TABLE OF CONTENTS

APPENDIX G

TALEN MONTANA

COMMENTS OF TALEN MONTANA, LLC ON THE PROPOSAL ON NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW

Docket ID: EPA-HQ-OAR-2018-0794

I. INTRODUCTION

On April 24, 2023, EPA published in the *Federal Register*, at 88 Fed. Reg. 24,854, a Proposal that would amend the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for coal- and oil-fired electric utility steam generating units ("EGUs") — *i.e.*, the Mercury and Air Toxics Standards ("MATS") ("Proposal" or "Proposed Rule"). Among other amendments, EPA is proposing to: (i) tighten the surrogate filterable particulate matter ("fPM") standard for demonstrating compliance with the emissions limits for non-mercury ("non-Hg") metal hazardous air pollutants ("HAPs") from 0.03 lb/MMBtu to 0.010 lb/MMBtu; and (ii) require continuous emissions monitoring systems ("CEMS") for demonstrating compliance with the fPM standard.[1]

Talen Montana, LLC ("Talen Montana") is part-owner and operator of Units 3&4 of the Colstrip Steam Electric Station ("Colstrip") in Rosebud County, Montana. On behalf of itself as an owner and with knowledge gained as the operator of Colstrip, Talen Montana has significant concerns about the Proposed Rule, particularly with the proposed tightening of the fPM standard. These concerns stem from the unique design and circumstances of Colstrip. Colstrip currently uses venturi wet scrubbers to address both sulfur dioxide ("SO_2") and fPM emissions. It would be extremely expensive — and potentially cost prohibitive — for Colstrip to comply with the 0.010 lb/MMBtu fPM limit because the venturi wet scrubbers cannot meet that limit. Colstrip would need to undertake a massive and complex construction project to install new controls — either new fabric filters ("FFs") or electrostatic precipitators ("ESPs") — when Colstrip's remaining life and future generation is likely limited given EPA's other rulemakings targeting older sources like Colstrip. The high costs associated with installing, testing, and implementing new controls, coupled with limited time and electric generation for the recovery of such costs, may cause Colstrip to shut down prematurely if the owners deem that it is not economically feasible to install the necessary controls to comply with the proposed fPM standard.

A premature shutdown of Colstrip would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission, factors that were not considered by EPA in setting the proposed fPM standard. Moreover, Colstrip bears a hugely disproportionate burden under the Proposed Rule, especially where EPA has not found any unacceptable risk related to Colstrip's (or any other affected facility's) operation under the current fPM standard. Indeed, by EPA's own calculations, Colstrip is expected to bear almost 50 percent

[1] *See* 88 Fed. Reg. 24,854 (Apr. 24, 2023).

of the costs of the Proposed Rule. For these reasons, as well as other legal and technical reasons discussed below, Talen Montana asks that EPA not finalize the proposed 0.010 lb/MMBtu fPM limit. However, should EPA ultimately finalize the proposed 0.010 lb/MMBtu fPM limit, Talen strongly urges EPA to establish a subcategory for coal-fired units that use wet scrubbers to address both SO_2 and PM emissions and that do not presently have an ESP or FF, where the fPM limit for those units is no lower than 0.025 lb/MMBtu fPM. Given that EPA's rationale for the Proposed Rule is that existing control technology is more effective and cost effective than was known at the time of the original MATS rule, a targeted limit that is specific to the existing wet scrubber technology is consistent and appropriate with that approach.

As an additional alternative, Talen Montana requests that EPA establish a subcategory for near-term existing coal units electing to retire where the fPM limit remains at 0.030 lb/MMBtu until ceasing operations. This would be consistent with the approach EPA has taken in other rulemakings. Under such an approach, units could opt-in to the subcategory by making an enforceable retirement commitment within a specified timeline after the Proposed Rule is finalized and with retirement planned by a specified date. For this subcategory, Talen Montana proposes that units opt-in within 18 months after the effective date of the final rule with a retirement date no later than December 31, 2035 (with a "safety valve" that would allow longer operation depending on circumstances in the future, as described below).

II. BACKGROUND

Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Talen Montana has a 15% ownership stake in Colstrip, which currently consists of two active coal-fired generating units capable of producing up to 1,480 MW of electricity that have been operating for approximately 37 years. Each of the units has approximately 740 MW of generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal.

A. Colstrip's Unique Design

Colstrip's design sets it apart from other coal-fired units in the country that are currently operating. Colstrip began construction in the 1970s and Units 3 and 4 began operations in the 1980s. Colstrip was designed to utilize low-sulfur coal and with then state-of-the-art venturi wet scrubbers to reduce its SO_2 emissions below the applicable limits. Colstrip also relies on the venturi wet scrubbers to mitigate fPM.

Colstrip has eight wet venturi scrubbers on each of unit. Seven scrubbers are used during normal full load operation and one scrubber is a "backup," used only when one of the other seven scrubbers in operation needs to be removed from service or is undergoing routine cleaning and maintenance. Below is a diagram of the wet venturi scrubber used at Colstrip Units 3&4:

