPA's fall Unified Agenda lists PM2.5 NAAQS reconsideration as imminent regulatory action; agency missed earlier self-imposed July 2025 proposal deadline.

4.3.10.2 Recent Developments

The EPA's February 2024 final rule lowering the annual PM2.5 standard to 9.0 µg/m³ represents the most aggressive tightening of federal air quality standards affecting coal combustion in over a decade. The 25-percent reduction in

allowable ambient concentrations became legally effective May 6, 2024, immediately constraining Prevention of Significant Deterioration permitting for new major industrial facilities and significant modifications to existing sources.

For Wyoming coal customers—predominantly coal-fired power plants across the Mountain West, Midwest, and South-Central states—the tighter standard shrinks available "atmospheric headroom" for new emissions. Any major facility modification must now demonstrate through air quality modeling that emissions will not push ambient PM2.5 above 9.0 µg/m³, even in areas currently meeting air quality standards. This reduced ceiling makes it substantially harder and costlier to permit coal plant life-extension projects, steering capital investment away from coal-dependent regions toward areas with cleaner existing air quality. Coal plants contemplating major retrofits face the prospect that expensive pollution controls may become stranded costs if the standard is reversed, while failure to begin compliance planning risks inability to meet a 2032 deadline if the standard survives—regulatory uncertainty that deters coal facility investment independent of the rule's ultimate legal status.

If EPA does not withdraw the 2024 PM2.5 NAAQS, the next implementation milestone would be EPA's designation of "nonattainment" areas, which would be required in February 2026. Based on 2020-2022 monitoring data, analysts project at least ten times as many monitoring locations will show violations of the 9.0 µg/m³ standard compared to the prior 12.0 µg/m³ threshold, dramatically expanding nonattainment geography. Under the 2024 rule, states with newly designated nonattainment areas must submit State Implementation Plans by mid-to-late 2027 detailing concrete emission reduction measures to achieve compliance by 2032. In nonattainment zones, new or modified major sources face the Clean Air Act's most stringent permitting requirements: installation of controls representing the Lowest Achievable Emission Rate without consideration of cost, and procurement of emission reduction "offsets" from existing sources. These requirements historically trigger coal plant retirement rather than compliance.

The rule does not directly mandate emission controls on specific facilities but establishes an ambient air quality ceiling that states must meet through implementation plans. For Wyoming's coal industry, this regulatory architecture creates a multi-year compliance pathway requiring costly retrofits for plants lacking state-of-the-art pollution controls or, more likely, tipping economics toward retirement for aging marginal units. Historical precedent supports this dynamic: population-weighted exposure to coal-related PM2.5 declined approximately 97 percent between 1999 and 2020, with much post-2010 reduction attributable to plant retirements driven by prior rounds of air quality regulations rather than installation of additional controls.

4.3.10.3 What's Next

The immediate regulatory trajectory depends on EPA's reconsideration process and parallel federal litigation. The Trump administration had initially signaled intent to propose a rule reversing the 9.0 µg/m³ standard and restoring the 12.0 µg/m³ level. However, in November 2025, EPA filed a motion with the D.C. Circuit to vacate the 2024 Biden EPA's PM2.5 NAAQS confessing error when issuing the rule. The case was already fully briefed before the D.C. Circuit, and oral argument was held in December 2024. The D.C. Circuit has not yet ruled on EPA's motion to vacate. Until a final reconsidered rule is issued, the 9.0 µg/m³ standard remains effective and enforceable for permitting purposes.

The litigation timeline is synchronized with the administrative reconsideration. The D.C. Circuit granted abeyance in consolidated legal challenges pending EPA's reconsideration completion. If EPA issues a final rule in February 2026 maintaining the 9.0 µg/m³ standard with a strengthened administrative record, current petitions will likely be mooted and industry petitioners forced to file new challenges, restarting the litigation clock. Conversely, if EPA finalizes a rule restoring the 12.0 µg/m³ level, environmental groups and states defending the stricter standard will almost certainly challenge the rollback as arbitrary and capricious given the scientific record. The abeyance strategy effectively ensures no final judicial resolution occurs until after reconsideration concludes, pushing any definitive court ruling into 2026 or beyond.

EPA's designation process continues in parallel, with final nonattainment determinations still expected by February 2026 regardless of reconsideration outcome unless EPA affirmatively delays that statutory deadline. States submitted initial

designation recommendations in February 2025. If EPA reverses the standard before finalizing designations, the agency will designate based on the new (or restored) standard level; if designations are finalized before reconsideration concludes, they will be based on the current 9.0 µg/m³ threshold.

Congressional efforts to legislatively nullify the Biden rule offer an alternative pathway but face uncertain prospects. House Republicans introduced H.R. 2288 to void the 9.0 µg/m³ standard and drafted broader legislation (the CLEAR Act) that would extend the NAAQS review cycle from five to ten years, codify consideration of attainability and economic feasibility in standard-setting, and ease permitting burdens related to exceptional events such as wildfire smoke. These bills are very unlikely to pass the Senate, given the need for Senate Democrats to support the measure and break a filibuster.

For Wyoming stakeholders, the practical planning horizon extends through 2027 regardless of whether the 9.0 µg/m³ standard survives. Even if EPA reverses course and restores the 12.0 µg/m³ level, the legal and procedural uncertainty of the past two years has already introduced friction into coal plant capital planning and permitting decisions. The regulatory uncertainty itself functions as a deterrent to investment in coal-fired capacity. State implementation plan development in 2026-2027—where abstract air quality targets translate into facility-specific emission limits—will determine which coal plants face prohibitively expensive retrofit requirements and which can demonstrate compliance through operational changes, shaping Wyoming coal demand for the subsequent decade.

4.3.11 Greenhouse Gas Reporting Rule

The Environmental Protection Agency proposed on September 16, 2025, to eliminate mandatory greenhouse gas emissions reporting for nearly all industrial sectors, including underground coal mines (currently Wyoming has no active underground mines), while suspending reporting for most oil and gas operations until 2034. This proposal would repeal most of the fifteen-year-old Greenhouse Gas Reporting Program (GHGRP), which currently collects data from approximately 8,200 facilities representing 85-90% of U.S. anthropogenic greenhouse gas emissions. EPA asserts that it lacks authority under Clean Air Act section 114 to continue collecting this information and argues the program imposes roughly $303 million in annual nationwide compliance costs without serving an underlying regulatory purpose. While power plants are still required to submit CO2 emissions data through requirements under the Acid Rain program, eliminating the GHGRP removes another layer of reporting for power plants.

For Wyoming's coal industry, the proposal offers modest direct compliance relief for mining operations that currently report methane emissions under Subpart FF. From a bigger picture perspective, GHGRP's unified, facility-level transparency created measurable pressure on utilities to reduce emissions, with coal-fired plants subject to public disclosure cutting carbon dioxide emissions by 7% on average and publicly traded utilities reducing emissions by 10-11% in response to investor and public scrutiny. Eliminating this transparency could reduce market pressure on Wyoming's primary coal customers.

The proposal faces substantial legal challenges from environmental groups arguing it violates congressional intent and contradicts EPA's own fifteen-year practice, creating significant uncertainty about whether and when the rule will take effect. Industry groups including the American Petroleum Institute have warned that eliminating federal emissions verification could undermine U.S. energy competitiveness in global markets and complicate tax credit claims for carbon capture projects that could represent a future pathway for coal-based generation.

4.3.11.1 Regulatory History

- **December 2007** – FY2008 Consolidated Appropriations Act directed EPA to develop mandatory GHG reporting covering "all sectors of the economy"
- **October 30, 2009** – EPA established mandatory GHG reporting for facilities emitting 25,000+ metric tons CO_2-equivalent annually under CAA section 114 authority, stating it "could have issued this rule absent congressional direction" (74 FR 56260)

- **July 12, 2010** – EPA finalized reporting requirements for underground coal mines (Subpart FF), magnesium production, industrial waste landfills, and wastewater treatment (75 FR 39736)
- **August 5, 2022** – Inflation Reduction Act enacted CAA section 136 requiring methane waste emissions charge for oil/gas facilities based on GHGRP-reported data
- **April 25, 2024** – EPA added five new source categories including ceramics manufacturing, coke calcining, and enhanced oil recovery facilities (89 FR 31802)
- **May 14, 2024** – EPA finalized Subpart W revisions for petroleum and natural gas systems to improve methane reporting accuracy pursuant to CAA section 136 (89 FR 42062)
- **July 4, 2025** – Congress amended CAA section 136(g) delaying methane waste emissions charge from 2024 to 2034, removing statutory requirement for near-term oil/gas reporting
- **August 28, 2025** – EPA proposed approval of Wyoming's coal combustion residuals permit program, reflecting cooperative federalism approach
- **September 16, 2025** – EPA proposed rule eliminating GHG reporting for all sectors except oil/gas, suspending oil/gas reporting until reporting year 2034, citing lack of CAA section 114 authority (90 FR 44594)

4.3.11.2 Recent Developments

EPA's proposal on September 16, 2025 contends the agency exceeded its legal authority under Clean Air Act section 114, which permits information collection only when necessary for developing specific regulations, determining compliance violations, or carrying out specific CAA provisions. The agency argues that for most reporting sectors, including coal mines and coal-fired power plants, it has not developed greenhouse gas emissions standards and therefore lacks ongoing authority to mandate continuous reporting. EPA characterizes its new interpretation as the "best reading" of section 114, though this directly contradicts the agency's 2009 legal position that it possessed independent authority to collect this information regardless of the congressional appropriations directive.

The proposal would remove reporting requirements for underground coal mines under Subpart FF, which currently mandates that mines liberating 36.5 million cubic feet or more of methane annually must monitor and report emissions from ventilation and degasification systems. Since Subpart FF applies only to underground operations and Wyoming's coal production comes from surface mines in the Powder River Basin and Green River Basin, this direct regulatory relief does not affect current coal mining operations in Wyoming. If the rule finalizes as proposed, no further federal greenhouse gas reporting would be required.

The substantially larger coal industry interest lies in the proposal's elimination of Subpart D requirements for coal-fired power plants—Wyoming coal's primary customers—to publicly report carbon dioxide, methane, and nitrous oxide emissions using highly accurate Continuous Emissions Monitoring Systems data. This facility-level transparency has enabled what policy analysts term a "transparency-to-pressure pipeline": environmental advocacy groups use publicly disclosed emissions data to target high-emitting coal plants for retirement campaigns through tools like the Sierra Club's "Beyond Coal" initiative; ESG-focused investors employ the standardized data to divest from utilities with large coal fleets or demand climate transition plans; and state utility commission intervenors cite specific facility emissions in regulatory proceedings challenging continued coal plant operation. A 2021 National Bureau of Economic Research study found that this transparency, by itself, incentivized power plants to reduce carbon dioxide emission rates by 7% on average, with plants owned by publicly traded firms showing 10-11% reductions driven by investor sensitivity.

By eliminating power plant emissions reporting, the proposal would remove the standardized, publicly accessible data that currently makes coal-fired generation's emissions profile starkly visible to investors, regulators, and advocates. This represents a potential indirect market benefit to Wyoming coal producers by reducing reputational and financial pressure

on their utility customers, though this benefit operates through reduced investor and public scrutiny rather than direct compliance cost savings.

The proposal also eliminates reporting under Subparts PP, RR, UU, and VV covering carbon dioxide supply, geologic sequestration, and enhanced oil recovery—the data infrastructure supporting carbon capture and storage (CCS) project verification. Industry representatives testified this could delay Class VI injection well permits and jeopardize section 45Q tax credit claims for carbon sequestration. While CCS deployment at coal plants remains technologically and economically challenging, Wyoming has strategic interest in preserving pathways that could extend coal-fired generation viability through emissions reduction technologies, particularly given the state's geological formations suitable for carbon sequestration.

EPA acknowledges that approximately twenty states currently operate greenhouse gas reporting or inventory programs, some incorporating federal GHGRP requirements by reference or accepting GHGRP compliance as satisfying state obligations. The National Association of Clean Air Agencies warned that federal withdrawal could trigger inconsistent state-level requirements as individual states develop independent programs to fill the data gap. For Wyoming coal sold to power plants across multiple state markets, this fragmentation could paradoxically create greater regulatory complexity than the current uniform federal program, with varying state reporting requirements, verification methodologies, and disclosure frameworks rather than a single federal standard.

4.3.11.3 What's Next

The proposal's September 21, 2025 comment deadline has closed, with EPA targeting final action by early 2026, according to agency officials, though the Spring 2025 regulatory agenda initially listed September 2025. The agency received substantial comments from environmental organizations challenging the legal rationale, industry groups seeking to preserve reporting for competitive and tax credit purposes, and state regulators warning about potential regulatory fragmentation. If finalized as proposed, reporting obligations would cease sixty days after Federal Register publication for all eliminated sectors, with EPA planning to remove electronic reporting system capabilities.

Legal challenges appear certain given environmental groups' statements that the repeal "violates a clear congressional requirement" from the FY2008 Appropriations Act and operates contrary to fifteen years of agency practice. Litigation would likely be filed in the U.S. Court of Appeals for the District of Columbia Circuit and could delay implementation by months or years, or result in court-ordered reinstatement if judges find EPA's legal reasoning arbitrary and capricious under the Administrative Procedure Act. EPA's claim that it now interprets Clean Air Act section 114 differently than in 2009—when the agency explicitly stated it possessed independent authority to collect greenhouse gas data—creates vulnerability under the standard requiring agencies to provide reasoned explanations for reversing prior interpretations.

For Wyoming coal operations, the practical timeline suggests potential elimination of Subpart FF methane reporting obligations in early 2026 if the rule finalizes without successful litigation blocking implementation. However, state policymakers should plan for multiple scenarios given substantial legal uncertainty, monitor whether elimination creates pressure for inconsistent state-level greenhouse gas reporting programs that could affect coal sold across multiple markets, assess whether loss of verified federal emissions data impacts Wyoming coal's competitiveness in domestic and international markets increasingly focused on emissions transparency, and track implications for carbon capture technology deployment that could represent a long-term pathway for coal-based generation in a carbon-constrained energy system.

4.3.12 Department of the Interior 2024 Public Lands Rule

The Bureau of Land Management's 2024 Public Lands Rule—formally titled the "Conservation and Landscape Health Rule"—poses a direct and substantial threat to Wyoming's coal industry by elevating "conservation" to equal legal status with mining and creating new mechanisms to restrict access to federal coal reserves. The rule, effective June 10, 2024, applies to all 245 million acres of BLM surface land and over 700 million acres of mineral estate, including Wyoming's coal-

bearing federal lands that generate critical royalty revenues funding the state's public schools and government services. For Wyoming, the rule threatens to lock up productive coal lands through conservation leases, impose perpetual regulatory instability through expanded land health reviews, and enable streamlined designations that place federal acreage off-limits to development—directly harming both federal coal production and adjacent state trust lands in Wyoming's checkerboard ownership pattern.

For Wyoming coal operations, the 2024 rule creates three compounding threat mechanisms. First, restoration and mitigation leases allow environmental organizations to preemptively lease coal-bearing lands for conservation, blocking mineral development. Second, expanded land health standards mandate comprehensive assessments of all BLM lands every ten years; when evaluations determine an area fails to meet ecological benchmarks and an authorized use like coal mining is identified as a causal factor, BLM must implement "appropriate management actions"—potentially imposing new mitigation requirements or operational restrictions on existing mines decades after initial permitting, with no grandfathering protection. Third, prioritized designation of Areas of Critical Environmental Concern to protect "landscape intactness and habitat connectivity" provides a streamlined administrative pathway to place coal-bearing federal lands off-limits without following formal congressional mineral or land withdrawal procedures.

Wyoming's response has created opportunities to eliminate these threats. The state joined Utah in federal litigation challenging the rule's legality, while a coalition of industry groups led by the National Mining Association filed a parallel lawsuit. Most significantly, the Department of the Interior proposed complete rescission of the rule on September 11, 2025, acknowledging it "violates existing statutory requirements" and unlawfully restricts productive uses. The public comment period closed November 10, 2025, advancing the process toward a final rescission decision expected in early-to-mid 2026. If successful through either administrative rescission or litigation, Wyoming's coal sector returns to the traditional regulatory framework; if both efforts fail, the state faces a fundamental shift where conservation interests can veto mineral development.

4.3.12.1 Regulatory History

- **December 12, 2016** – BLM finalized the "Planning 2.0" rule, imposed new restrictions on BLM land use and elevating conservation as a "use" under the Federal Land Management and Policy Act of 1976.
- **March 27, 2017** - Congress used the Congressional Review Act to disapprove and nullify BLM's "Planning 2.0" rule, which had expanded public participation and landscape-level planning in BLM land use decisions. This action created a legal barrier to reissuing a substantially similar rule.
- **May 9, 2024** - BLM published final Public Lands Rule in Federal Register (89 FR 40308), establishing conservation as co-equal "use," creating restoration and mitigation leasing programs, expanding land health standards, and prioritizing Area of Critical Environmental Concern designations.
- **June 10, 2024** - BLM Conservation and Landscape Health Rule became effective, applying to all BLM-managed lands and subsurface mineral estate.
- **June 18, 2024** - Wyoming and Utah filed joint lawsuit in U.S. District Court for District of Utah challenging rule for NEPA violations and exceeding statutory authority under FLPMA.
- **July 18, 2024** - National Mining Association and industry coalition filed lawsuit in U.S. District Court for District of Wyoming challenging Public Lands Rule under FLPMA, Congressional Review Act, and NEPA.
- **September 11, 2025** - Department of Interior published proposed rule to completely rescind the Conservation and Landscape Health Rule, citing legal deficiencies and improper restriction of productive uses (90 FR 43990).
- **November 10, 2025** – Public comment period closed on BLM's proposed rescission of Conservation and Landscape Health Rule (Docket BLM-2025-0001).

4.3.12.2 Recent Developments

The Department of Interior's September 11, 2025 rescission proposal represents a fundamental policy reversal, determining that the 2024 rule is "unnecessary," "undermines the BLM's management of public lands," and places "an outsized priority on conservation or non-use at the expense of multiple-use access." The proposal identifies the conservation leasing program—which authorizes third parties to lease federal land for restoration or mitigation purposes under 43 CFR 6102.4—as functioning as unlawful de facto land withdrawals that bypass the congressional procedures required by FLPMA Section 204. Because other activities on leased parcels must be "compatible" with conservation lease terms, these instruments effectively give environmental groups veto power over subsequent coal lease applications on the same federal acreage, creating a race-to-lease scenario that can permanently block access to Wyoming's coal reserves.

The rescission proposal also invokes the major questions doctrine articulated in *West Virginia v. EPA*, arguing the rule addresses an issue of "vast economic and political significance" without "clear statutory authority" from Congress. This legal framework shifts the burden onto the rule's defenders to demonstrate explicit congressional authorization for conservation leasing and other new programs—a substantially higher standard than routine statutory interpretation and one that significantly improves prospects for successful rescission. The proposal also notes that public comments during the 2024 rulemaking raised "important questions about whether the economic impacts were materially underestimated," providing additional procedural grounds to reconsider the rule's justification.

Wyoming's distinctive checkerboard land ownership pattern—where federal parcels and state trust lands alternate across major coal regions—amplifies these federal restrictions. When federal sections within the checkerboard are locked up through conservation leases or ACEC designations, they do not merely reduce total available reserves; they destroy economic viability of adjacent state trust lands because coal operations cannot economically develop alternating accessible and restricted sections. This multiplier effect directly impairs Wyoming's constitutional obligation to manage state trust lands for beneficiaries, primarily the public school system, converting federal overreach into an attack on state sovereignty and fiscal capacity.

4.3.12.3 What's Next

With the comment period closed as of November 10, 2025, BLM will review submitted comments and prepare a final decision on rescission. While no statutory deadline governs this timeline, the agency's strong justification in the proposal signals its intent to move forward expeditiously. Wyoming policymakers should anticipate a final rescission rule in the first or second quarter of 2026, barring major administrative delays. Upon finalization, conservation groups will almost certainly file suit to block the rescission, triggering litigation likely extending 12 to 18 months with the risk of preliminary injunctive relief keeping the 2024 rule in effect during court proceedings.

The two pending lawsuits provide parallel and potentially faster pathways to eliminating the rule. Both cases are in U.S. District Courts within the Tenth Circuit Court of Appeals. The industry coalition's Congressional Review Act argument presents a potentially dispositive claim: if the court determines the 2024 rule is "substantially the same" as the Planning 2.0 rule Congress disapproved in 2017, the CRA requires automatic invalidation without reaching other substantive issues. Wyoming should expect initial district court rulings on summary judgment motions in mid-to-late 2026, with appeals following if either party loses. A favorable judicial ruling would immediately vacate the rule and establish binding Tenth Circuit precedent constraining future BLM conservation rulemaking.

Wyoming's optimal strategy requires coordinated engagement across three simultaneous tracks: maintaining close coordination with the state Attorney General to support pending litigation through amicus briefs providing Wyoming-specific economic harm data and state sovereignty arguments; monitoring the administrative rescission process and preparing comprehensive legal defenses for the final rescission rule against anticipated conservation group challenges; and proactively engaging BLM Wyoming State Office and field office directors to shape local Resource Management Plan revisions and implementation decisions that protect state interests regardless of which regulatory framework ultimately prevails at the national level. The convergence of administrative rescission and litigation creates a window to eliminate

the threat created by the 2024 Rule, but success demands sustained strategic pressure across all available forums during this critical 12-to-18-month period.