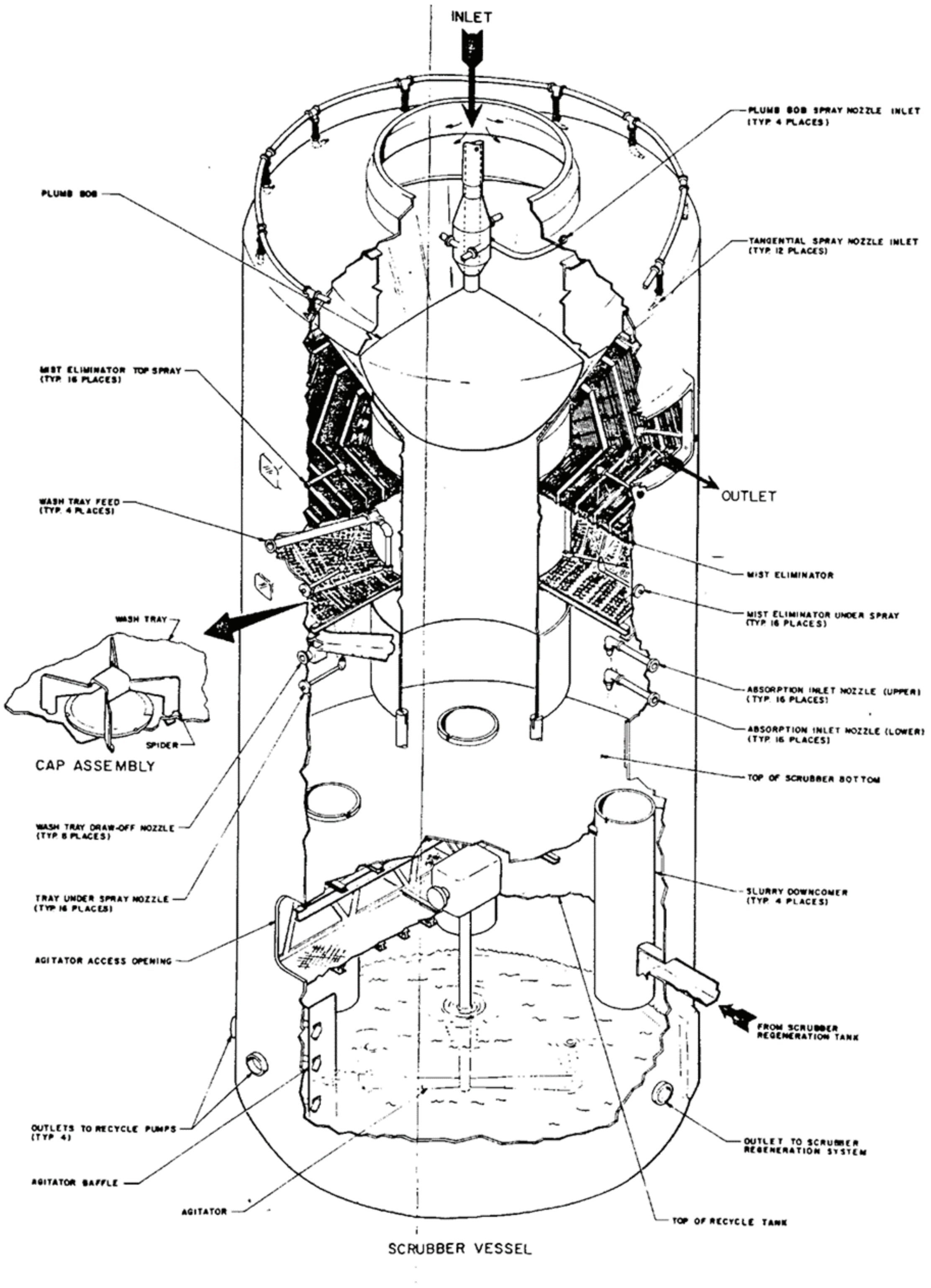

Figure 1 - Diagram of Colstrip Scrubber

The venturi wet scrubbers at Colstrip Units 3 and 4 remove approximately 99.7% of fly ash particulate from the flue gas and 95% of the SO2 via a sequence of removal processes. The flue gas enters the scrubber vessel and is accelerated by the converging surfaces of the plumb bob and venturi bowl. The flue gas and slurry meet in the venturi throat where turbulence atomizes the slurry. Acceleration of the flue gas causes the particulate to collide with and be absorbed by slurry droplets. The majority of the fly ash particulate and most of the SO_2 are removed in the venturi section. The wet venturi scrubbers utilize the alkalinity of the fly ash particle removed to help meet the high level of SO_2 removal. The throat area of the venturi is adjusted by moving the plumb bob up or down to obtain the desired pressure drop across the plumb bob of each scrubber. The flue gas velocity caused by this pressure drop ensures optimum fly ash removal. The slurry and collected fly ash are separated from the flue gas as it turns up to enter the absorption area. The flue gas then enters the absorption spray area in the annular space between the downcomer and shell of the scrubber vessel. The flue gas is contacted with recycle slurry for additional removal of SO_2. Above the absorption section is the wash tray which uses recirculation water to contact the flue gas and remove entrained recycle slurry from the flue gas. The flue gas then flows through the mist eliminator where entrained droplets are removed.

As EPA recognized, Colstrip does not have a FF or an ESP and would need to install one to comply with the proposed 0.010 lb/MMBtu fPM limit, as the current venturi wet scrubbers will not be able to meet the proposed limit.[2] While EPA recognizes that Colstrip's venturi wet scrubbers would not be able to comply with the proposed limit, EPA assumes Colstrip could make a "minimal cost ($10/kW) for [wet scrubber] maintenance or minor upgrades . . . to meet a potential 0.015 lb/MMBtu standard."[3] This assumption, however, is inaccurate. Colstrip has typically been able to remain just below the current limit of 0.030 lb/MMBtu. However, due to occasional variability in fuel and operating condition, Colstrip has, since 2018, hired consultants and engineers to explore ways to further enhance the efficiencies of the venturi wet scrubbers. This work, as described below, has made the venturi wet scrubber emissions more stable. But, as reflected in Attachment A (Colstrip's MATS PM CEMS compliance data from September 2018 to April 2023), the work demonstrated that 0.015 lb/MMBtu fPM is not achievable with upgrades to the existing wet scrubbers and further that the efforts to reduce fPM emissions with the existing control technology has reached its limits:

- The original operating condition for the plumb bob delta P (pressure drop) was 17" to meet particulate and SO2 removal requirements. In an effort to optimize the performance of the scrubbers, the plumb bob delta P is currently operated at 27-28", the maximum delta P achievable which is limited by the capability of the induced draft ("ID") Fans.

- The original mist eliminators have been upgraded with improved performance to better control entrained droplets in the flue gas. In 2018, the mist eliminator supplier (Munters)

[2] *See* 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo"), Doc. ID. EPA-HQ-OAR-2018-0794-5789, at PDF p. 9, posted Apr. 24, 2023.
[3] *See id.*

conducted a mist eliminator performance test, and the results showed dry conditions with very little or any droplet carry over.

- Scrubber slurry solids level has been controlled to 25-30% solids to minimize potential particulate contribution from entrained droplets in the flue gas.

- Flow distribution plates have been installed on each scrubber to improve the flow balance across the scrubber, provide a more uniform flow, and improve particulate removal performance.

Colstrip also implemented additional measures to address combustion conditions to help ensure that combustion of the coal occurs in a manner that prevents to formation of small fly ash particles that are difficult to remove in the wet venturi scrubbers, including:

- Combustion tuning and incorporation of optimum conditions over variable operating conditions into the Combustion Optimizer System.

- Optimization of the furnace sootblower system to ensure optimum heat transfer in the furnace and prevent elevated temperatures in the upper part of the furnace that can contribute to formation of small particulate particles that are difficult to remove in the wet venturi scrubbers.

- Optimization of coal mill fineness by regularly performing coal mill sieve analysis to ensure correct particle size distribution of the coal entering the furnace.

Together, these comprehensive efforts reflect all known upgrades available to be implemented to the Colstrip scrubber/combustion process to reduce fPM, which enables Colstrip to achieve compliance with the current 0.030 lb/MMBtu fPM limit with an adequate compliance margin. While the majority of stack testing has shown emission rates between 0.020 lb/MMBtu and 0.025 lb/MMBtu fPM, there have been several instances where stack tests were above 0.025 lb/MMBtu fPM.[4] In 2022, based on stack tests, the two units combined achieved approximately 0.022 lb/MMBtu fPM on an annual basis.