4.3.13 Federal Energy Incentives

4.3.13.1 Executive Summary

The One Big Beautiful Bill Act (OBBBA), signed into law on July 4, 2025, has fundamentally reshaped the federal tax landscape for energy production in ways that directly affect Wyoming's coal industry. The legislation sharply curtails the wind and solar tax credits that have been artificially undercutting coal-fired generation while simultaneously strengthening incentives for carbon capture technology that could preserve Wyoming's existing coal fleet. This represents the most significant reversal of federal clean energy policy in over a decade and creates both immediate relief and new strategic opportunities for Wyoming coal producers.

The OBBBA accelerates the termination of production and investment tax credits for new wind and solar facilities, requiring these projects to be placed in service by December 31, 2027—a dramatic compression of what was designed as a decade-long (or decades-long) subsidy runway under the 2022 Inflation Reduction Act. At the same time, the law increases the Section 45Q tax credit for carbon capture, utilization, and storage to $85 per metric ton for both permanent storage and enhanced oil recovery, establishing parity that significantly improves the economics of retrofitting coal plants. Independent analysts project this will reduce federally subsidized alternative capacity additions by more than half through 2035, moderating the competitive pressure that has threatened Wyoming coal markets.

For Wyoming, this creates a window to pursue carbon capture retrofits on existing coal plants while the reduced pace of renewable deployment provides breathing room. However, the legislation also eliminated billions in grant funding for economic diversification in coal communities, narrowing transition options. The immediate priority is capturing the enhanced carbon capture credits before the January 1, 2033 construction deadline and maximizing Wyoming's share of the $11 billion Abandoned Mine Land reclamation funding that survived the federal cuts.

4.3.13.2 Regulatory History

- **November 2021** – Bipartisan Infrastructure Law (BIL) enacted, appropriating $11 billion over 15 years for Abandoned Mine Land reclamation and creating Energy Community bonus credits for projects sited in coal-impacted areas.
- **August 2022** – Inflation Reduction Act (IRA) enacted, establishing long-term, technology-neutral production tax credits (Section 45Y) and investment tax credits (Section 48E) for clean electricity designed to last through at least 2032 and accelerate displacement of fossil fuel generation.
- **January 2025** – Executive order freezes disbursement of all Inflation Reduction Act grant funds, triggering project delays and litigation from affected recipients.
- **July 4, 2025** – One Big Beautiful Bill Act (OBBBA) enacted, curtailing Inflation Reduction Act clean energy tax credits for wind and solar while enhancing Section 45Q carbon capture incentives and imposing Foreign Entity of Concern restrictions on remaining credits.
- **July 7, 2025** – Executive order directs Treasury Department to strictly enforce termination of wind and solar tax credits and review "begin construction" safe harbor rules, adding uncertainty for developers attempting to qualify under compressed timelines.

4.3.13.3 Recent Developments

The OBBBA fundamentally disrupts the economic landscape that has threatened Wyoming coal by sharply curtailing federal subsidies for wind and solar development. Under the IRA framework, wind and solar projects were eligible for Section 45Y production tax credits and Section 48E investment tax credits for facilities beginning construction through

2033. The OBBBA compresses this timeline dramatically: wind and solar facilities must now be placed in service by December 31, 2027, to qualify for these credits. A narrow exception allows projects that begin construction on or before July 4, 2026, to access the original multi-year safe harbor provisions, creating a one-year rush for developers to break ground. However, a July 7, 2025 executive order directed the Treasury Department to review and potentially restrict these construction rules, adding regulatory uncertainty even for projects racing to meet the deadline.

In addition, the Section 45Q tax credit for carbon capture, utilization, and storage was enhanced by OBBBA. The OBBBA increases the credit value for carbon utilization and enhanced oil recovery from approximately $60 per metric ton to $85 per metric ton, matching the credit for dedicated geologic storage. This parity makes it equally profitable to capture CO_2 for use in Wyoming's oil fields as it is to permanently sequester it underground, creating a potential revenue stream for coal plants that can capture and monetize their emissions. The "begin construction" deadline for 45Q remains January 1, 2033, providing a full decade for project development. While carbon capture retrofits face real challenges—high capital costs, operational energy penalties, and the need for pipeline infrastructure, the improved federal incentive substantially strengthens the business case for preserving Wyoming coal plants through CCUS deployment.

The legislation also introduced Foreign Entity of Concern restrictions that prohibit entities with ownership or control ties to China, Russia, Iran, and North Korea from benefiting from remaining tax credits, including the enhanced 45Q carbon capture credit. These restrictions require additional supply chain due diligence and compliance work, particularly for projects using Chinese-manufactured capture equipment or seeking international financing.

Independent modeling by the Rhodium Group projects the OBBBA will reduce new wind and solar power capacity additions by 53–59% between 2025 and 2035 compared to the IRA baseline. This directly translates to less subsidized displacement of coal generation.

The OBBBA also rescinded billions in unobligated grant funding from IRA-era programs, including the EPA's Greenhouse Gas Reduction Fund and the DOE's Energy Infrastructure Reinvestment loan program that was designed to help repurpose retired power plant sites. However, the Bipartisan Infrastructure Law's $11 billion, 15-year allocation for Abandoned Mine Land reclamation remains fully intact. The Department of the Interior announced nearly $725 million in fiscal year 2025 AML funding, with substantial allocations for Wyoming. This represents the most durable source of federal funding for job creation and environmental remediation in Wyoming coal communities. The Economic Development Administration's Assistance to Coal Communities initiative also survived, funded through ongoing annual appropriations rather than one-time IRA allocations.

The 10% Energy Community bonus credit for projects sited in coal-impacted areas remains law, though its utility for wind and solar is now limited to the compressed 2027 timeline. The bonus remains fully available through the early 2030s for battery storage, geothermal, advanced nuclear, and other technologies, creating opportunities for alternative investments in Wyoming coal communities beyond the wind and solar window.

4.3.13.4 What's Next

The immediate deadline affecting Wyoming is July 4, 2026, when the window closes for wind and solar projects to begin construction and access the remaining safe harbor provisions under the original IRA framework. Treasury Department guidance clarifying what qualifies as "beginning construction" and implementing any new restrictions mandated by the July 7, 2025 executive order is expected in late 2025 or early first quarter 2026. This guidance will determine whether developers can successfully claim credits or whether the federal subsidy advantage for renewables effectively ends even sooner than the statutory deadline suggests.

For carbon capture projects, the longer timeline through January 1, 2033 provides planning runway, but Wyoming policymakers and coal plant operators should recognize that CCUS projects typically require over a decade from initial feasibility studies to full operation. To preserve optionality for meeting the 2033 construction deadline, project sponsors will need to initiate geologic storage assessments, preliminary engineering work, and CO_2 pipeline corridor planning within

the next 12–24 months. The state should consider prioritizing mapping Wyoming's geologic storage capacity, identifying coal plants best suited for retrofits, and streamlining permitting for CO_2 pipeline infrastructure to position Wyoming as a leader in capturing these enhanced federal incentives before the window closes.

The Department of the Interior will continue annual allocations of AML reclamation funding through the BIL's 15-year appropriation period. Fiscal year 2026 funding announcements are expected in mid-2026, and Wyoming should consider aggressively pursue its full allocation to maximize job creation and land restoration in coal communities. The EDA's Assistance to Coal Communities initiative will also continue accepting applications on an ongoing basis through its Economic Adjustment Assistance program.

Energy market dynamics through 2026–2027 will clarify whether the OBBBA produces a sustained increase in coal generation or merely slows the rate of decline. With alternative deployment curtailed, growing electricity demand from data centers, manufacturing reshoring, and electrification may create capacity constraints that increase utilization of existing coal plants. However, this depends on whether natural gas generation and battery storage expand to fill the supply gap. Wyoming should monitor regional capacity markets and generation dispatch patterns to assess whether the reduced renewable pipeline translates into measurable improvements in coal plant economics and capacity factors.

The broader policy environment remains volatile. The rapid reversal from IRA to OBBBA demonstrates that federal energy incentives can shift dramatically with changes in congressional control. Wyoming's strategy should balance capturing immediate opportunities under current law—particularly the enhanced 45Q credits and AML funding—with maintaining flexibility for future policy shifts. The carbon capture pathway offers the one of the most durable federal support for preserving Wyoming coal assets, but success depends on moving quickly enough to initiate projects before the 2033 deadline while navigating the technical, infrastructure, and financing challenges inherent in large-scale CCUS deployment.

5 Evaluation of Overseas Markets & U.S. Infrastructure for Wyoming Coal Exports

5.1 Executive Summary

This report evaluates the viability of exporting thermal coal from Wyoming's Powder River Basin (PRB) and Green River Basin (GRB) to international markets, focusing on realistic end-use markets, infrastructure constraints, and the economic competitiveness of Wyoming coal relative to incumbent global suppliers. Historically, Wyoming coal exports have accounted for only a very small share of global and U.S. coal trade, reflecting geographic disadvantages and limited access to cost-effective export infrastructure. As domestic coal demand continues to decline, export opportunities are increasingly considered a potential outlet for Wyoming coal production.

From a market perspective, Asia is the only logical long-term destination for Wyoming coal exports. Global coal demand and trade have shifted decisively toward Asia over the past two decades, while coal consumption in Europe and the Americas continues to decline. Wyoming's inland location places it significantly closer to Pacific Coast ports than to Atlantic or Gulf Coast export terminals, making Asian markets structurally more accessible than Europe, Africa, or South America. Even so, Wyoming coal remains at a disadvantage relative to other western coal producers that enjoy shorter rail distances to West Coast terminals.

In Asia, Wyoming coal competes most directly with Indonesian sub-bituminous coal, which shares similar quality characteristics[59] but benefits from substantially lower delivered costs due to Indonesia's proximity to end-use markets and its low-cost mining base. Indonesian coal dominates the seaborne thermal coal trade in Asia and sets the marginal price in many importing countries. Wyoming coal faces a structural cost disadvantage driven by higher inland transportation costs, rather than mine economics or superior coal quality. EVA's analysis shows that Wyoming coal is only intermittently competitive in select Asian markets, primarily during periods of higher global coal prices.

Among Asian markets, Japan and South Korea are the most economically viable destinations for Wyoming coal, reflecting shorter ocean freight distances from North American West Coast ports and stable demand for sub-bituminous coal in the power sector. By contrast, Southeast Asia and China remain highly competitive markets dominated by Indonesian supply and increasingly exposed to liquefied natural gas competition. Even in the most favorable markets, Wyoming coal generally struggles to undercut average seaborne market prices, mainly due to rail costs, and remains vulnerable to downturns in global coal prices.

Export infrastructure availability is the binding constraint on Wyoming coal export potential. West Coast terminals offer the lowest delivered costs, while exports through Gulf Coast, East Coast, and Great Lakes terminals are uneconomic in nearly all price scenarios. However, available West Coast capacity is extremely limited. The Westshore Coal Terminal in Vancouver remains the primary export outlet for western coal, but it is increasingly constrained by competing supply from Montana and Canadian producers that enjoy meaningful inland freight cost advantages over Wyoming coal. Additional West Coast terminals face material limitations:

- The Richmond Levin Coal Terminal is scheduled to close at the end of 2026.
- The Port of Long Beach has little to no available excess capacity and is dominated by petroleum coke and Utah coal exports.
- The Neptune Coal Terminal is effectively captive to Teck Resources' metallurgical coal supply.

[59] The heat content of Indonesian coal has been declining because the higher-quality coal reserves were developed first. The growth in Indonesian coal supply has come from lower-quality subbituminous coal and lignite, which is not acceptable in traditional Asian markets in Japan, South Korea, and Taiwan. In contrast, Wyoming PRB coal heat content will continue to slowly increase as mining operations progress away from the outcrop.

- The Trigon (Prince Rupert) and Guaymas terminals impose inland transportation and border inspection costs that render Wyoming coal uncompetitive.

Without the development of new West Coast export capacity, Wyoming coal exports are likely to remain constrained to approximately 0 to 3 million tons per year, limited to sporadic shipments through Westshore during favorable price cycles. The development of new terminals is therefore critical to any meaningful increase in Wyoming coal export volumes. Of the proposed projects, the shelved Millennium Coal Terminal in Washington would offer the best pathway to large-scale exports. It was proposed to have a capacity of 48 million tons per year. This would potentially enable up to 30 million tons per year of Wyoming PRB coal exports if revived (allowing for capacity likely to be used by exports from existing coal mines in Montana), though current regulatory and political conditions make such development highly uncertain. The proposed Oakland Coal Terminal in California is more likely to come online by the late 2020s, but its limited capacity of approximately 5 million tons per year and strong competition from transportation-advantaged Utah coal producers significantly constrain its ability to accommodate Wyoming coal.

Key findings from the analysis include:

- Wyoming coal exports have historically been minimal, reflecting geographic disadvantages and limited access to competitive export infrastructure.
- Asia is the only viable long-term export market, driven by the global shift in coal demand away from Europe and the Americas.
- Wyoming's location favors Pacific markets, but it remains disadvantaged relative to Montana and Canadian coal due to higher inland freight costs.
- Competition in Asia is dominated by Indonesian coal, which shares similar quality characteristics but benefits from lower delivered costs and proximity.
- Existing West Coast terminal capacity is largely unavailable, with Westshore capacity almost consumed by existing exports of Canadian and Montana coals and other existing terminals facing closure (Richmond), capacity limits (Long Beach), or unfavorable transportation and border inspection costs (Trigon and Guaymas).
- Without new terminals, Wyoming coal exports are likely limited to 0 to 3 million tons per year.
- A new Millennium terminal could theoretically expand export potential to about 30 million tons per year but faces severe development hurdles.
- The proposed Oakland terminal is more likely to be developed but offers a limited incremental opportunity for Wyoming coal due to capacity limits and supply competition from Utah and Colorado producers.
- Increased exports of Wyoming coal would be environmentally superior by displacing coal production in other countries, because Wyoming coal has very low greenhouse gas (methane) emissions from production, high safety due to very high productivity (fewer employees per ton of coal), strong reclamation standards, and low emissions of fine particulates due to very low sulfur content.

Taken together, the analysis indicates that Wyoming coal exports can play a limited, opportunistic role in select Asian markets under favorable pricing and logistics conditions, particularly in Japan and South Korea. However, structural transportation disadvantages, limited export infrastructure, strong competition from Indonesian and other western coal suppliers, and growing LNG penetration prevent Wyoming coal from serving as a scalable or durable long-term replacement for declining domestic demand. Export opportunities are therefore best viewed as cyclical supplements rather than a strategic solution for Wyoming coal production, unless new export infrastructure is developed.

In the past (1970's through the early 2000's), Asian countries who were strategic allies of the United States and depended on its military and political support (including Japan, Taiwan, and South Korea) purchased large quantities of coal produced in western states, Appalachia, and Alaska as part of the strategic relationship. In future trade and political relationships, the Administration could negotiate for increased U.S. coal exports, including Wyoming PRB coal, as part of the long-term partnerships.

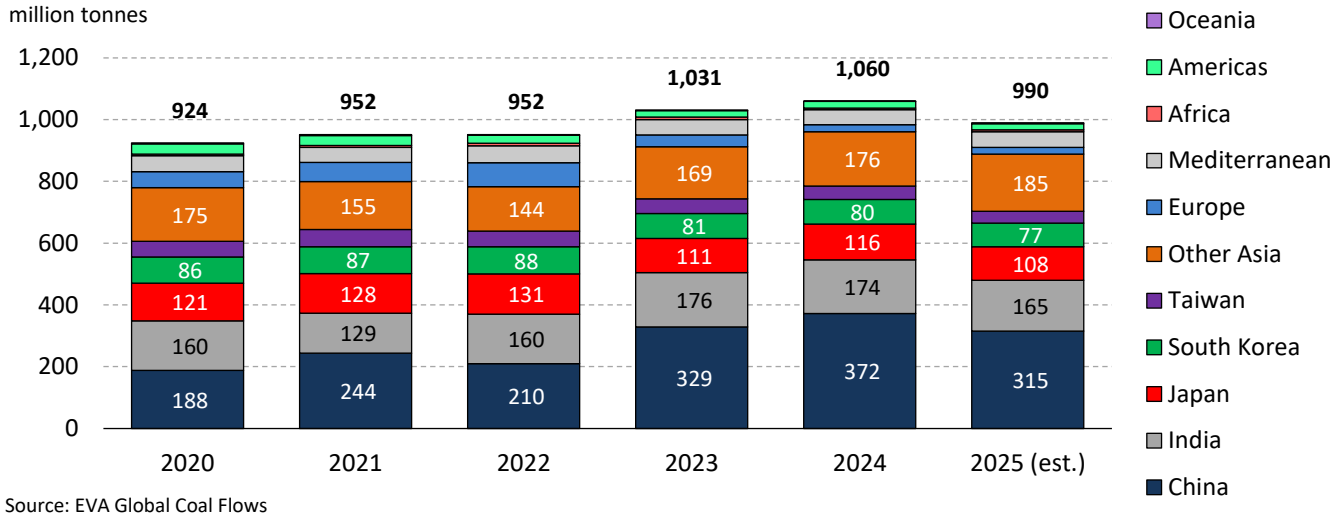
5.2 Historical Global Thermal Coal Demand and Supply

5.2.1 Historical Global Thermal Coal Demand

As in the United States, thermal coal is consumed primarily in the power sector worldwide, with smaller quantities used in the industrial and commercial sectors. Industrial uses include cement production, coal-to-chemicals, and feedstock for food and mineral processing. Since 2000, global thermal coal consumption has more than doubled to over 7 billion tonnes in 2024, despite international efforts to reduce coal use to limit the effects of human-caused climate change. Virtually all the growth has been concentrated in Asia, where countries' coal consumption grew from 1.7 billion tonnes in 2000 to over 6 billion tonnes in 2024. China alone accounted for about 60% of global thermal coal consumption in 2024. Conversely, coal consumption in countries outside Asia has declined from about 1.5 billion tonnes to less than 1 billion tonnes in 2024, as European countries and the United States shifted a significant share of their power generation from coal to natural gas and renewable energy over the last 25 years.

As a result of the heavy tilt in thermal coal consumption toward the Asian continent, the global thermal coal trade is also focused on Asia. **EXHIBIT 5-1** shows global thermal coal imports by major importing country or region. In 2025, thermal coal imports by Asian countries are estimated to account for approximately 90% of global thermal coal imports. Despite being the world's largest coal producer, China is also the single largest importer of thermal coal, importing over 300 million tonnes of thermal coal per year in each of the last three years.

EXHIBIT 5-1: GLOBAL THERMAL COAL IMPORTS BY REGION

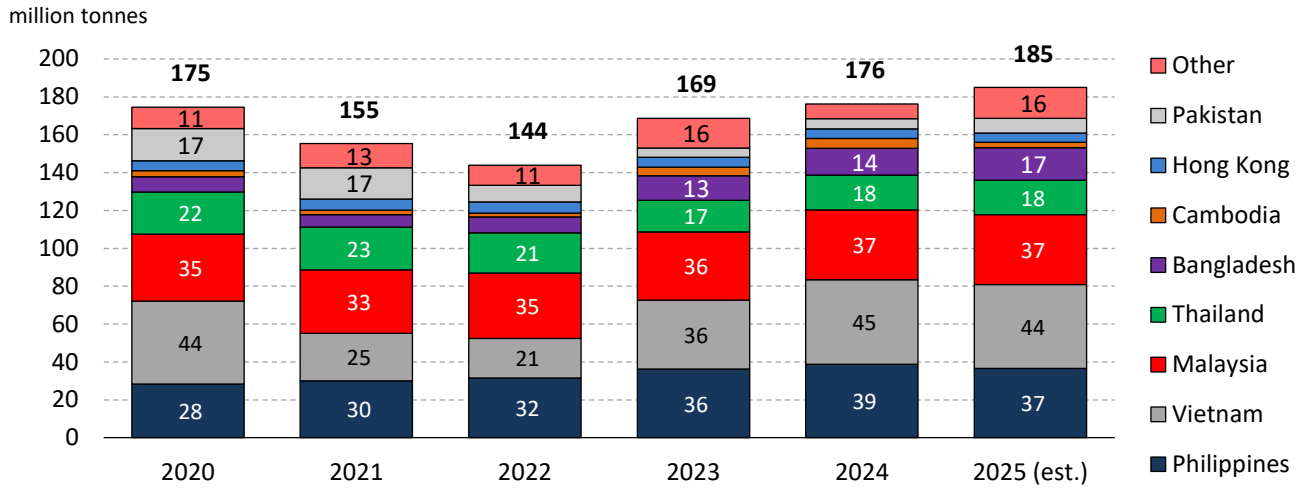


Source: EVA Global Coal Flows

After years of continuous growth following the global COVID-19 pandemic, global thermal coal imports are estimated to decline in 2025, primarily due to reduced imports by China and India, the two largest thermal coal importers in the world. Displacement of coal generation by new renewable energy projects led to lower year-on-year coal consumption in the two countries' power sectors, while increased domestic coal production further reduced both countries' demand for imported coal in 2025.

Continued growth in thermal coal imports in 2025 came primarily from Asian countries other than China, India, Japan, South Korea, or Taiwan. **EXHIBIT 5-2** shows the breakdown of the estimated 185 million tonnes of thermal coal imports in 2025 to Other Asia by importing country.

EXHIBIT 5-2: ANNUAL THERMAL COAL IMPORTS BY OTHER ASIAN COUNTRIES

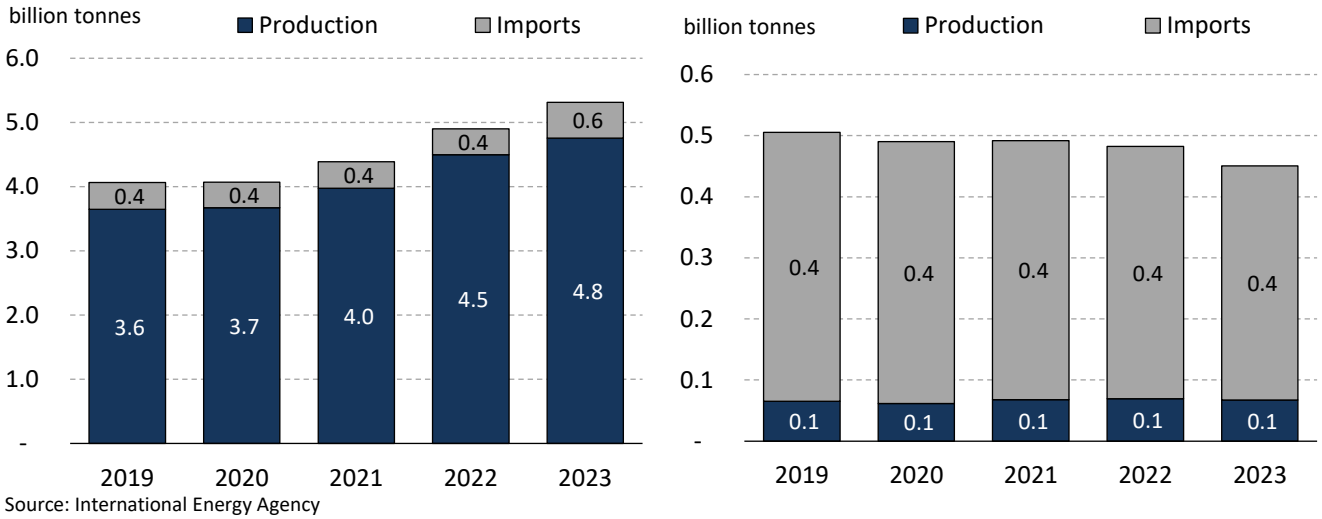


Source: EVA Global Coal Flows

The largest thermal coal importers in Southeast Asia are Vietnam, the Philippines, and Malaysia, which together accounted for about two-thirds of all thermal coal imports in the region in 2025. Thermal coal imports in the region have grown significantly over the past two decades as countries have built new coal-fired power plants to meet rising electricity demand driven by electrification. Notably, the coal-fired power plants built in the region are designed to use both bituminous and sub-bituminous coal as feedstock.

Thermal coal imports by Asian countries, excluding China and India, are also less affected by changes in domestic coal production. **EXHIBIT 5-3** shows the share of domestic thermal coal production and imports over the last five years, based on available data. China and India, the two largest thermal coal importers in the world, are also the two largest thermal coal producers. Together, these countries cover about 90% of their thermal coal demand with indigenous production. Conversely, all other Asian countries cover only about 15% of their thermal coal demand with domestic thermal coal production. As a result, changes in domestic coal production have a significantly lower impact on expected demand for thermal coal imports in Other Asian countries. Additionally, any new coal-fired power plants in the region will be almost entirely dependent on thermal coal imports.

EXHIBIT 5-3: THERMAL COAL PRODUCTION AND IMPORTS FOR CHINA AND INDIA (LEFT) VERSUS NON-CHINA/INDIA ASIAN COUNTRIES (RIGHT)

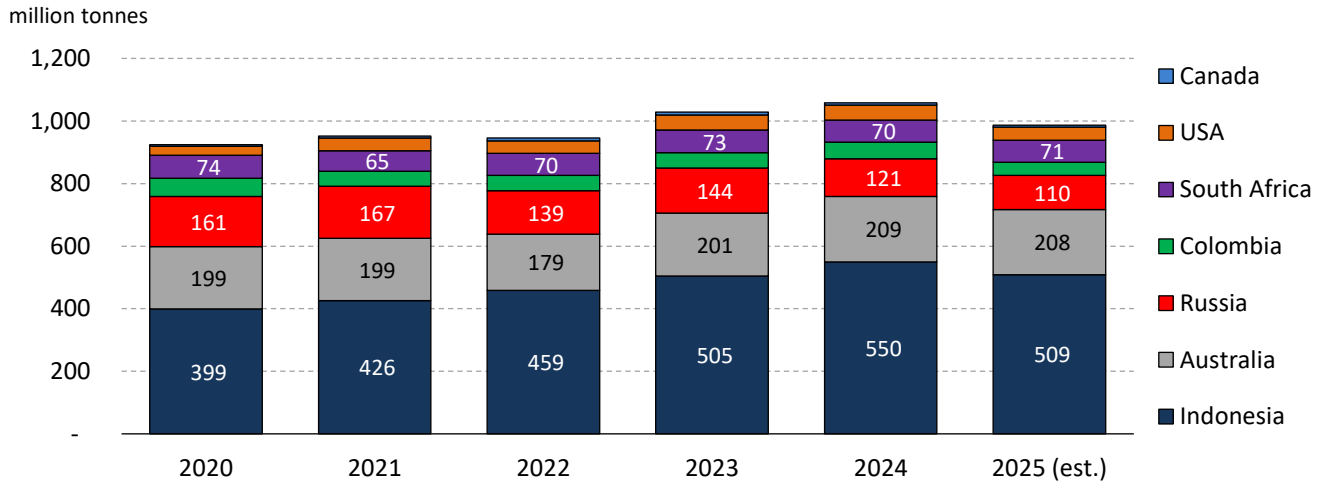


Source: International Energy Agency

5.2.2 Historical Global Thermal Coal Supply

Only seven countries account for virtually all global thermal coal exports: Indonesia, Australia, Russia, Colombia, South Africa, the United States, and Canada. **EXHIBIT 5-4** presents annual thermal coal exports by country for the past six years.

EXHIBIT 5-4: GLOBAL THERMAL COAL EXPORTS BY COUNTRY

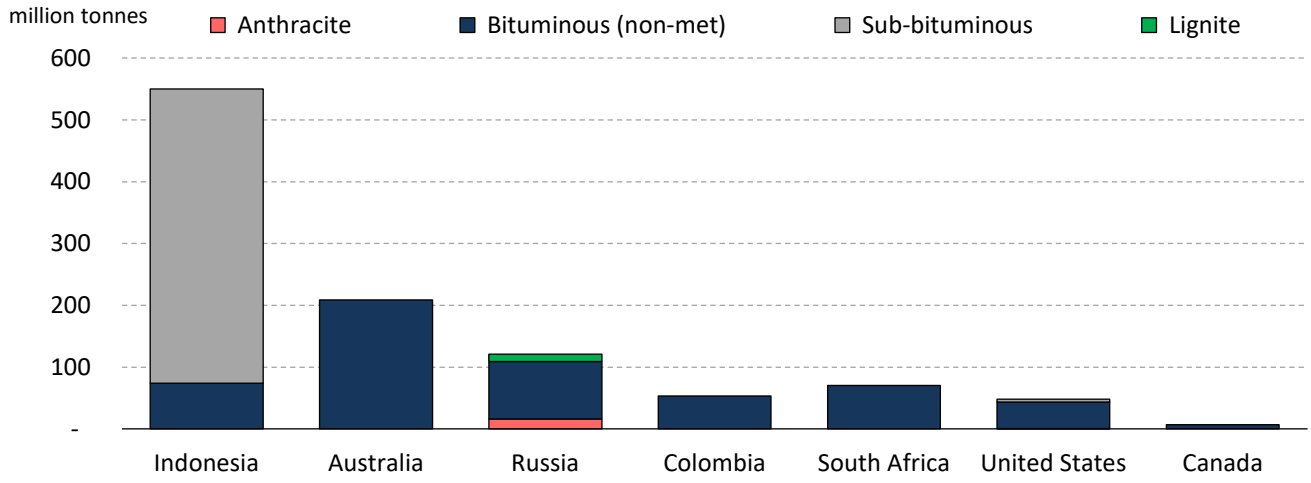


Source: EVA Global Coal Flows

Indonesia accounts for approximately half of all global thermal coal exports, primarily because of its proximity to major thermal coal-importing countries in South, East, and Southeast Asia and its low-cost thermal coal supply. Australia, Russia, and South Africa are also major coal suppliers to Asian countries.

It is worth highlighting differences in coal quality among thermal coal-exporting countries. **EXHIBIT 5-5** shows 2024 thermal coal exports for the seven primary thermal coal-exporting countries, broken down by coal quality. Notably, over 85% of Indonesian coal exports are sub-bituminous. The only other country with notable sub-bituminous coal exports in 2024 was the United States. Most other coal-exporting countries export primarily bituminous coal with calorific values (CV) of 5,500 kcal/kg (>10,000 Btu/lb.), net-as-received (NAR), or higher.

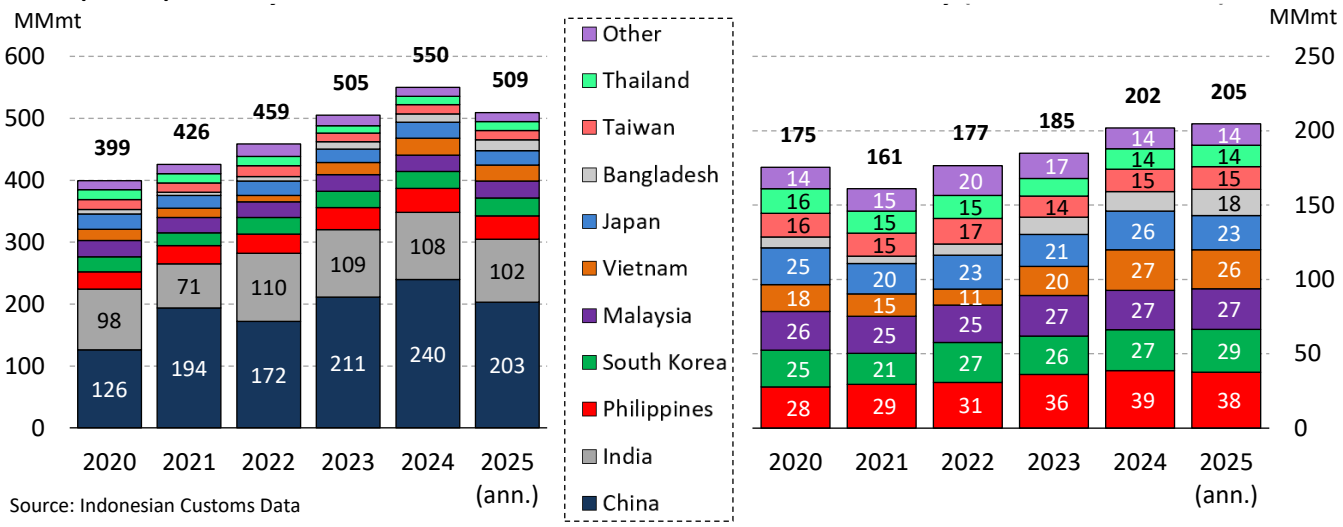
EXHIBIT 5-5: 2024 THERMAL COAL EXPORTS BY COUNTRY AND QUALITY



Source: International Energy Agency

Given the similarities in coal quality between Indonesian and Wyoming coal (Wyoming PRB is ~4,700 kcal/kg NAR, while Green River Basin coal is ~5,000 kcal/kg NAR), it is worth highlighting the primary destinations of Indonesian thermal coal exports. **EXHIBIT 5-6** shows annual Indonesian thermal coal exports by destination country.

EXHIBIT 5-6: INDONESIAN THERMAL COAL EXPORTS BY COUNTRY – ALL COUNTRIES (LEFT) AND EXCLUDING CHINA & INDIA (RIGHT)



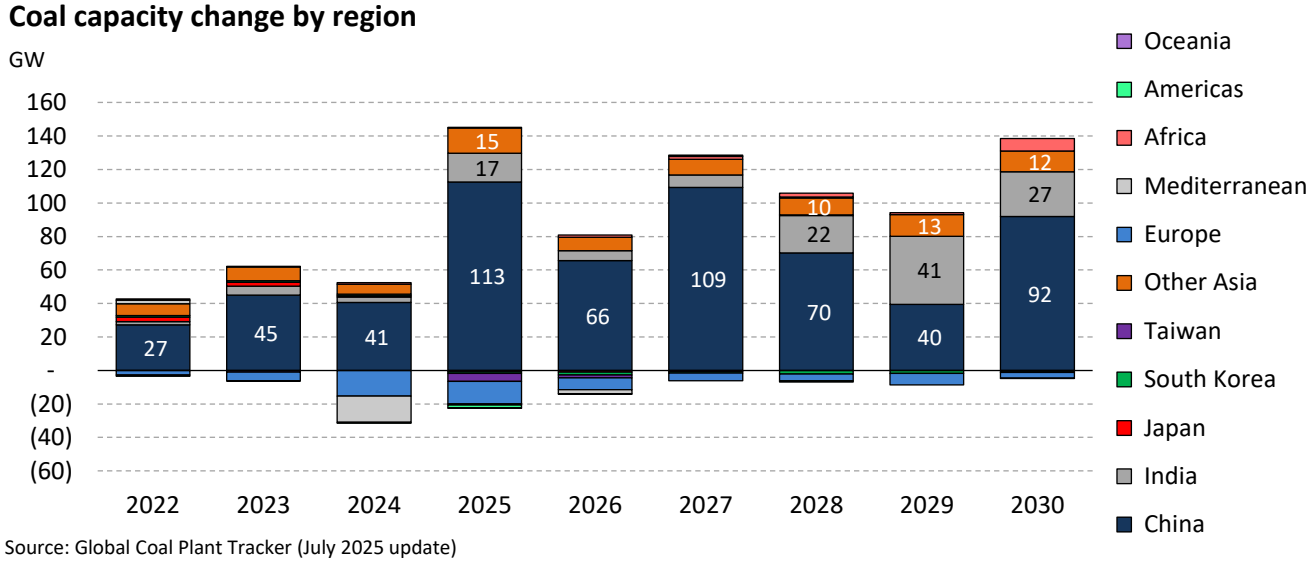
Source: Indonesian Customs Data

China and India together account for approximately 60% of Indonesian thermal coal exports. Other Asian countries account for about 35% of Indonesian coal exports, including exports to the Philippines, South Korea, Malaysia, Vietnam, and Japan. Less than 5% of Indonesian exports go to countries outside Asia.

5.3 Forecasted Global Thermal Coal Demand

As in the last decade, thermal coal demand growth will be concentrated in Asia. **EXHIBIT 5-7** shows annual coal capacity changes based on individual coal-fired power plant projects tracked by the Global Coal Plant Tracker. Over the next five years, more than 540 GW of new coal-fired power plants are either under construction or in advanced development stages worldwide, with more than 530 GW located in Asian countries. The only other region with notable growth in new coal-fired power plant capacity is Africa, where new coal plants are planned in countries such as Zimbabwe, Botswana, and Tanzania.

EXHIBIT 5-7: ANNUAL NET COAL CAPACITY CHANGE BY REGION



Source: Global Coal Plant Tracker (July 2025 update)

On the other hand, a significant amount of coal capacity across Europe, parts of the Mediterranean, and the Americas is slated for retirement over the next decade. Both Germany and Chile plan to close all their remaining coal plants by 2035, while Israel plans to close its last remaining coal plants later this year.

Future coal generation in other countries will depend on the same factors as in the United States: overall electricity demand growth, investments in non-fossil generation, including nuclear, hydro, wind, and solar, and competition from natural gas. Additionally, future thermal coal import demand will depend on indigenous coal production gains or losses in major thermal coal-importing countries such as China and India. For example, the primary reason for the drop in thermal coal imports in 2025 was the decline in coal generation in both China and India as the countries expanded their renewable energy portfolios, while they also increased indigenous coal production, leading to lower demand for imported coal.

One of the major developments that will impact the global energy market over the next few years is continued substantial growth in liquefied natural gas exports from the U.S., Canada, Mexico, and Qatar. Over the next three years, global LNG exports are projected to increase by over 100 million tonnes per year (MTPA), an increase of almost 25% from the 2025 supply base, as shown in **EXHIBIT 5-8**. To ensure adequate off-take demand for existing and future U.S. LNG terminals, the Trump administration is increasingly including LNG trade agreements with countries such as Vietnam, South Korea, and India in its ongoing tariff negotiations. Greater LNG imports by countries in Southeast Asia could displace thermal coal in their power and industrial sectors, leading to future coal plant project cancellations and further reducing demand for imported coal.

EXHIBIT 5-8: GLOBAL LNG EXPORTS BY COUNTRY

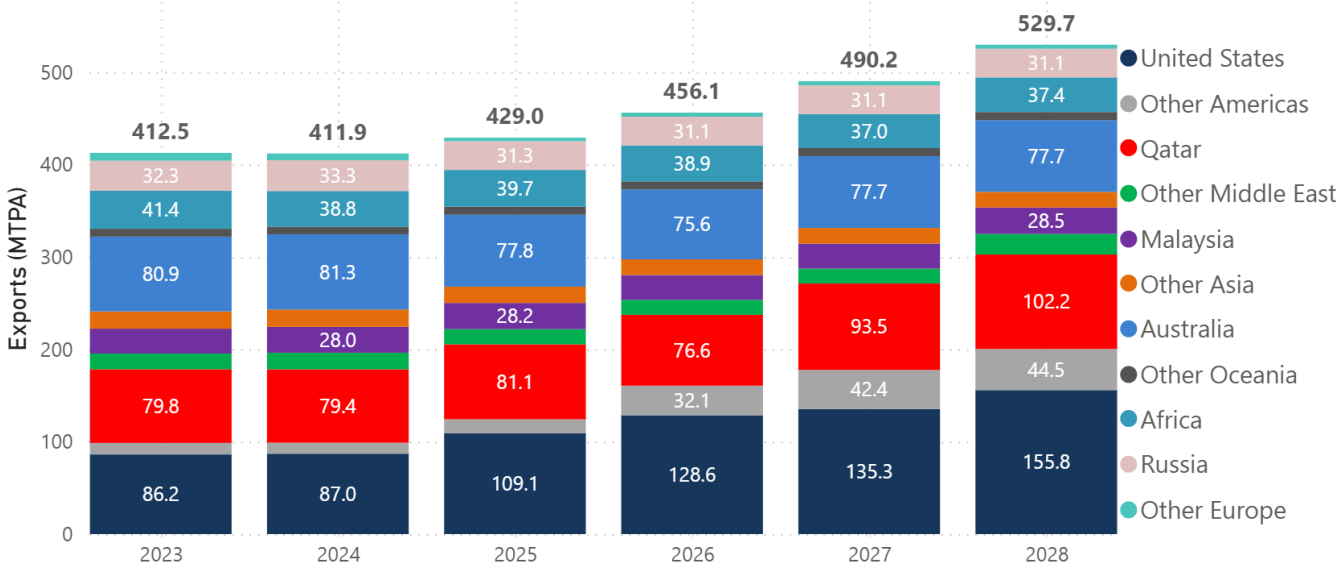
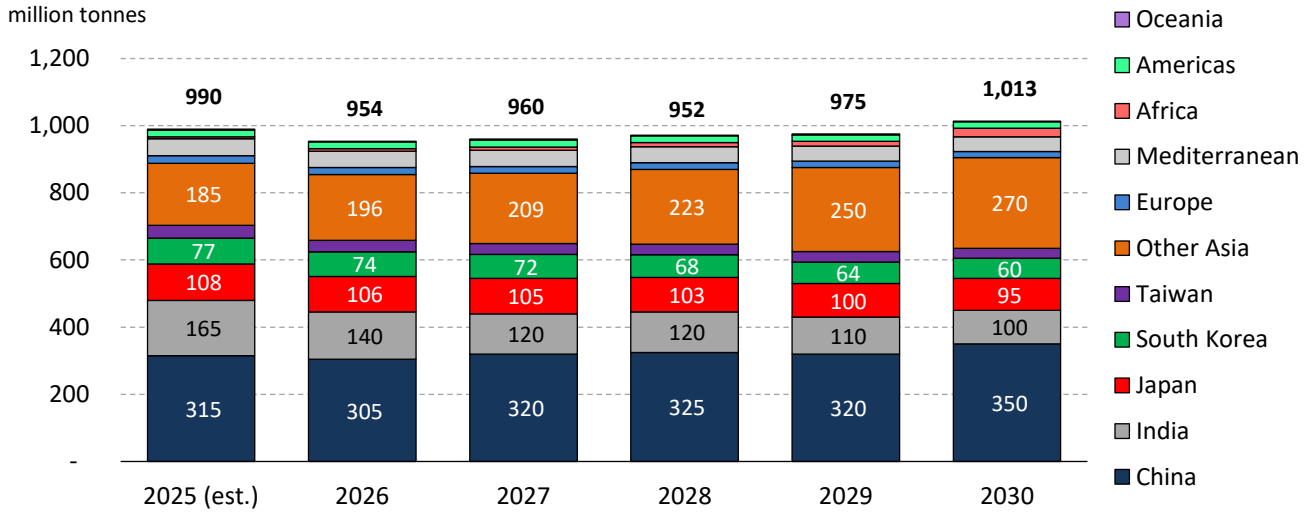


EXHIBIT 5-9 shows thermal coal import demand by country or region through 2030, based on the most recent data on future coal plant projects and assumptions about changes in domestic coal production and coal plant utilization. While China will likely remain the largest thermal coal importer through 2030, its demand for imported coal can vary considerably. Given the sheer size of the Chinese thermal coal market, small changes in China's domestic coal production can lead to substantial shifts in its demand for imported coal. In Southeast Asia (excluding Indonesia), indigenous coal production is much smaller, so demand for imported coal depends primarily on the number of new coal-fired power plants in the region and, ultimately, their utilization. With over 50 GW of new coal-fired power plants either under construction or in advanced development stages, the region will likely see the most notable growth in demand for imported coal over the next five years.