With the extensive scrubber/combustion process reviews by consultants and engineers and implementation of the upgrades previously identified, Talen Montana believes that these efforts have optimized the current control technology to the maximum extent feasible. While Colstrip remains dedicated to continued optimization to control fPM, Colstrip cannot meet a the more stringent fPM limits in the Proposed Rule (either the 0.015 lb/MMBtu or the proposed 0.010 lb/MMBtu) without installation of a FF or ESP, which as noted previously would be a massive, complex, and expensive construction project.

[4] *See* Attachment A.

B. Colstrip's Unique Circumstances

Despite the importance of Colstrip to Montana and the surrounding region, Colstrip's future is uncertain. Colstrip's remaining life and future generation may be limited by the Inflation Reduction Act ("IRA"), which EPA's IPM runs suggest will cause Colstrip to significantly reduce generation as more renewables come online and other EPA rulemakings targeting older sources such as Colstrip are implemented. These rulemakings, excluding forthcoming ones, impacting Colstrip include: (i) the proposed rule on the Hazardous Solid Waste Management System: Disposal of Coal Combustion Residuals ("CCR") from Electric Utilities; Legacy CCR Surface Impoundments (88 Fed. Reg. 31,982 (May 18, 2023)) ("Proposed CCR Rule"); and (ii) the proposed rule on New Source Performance Standards for Greenhouse Gas ("GHG") Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired EGUs; and Repeal of the Affordable Clean Energy Rule (88 Fed. Reg. 33,240 (May 23, 2023)) ("Proposed GHG Rule").

The costs associated with complying with the proposed fPM limit, compounded with the proposed requirements in these other rulemakings, are massive. Given the reduced lifespan and generation that may be on the horizon for Colstrip, it will be extremely difficult to justify installing new controls to meet such the fPM limit in the Proposed Rule. At a certain point, it is likely that the owners will determine that it is no longer economically feasible to continue operating Colstrip, as they will not be able to recoup the cost of installing controls.

Furthermore, any closure plans necessitate intensive engagement and coordination among stakeholders because Colstrip is vital to Montana and the surrounding region. As concluded in a 2017 study by University of Montana's Bureau of Business and Economic Research, "[t]he early retirement of Colstrip Units 3 and 4 would ultimately produce:

- [A]n economy with, on average, almost 3,300 fewer jobs than would have been present if the units continued to operate through the 2028-43 period[.]

- [A] loss of income received by Montana households varying between $250 and $350 million per year, adding up to a total of about $5.2 billion over the full 16-year period 2028-43. Losses in after-tax income . . . for Montana households would total almost $4.6 billion over the same period.

- [D]eclines in annual gross sales by businesses and other organization, or economic output, between $700 and $800 million, cumulating to $12.5 billion over the full sixteen period.

TALEN MONTANA

- [A] decline in population which occurs as works and families migrate to other economic opportunities, growing to more than 7,000 people by year 2043."[5]

Colstrip also is vital to ensuring that Montanans have affordable and reliability electricity, especially during peak winter and summer months. Colstrip is one of Montana's most important energy assets, especially as demand for reliable baseload power in the western U.S. continues to grow. As Montana state Governor Gianforte has recognized, Montana needs Colstrip.[6]

Thus, EPA's proposal to make the fPM limit more stringent, as well as require CEMS to demonstrate compliance with that limit, has far-reaching ramifications given Colstrip's unique design and circumstances. Talen Montana strongly recommends that EPA reconsider its proposed amendments or to provide the relief requested by Talen Montana herein.

III. COMMENTS

Talen Montana understands that EPA conducted the MATS Residual Risk and Technology Review ("RTR") pursuant to President Biden's Executive Order 13990.[7] The order required EPA to review certain actions undertaken by the prior administration, including the MATS RTR finalized in May 2020.[8] The 2020 MATS RTR indicated that HAP emissions from the source category are acceptable and also did not identify any cost-effective controls that would achieve further HAP emission reductions.[9] While EPA acknowledges in the Proposal that the 2020 Residual Risk Review was sound and is not proposing to modify it, EPA is proposing to determine that the 2020 Technology Review was flawed because it "did not consider developments in the cost and effectiveness of . . . proven technologies, nor did EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs."[10] Following the consideration of such factors, EPA is proposing that the updated technology review requires certain changes to MATS.[11] These changes include the fPM limit and the use of PM CEMS.[12]

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[5] Barkey, Patrick M. "The Economic Impact of the Early Retirement of Colstrip Units 3 and 4 Final Report," June 2018 at 6.
[6] "Governor Gianforte: 'Montana Needs Colstrip,'" State of Montana Newsroom, Jan. 17, 2023, https://news.mt.gov/Governors-Office/Governor_Gianforte_Montana_Needs_Colstrip.
[7] 88 Fed. Reg. at 24,856.
[8] *See* National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units-Reconsideration of Supplemental Finding and Residual Risk and Technology Review, 85 Fed. Reg. 31,286 (May 22, 2020).
[9] *See id*.
[10] 88 Fed. Reg. at 24,865.
[11] *See id.* at 24,856.
[12] *See id.* at 24,857-58.

A. <u>EPA Has Not Established a Sufficient Basis for Tightening the fPM Limit</u>.

Existing coal-fired EGUs currently can demonstrate compliance with the emission limits for non-Hg metal HAPs by meeting: (i) the individual emission limits for each of the 10 non-Hg metals; (ii) an emission standard for total non-Hg metals; or (iii) a surrogate fPM emission standard of 0.030 lb/MMBtu.[13] EPA is proposing to eliminate the non-Hg HAP metals standards, leaving only the surrogate fPM standard. Further, EPA is proposing to tighten the surrogate fPM standard to 0.010 lb/MMBtu, which is comparable to the MATS new source standard of 0.09 lb/MWh fPM (equivalent to a new coal-fired EGU with a heat rate of 9.0 MMBtu/MWh).[14] EPA also is soliciting comment on whether to revise the fPM standard to an even more stringent level of 0.006 lbs/MMBtu.[15]

EPA's proposal to tighten the fPM limit is based on its evaluation that "most-existing coal-fired EGUs are reporting fPM well below the current fPM emission limit of 3.0E-02 lb/MMBtu" and that "the fleet is achieving these performance levels at lower costs than assumed during promulgation of the original MATS fPM emission limit."[16] EPA acknowledged that it did not identify any new practices, processes, or control technologies for non-Hg metal HAPs.[17] For the reasons discussed below, this rationale is not a sufficient basis for tightening the fPM limit.