Rapid growth in global LNG supply introduces a structural constraint on future thermal coal prices in key Asian markets. In several Southeast Asian countries, LNG increasingly sets the marginal fuel price for new power generation, effectively capping coal import prices over the medium term. During periods of lower LNG prices or excess LNG supply, coal-fired generation becomes more vulnerable to displacement, particularly at higher delivered coal costs. This dynamic disproportionately affects higher-cost coal suppliers, including Wyoming coal, whose competitiveness deteriorates more rapidly in low- to moderate coal price environments.

EXHIBIT 5-9: GLOBAL THERMAL COAL IMPORT DEMAND FORECAST BY REGION

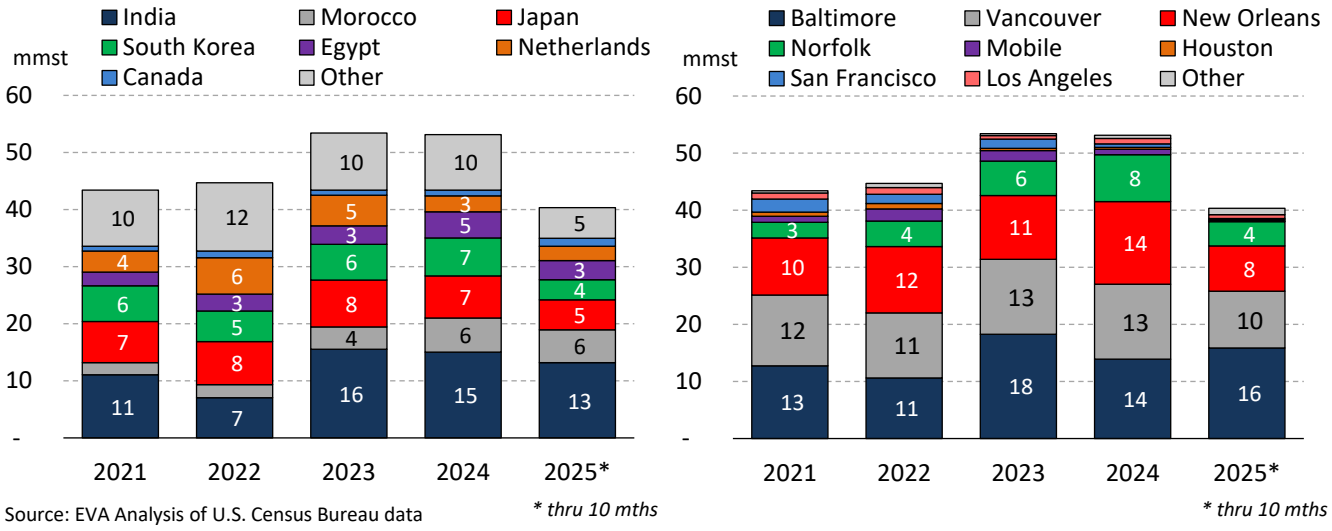


Import demand sensitivity to coal pricing can also vary materially across Asian markets. Japan and South Korea, which operate mature coal fleets with limited near-term replacement capacity, exhibit relatively inelastic short-term demand for imported coal, particularly for baseload generation. In contrast, Southeast Asian markets tend to be more price-sensitive, with coal generation increasingly competing against imported LNG, renewables, and in some cases domestic gas supply. This divergence implies that Wyoming coal is more exposed to price-driven demand erosion in emerging Southeast Asian markets than in Northeast Asia, further narrowing the set of destinations where Wyoming coal can compete consistently across market cycles.

5.4 U.S. Coal Export Infrastructure for Wyoming Coal

The United States ranks among the seven largest thermal coal exporters in the world, accounting for approximately 4% of global thermal coal trade over the past five years. **EXHIBIT 5-10** shows U.S. thermal coal exports by country of destination (left) and by export port (right).

EXHIBIT 5-10: U.S. THERMAL COAL EXPORTS BY DESTINATION COUNTRY (LEFT) AND EXPORT PORT (RIGHT)



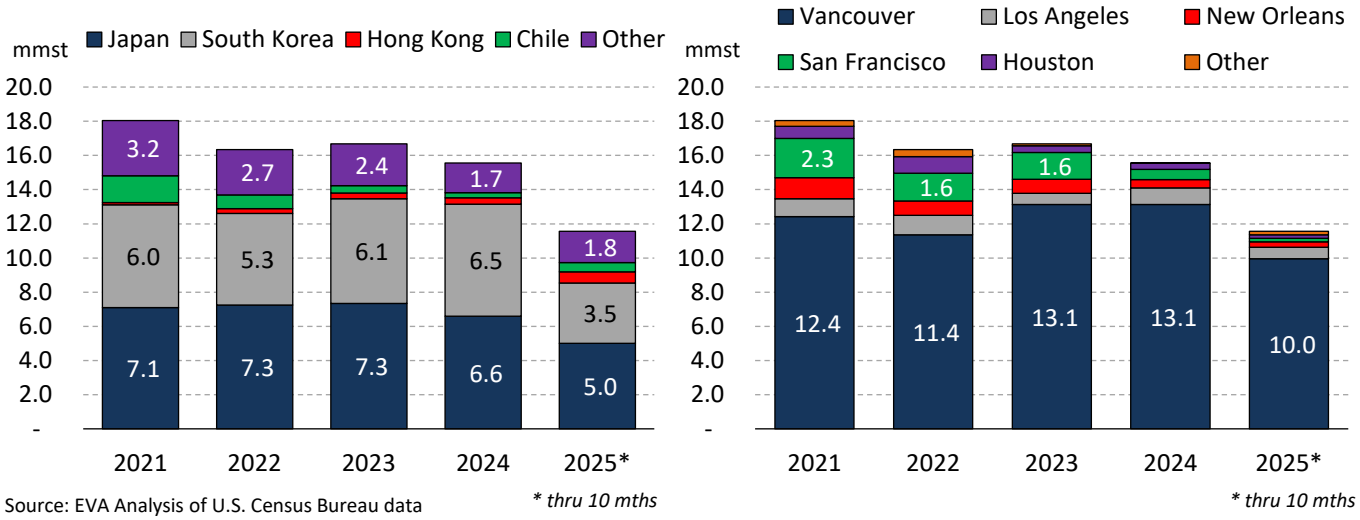
Source: EVA Analysis of U.S. Census Bureau data

India is the largest trading partner for U.S. thermal coal, accounting for over 20% of U.S. thermal coal exports. Most U.S. thermal coal exported to India is Northern Appalachian (NAPP) coal with a high heating value (>7,000 kcal/kg or 13,000 Btu/lb), shipped through Baltimore. It primarily competes with international petroleum coke and is consumed in India's

cement and brick kiln industries. A small share of U.S. thermal coal exports to India is Illinois Basin coal, shipped through coal terminals along the Mississippi River near New Orleans. Other notable destinations for U.S. thermal coal include Morocco (primarily Illinois Basin coal through New Orleans and Norfolk), Japan and South Korea, (both Montana coal – Bull Mountains and Spring Creek mines – through Vancouver and Rockies coal – Utah and Colorado mines – through California ports), and Egypt (Illinois Basin coal through New Orleans or NAPP coal through Baltimore).

EXHIBIT 5-11 further details U.S. thermal coal exports of western coal originating in the Powder River Basin (PRB) or the Rockies. The data is shown by destination country (left) and export port (right) for the past five years.

EXHIBIT 5-11: PRB & ROCKIES EXPORTS BY DESTINATION COUNTRY (LEFT) AND EXPORT PORT (RIGHT)



Source: EVA Analysis of U.S. Census Bureau data

PRB and Rockies exports have totaled about 16 to 18 million tons over the past four years. More than 75% of these exports went to customers in South Korea and Japan, where the coal is consumed primarily in the power sector. Other destinations include Hong Kong, Chile, China, and Vietnam, with Malaysia, Indonesia, and India emerging as new markets.

Over 75% of PRB and Rockies coal exports are shipped through the Port of Vancouver in British Columbia, Canada, specifically the Westshore Coal Terminal. Smaller quantities of PRB and Rockies coal are also exported through California coal terminals in the San Francisco Bay Area and Los Angeles (Long Beach), as well as through Gulf Coast terminals in Houston and New Orleans.

EXHIBIT 5-12 presents the total amount of coal (both metallurgical and thermal) exported through all major North American coal terminals over the last four years, along with complete data on their annual throughput capacity, to better assess the capacity to handle additional coal exports from Wyoming coal mines.

Coal terminals in the Port of Vancouver, BC, account for the largest share of coal exports over the last four years, with over 40 million tons exported each year. This includes significant amounts of metallurgical coal exported through both the Westshore and Neptune coal terminals. Neptune's recent expansion of its export terminal increased its capacity from about 14 million tons to 20 million tons in 2021, allowing Teck Resources (the largest metallurgical coal producer in Canada and the owner of the Neptune Terminal) to shift most of its metallurgical coal exports from the Westshore coal terminal to the Neptune Coal Terminal and thereby freeing up capacity at Westshore. Besides the Vancouver terminals, the only other coal terminal operating near capacity is Core Natural Resources' CNX Marine Terminal, which has exported around 17-18 million tons of metallurgical and thermal coal since 2023, following its capacity expansion to approximately 20 million tons per annum.

In 2021, the San Francisco Bay terminals (Levin-Richmond and Stockton) combined to export nearly 2.5 million tons, close to the two terminals' combined capacity of about 3 million tons per year, primarily coal from Utah coal mines. However, the Lila Canyon mine fire and subsequent closure created long-lasting tight market conditions in the Utah coal market, while global coal prices declined, and coal exports through the Bay Area have since declined to an estimated less than half a million tons in calendar year 2025.

Based on EVA's analysis, any coal exports from Wyoming coal mines were PRB exports, primarily through Westshore, with some sporadic exports through New Orleans and Houston. However, it is likely that there have been no Wyoming coal exports in 2025.

EXHIBIT 5-12: NORTH AMERICAN AND WYOMING COAL EXPORTS BY PORT AND TERMINAL

million short tons			All Coal (inc. ANT + LIG)					PRB & Rockies exports					WY exports				
Country	Port	Capacity	2021	2022	2023	2024	2025*	2021	2022	2023	2024	2025*	2021	2022	2023	2024	2025*
USA	Norfolk	86.0	28.7	32.2	34.9	41.6	34.6	-	-	-	-	-	-	-	-	-	-
	Lamberts Point	*48.0*	*10.5*	*11.6*	*13.1*	*17.4*	*14.0*	-	-	-	-	-	-	-	-	-	-
	Pier IX	*16.0*	*5.6*	*7.8*	*7.8*	*9.7*	*9.3*	-	-	-	-	-	-	-	-	-	-
	DTA	*22.0*	*12.6*	*12.7*	*14.1*	*14.5*	*11.3*	-	-	-	-	-	-	-	-	-	-
USA	Baltimore	30.0	19.1	18.4	27.9	25.6	26.4	-	-	-	-	-	-	-	-	-	-
	CNX	*20.0*	*12.1*	*12.9*	*18.6*	*16.7*	*17.2*	-	-	-	-	-	-	-	-	-	-
	Curtis Bay	*14.0*	*7.0*	*5.5*	*9.3*	*8.8*	*9.2*	-	-	-	-	-	-	-	-	-	-
USA	New Orleans	58.0	10.4	12.1	12.2	15.2	9.7	1.2	0.8	0.8	0.5	0.4	-	0.8	0.3	0.0	-
USA	Mobile	30.0	8.6	9.5	11.4	12.4	11.9	-	-	-	-	-	-	-	-	-	-
USA	Bay Area	3.0	2.3	1.6	1.6	0.6	0.3	2.3	1.6	1.6	0.6	0.3	-	-	-	-	-
USA	Los Angeles	4.0	1.1	1.1	0.7	1.0	0.8	1.1	1.1	0.7	1.0	0.8	-	-	-	-	-
USA	Houston	10.3	0.7	1.0	0.4	0.4	0.3	0.7	1.0	0.4	0.4	0.3	0.4	0.1	-	-	-
USA	Great Lakes	n/a	3.6	3.3	4.1	3.2	2.1	-	-	-	-	-	-	-	-	-	-
USA	Other U.S.	n/a	0.5	0.8	0.5	0.7	1.6	0.3	0.4	0.1	0.0	0.2	-	-	-	-	-
Canada	Vancouver	55.0	41.5	43.9	47.0	46.1	44.7	12.4	11.4	13.1	13.2	11.9	0.8	0.8	1.2	0.5	-
	Westshore (total)	*35.0*	*32.1*	*27.3*	*29.2*	*28.3*	*27.1*	-	-	-	-	-	-	-	-	-	-
	Westshore (U.S. only)		*12.4*	*11.4*	*13.1*	*13.2*	*11.9*	*12.4*	*11.4*	*13.1*	*13.2*	*11.9*	*0.8*	*0.8*	*1.2*	*0.5*	-
	Neptune	*20.0*	*9.5*	*16.6*	*17.8*	*17.8*	*17.6*	-	-	-	-	-	-	-	-	-	-
Canada	Prince Rupert	20.0	6.6	6.4	8.0	6.1	8.6	-	-	-	-	-	-	-	-	-	-
Mexico	Guaymas	5.0	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	-
	Total		**123.2**	**130.4**	**148.7**	**152.9**	**141.1**	**18.0**	**16.4**	**16.7**	**15.6**	**13.9**	**1.1**	**1.7**	**1.5**	**0.6**	**-**

** annualized based on data through October*

EXHIBIT 5-13 lists all major North American coal terminals and key characteristics for each, including terminal throughput capacity, ground storage capacity, terminal draft limits, maximum vessel size, delivery modes, and rail carriers serving the terminal, if applicable. The tables also include information on the Millennium Coal Terminal, planned (but now shelved) for Longview, Washington, along the Columbia River, as well as the proposed Oakland terminal.

The proposed Oakland Coal Terminal and the shelved Millennium Coal Terminal are included in this analysis as economic reference cases to illustrate the cost reductions required for Wyoming coal to approach competitiveness in Asian markets. Both projects face significant permitting, political, and timing uncertainties that materially limit their near-term feasibility. Accordingly, results associated with these terminals should be interpreted as indicative of best-case logistics outcomes rather than as forecasts of realizable export capacity.

Bulk carriers transporting coal are generally classified by vessel tonnage and draft. The three most common vessel types in the international coal shipping industry are the Handymax, with a deadweight metric tonnage (DWT) of around 30,000; the Panamax, with a DWT of around 70,000; and the Capesize, with DWTs over 150,000 tonnes. Notably, only the Trigon terminal in Prince Rupert, British Columbia, and the Westshore Terminal can handle and fully load Capesize vessels because their terminal draft limits exceed 70 ft. Some other terminals can handle Capesize vessels but cannot fully load them due to draft limitations within the port. Vessel size is a key factor in lowering transportation costs. Generally, the larger the vessel, the lower the ocean freight cost per ton of coal due to economies of scale.

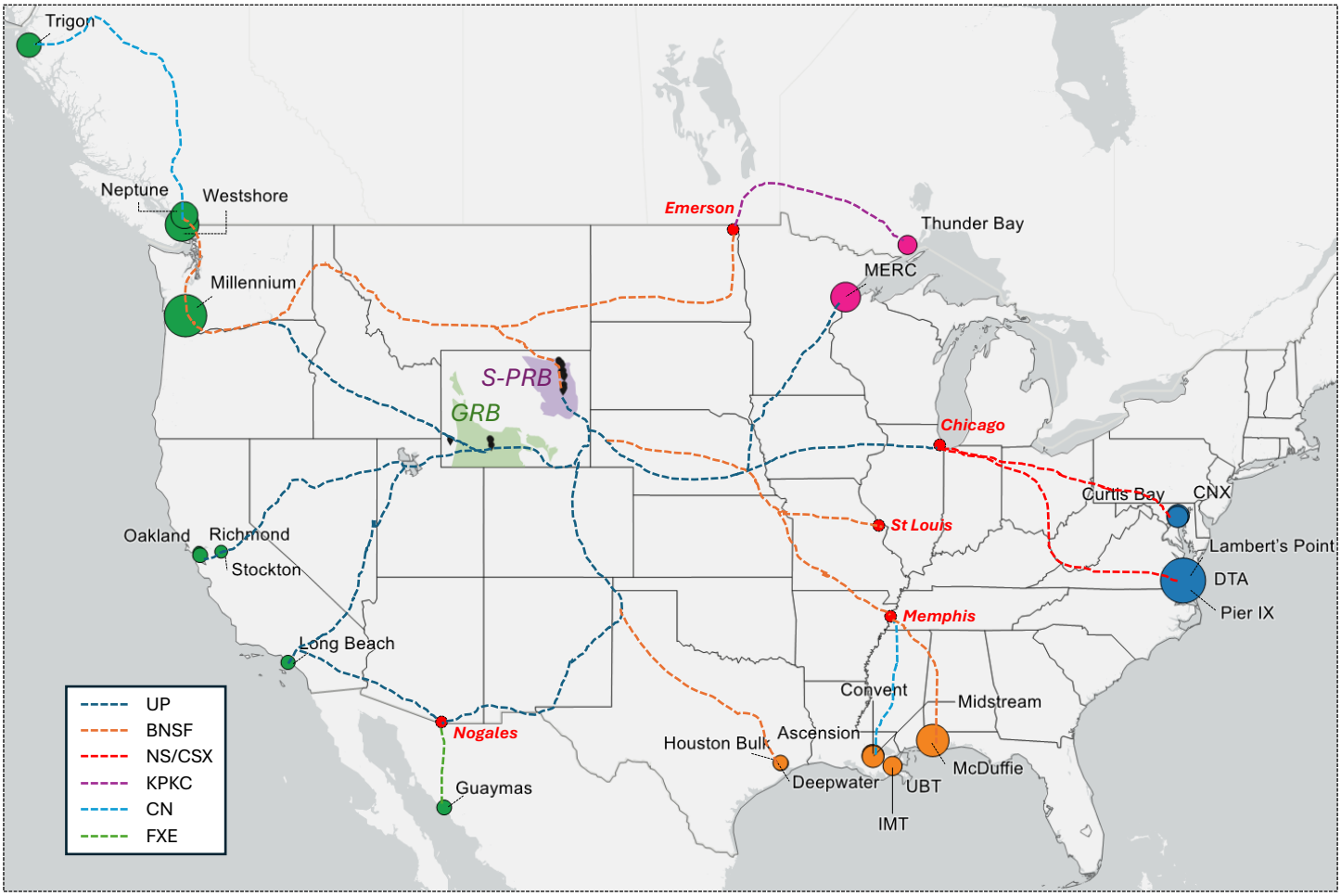
EXHIBIT 5-13: MAJOR NORTH AMERICAN COAL TERMINALS

Terminal Name	Owner	City (State)	Country	Region	Status
Trigon	Trigon Pacific Terminals Limited	Prince Rupert, BC	Canada	West Coast	Operational
Neptune	Neptune Bulk Terminals	Vancouver, BC	Canada	West Coast	Operational
Westshore	Westshore Terminals Ltd.	Vancouver, BC	Canada	West Coast	Operational
Millennium	Millenium Bulk Terminals	Longview, WA	USA	West Coast	Shelved
Stockton	Port of Stockton	Stockton, CA	USA	West Coast	Operational
Richmond	Levin Richmond Terminal	Richmond, CA	USA	West Coast	Closing
Oakland	Insight Terminal Solutions	Oakland, CA	USA	West Coast	Proposed
Long Beach	Port of Long Beach	Long Beach, CA	USA	West Coast	Operational
Guaymas	MEXPORT Coal & Minerals Terminal	Sonora, MX	Mexico	West Coast	Operational
Deepwater	Kinder Morgan	Houston, TX	USA	Gulf Coast	Operational
Houston Bulk	Kinder Morgan	Houston, TX	USA	Gulf Coast	Operational
Ascension	Host Terminals	New Orleans, LA	USA	Gulf Coast	Operational
Midstream	Associated Terminals	New Orleans, LA	USA	Gulf Coast	Operational
Convent	SunCoke Energy (CMT)	New Orleans, LA	USA	Gulf Coast	Operational
UBT	Host Terminals	New Orleans, LA	USA	Gulf Coast	Operational
IMT	Kinder Morgan	New Orleans, LA	USA	Gulf Coast	Operational
McDuffie	Alabama State Port Authority	Mobile, AL	USA	Gulf Coast	Operational
CNX	Core Natural Resources	Baltimore, MD	USA	East Coast	Operational
Curtis Bay	CSX	Baltimore, MD	USA	East Coast	Operational
DTA	Dominion Terminal Associates	Norfolk, VA	USA	East Coast	Operational
Pier IX	Kinder Morgan	Norfolk, VA	USA	East Coast	Operational
Lambert's Point	Norfolk Southern	Norfolk, VA	USA	East Coast	Operational
MERC	DTE Energy (MER)	Superior, WI	USA	Great Lakes	Operational
Thunder Bay	Thunder Bay Terminals / Russel Metals	Thunder Bay, ON	Canada	Great Lakes	Operational