1. EPA exceeds its statutory authority in 42 U.S.C. § 7412(d)(6).

42 U.S.C. § 7412(d)(6) requires EPA to "review, and revise as necessary (taking into account *developments* in practices, processes, and control technologies) emission standards . . . every eight years."[18] Among other considerations, EPA deems "[a]ny *improvements* in add-on control technology or other equipment (that were identified and considered during development of the original MACT [Maximum Achievable Control Technology] standards) that could result in additional emission reductions" as such "development" under § 7412(d).[19] But EPA has identified no such "developments" or "improvements." Rather, EPA is revising the fPM limit because the Agency says it now has more information about the cost and performance of existing technology than it did when promulgating the original MATS rule.[20] According to EPA's evaluation of such information, existing controls are cheaper and perform better than anticipated, and as discussed below, EPA's evaluation is flawed.[21]

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[13] *See* Table 1, Emission Limits for New or Reconstructed EGUs, Subpart UUUUU, 40 C.F.R. Part 63.
[14] 88 Fed. Reg. at 24,856.
[15] *Id.* at 24,857.
[16] *Id.* at 24,868.
[17] *Id.* at 24,867-68.
[18] 42 U.S.C. § 7412(d)(6) (emphasis added).
[19] 88 Fed. Reg. at 24,863.
[20] *See id.* at 24,863 fn. 15. *See also* National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012).
[21] *See* 88 Fed. Reg. at 24,867-68.

The statute places guardrails on EPA's discretion to revise the existing standards. EPA does recognize that § 7412(d)(6) provides the Agency with authority to revise emission standards but only on specific grounds. This is most evidently reflected in a mere footnote that EPA inserted in the Proposed Rule, where EPA explains that the term "developments" could encompass "getting new or better information about the performance of an add-on or existing control technology (*e.g.*, emissions data from affected sources showing an add-on control technology performs better than anticipated during development of the rule)."[22] Such an interpretation of the term "developments," however, impermissibly stretches the statutory authority EPA has in revising emission standards.[23] Nowhere does the statute provide EPA the discretion to make such revisions for any other reason not enumerated in the statute. To establish a sufficient basis for tightening the fPM limit, EPA needs to point to a *change* in practices, processes, or control technologies and equipment that justifies the corresponding change to the fPM limit. EPA has not done so. As such, EPA does not have authority to promulgate the revised fPM standards.

2. EPA's proposal to tighten the fPM limit is arbitrary and capricious.

a) EPA's evaluation of current fPM emission levels is flawed.

EPA's proposal to tighten the fPM limit is arbitrary and capricious because its evaluation justifying the proposed tightening of the fPM limit relies on questionable methods of analysis and is flawed. EPA states that its proposal to tighten the fPM standard is based on its review of "developments in the current emission levels of fPM from existing coal-fired EGUs, the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a standard that is more stringent than 3.0 E-02 lb/MMBtu and the other statutory factors."[24] According to EPA:

> Currently, 96 percent of existing coal-fired capacity without known retirement plans before the proposed compliance period already have *demonstrated* an emission rate of 1.5E-02 lb/MMBtu or lower, 91 percent of existing coal-fired capacity have *demonstrated* an emission rate of 1.0E-02 lb/MMBtu or lower, and 72 precent of existing coal-fired capacity have *demonstrated* an emission rate of 6.0E-03 lb/MMBtu or lower."[25]

The statistics above appear to be based on the evaluation summarized in the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo"). EPA should not rely on the 96% threshold as justification for setting the proposed fPM limit at 0.010 lb/MMBtu. EPA's reliance on that evaluation is problematic for several reasons and likely overstates the universe of units that will be able to meet the proposed standard.

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[22] *See* 88 Fed. Reg. 24,863 fn. 15.
[23] *See e.g.*, *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 328 (2014) ("We reaffirm the core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate.").
[24] *See* 88 Fed. Reg. at 24,857.
[25] *Id.* at 24,868 (emphases added).

First, the evaluation summarized in the Technical Memo excludes units that have shut down, will shut down, or will no longer burn coal/oil by December 31, 2028, or reported data in lbs/MWh.[26] By failing to include units that will shut down or no longer burn coal/oil by December 31, 2028, EPA is not appropriately accounting for units that are likely emitting fPM at levels closer to the current standard than the more stringent proposed fPM limit. EPA should have accounted for such units given that affected EGUs will have up to three years after the effective date of the final rule to demonstrate compliance with the revised limit, and some of the excluded units may not have retired or ceased burning coal or oil by the compliance deadline.[27] These units should be included when evaluating what fPM levels current technologies are capable of achieving.

If the final rule is issued before December 31, 2025, or if the announced retirements are delayed, these excluded units might become subject to a tighter standard that they cannot meet without large capital outlays to install PM control technology despite near-term projected fuel switches or retirement dates that would render such investments not cost-effective. Units that are retiring in the near-term and cannot meet the fPM limit without the installation of controls could be forced to shut down early, which could destabilize electric reliability in their service areas and could have long-lasting effects. Significant dollars would need to be spent to restart certain generating facilities if it is later determined that the decision to shut down early was detrimental to reliable grid operations. A compliance date based on three years after the final rule's effective date is inconsistent with other recent EPA rulemakings, which recognize that significant investments in emissions controls should not be required for EGUs that will retire in the near-term.

Second, the evaluation is based on selected quarterly data from 2017, 2019, and 2021.[28] The Agency fails to explain how and why it selected the specific quarterly data for those years for its evaluation when EPA has all quarterly tests and PM CEMS for the entire fleet since the effective date of the original MATS rule.[29] The Agency also fails to explain why it used a single quarter of data to present the unit's "baseline" and why "[t]he 99th percentile of the *lowest* quarter was chosen to describe the baseline fPM rate for each EGU."[30] This results in a questionable dataset comprised of an extremely small industry sample size and where a single data point is narrowed down for each EGU. For example, for Colstrip, EPA utilized a baseline of 0.018 lb/MMBtu fPM for Unit 3 and 0.021 lb/MMBtu fPM for Unit 4.[31] These numbers do not reflect what is consistently achievable for Colstrip, as Colstrip has already optimized its existing controls to the greatest extent

[26] *See* Technical Memo at PDF p. 2.

[27] 88 Fed. Reg. at 24,868, fn. 20. EPA excluded units that have *announced* that they will shut down by the end of 2028 based on the National Electric Energy Data System ("NEEDS") database, but such retirement plans are not legally binding and thus such units should *not* be excluded from the Agency's evaluation.

[28] Technical Memo at PDF p. 2. ("Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed because data for all affected EGUs subject to numeric emissions limits had been previously extracted from CEDRI. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019).")

[29] The fact that this information had previously been extracted from CEDRI is no explanation at all. *See id.*

[30] Technical Memo at PDF p. 4. (emphasis added).