Terminal Name	Capacity (mmst)	Ground Storage (mmst)	Terminal Draft	Max. Vessel Size	Delivery Modes	Rail Carriers
Trigon	20.0	1.6	< 70 ft	Capesize	Rail	CN
Neptune	20.0	0.6	50 ft	small Capesize	Rail	CN
Westshore	35.0	1.7	< 75 ft	Capesize	Rail	CN, CP, BNSF
Millennium	48.0	n/a	40+ ft	Panamax	Rail	BNSF, UP
Stockton	2.0	n/a	35 ft	Panamax (partially loaded)	Rail	UP
Richmond	1.0	n/a	< 40 ft	Panamax	Rail	UP
Oakland	5.0	n/a	50 ft	small Capesize	Rail	BNSF, UP
Long Beach	4.0	0.7	65 ft	Panamax	Rail	UP
Guaymas	5.0	n/a	43 ft	small Capesize (partially loaded)	Rail	UP, Ferromex
Deepwater	5.0	1.6	40 ft	Panamax	Rail	UP, BNSF
Houston Bulk	5.3	0.6	40 ft	Panamax	Rail	UP, BNSF, KCS
Ascension	8.0	0.6	< 50 ft	Panamax	Barge	none
Midstream	15.0	n/a	< 50 ft	Panamax	Barge	none
Convent	15.0	1.0	< 50 ft	Panamax	Rail/barge	CN
UBT	9.0	1.5	< 50 ft	Panamax	Barge	none
IMT	11.0	1.7	< 50 ft	Panamax	Barge	none
McDuffie	30.0	2.3	50 ft	small Capesize	Rail/barge	CSX, CN
CNX	20.0	1.2	45 ft	small Capesize (partially loaded)	Rail	NS, CSX
Curtis Bay	14.0	n/a	40 ft	small Capesize (partially loaded)	Rail	CSX
DTA	22.0	1.7	50 ft	small Capesize	Rail	CSX
Pier IX	16.0	1.4	50 ft	small Capesize	Rail	CSX
Lambert's Point	48.0	0.9	50 ft	small Capesize	Rail	NS
MERC	26.0	5.0	28 ft	Handymax	Rail	BNSF, UP
Thunder Bay	11.0	2.0	30 ft	Handymax	Rail	CN, CP

EXHIBIT 5-14 shows the locations of each coal terminal listed in **EXHIBIT** 5-13 and the most commonly used transportation route for Wyoming coal from the Powder River or Green River basins to the terminal. Notably, BNSF Railroad is the only U.S. railroad with direct access to the Westshore Coal Terminal. Shipments to the Trigon Terminal would be transferred in Vancouver to Canadian National (CN) Railroad. All Californian coal terminals are serviced by Union Pacific (UP). UP is also the only railroad with access to the Guaymas Coal Terminal in Sonora, Mexico, via transfer to Ferromex in Nogales, Arizona. Wyoming coal can be delivered to East Coast ports via CSX or Norfolk Southern, with railcar transfer in Chicago from either UP or BNSF. Along the Gulf Coast, Houston Bulk and Deepwater have direct access via UP or BNSF, while BNSF provides direct access to Mobile's McDuffie Coal Terminal. SunCoke Energy's Convent Coal Terminal is serviced only by CN or via barge transfer. UP or BNSF rail shipments are often transferred to CN in Memphis, Tennessee. The remaining coal terminals along the Mississippi River near New Orleans allow only barge deliveries. Coal terminals along the Mississippi or lower Ohio River, including the Cora, Kellogg, Hall Street, Calvert City, and Four Rivers coal terminals, are the most likely rail-to-barge transfer points for PRB or GRB coal shipments. Lastly, both UP and BNSF provide direct rail service to DTE's Midwest Energy Resources Company (MERC) terminal, while shipments to the Thunder Bay Coal Terminal would likely be transferred in Emerson, Manitoba, from BNSF to Canadian Pacific Kansas City (CPKC).

EXHIBIT 5-14: MAJOR NORTH AMERICAN COAL TERMINALS AND TRANSPORTATION CONNECTIONS TO WYOMING COAL MINES



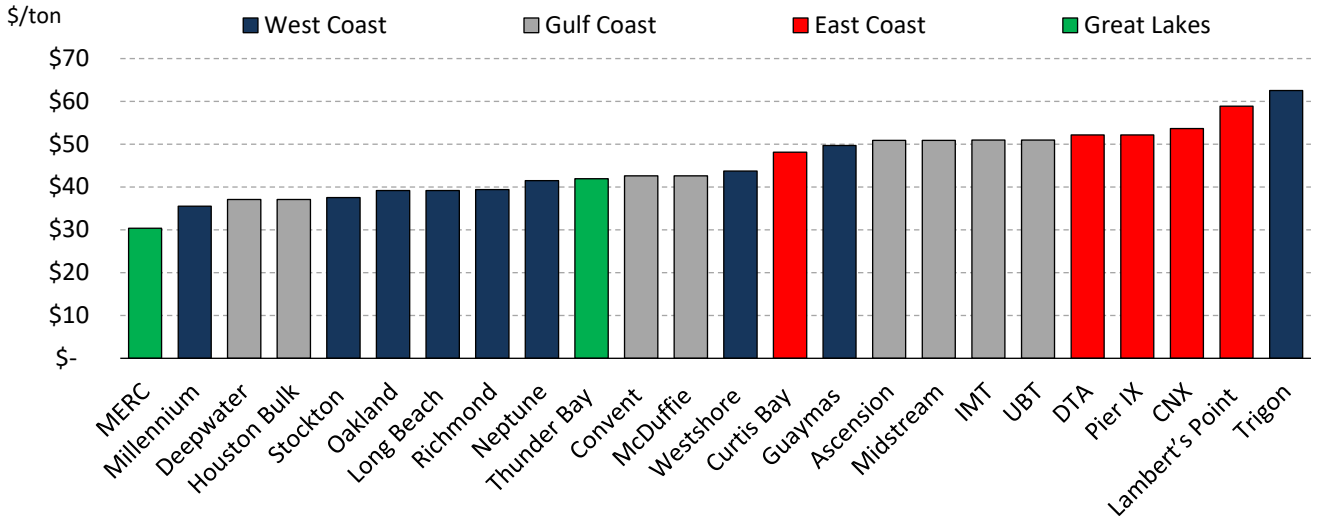
5.5 Economic Evaluation of Export Markets for Wyoming Coal

The following section evaluates the economic viability of Wyoming coal exports, primarily to Asian markets, across all major North American coal terminals presented in the previous section. In general, the delivered cost of Wyoming coal to international markets is calculated as follows:

$$\begin{aligned} &Delivered\ Cost \\ &\quad = Coal\ Cost\ (FOB\ Mine) + Rail\ Cost + Rail - to - Barge\ Transfer\ Fee\ (if\ applicable) \\ &\quad + Barge\ Cost\ (if\ applicable) + Terminal\ Transloading\ Cost + Ocean\ Freight \end{aligned}$$

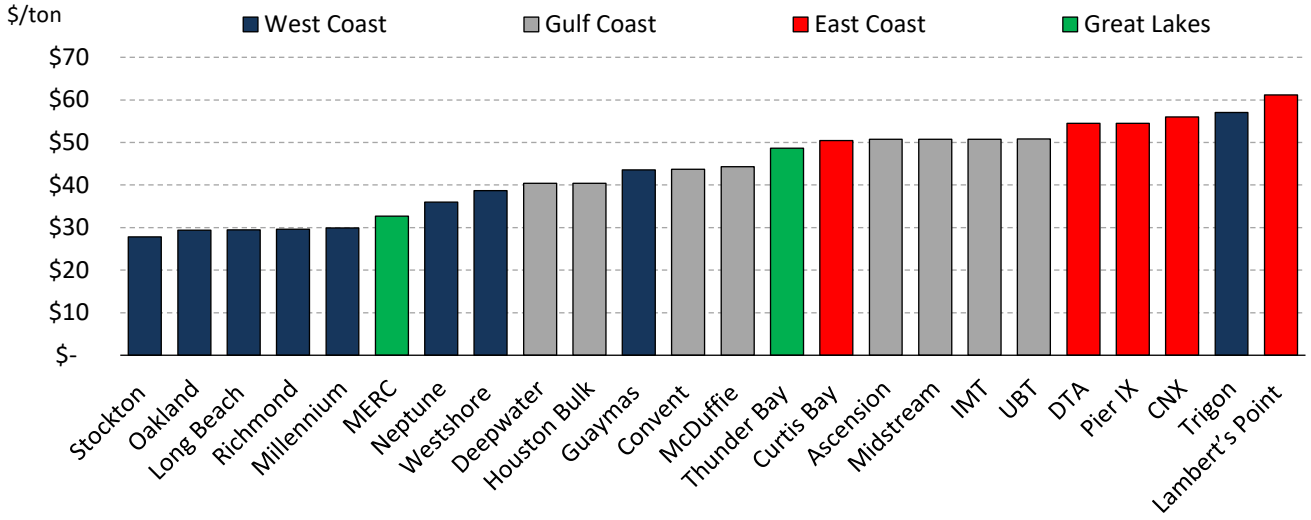
The following cost estimates assume $14 per ton and $40 per ton as representative coal costs FOB mine for Wyoming PRB (WY-PRB) and GRB coal mines in 2025. EVA estimated rail costs for all rail routes using the U.S. Surface Transportation Board's Uniform Rail Cost System (URCS) data for 2023 and adjusted them for 2025 using the Association of American Railroad's Rail Cost Adjustment Factor (RCAF), including fuel. Rail mileage for each rail move was established using the industry-standard PC-Miler Rail software. A revenue-to-variable cost ratio of 1.2 was assumed for all rail segments. A flat $2.50 per ton rail-to-barge transfer fee was applied where applicable. Applicable barge costs were calculated using 2025 average barge rates for coal transportation as published by River Transport News. Only a few terminals published their transloading costs, while most disclose them only to contract customers of the respective terminal. As a publicly traded company, Westshore Terminals, discloses coal revenues and tonnage handled, allowing calculation of its loading rate. For 2025, Westshore's estimated loading rate is $13.55 CAD per tonne (~$10.50 USD per short ton). Similarly, SunCoke provides revenue and tonnage handled for its logistics segment, which includes the Convent Marine Terminal. The calculated loading fee was adjusted upward because it includes lower loading fees for its other river terminals handling domestic tonnage. Public loading fees from previous years for Trigon, McDuffie, and Curtis Bay were inflation-adjusted to estimate 2025 rates. For all other terminals without public information on loading fees, an average of $8 per ton was assumed. **EXHIBIT 5-15** and **EXHIBIT 5-16** show the 2025 inland transportation cost estimates by terminal for WY-PRB and GRB origins, respectively.

EXHIBIT 5-15: 2025 WY-PRB INLAND TRANSPORTATION COST ESTIMATES BY TERMINAL



For Wyoming PRB coal, inland transportation costs to the MERC terminal are the lowest among the 24 terminals evaluated, due to its single-line UP service at approximately 1,100 miles, making it the closest terminal to Wyoming PRB coal mines (however, the MERC terminal is on Lake Superior, with high-cost vessel transportation to reach Asian markets). Westshore's higher port loading fee resulted in higher inland freight costs than at the Neptune Terminal, also located in Vancouver, BC. Unsurprisingly, the East Coast terminals and the Trigon terminal (~2,600 miles from Wyoming PRB coal mines) have some of the highest estimated inland freight costs.

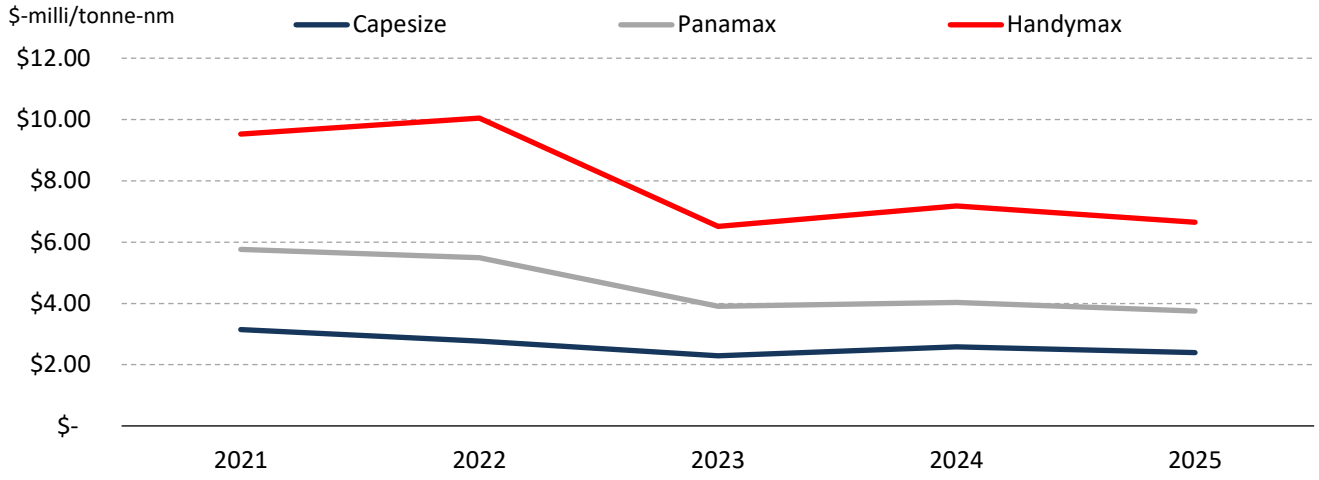
EXHIBIT 5-16: 2025 GRB INLAND TRANSPORTATION COST ESTIMATES BY TERMINAL



For Green River Basin coal mines (e.g., Black Butte), coal terminals along the U.S. and Canadian West Coast (excluding Trigon) have some of the lowest estimated inland freight costs due to their relative proximity (e.g., ~1,000 miles from Black Butte to coal terminals in the Bay Area). Conversely, the coal terminals farthest from the GRB coal mines (i.e., East Coast and Trigon terminals) have the highest estimated inland transportation costs.

The next cost component for delivering Wyoming coal to customers in Asia is ocean freight. As noted earlier, ocean freight rates depend on the size of the chartered vessel and the delivery route. While ocean freight rates can vary considerably throughout the year based on supply or demand, the relationship between rates for different vessel sizes is relatively constant. **EXHIBIT 5-17** shows annual average ocean freight rates by vessel size for the last five years, based on ocean freight rate assessments from S&P Global Platts and OPIC McCloskey.

EXHIBIT 5-17: ANNUAL AVERAGE OCEAN FREIGHT RATES BY VESSEL SIZE



Source: EVA analysis of ocean freight rates from S&P Global Platts and OPIS McCloskey

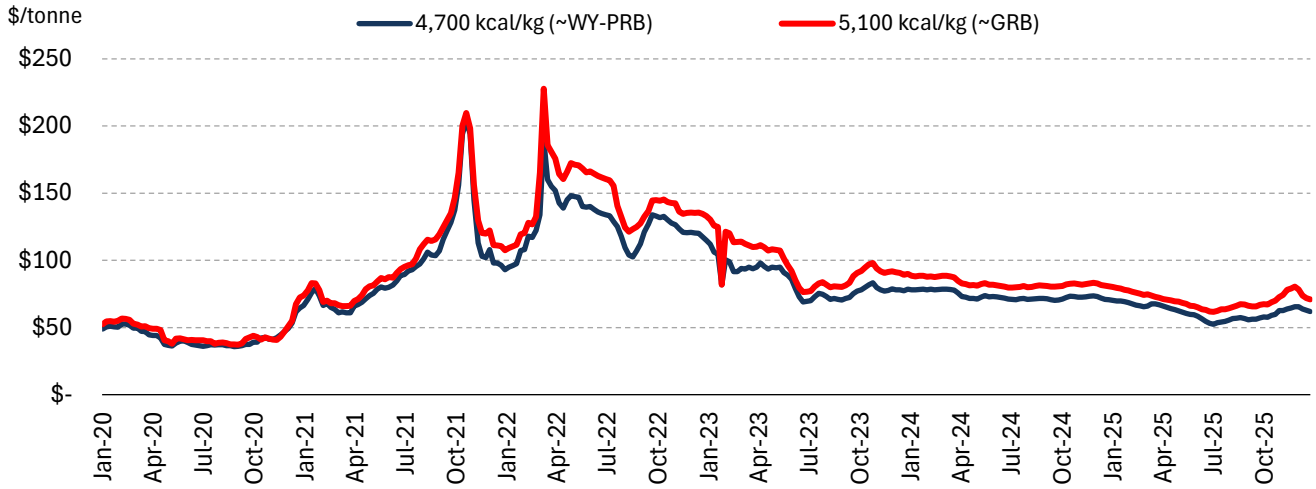
After global coal trade flows normalized in 2023 following the 2022 energy crisis, ocean freight rates for Panamax-sized vessels were, on average, about 70% higher than for Capesize vessels. Handymax vessels were nearly three times as expensive as Capesize vessels over the same period.

Due to significant price differences between vessel sizes, allowing larger vessels can significantly reduce ocean freight costs for Wyoming coal exports via North American coal terminals. For example, allowing the handling of Capesize vessels

at the proposed Oakland coal terminal would lower the estimated ocean freight rate to destinations in Asia by over 35% compared with the nearby Richmond Levin Coal Terminal, which is closing at the end of 2026.

Finally, to assess the viability of Wyoming coal exports to Asia, the analysis includes delivered costs of PRB and GRB coal from Wyoming mines to China, South Korea, and Japan, and compares them to the delivered cost of Indonesian coal of the same quality. **EXHIBIT 5-18** shows the weekly assessed price of Indonesian coal FOB East Kalimantan for coal with heating values of 4,700 kcal/kg NAR (WY-PRB equivalent) and 5,100 kcal/kg NAR (GRB equivalent). Excluding the global energy crisis from late 2021 through early 2023, Indonesian coal prices for 4,700 and 5,100 averaged $67/tonne and $76/tonne in 2024 and 2025, respectively.

EXHIBIT 5-18: THERMAL COAL MARKET PRICE - FOB EAST KALIMANTAN (INDONESIA) BY QUALITY



Source: S&P Global Platts

EXHIBIT 5-19, **EXHIBIT 5-20**, and **EXHIBIT 5-21** compare the total delivered coal cost of Wyoming PRB coal at representative ports in China, South Korea, and Japan across all 24 major North American coal terminals, respectively, and compare it to the estimated average, minimum, and maximum market price in 2025 based on Indonesian delivered coal.

Similarly, **EXHIBIT 5-22**, **EXHIBIT 5-23**, and **EXHIBIT 5-24** compare the total delivered coal cost of GRB coal to representative ports in China, South Korea, and Japan across all 24 major North American coal terminals, respectively, and compare it to the estimated average, minimum, and maximum market price in 2025 based on Indonesian delivered coal.

Unsurprisingly, across all six delivered coal price assessments, all major West Coast terminals show the lowest delivered coal costs compared with terminals along the Gulf, East, and Great Lakes coasts, due to substantially shorter inland and vessel transportation routes. On the other hand, delivered costs for the two coal terminals along Lake Superior are estimated to be more than twice as high as those for West Coast terminals, due to smaller vessel size and significantly longer transportation routes.

In all six price assessments, the proposed Oakland Coal Terminal is estimated to have the lowest delivered cost to all three assessed destinations. Its price advantage over other Bay Area coal terminals, such as Stockton or Richmond Levin, is due to Oakland's assumed capability to handle Capesize vessels.