[31] *See id.* at PDF p. 4; Appendix C, *id.* at PDF p. 46.

practicable and cannot sustain emissions this low. In 2022, Colstrip achieved approximately 0.022 lb/MMBtu on an annual basis, far above EPA's assumption of the 99th percentile of the lowest quarter.

EPA should use all data available from coal-fired EGUs — except as noted below with respect to units co-firing natural gas and units with an early retirement date — to provide a full picture of achieved fPM emission rates. At the least, EPA should provide justification for its selection of the data, why reliance on the selected data is appropriate, and why certain quarterly data from 2017, 2019, and 2021 were excluded, so that interested stakeholders can verify the accuracy and representativeness of the underlying unit-specific data.[32]

Among other issues in the evaluation, EPA:

- Included some units that will be converted to gas in 2025.
- Did not include data for all quarters but instead selected only quarters with the lowest emissions for some units and excluded other quarters with higher emissions (peaking for some units, ramping for others).
- Excluded some units with no current plans to retire or switch to gas.
- Included some units that have a federally enforceable requirement to cease coal combustion by December 31, 2028 (despite stating that the evaluation excluded coal-fired EGUs that will retire by that date).
- Used the last day of a quarter in some cases and the *average* of 30-day averages for others.
- Included only certain test runs in conducting its distribution analysis.[33]

As to the last point above, EPA should use a historical data pool that encompasses data from different times of year and operating conditions. EPA should include all affected units and all operating quarters in its analysis. Without a more comprehensive data pool, it is difficult to see how EPA could conduct a proper statistical analysis to justify the proposed fPM limit. Talen Montana strongly recommends that EPA correct the deficiencies identified above, as well as make its statistical analysis or Python code used for the fPM evaluation available for public review, to ensure that the proposed fPM limit is not deemed arbitrary and capricious.

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[32] It is confusing as to which units EPA included/excluded, and as to which quarterly data sets were included/excluded. EPA failed to explain its rationale for determining which units and data sets should be included or excluded. The lack of explanation, coupled with the large number of supporting documents in the docket, makes it extremely difficult to identify the unit-specific data compiled, analyzed, and ultimately relied upon by EPA and, more importantly, to meaningfully review EPA's evaluation.

[33] For the same reasons articulated in fn. 32, it is confusing as to which test runs EPA included/excluded in its distribution analysis, and EPA's lack of rationale for how it determined which test runs to use.

Third, the evaluation fails to properly address differences in typical unit operating variability by combining stack test data with PM CEMS data. Stack test data represent unit performance at a discrete point in time under full load conditions, whereas PM CEMS data provide a more comprehensive assessment of unit operating variability under all load and process conditions. These are two different data sets and should be treated independently. This is reflected in EPA's performance specification for PM CEMS, which only requires the readings to be within +/-25% of actual stack testing values two-thirds of the time (with the other one-third of the time not having any accuracy constraint) to be considered as valid readings.[34] EPA fails to explain how using such an error prone data set is justified for establishing an emissions standard. The evaluation fails to recognize that PM CEMS is not constrained to a linear correlation with direct emissions. In cases where non-linear correlations are used, an allowable +/-25% error from the correlated value could have a much larger deviation from the actual measured emissions compared to when a linear correlation is used.[35] Any emissions analysis based upon PM CEMS readings must attempt to compare unit performance in the allowable error band.

Further, any unit using a PM CEMS to demonstrate compliance with the emissions limit also must conduct annual emissions measurements under steady-state conditions, which are utilized in either a Response Correlation Audit ("RCA") or Relative Response Audit ("RRA"). The tested unit must show compliance in the short-term via stack testing measurement values and in the long-term via PM CEMS 30-day average values. For these purposes, PM CEMS data and the PM testing measurements should be treated separately and not merged as a data set. Failing to address these differences is especially problematic because EPA is proposing to require PM CEMS as the sole compliance demonstration method, as discussed further below. EPA should thus revise its current "apples-to-oranges" comparison to establish consistently achievable baseline emissions for each unit by using all available data *and* by accounting for any bias related to operating variability.

Fourth, the evaluation fails to take into consideration different control configurations — specifically, the variation in PM removal efficiencies. Some PM control technology, such as hot-side electrostatic precipitators ("ESPs"), inherently have higher particulate emissions. Similarly, depending on the coal combusted, units that utilize hydrated lime as a control technology for minimizing SO_2 and acid gases inherently have higher variability in particulate emissions. Wet flue gas desulfurization ("WFGD") controls, like Colstrip's venturi wet scrubbers, also may result in higher variability in particulate emissions. EPA should factor in these specific control configurations. EPA also should analyze more comprehensive data sets across a longer time frame — rather than using a snapshot of EGUs "demonstrating" the proposed limit during selected quarters — prior to concluding that continuous compliance with the proposed limit is achievable.

Fifth, the evaluation fails to recognize that some units have converted to natural gas co-firing. Since these units continue to have the capability to combust coal, all of their emissions data is reported as subject to MATS. However, co-firing natural gas inherently results in significantly

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[34] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.

[35] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.

reduced fPM emissions, which could bias the data set low. EPA should exclude data from units that co-fire natural gas in evaluating what a revised fPM standard should be. Any proposed fPM limit that EPA establishes should be based on fPM from affected units that only combust coal.

Lastly, EPA's evaluation is replete with questionable assumptions and statements. For instance, in the technical reports developed by Sargent & Lundy ("S&L"), on which EPA relies for cost and emissions reductions assumptions, S&L acknowledges that "[b]ased on S&L's recent industry experience, the lowest filterable PM emission rates that an ESP supplier has been willing to guarantee is 0.030 lb/MMBtu for a new and/or completely rebuilt ESP."[36] Yet, the study states that "it is clear that emission levels down to 0.010 lb/MMBtu and below are achievable in most ESP applications based on the reported emissions data" despite acknowledging that the authors are unable to tie a specific performance improvement to a specific set of ESP upgrades.[37] EPA should not rely on such unsupported statements to justify a fPM limit of 0.010 lb/MMBtu.

b) EPA's fPM proposal disproportionately impacts Colstrip.

EPA's proposal to tighten the fPM limit also is arbitrary and capricious because it disproportionately impacts Colstrip. Even if EPA were correct that most units subject to the Proposed Rule would have to do nothing and that the remainder would only need to upgrade existing control technology, the same is not true for Colstrip.[38] As EPA acknowledges in the proposal, Colstrip would need to install new ESPs or FFs — and the Colstrip units, based on EPA's analysis, would be the only two units that would need to do so to comply with the proposed 0.010 lb/MMBtu fPM limit.[39]

Given that EPA's rationale for the Proposed Rule is that *existing* control technology is more effective and cost effective than was known at the time of the original MATS rule — that 91% of units already have either a FF or ESP and are meeting the proposed standard and that the rest would only need to upgrade existing control technology at relatively low cost — it simply does not follow that Colstrip should be required to install new, complex, and prohibitively expensive control technology to meet a significantly lower standard.[40] The logical conclusion that should flow from EPA's rationale (assuming that it is not flawed), is that Colstrip should upgrade its *existing* venturi wet scrubber technology to the greatest extent possible.