EXHIBIT 5-19: ESTIMATED 2025 WY-PRB DELIVERED COST TO QINGDAO, CHINA BY TERMINAL

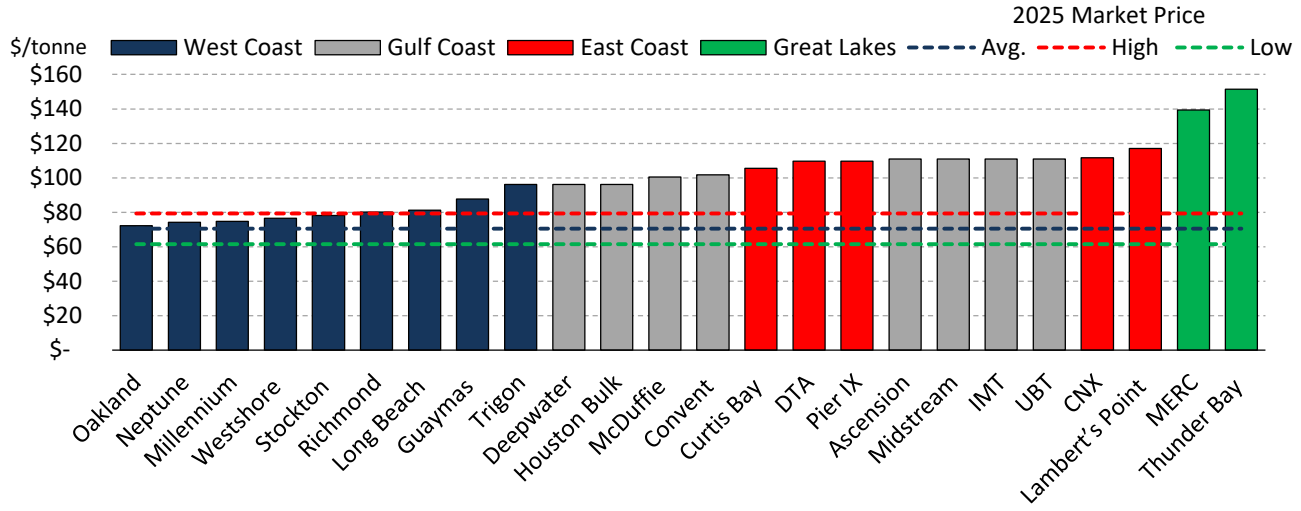


EXHIBIT 5-20: ESTIMATED 2025 WY-PRB DELIVERED COST TO YEOSU, SOUTH KOREA BY TERMINAL

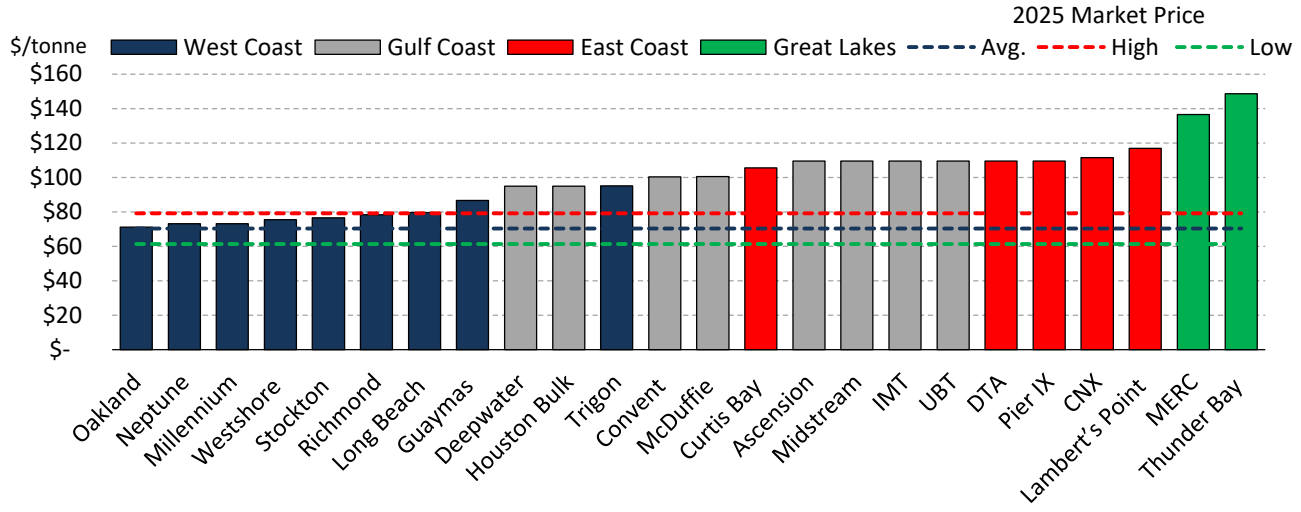


EXHIBIT 5-21: ESTIMATED 2025 WY-PRB DELIVERED COST KINUURA, JAPAN BY TERMINAL

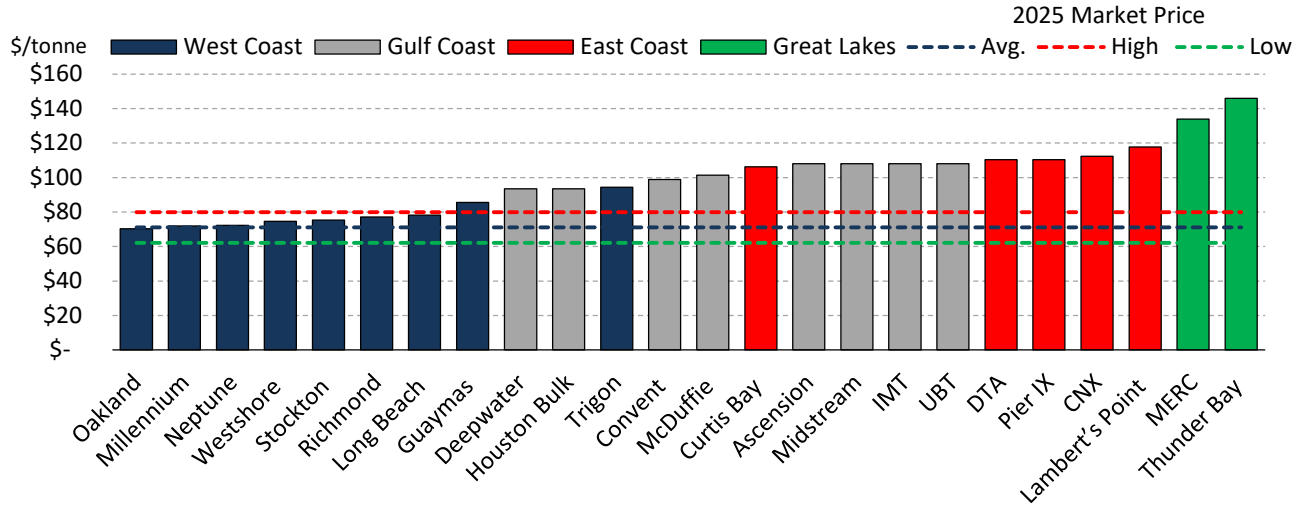


EXHIBIT 5-22: ESTIMATED 2025 GRB DELIVERED COST TO QINGDAO, CHINA BY TERMINAL

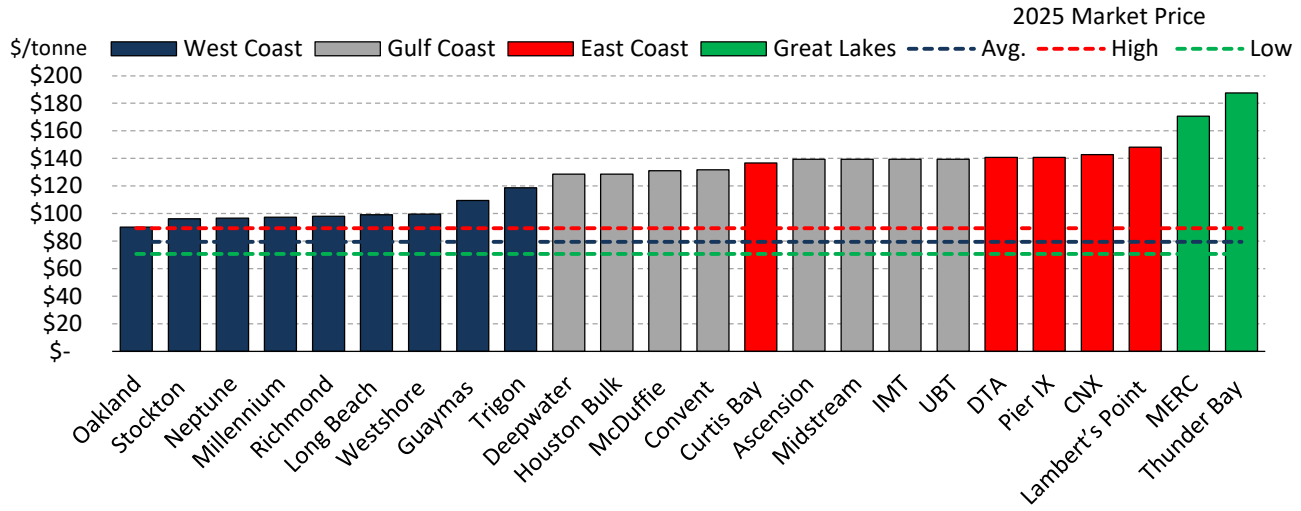


EXHIBIT 5-23: ESTIMATED 2025 GRB DELIVERED COST TO YEOSU, SOUTH KOREA BY TERMINAL

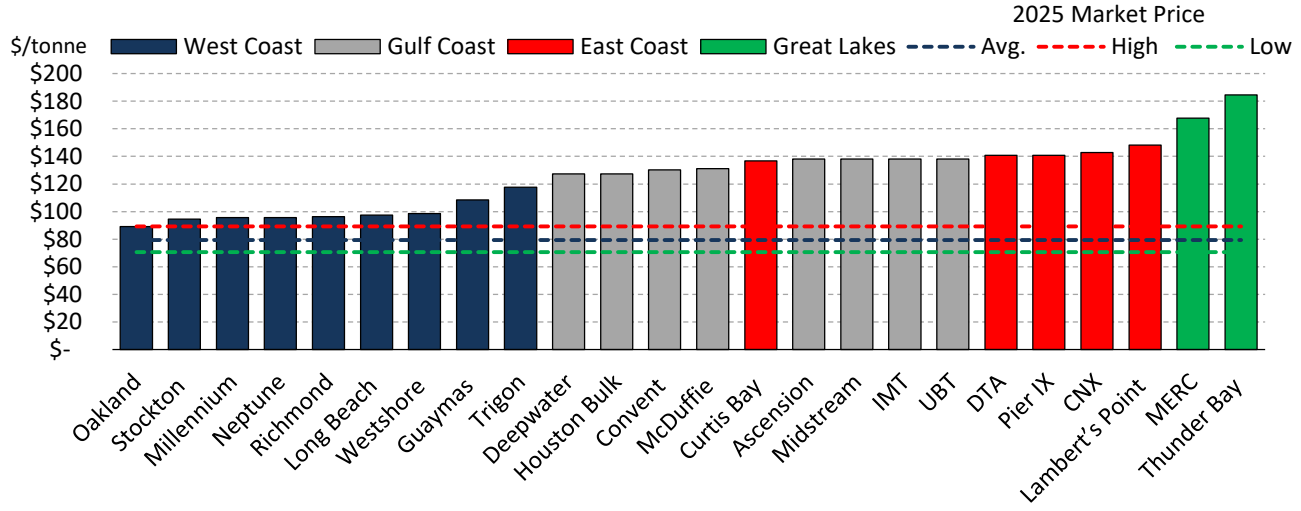
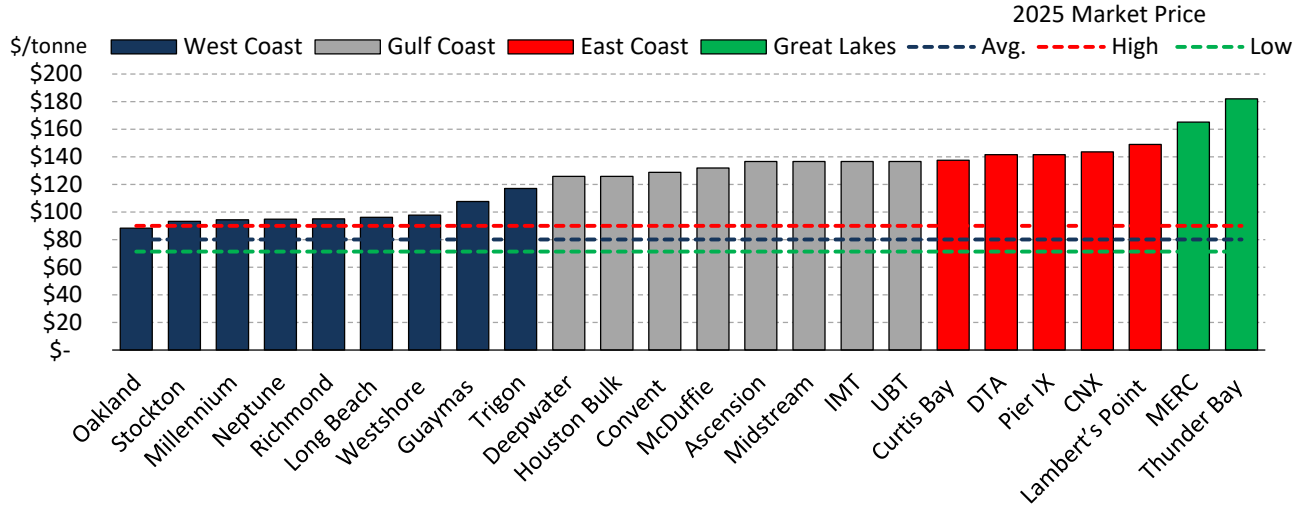


EXHIBIT 5-24: ESTIMATED 2025 GRB DELIVERED COST TO KINUURA, JAPAN BY TERMINAL



The shelved Millennium Coal Terminal is also consistently among the lowest-cost estimates across the six price assessments, thanks to its advantageous location, which yields some of the lowest inland freight costs, especially for

Wyoming PRB coal. Unfortunately, its location along the Columbia River limits the size of vessels the terminal can service to Panamax, which have notably higher ocean freight rates, as previously mentioned.

As mentioned, all six price assessments also include estimated delivered costs for Indonesian coal of comparable quality to the three destinations. Consistent with this, Wyoming coal is most competitive with Indonesian coal in Japan due to lower ocean freight from North American West Coast ports. However, the only North American coal terminal with estimated delivered costs for Wyoming PRB coal to Japan below the average 2025 market price (~$71.10/tonne) is the proposed Oakland Coal Terminal (~$70.30/tonne). For reference, the estimated delivered cost of Wyoming coal to Japan via Westshore is $74.64/tonne. No North American coal terminal had estimated delivered costs for Wyoming PRB coal to Japan below the lowest estimated market price in 2025 ($62.20/tonne).

For GRB, no North American coal terminal had estimated delivered costs for Wyoming PRB coal to Japan below the 2025 average estimated market price ($80.10/tonne). Again, the proposed Oakland terminal has the lowest delivered cost for GRB coal to Japan at $88.24/tonne. For reference, delivered costs via Stockton and Long Beach are estimated at $93.22 and $96.11 per tonne, respectively.

EXHIBIT 5-25 and **EXHIBIT 5-26** provide a detailed estimated cost breakdown by terminal delivered to Japan for Wyoming PRB and GRB coal, respectively.

EXHIBIT 5-25: DETAILED ESTIMATED DELIVERED COSTS BY TERMINAL FOR WYOMING PRB DELIVERED TO JAPAN

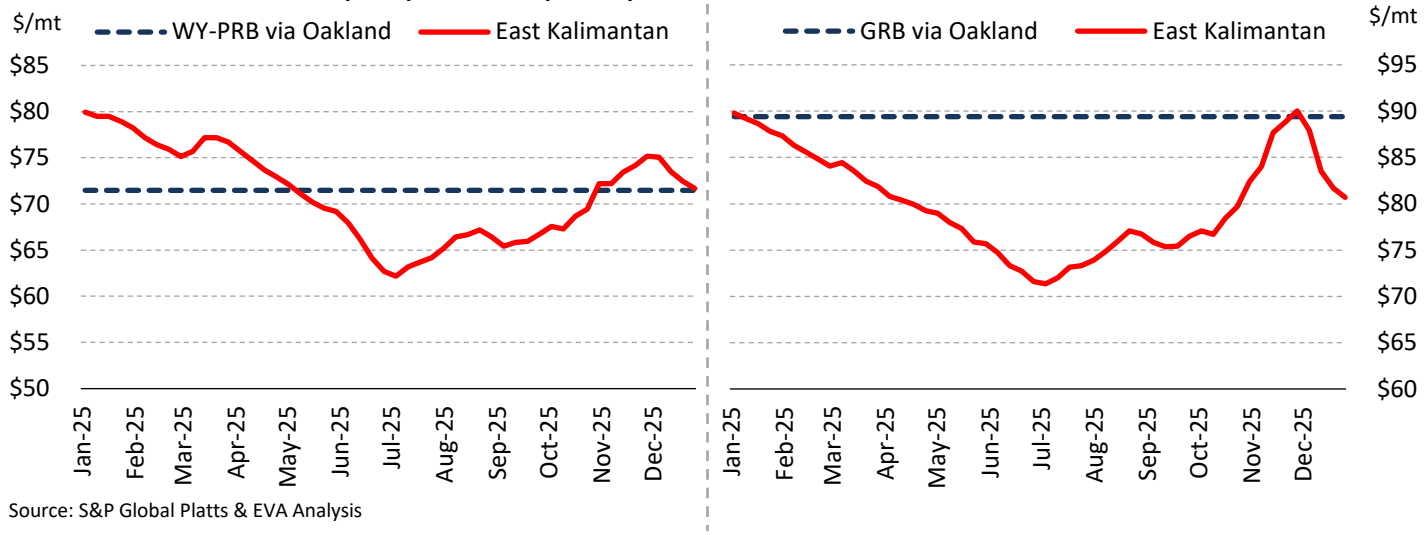
Region/Coast	Terminal Name	FOB Mine ($/ton)	Inland Freight ($/ton)	Port Fee ($/ton)	FOB Terminal ($/mt)	Ocean Feight ($/mt)	Delivered - Japan ($/mt)
Indonesia	***East Kalimantan***	***$ -***	***$ -***	***$ -***	***$ 61.46***	***$ 9.68***	***$ 71.15***
West Coast	Oakland	$ 14.00	$ 31.14	$ 8.00	$ 58.57	$ 11.72	$ 71.46
West Coast	Millennium	$ 14.00	$ 27.53	$ 8.00	$ 54.60	$ 17.31	$ 71.91
West Coast	Neptune	$ 14.00	$ 33.46	$ 8.00	$ 61.13	$ 11.12	$ 72.25
West Coast	Westshore	$ 14.00	$ 33.24	$ 10.46	$ 63.60	$ 11.04	$ 74.64
West Coast	Stockton	$ 14.00	$ 29.50	$ 8.00	$ 56.77	$ 18.50	$ 75.27
West Coast	Richmond	$ 14.00	$ 31.36	$ 8.00	$ 58.82	$ 18.31	$ 77.13
West Coast	Long Beach	$ 14.00	$ 31.17	$ 8.00	$ 58.61	$ 19.63	$ 78.25
West Coast	Guaymas	$ 14.00	$ 41.66	$ 8.00	$ 70.17	$ 15.47	$ 85.64
Gulf Coast	Deepwater	$ 14.00	$ 29.03	$ 8.00	$ 56.25	$ 37.21	$ 93.45
Gulf Coast	Houston Bulk	$ 14.00	$ 29.03	$ 8.00	$ 56.25	$ 37.21	$ 93.45
West Coast	Trigon	$ 14.00	$ 55.88	$ 6.67	$ 84.38	$ 9.93	$ 94.31
Gulf Coast	Convent	$ 14.00	$ 36.88	$ 5.68	$ 62.35	$ 36.49	$ 98.84
Gulf Coast	McDuffie	$ 14.00	$ 33.90	$ 8.71	$ 62.41	$ 38.87	$ 101.28
East Coast	Curtis Bay	$ 14.00	$ 40.39	$ 7.73	$ 68.47	$ 37.72	$ 106.19
Gulf Coast	Ascension	$ 14.00	$ 42.86	$ 8.00	$ 71.50	$ 36.49	$ 107.99
Gulf Coast	Midstream	$ 14.00	$ 42.89	$ 8.00	$ 71.53	$ 36.49	$ 108.02
Gulf Coast	IMT	$ 14.00	$ 42.91	$ 8.00	$ 71.56	$ 36.49	$ 108.04
Gulf Coast	UBT	$ 14.00	$ 42.93	$ 8.00	$ 71.58	$ 36.49	$ 108.06
East Coast	DTA	$ 14.00	$ 44.15	$ 8.00	$ 72.92	$ 37.38	$ 110.31
East Coast	Pier IX	$ 14.00	$ 44.15	$ 8.00	$ 72.92	$ 37.38	$ 110.31
East Coast	CNX	$ 14.00	$ 45.64	$ 8.00	$ 74.56	$ 37.72	$ 112.28
East Coast	Lambert's Point	$ 14.00	$ 50.82	$ 8.00	$ 80.28	$ 37.38	$ 117.66
Great Lakes	MERC	$ 14.00	$ 22.32	$ 8.00	$ 48.86	$ 84.94	$ 133.80
Great Lakes	Thunder Bay	$ 14.00	$ 33.93	$ 8.00	$ 61.65	$ 84.25	$ 145.90

EXHIBIT 5-26: DETAILED ESTIMATED DELIVERED COSTS BY TERMINAL FOR GRB COAL DELIVERED TO JAPAN

Region/Coast	Terminal Name	FOB Mine ($/ton)	Inland Freight ($/ton)	Port Fee ($/ton)	FOB Terminal ($/mt)	Ocean Feight ($/mt)	Delivered - Japan ($/mt)
Indonesia	***East Kalimantan***	***$ -***	***$ -***	***$ -***	***$ 70.40***	***$ 9.68***	***$ 80.09***
West Coast	Oakland	$ 40.00	$ 21.42	$ 8.00	$ 76.52	$ 11.72	$ 89.41
West Coast	Stockton	$ 40.00	$ 19.78	$ 8.00	$ 74.72	$ 18.50	$ 93.22
West Coast	Millennium	$ 40.00	$ 21.93	$ 8.00	$ 77.08	$ 17.31	$ 94.39
West Coast	Neptune	$ 40.00	$ 27.97	$ 8.00	$ 83.75	$ 11.12	$ 94.87
West Coast	Richmond	$ 40.00	$ 21.64	$ 8.00	$ 76.77	$ 18.31	$ 95.08
West Coast	Long Beach	$ 40.00	$ 21.46	$ 8.00	$ 76.56	$ 19.63	$ 96.19
West Coast	Westshore	$ 40.00	$ 28.21	$ 10.46	$ 86.71	$ 11.04	$ 97.75
West Coast	Guaymas	$ 40.00	$ 35.55	$ 8.00	$ 92.10	$ 15.47	$ 107.56
West Coast	Trigon	$ 40.00	$ 50.40	$ 6.67	$ 107.00	$ 9.93	$ 116.93
Gulf Coast	Deepwater	$ 40.00	$ 32.38	$ 8.00	$ 88.60	$ 37.21	$ 125.81
Gulf Coast	Houston Bulk	$ 40.00	$ 32.38	$ 8.00	$ 88.60	$ 37.21	$ 125.81
Gulf Coast	Convent	$ 40.00	$ 38.03	$ 5.68	$ 92.27	$ 36.49	$ 128.76
Gulf Coast	McDuffie	$ 40.00	$ 35.59	$ 8.71	$ 92.93	$ 38.87	$ 131.79
Gulf Coast	Ascension	$ 40.00	$ 42.74	$ 8.00	$ 100.02	$ 36.49	$ 136.51
Gulf Coast	Midstream	$ 40.00	$ 42.77	$ 8.00	$ 100.05	$ 36.49	$ 136.54
Gulf Coast	IMT	$ 40.00	$ 42.79	$ 8.00	$ 100.07	$ 36.49	$ 136.56
Gulf Coast	UBT	$ 40.00	$ 42.81	$ 8.00	$ 100.10	$ 36.49	$ 136.58
East Coast	Curtis Bay	$ 40.00	$ 42.73	$ 7.73	$ 99.72	$ 37.72	$ 137.44
East Coast	DTA	$ 40.00	$ 46.50	$ 8.00	$ 104.17	$ 37.38	$ 141.56
East Coast	Pier IX	$ 40.00	$ 46.50	$ 8.00	$ 104.17	$ 37.38	$ 141.56
East Coast	CNX	$ 40.00	$ 47.99	$ 8.00	$ 105.81	$ 37.72	$ 143.53
East Coast	Lambert's Point	$ 40.00	$ 53.17	$ 8.00	$ 111.53	$ 37.38	$ 148.91
Great Lakes	MERC	$ 40.00	$ 24.67	$ 8.00	$ 80.11	$ 84.94	$ 165.05
Great Lakes	Thunder Bay	$ 40.00	$ 40.65	$ 8.00	$ 97.72	$ 84.25	$ 181.97

Additionally, **EXHIBIT 5-27** shows the estimated delivered cost of Wyoming PRB and GRB coal to Japan and compares it to the actual market price of Indonesian 4,700 kcal/kg and 5,100 kcal/kg NAR delivered to Japan in 2025.