Instead, EPA proposed that Colstrip should meet the proposed standard by installing new FFs or ESPs at Colstrip. Below is a table summarizing the total annualized cost and the annualized

[36] Sargent & Lundy. PM Incremental Improvement Memo, Doc. ID. EPA-HQ-OAR-2018-0794-5836 at 2 (Mar. 2023). *See also* Technical Memo at PDF p. 8.
[37] PM Incremental Improvement Memo at 2.
[38] *See* Technical Memo at PDF p. 9-10.
[39] *See id.* at PDF p. 10 ("For the *one* facility with existing venturi-type WS (and without an existing ESP or FF), EPA assumes that ESP upgrades will reduce fPM emission to 1.5E-02 lb/MMBtu. To achieve the lower potential fPM standards, EPA assumes that these EGUs would require FF installation, reducing baseline fPM rates by 90% subject to a floor of 2.0 E-03 lb/MMBtu." (emphasis added)).
[40] *See* 88 Fed. Reg. at 24,868; Technical Memo at PDF p. 9-10.

cost EPA attributes for Colstrip to comply with 0.015 lb/MMBtu, 0.010 lb/MMBtu, and 0.006 lb/MMBtu fPM limits:

Table 1: Annual Costs by Potential fPM Standard

	Potential fPM Standard		
Annualized Costs	**0.015 lb/MMBtu**	**0.010 lb/MMBtu**	**0.006 lb/MMBtu**
Total of All Facilities[41]	$13-9-$19.3M	$77.3-$93.2M	$633M
Colstrip[42]	Unit 3: $843,600 Unit 4: $843,600 Total: $1,687,200	Unit 3: $18,992,866 Unit 4: $19,058,306 Total: $38,051,172	Unit 3: $18,992,866 Unit 4: $19,058,306 Total: $38,051,172

As reflected by EPA's own numbers, the annualized cost for Colstrip to comply with the proposed 0.010 lb/MMBtu fPM limit is approximately $38M, which represents 41-49% of the total annualized cost of the Proposed Rule. ***This means that EPA is asking the owners of one facility — representing 0.7% of EGUs subject to the Proposed Rule — to bear nearly 50% of the costs associated with the proposed amendment.***[43] This result is grossly unreasonable, unwarranted, and inconsistent with EPA's rationale for the Proposed Rule and should not be finalized.

c) EPA's cost effectiveness analysis is flawed.

Additionally, EPA's proposal to tighten the fPM standard is arbitrary and capricious because the Agency's cost-benefit analysis is flawed. First, EPA overestimated the benefits attributed to Colstrip if Colstrip were to comply with the 0.010 lb/MMBtu fPM limit. Below is a table summarizing the total fPM emission reductions calculated by EPA and the fPM emission reduction from Colstrip (as calculated by EPA) if Colstrip were to comply with a 0.015 lb/MMBtu, 0.010 lb/MMBtu, and 0.006 lb/MMBtu fPM limits.

[41] Table 7, Technical Memo at PDF p. 12.
[42] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).
[43] *See id.* at PDF p. 2 (evaluating fPM rates from a total of 275 individuals EGUs with Colstrip representing two of those EGUs)

Table 2: fPM Emission Reductions by Potential fPM Standard

	Potential fPM Standard		
fPM Emission Reduction	**0.015 lb/MMBtu**	**0.010 lb/MMBtu**	**0.006 lb/MMBtu**
Total of All Facilities[44]	463 tons/yr	2074 tons/yr	6163 tons/yr
Colstrip[45]	Unit 3: 82.3 tons/yr Unit 4: 166.6 tons/yr Total: 248.9 tons/yr	Unit 3: 442.1 tons/yr Unit 4: 528.3 tons/yr Total: 970.4 tons/yr	Unit 3: 442.1 tons/yr Unit 4: 528.3 tons/yr Total: 970.4 tons/yr

As reflected above, EPA associated nearly 47% of the total fPM emission reduction for the proposed 0.010 lb/MMBtu fPM limit to Colstrip. However, that result relies on questionable assumptions. For instance, to achieve the 0.015 lb/MMBtu fPM limit, EPA assumed that Colstrip would conduct maintenance of its venturi wet scrubbers. But maintenance alone (or any other optimization measures) will not further improve the performance of Colstrip's wet scrubbers, as they are already performing at maximum optimization, as discussed above in Section II.A.[46]

Similarly, to achieve both the 0.010 lb/MMBtu and 0.006 lb/MMBtu fPM limits, EPA assumes that Colstrip will install a new FF that would "reduce[] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu."[47] In taking the 99th percentile of the lowest quarter to describe the baseline fPM rate for each EGU, EPA assumes for Colstrip a baseline of 0.018 lb/MMBtu fPM for Unit 3 and 0.021 lb/MMBtu fPM for Unit 4.[48] ***With a 90% reduction, this means that EPA is assuming that Unit 3 would achieve 0.0018 lb/MMBtu fPM (subject to the 0.0020 lb/MMBtu fPM floor caveat) and Unit 4 would achieve 0.0021 lb/MMBtu fPM with a FF.*** But such emission rates are significantly below either the proposed 0.010 lb/MMBtu fPM limit or the more stringent 0.006 lb/MMBtu fPM limit EPA is considering.

Moreover, EPA has provided zero engineering justification for its assumption that any EGU could achieve such emission rates with FFs/baghouses, much less Colstrip's units with their unique configuration. S&L's technical reports in fact states that FF vendors would not be able to guarantee rates as low as EPA's 0.0020 lb/MMBtu fPM floor assumption. For instance, S&L state that "[w]ith the usage of more expensive fiberglass bags with a PTFE [polytetrafluroethylene] membrane coating, it is expected that 0.00375 lb/MMBtu of filterable PM emission could be achieved *but would not be guaranteed by vendors*" and "[a]s such, a best-case scenario would be

[44] Table 6, *id.* at PDF p. 11.
[45] Appendix D, *id.* at PDF p. 80 (total fPM emission reductions for Colstrip are calculated by summing the annualized costs for Units 3 and 4).
[46] *See id.*; Table 5, *id.* at PDF p. 10-12.
[47] *See id.* at PDF p. 10.
[48] *See id.* at PDF p. 4; Appendix C, *id.* at PDF p. 46.

achieving 0.005 lb/MMBtu."[49] Indeed, based on Talen Montana's discussions with consultants and vendors, it may not be possible to guarantee anything under 0.010 lb/MMBtu depending on the configuration. As a result, EPA has grossly overestimated the emission reductions from Colstrip that, coupled with EPA's unjustified assumptions, renders its cost-benefit analysis flawed. For example, EPA estimates fPM emission reductions of 970.4 tons/yr from Colstrip assuming that Colstrip will achieve emission rates of 0.0020 lb/MMBtu fPM for Unit 3 and 0.0021 lb/MMBtu fPM for Unit 4 once controls are installed. However, as discussed below, Colstrip may only attain an emission rate of 0.010 lb/MMBtu fPM, which corresponds to a reduction of 538 tons/yr using EPA's "baseline."

Second, EPA also underestimated the cost per ton of fPM reduced for Colstrip because EPA's cost effectiveness analysis fails to account for the impacts of the IRA. As EPA states in the Proposal, the Agency's estimates in the analysis "do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the Inflation Reduction Act (IRA), future regulatory actions, or changes in economic conditions."[50] This is problematic because it means that EPA is assuming that Colstrip Units 3 and 4 will continue to operate as baseload units for the foreseeable future.[51] But such an assumption is contrary to EPA's post-IRA IPM model, which predicts that Colstrip will shift away from operating as baseload units and its utilization will decrease. Specifically, the post-IRA IPM model — which accounts for future changes that are likely to occur *only* as a result of the IRA and *not* other factors (*e.g.*, Proposed Rule, Proposed GHG Rule) — assumes that Colstrip will:

- Through 2030, continue to operate as baseload units with an estimated combined heat input of 113 TBtu/year.[52]

- By 2040, reduce its utilization by 25% so that it is estimated to operate at a combined heat input of 85 TBtu/year.[53]

- By 2050, reduce its utilization by 88% so that it is estimated to operate at a combined heat input of 13 TBtu/year.[54]

As reflected in Attachment B, the cost effectiveness of installing new baghouses at Colstrip significantly decreases over time because of reduced utilization. Utilizing EPA's cost numbers (and presumed emission reductions), the cost effectiveness is estimated to be $39,192/ton fPM reduction in 2030 assuming baseload operation (*i.e.*, 113 TBtu/year). However, the cost

[49] PM Incremental Improvement Memo at 9 (original underline omitted, italicized emphasis added). *See also id.* at 10 ("[S]uppliers *may* be willing to provide a filterable PM guarantee of 0.005 lb/MMBtu for new baghouses with PTFE bags." (original underline omitted, italicized emphasis added)).
[50] 88 Fed. Reg. at 24,869-70.
[51] *See* Technical Memo at PDF p. 11.
[52] Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.
[53] *Id.*
[54] *Id.*

effectiveness would be $51,071/ton fPM by 2040 assuming 75% of baseload utilization and $330,026/ton fPM by 2050 assuming 12% of baseload utilization. The post-IRA IPM model predicts an 88% reduction in fPM emissions from Colstrip by 2050, as a result of the IRA *only* and *without* reductions from the Proposed Rule. Thus, by not incorporating the post-IRA IPM model into the analysis, EPA's cost effectiveness estimate for Colstrip is severely underestimated because it is premised on the Colstrip units operating at baseload utilization across a fifteen-year time horizon and fails to account for the change in utilization that Colstrip is projected to undergo by the latter part of that horizon.[55] In other words, Colstrip is projected to operate and emit less, and thus the same costs will be borne to generate fewer tons of reductions.

Third, EPA fails to account for the reduction in remaining useful life and utilization that also may result from EPA's other rulemakings targeting Colstrip, including the Proposed CCR Rule and the Proposed GHG Rule. For instance, EPA's Proposed GHG Rule, if finalized, would make it challenging for Colstrip to meaningfully operate past 2034, or even 2031, given the proposed 20% capacity factor limit for near-term units in the Proposed GHG Rule (assuming that units would need to adopt that limit from 2031 to 2034). But the Proposed Rule would require the Colstrip owners to spend hundreds of millions of dollars to install FFs or ESPs by 2027 or 2028, only to potentially shut down or seriously curtail operations by 2031 due to the Proposed GHG Rule. In considering the cost effectiveness of the rule, EPA should have considered that the costs to upgrade Colstrip may only be spread over three to four years. This would yield astronomically high annualized costs. Moreover, it is highly improbable that the Colstrip owners would shell out those huge sums of money to operate for three or four more years, as the owners would not be able to recoup those costs. Colstrip shutting down prematurely would have far-reaching ramifications on Montana's economy and the surrounding region and grid stability and transmission, as discussed in Section II.B. — none of which EPA considered.

B. <u>The Cost for Colstrip to Comply with the Proposed 0.010 lb/MMBtu fPM Limit is Exorbitant and Requires Significant Time to Install, Test, and Implement the Controls</u>.

Talen Montana retained Burns and McDonell ("B&M"), an engineering consulting firm, to evaluate the cost and feasibility of control technologies available to Colstrip to comply with the proposed 0.01 lb/MMBtu fPM limit. Working with equipment vendors, B&M evaluated the cost and feasibility of a number of controls, including an ESP or a FF upstream of Colstrip's existing wet scrubbers, a wet ESP, and an ESP or a FF downstream of Colstrip's existing wet scrubbers. For the purposes of these comments, B&M conducted a high-level feasibility and cost review that would need to be refined with additional engineering. Actual costs when compared to this level of estimate could be as much as 50% higher than those projected here. Sufficient time was not

[55] *See* Technical Memo at PDF p. 10.

available during the comment period to further refine the feasibility and costs, and EPA rejected Talen Montana's request for more time to undertake additional efforts.[56]

B&M's estimates for the two units combined are summarized below (see Attachment C for the memorandum from B&M which contains a detailed summary of estimates). The first table is how B&M estimates costs, including cost escalation during construction. The second table is meant to be more aligned with how EPA estimates costs, which leads to underestimates:

[56] *See* Talen Montana's Request for Extension of the Comment Period on the National Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, Doc. ID. EPA-HQ-OAR-2018-0794-5880, submitted May 25, 2023 (denied on June 12, 2023).