EXHIBIT 5-27: 2025 WY-PRB (LEFT) AND GRB (RIGHT) ESTIMATED DELIVERED COSTS TO JAPAN VS. INDONESIA



Source: S&P Global Platts & EVA Analysis

EXHIBIT 5-28 shows the sensitivity of the delivered cost of Wyoming coal to Japan via the Oakland Coal Terminal to changes in various cost components, as well as the size of the vessel that can be serviced at the proposed terminal.

EXHIBIT 5-28: DELIVERED COAL COST SENSITIVITY BY CATEGORY (DELIVERED TO JAPAN VIA OAKLAND)

	10% change in			Change from Capesize to Panamax
	FOB Mine	Inland Transport	Ocean Freight	
WY-PRB	2.2%	6.1%	1.7%	9.4%
GRB	5.0%	3.7%	1.3%	7.5%

The largest estimated impact on delivered coal prices for Wyoming coal to Japan via the Oakland Coal Terminal is the terminal's Panamax vessel size limit, resulting in estimated increases in delivered costs of 9.4% and 7.5% for WY-PRB and GRB coal, respectively. By comparison, a 10% change in ocean freight rates would result in only 1.7% and 1.3% increases in delivered costs for WY-PRB and GRB coal, respectively, due to their relatively small share of total delivered costs.

For WY-PRB coal, inland transportation costs account for a larger share of total delivered costs than mine costs. As a result, a 10% increase in inland transportation costs would raise total delivered costs for WY-PRB coal to Japan via Oakland by 6.1%. Conversely, a 10% increase in WY-PRB mine prices would increase total delivered costs by only 2.2%.

For GRB coal, mine costs account for a larger share of total delivered costs than inland freight and coal handling rates. As a result, a 10% increase in GRB mine costs would raise total delivered costs for GRB coal to Japan via Oakland by 5%. Conversely, a 10% increase in inland transportation costs would raise total delivered costs by only 3.7%.

5.5.1 Wyoming Coal Export Potential

Wyoming coal exports face significant challenges stemming from existing port infrastructure and competition for available port capacity with other coal mines. First, as previously described, any future growth in thermal coal demand is concentrated in Asia. While some export opportunities exist in South America, Africa, and the Mediterranean, PRB exports would face considerable competition from other U.S. coal basins with more favorable inland and ocean freight costs to these regions, as well as from other countries (e.g., Colombia and Russia) offering thermal coal of similar or better quality, again with considerable transportation cost advantages. As a result, the following port-by-port analysis focuses on Wyoming coal export potential to customers in Asia.

5.5.1.1 Wyoming Coal Exports through Vancouver

The Westshore Coal Terminal has been the primary export terminal for U.S. and Canadian thermal coal to Asia for the past decade. Following the expansion of the nearby Neptune Coal Terminal, Teck Resources shifted approximately 8 million tons of metallurgical exports from Westshore to its jointly owned Neptune Coal Terminal. Since Neptune's expansion in 2021, the terminal has operated at or near its throughput capacity of about 20 million tons. Despite the recent expansion at Neptune, Teck's current metallurgical coal production still exceeds Neptune's available capacity, forcing Teck to continue exporting about 10 million tonnes of metallurgical coal through Westshore.

In addition to Teck Resources, Westshore also handles thermal coal exports from Coalspur's Vista coal mine in Alberta, as well as NTEC's Spring Creek and Signal Peak's Bull Mountains coal mines in Montana. All three coal mines have a notable advantage in inland transportation costs over Wyoming PRB and GRB coal mines.

Although available coal export capacity at Westshore currently exists due to the Neptune terminal expansion, that additional capacity is likely to be absorbed by increased Spring Creek coal exports as its domestic customer base declines. Spring Creek's notable domestic customers include DTE's Belle River coal plant in Michigan, TransAlta's Centralia coal plant in Washington State, Clay Boswell in Minnesota, and SRP's Coronado coal plant in Arizona. These plants accounted for about 7 million tons per year of Spring Creek coal sales over the last five years. However, planned coal-to-gas conversions at Belle River and Centralia, as well as scheduled retirements of Clay Boswell and Coronado, will likely reduce Spring Creek's domestic customer base to less than 1.5 million tons. Should Spring Creek maintain its production of about 12 million tons per year, exports through Westshore could increase to over 10 million tons by 2035. Assuming the continuation of current export levels of metallurgical coal (~10 million tons) as well as thermal coal exports from the Vista

(~6 million tons) and Bull Mountains (~7 million tons) coal mines, Westshore coal export capacity is at its maximum level, with only minimal availability for Wyoming PRB or GRB coal exports.

5.5.1.2 Existing California Coal Terminals

Existing California coal terminals include the coal terminal at the Port of Stockton, the Richmond Levin Coal Terminal in Richmond, and the coal terminal at the Port of Long Beach. Because Panamax-sized coal vessels can be only partially loaded at the Stockton coal terminal due to the maximum draft in the San Joaquin River, vessels have traditionally been "topped off" at the Richmond Levin Coal Terminal before leaving for Asia. However, after years of legal battles, the Richmond Levin Coal Terminal is closing at the end of 2026. Without another opportunity to add coal to coal vessels at a terminal in the Bay Area, coal exports through the Port of Stockton will likely become uneconomical.

California's other major coal terminal at the Port of Long Beach has only limited excess capacity, as it is also a major petroleum coke export terminal for California's refineries. Additionally, about 1 million tons of Long Beach's 4 million-ton throughput capacity is currently used by Utah coal miners, who enjoy a notable transportation cost advantage over both Wyoming PRB and GRB coal mines to the port.

5.5.1.3 Other North American Coal Terminals

Other North American coal terminals along the West Coast include the Trigon terminal in Prince Rupert and the coal terminal at the port of Guaymas in Mexico. The total transportation costs for Wyoming PRB or GRB coal through either terminal make exports through those terminals cost-prohibitive in all but the most extreme cost scenarios for forecasted global thermal coal prices.

As mentioned earlier, exports through Gulf or East Coast coal terminals are also uneconomic in almost all price scenarios. However, sporadic exports of Wyoming PRB coal through Gulf Coast terminals (Houston, Convent, and Mobile) to customers in Europe, Africa, and South America are possible. In most cases, other U.S. and international coal producers are significantly more competitive than Wyoming coal exports.

5.5.1.4 Millennium Coal Terminal

The proposed Millennium Bulk Terminals project was located on a shuttered aluminum smelter industrial site. The project faced more than a decade of permitting delays, ultimately preventing its development. Originally proposed as a large-scale coal export terminal on the Columbia River capable of handling up to approximately 48 million tons per year, the project faced opposition from state agencies and environmental groups. Stakeholders from the local area and along the rail corridor were supportive, including statewide private-sector unions. Key disputes centered on unprecedented environmental review requirements under the Washington State Environmental Policy Act (SEPA), including global greenhouse gas (GHG) emissions, statewide impacts on rail corridors, tribal resources, and river traffic. Contrary to the expectations of many project opponents, the GHG analysis showed a decrease in global GHG emissions if the terminal were built, due to the lower GHG generation of PRB coal mining compared to foreign coal mining. However, the Washington Department of Ecology denied a water quality certification. The SEPA analysis showed no non-mitigatable water quality issues – the water quality certification denial was based on rail and social impacts. Subsequent legal challenges by the company and the states of Wyoming and Montana were dismissed as moot after the company declared bankruptcy due to long permitting delays.

A potential development of the Millennium coal terminal could enable significant Wyoming PRB coal exports. Despite the inland freight advantages of Montana coal mines to the terminal, the proposed size of the Millennium coal terminal would allow 30 million tons per year of Wyoming PRB coal exports. However, current regulatory and political conditions make reviving the project extremely challenging.

5.5.1.5 Oakland Coal Terminal

The proposed Oakland Coal Terminal is a multi-commodity bulk export facility at the former Oakland Army Base, originally designed to handle a range of dry bulk materials, including coal. Unlike the Millennium project, the Oakland terminal has

secured significant infrastructure investment and completed substantial site development, positioning it closer to potential commercialization. However, coal handling at the terminal has been delayed by ongoing legal disputes between the terminal developers and the City of Oakland, primarily over a municipal ordinance restricting coal storage and handling. Recent court rulings have overturned portions of Oakland's coal ban, though litigation and settlement negotiations continue. If the remaining legal and contractual issues are resolved, the terminal could begin coal export operations by the late 2020s, with some market participants targeting late 2028.

From an economic perspective, the Oakland terminal is among the lowest-cost hypothetical export pathways for Wyoming coal, given its proximity to rail corridors and the assumed ability to accommodate larger vessels. However, Utah coal producers are also seeking additional export capacity, especially following the closure of the Richmond Levin terminal in 2026, and they enjoy a notable inland transportation advantage over Wyoming PRB and GRB coal producers. Given the terminal's capacity of 5 million tons and the significant amount of Utah coal available for export, the terminal is unlikely to handle any significant amount of Wyoming coal exports in the near future.

All in all, Wyoming's coal export potential through existing North American coal terminals is minimal due to its comparatively high inland freight costs to key terminals and competition with other domestic and international coal producers for the same customers. Of the two proposed coal terminals, only the Millennium Coal Terminal would allow for significant Wyoming coal exports of about 30 million tons per year, should demand and coal pricing in Asia support it. Although the Oakland terminal has a greater chance of development, its limited capacity and the likely excess supply of transportation-cost-advantaged Utah coal would likely limit the amount of Wyoming coal shipped through the terminal.

6 Coal Supply and Demand Determination

6.1 Executive Summary

This section is an assessment of the Wyoming coal supply capability analyzed in **Section 2** of this report and the demand for Wyoming coal analyzed in **Section 3** for domestic markets and **Section 5** for export markets. The purpose of this section is to integrate the demand outlook for Wyoming coal (both PRB and GRB) and the ability of Wyoming coal production to meet demand under the different cases analyzed.

Section 2 of this report evaluated the annual production capacity and mineable coal reserves at each mine in the two coal-producing regions in Wyoming – the Powder River Basin (PRB) and Green River Basin (GRB). **Section 3** evaluated expected demand for Wyoming coal by sector (power, industrial, and export) under three alternate cases for power sector demand – the Blue Case (most likely under current rules), the Gray Case (the high case assuming replacement of environmental rules restricting coal generation), and the Green Case (the low case assuming implementation of major environmental rules promulgated in 2024). Future coal supply under each case was limited by the availability of mineable coal reserves under existing leases, without new coal leasing. Production was forecast for each coal mine (mine names are withheld to preserve confidentiality), and supply was balanced to match demand. **Section 5** evaluated the potential for Wyoming coal demand in overseas export markets.

Demand for Wyoming coal is projected to decline after 2028 under the Blue Case, because many coal power plants burning Wyoming coal are expected to retire in the 2028 – 2030 period, primarily due to federal and state environmental regulations that require significant capital investments to continue burning coal. Under the Gray Case, coal demand is expected to increase modestly in the near term and continue at or above the current level due to the efforts of the current Administration to support continued operation of coal power plants and repeal the 2024 GHG Rule and the GHG Endangerment Finding. Under the Green Case, coal demand is expected to drop rapidly after 2027 and fall to low levels after 2031, primarily due to the implementation of the 2024 GHG Rule that would force existing coal plants either to co-fire or convert to natural gas after 2029 or retrofit carbon capture and sequestration technology to continue burning coal after 2031.

Without new coal leases, Wyoming PRB coal supply cannot be sustained at the current level of over 200 million tons per year past 2029. Under the Blue Case, coal demand is expected to decline after 2028, which would enable the existing mines to meet demand through 2035. However, if coal demand were sustained at current levels (or increased) under the Gray Case, the existing coal mines will begin to deplete reserves and leave the market short of coal supply before 2030.

Under the Blue Case for coal demand, coal reserves and production capacity is expected to be adequate to meet demand through 2035 in the PRB and 2036 in the GRB before depletion of existing coal reserves would limit coal production. It is likely that the market would feel the effect of the pending reserve depletion by 2032, several years prior to 2035, as many coal power plants purchase coal under multi-year coal supply contracts. Several large PRB coal mines will deplete their existing reserves in the 2033 – 2035 period, so these producers would not be able to offer to supply coal under contracts longer than one year. Under this case, reserve depletion at existing mines would be rapid in the 2035 – 2039 period, and annual coal production capacity would fall below 100 million tons per year, less than half of current levels.

Under the Gray Case for coal demand, the existing PRB coal mines would be unable to meet expected demand by 2030 without additional coal leases. Because of the time required to lease, permit, and develop additional coal reserves, it is questionable whether Wyoming coal supply would be adequate to meet 2030 coal demand even if coal leasing resumes promptly in 2026. In order to meet the Gray Case timeline, it would likely require the immediate implementation of federal leasing and permitting reforms to facilitate timely access to new reserves.

Under the Green Case, the decline in coal demand after 2027 would leave excess production capacity for the foreseeable future. If demand falls to less than half of current levels by 2032, the life of most PRB coal mines would be extended at low production levels to defer mine closing and reclamation.

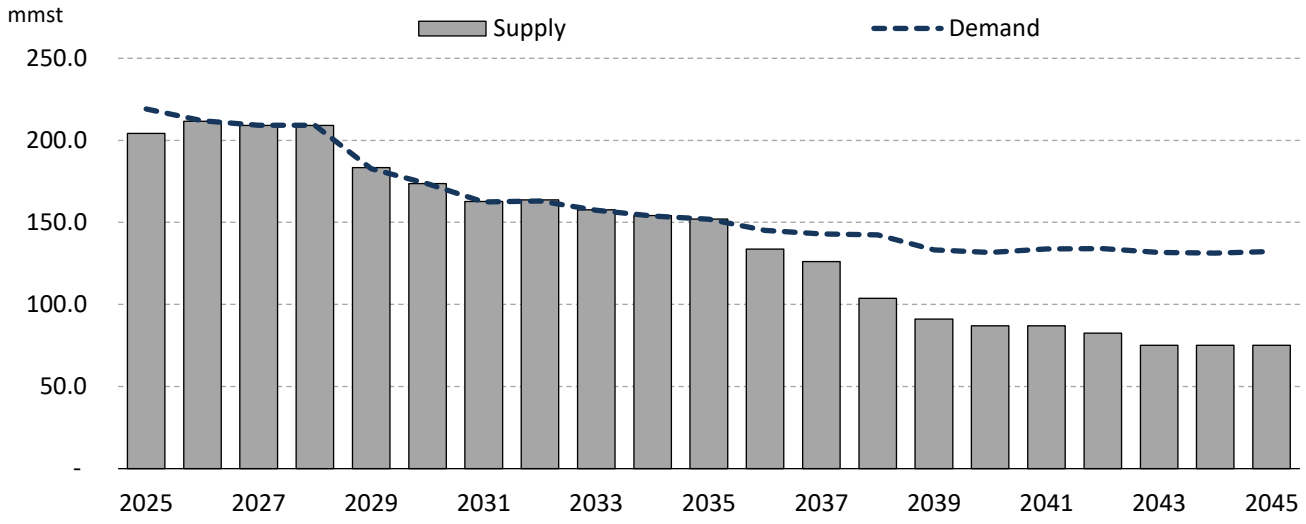
Without a new export coal terminal on the West Coast of the United States, overseas exports are unlikely to be a significant factor for Wyoming coal demand. Export markets are not expected to affect the supply capability for Wyoming coal production to meet demand under different domestic scenarios. However, a new large export terminal, similar to the previously planned Millennium Bulk Terminal in the state of Washington, could meaningfully increase Wyoming coal exports and challenge the ability of Wyoming coal supply to support coal demand in the Blue Case and Gray Case earlier than expected.

6.2 Blue Case

6.2.1 Wyoming Powder River Basin

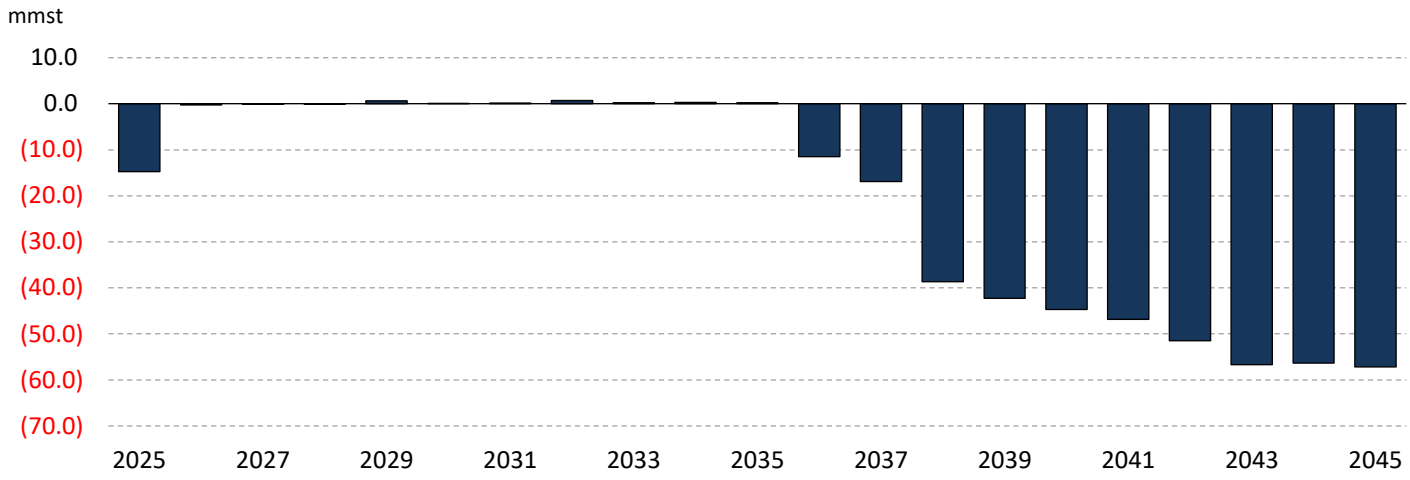
Under the Blue Case, Wyoming PRB coal demand is projected to remain above 200 million tons per year through 2028, then decline to 150 – 160 million tons per year from 2031 through 2035. Long-term demand is projected to remain in the range of 130 – 150 million tons per year through the remaining forecast period.

EXHIBIT 6-1: WY PRB COAL DEMAND & MINE PRODUCTION FORECAST - BLUE CASE



Wyoming PRB coal production capacity is currently over 200 million tons per year and is expected to be adequate to meet demand through 2035 (note: the current year 2025 shortfall is filled by customer inventory drawdown). However, depletion of currently leased reserves will limit WY PRB mine production. Of the 12 existing WY PRB mines, at current production rates, 5 will exhaust their current leased coal reserves and will likely be forced to close by 2036. The coal supply shortfall will grow rapidly, as another 3 existing mines will deplete their leased reserves before 2040. Without additional coal leases, the projected demand will exceed the available supply by more than 40 million tons per year after 2038.

EXHIBIT 6-2: WY PRB PRODUCTION SHORTFALL VS. FORECASTED DEMAND - BLUE CASE



6.2.2 Green River Basin

Under the Blue Case, Wyoming Green River Basin coal demand is projected to drop to about 4.0 million tons per year in 2026, with the conversion of the Naughton power plant to natural gas, and will remain in the range of 3.0 – 4.0 million tons per year through the forecast period. The coal demand is primarily for the Jim Bridger power plant and the trona processing plants in southwest Wyoming.

However, coal supply is projected to decline with the announced closure of the Kemmerer mine and the depletion of the reserves at the remaining mines after 2036 without additional coal leasing.

EXHIBIT 6-3: GRB COAL DEMAND & MINE PRODUCTION FORECAST - BLUE CASE

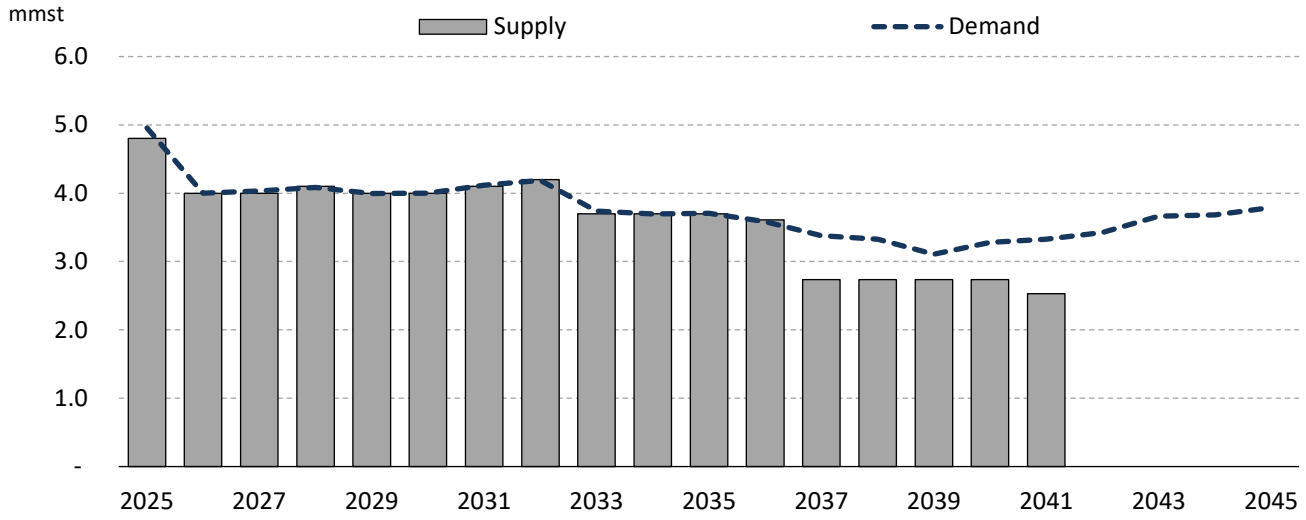
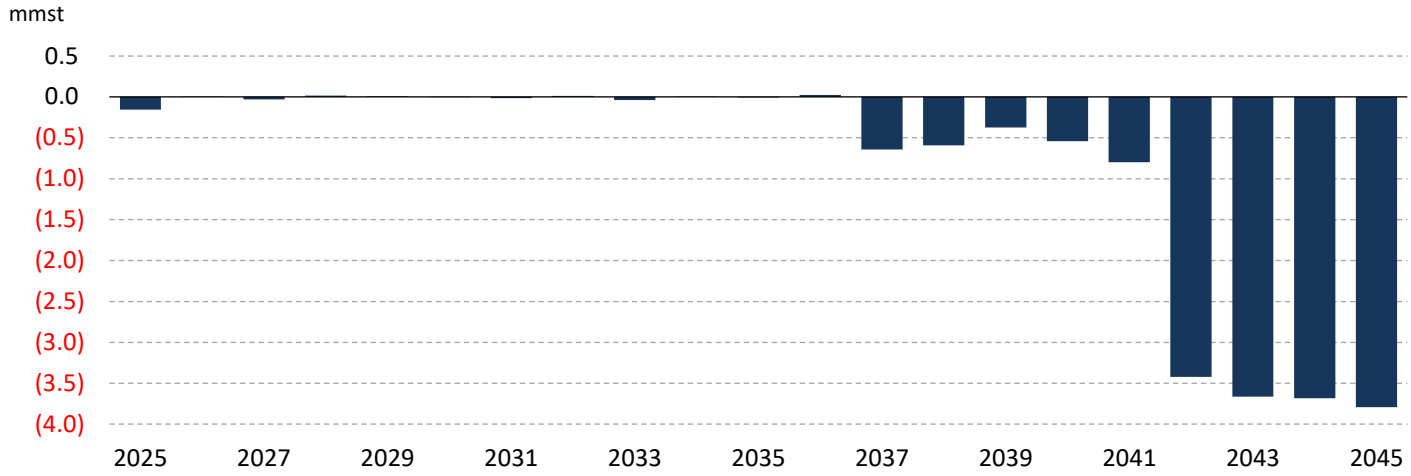


EXHIBIT 6-4: GRB PRODUCTION SURPLUS/(SHORTFALL) VS. FORECASTED DEMAND - BLUE CASE



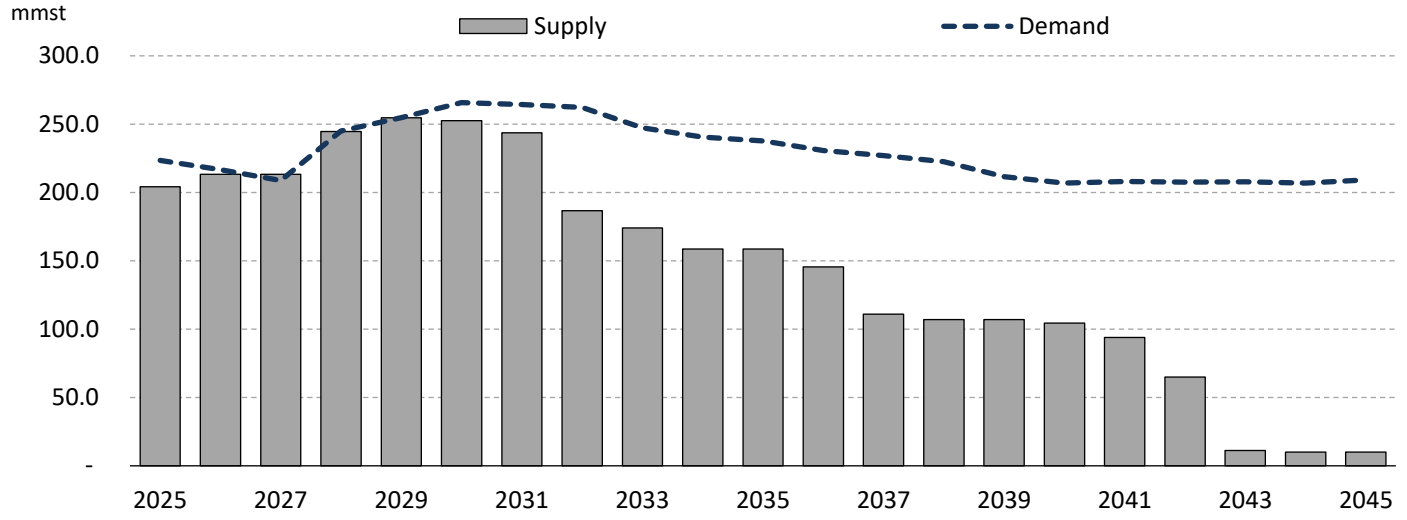
6.3 Gray Case

6.3.1 Wyoming Powder River Basin

In the Gray Case, demand for PRB coal is projected to increase to about 250 million tons per year in 2028 and stay above this level through 2033, as the lives of existing coal power plants are extended and the coal plants dispatch at higher capacity factors due to higher demand for electricity and higher prices for natural gas. While the existing PRB coal mines

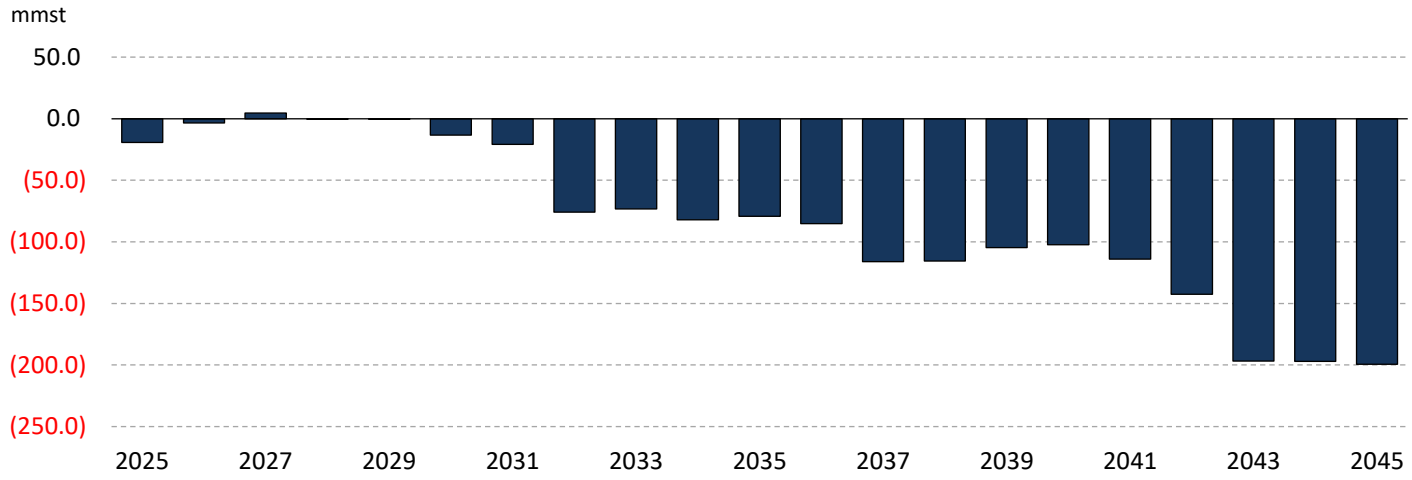
can increase production to meet this higher level of demand in 2028, the mines can only sustain production at this level until 2031, as 3 mines would deplete their existing reserves in the 2029 – 2031 period. Without new coal leases, the existing production capacity would be limited to about 186 million tons in 2032 and would drop quickly through 2037 to less than 110 million tons per year.

EXHIBIT 6-5: WY PRB COAL DEMAND & MINE PRODUCTION FORECAST - GRAY CASE



In the Gray Case, a small PRB production shortfall would begin in 2030 and 2031, but power plants might be able to meet demand using coal inventories. However, by 2032 the shortfall would exceed 70 million tons and would continue to grow in following years. This shortfall would drive up coal prices and force customers to limit coal power generation and switch to other fuels. This shortfall would likely have repercussions across the energy markets, forcing higher power prices and higher natural gas prices for residential, commercial, and industrial customers as natural gas would be needed to replace the shortfall in coal power generation.

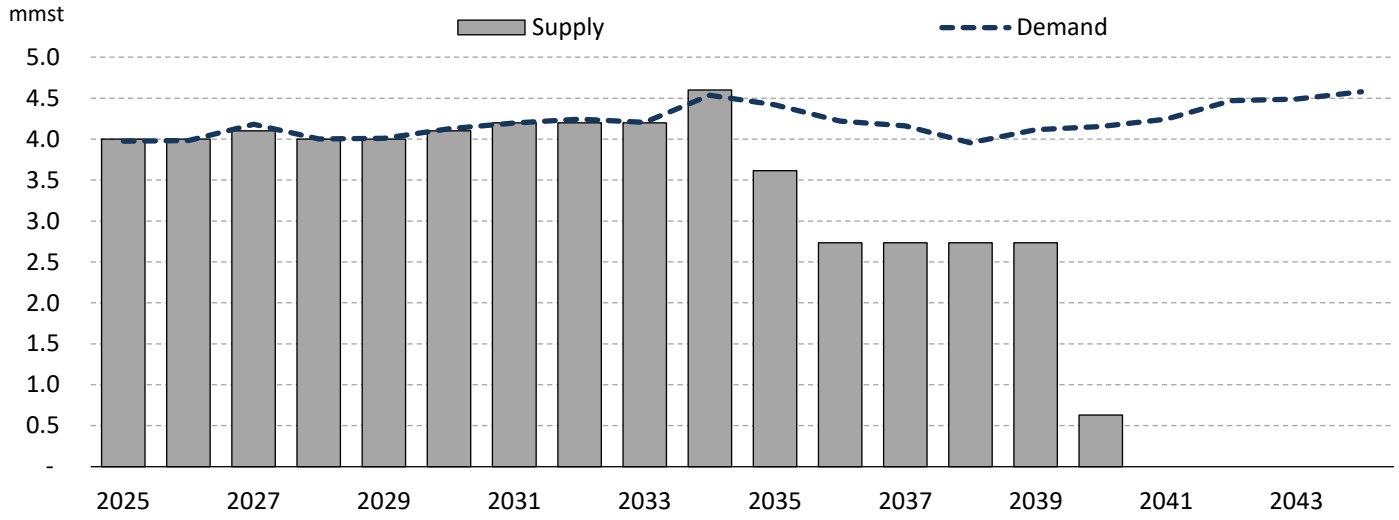
EXHIBIT 6-6: WY PRB PRODUCTION SURPLUS/(SHORTFALL) VS. FORECASTED DEMAND - GRAY CASE



6.3.2 Green River Basin

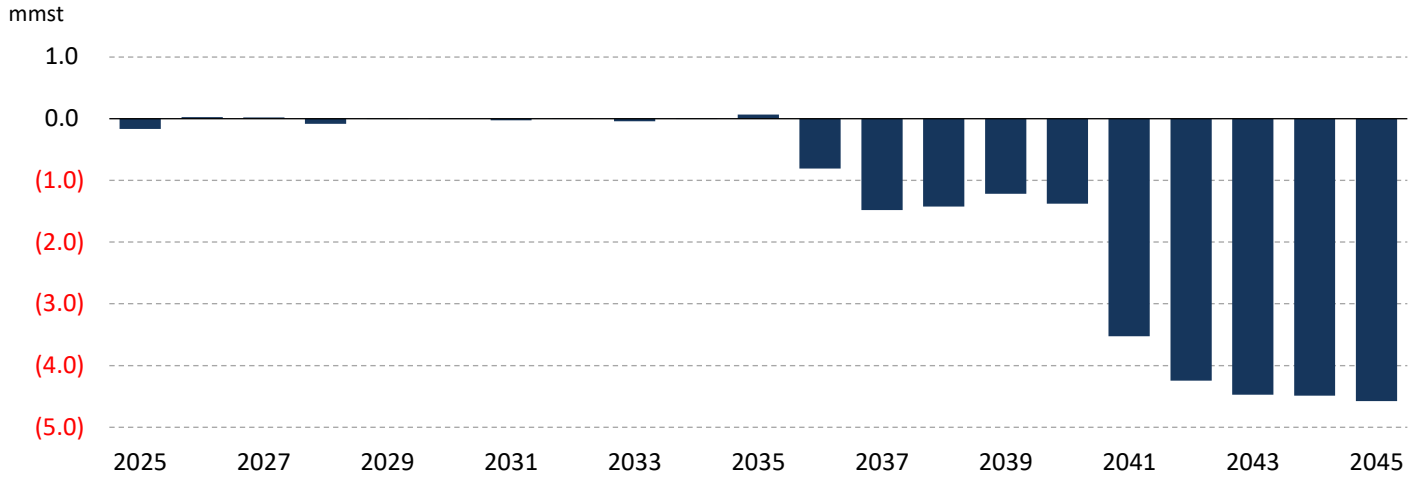
Under the Gray Case, GRB coal demand is expected to be similar to the Blue Case through 2032 but would be sustained at the 4.0 – 4.5 million ton per year throughout the forecast period. The existing mines have the production capacity and the reserves to meet this level of demand through 2034 but will begin to deplete their existing reserves by 2035 and these reserves would be exhausted by 2040.

EXHIBIT 6-7: GRB COAL DEMAND & MINE PRODUCTION FORECAST - GRAY CASE



Without additional new coal reserves, the shortfall of GRB coal supply in the Gray Case begins in 2035. The production shortfall would force the remaining customers (Jim Bridger power plant and the trona mines) to co-fire or convert to natural gas to maintain operations.

EXHIBIT 6-8: GRB PRODUCTION SURPLUS/(SHORTFALL) VS. FORECASTED DEMAND - GRAY CASE

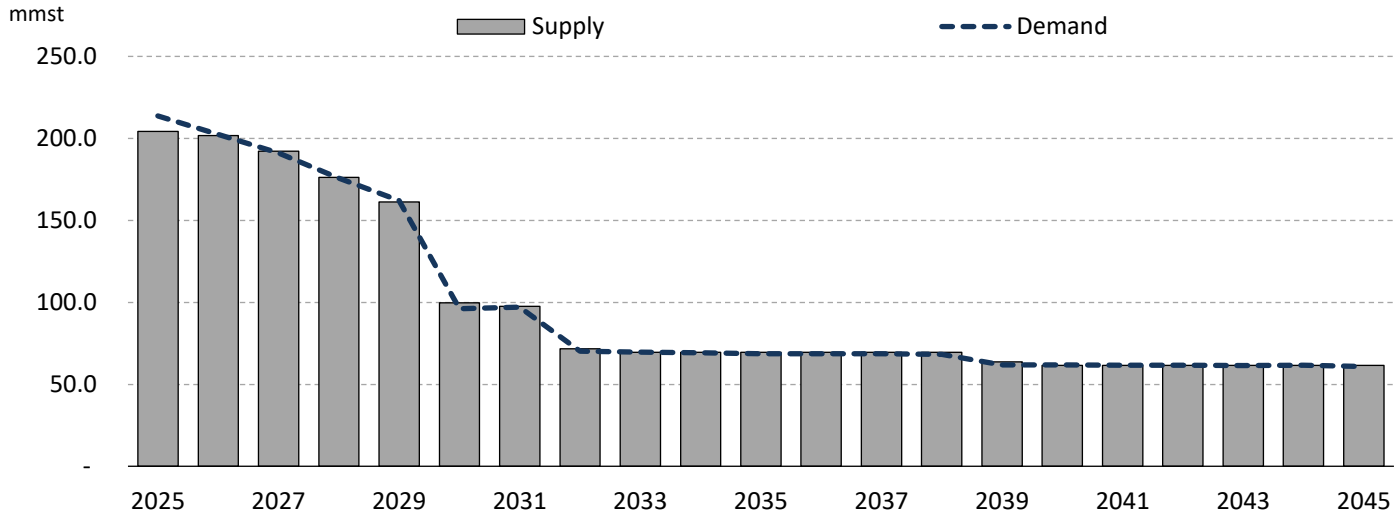


6.4 Green Case

6.4.1 Wyoming Powder River Basin

Under the Green Case, demand for Wyoming PRB coal drops quickly by 2030, as many coal power plants are forced to close by the implementation of the 2024 GHG Rule. Under this case, PRB coal mines will be forced to cut production to match the lower demand levels. Based on prior practice, it is likely that many mines will extend production at low rates to meet due diligence lease requirements and defer mine closure costs. Extended production at low rates would preserve the ability of coal mines to increase output if future demand recovers.

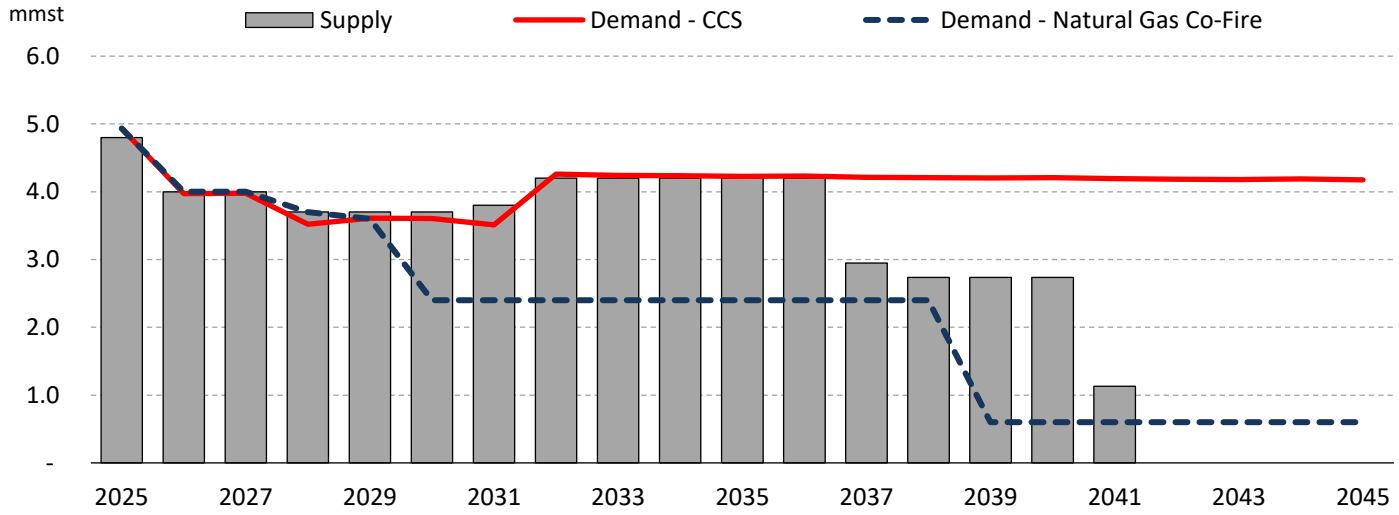
EXHIBIT 6-9: WY PRB COAL DEMAND & MINE PRODUCTION FORECAST - GREEN CASE



6.4.2 Green River Basin

After the conversion of the Naughton plant to natural gas at the end of 2025, demand for Wyoming GRB coal will be limited to the large Jim Bridger power plant and the trona mines located in Southwest Wyoming. Under the Green Case, the Jim Bridger power plant is expected to comply with the 2024 GHG Rule and either add carbon capture and sequestration (CCS) technology by 2032 or convert to co-firing 40% natural gas by 2030 and stop burning coal after 2038. If Jim Bridger adds CCS technology, GRB coal demand is projected to remain about 4.0 million tons per year, while the co-firing technology option would reduce demand to about 2.5 million tons per year in 2030 and drop to only 0.6 million tons per year after 2038.

EXHIBIT 6-10: GRB COAL DEMAND & MINE PRODUCTION FORECAST - GREEN CASE



Under the Green Case with CCS, coal production from the GRB mines is expected to be adequate to support demand through 2036. Depletion of the existing reserves will reduce the available production capacity to less than 3.0 million tons per year in 2037, and the existing reserve base will be depleted in 2041 without additional coal leases.