Table 3: Annual Costs of Control Options at Colstrip to Meet the Proposed 0.010 lb/MMBtu fPM Limit (B&M Class 5 Feasibility Estimates)

		Installed Capital Cost	*Annualized Cost of Controls*
Total (EPA)[57]			$77.3-$93.2M
Colstrip[58]	**Baghouse (EPA)**[59]		$38,051,172
	Upstream ESP (B&M)	$486.0M	$87.4M
	Upstream FF (B&M)	$404.9M	$78.0M
	Wet ESP (B&M)	$744.5M	$104.9M
	Reheat ESP (B&M)	$263.5M	$41.8M
	Reheat FF (B&M)	$351.2M	$56.5M

Table 4: Annual Costs of Control Options at Colstrip to Meet the Proposed 0.010 lb/MMBtu fPM Limit (B&M Estimates Using EPA Cost Approach)

		Installed Capital Cost	*Annualized Cost of Controls*
Total (EPA)[60]			$77.3-$93.2M
Colstrip[61]	**Baghouse (EPA)**[62]		$38,051,172
	Upstream ESP (B&M)	$406.1M	$77.8M
	Upstream FF (B&M)	$338.3M	$70.1M
	Wet ESP (B&M)	$622.2M	$90.4M
	Reheat ESP (B&M)	$220.2M	$36.6M
	Reheat FF (B&M)	$293.4M	$49.7M

[57] Table 7, Technical Memo at PDF p. 12 (for all EGUs subject to the Proposed Rule).

[58] Cost estimates are based on the following assumptions, scope, and other cost factors. Assumptions include: 85% capacity factor, $15/ton disposal, $200/ton lime, $45/MW power, 15-year life, and 8.25% prime rate. Scope includes: ductwork, foundations, control device, electrical (percent based), no fans, no stack modifications, and ash and lime silos and slurring/feed for upstream control options. Other cost factors include: 5% indirect costs, 8% engineering cost, 5% escalation during construction, 15% contingency costs, and 0% owners' cost.

[59] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).

[60] Table 7, Technical Memo at PDF p. 12 (for all EGUs subject to the Proposed Rule).

[61] Cost estimates are based on the following assumptions, scope, and other cost factors. Assumptions include: 85% capacity factor, $15/ton disposal, $200/ton lime, $45/MW power, 15-year life, and 8.25% prime rate. Scope includes: ductwork, foundations, control device, electrical (percent based), no fans, no stack modifications, and ash and lime silos and slurring/feed for upstream control options. Other cost factors include: 0% indirect costs, 8% engineering cost, 0% escalation during construction, 10% contingency costs, and 0% owners' cost.

[62] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).

As reflected above, B&M's estimates of annualized costs are significantly higher than EPA's $38M estimate[63] for a new FF at Colstrip, ranging from $41.7M to $104.9M (using B&M's Class 5 Estimate) and $36.6M to $90.3M (using EPA's approach), assuming that Colstrip is just able to meet the proposed 0.010 lb/MMBtu fPM limit.

Further, the cost effectiveness of each of the control options that B&M evaluated are below, where the first B&M column is based on a fPM baseline of 0.022 lb/MMBtu, which represents Colstrip's average fPM emission rate in 2022, and the second B&M column is based on a fPM baseline of 0.0195 lb/MMBtu, which represents the average of the EPA's fPM baselines for Colstrip's Units 3 and 4. The B&M estimates are calculated using EPA's cost approach.[64]

Table 5: Cost Effectiveness of Control Options at Colstrip

		EPA[65]	***B&M 0.022 lb/MMBtu fPM baseline***	***B&M 0.0195 lb/MMBtu fPM baseline***
Colstrip	**Baghouse**	$39,192/ton		
	Upstream ESP		$114,900/ton	$145,000/ton
	Upstream FF		$103,200/ton	$130,300/ton
	Wet ESP		$133,100/ton	$168,000/ton
	Reheat ESP		$53,900/ton	$68,000/ton
	Reheat FF		$73,200/ton	$92,400/ton

As reflected above, the cost effectiveness for Colstrip to install the various controls are significantly higher than EPA's estimate of $39,192/ton (see Section III.A.2.c, assuming baseload operation), ranging from $73,156/ton to $133,104/ton (using the actual 0.022 lb/MMBtu fPM baseline) and from $68,114/ton to $168,132/ton (using an average of EPA's fPM baseline for the units). In the B&M scenarios, the cost per ton is calculated assuming that the units will just be able to achieve 0.010 lb/MMBtu after controls based on the technical review to date, as opposed to EPA's unrealistic assumptions of a 90% reduction in fPM down to 0.002 lb/MMBtu.

At this preliminary stage, the downstream ("Reheat") options are the most cost-effective. The upstream options, and wet ESP option, are even more costly, and come with additional technical challenges, as outlined in the B&M memorandum attached as Attachment C. Despite the lower cost of the Reheat ESP compared to the Reheat FF, the Reheat ESP comes with more technical challenges in meeting the 0.010 lb/MMBtu standard.[66] The Reheat FF has fewer technological challenges and could be the preferred alternative should Colstrip retrofit to comply with the Proposal. However, with an annualized cost of $56.5 M (using B&M's Class 5 estimates)

[63] Note that EPA fails to provide meaningful information as to how annualized control costs were estimated, how capital costs were specifically calculated for Colstrip, or what specific control configurations were accounted for in the estimates. This has made it difficult for Talen Montana to fully comment on EPA's cost estimates.
[64] *Supra* fn. 61.
[65] *See* Attachment B.
[66] *See* Attachment C.

or $49.7M (B&M's estimates using EPA's cost approach), and with a limited lifespan and limited generation to recoup the costs, it is far more likely that Colstrip would suffer a premature retirement with the potential for serious economic disruption and impacts on grid reliability and transmission.

C. Should EPA Finalize the Proposed 0.010 lb/MMBtu fPM Limit, EPA Should Create Additional Subcategories.

EPA should not finalize the 0.010 lb/MMBtu fPM limit. But should EPA do so, the Agency should establish subcategories so that it accounts for Colstrip's unique design and circumstances. Specifically, EPA should establish a subcategory for coal-fired units that use wet scrubbers to address both SO_2 and PM, and that do not have ESPs or FFs, where the fPM limit for those units is no lower than 0.025 lb/MMBtu pursuant to its authority under 42 U.S.C. § 7412(c)(5). As discussed above, application of the 0.010 lb/MMBtu fPM standard to Colstrip is not appropriate or warranted. At most, EPA should require Colstrip to optimize its existing control technology, consistent with the burden borne by other EGUs, as evaluated by the Agency. While Talen Montana believes that its efforts to reduce fPM have already been optimized, a limit of 0.025 lb/MMBtu fPM may be more achievable, especially as compared to the 0.010 lb/MMBtu fPM limit, as it would at least provide Colstrip an opportunity to try to meet the limit without new control technology. It also would provide for a more stringent limit for Colstrip, with additional emission reductions, and would be more appropriate for Colstrip given its unique circumstances.

As an additional alternative, EPA should establish a subcategory with units making an enforceable commitment to retire, where the fPM limit remains at 0.03 lb/MMBtu through retirement.[67] This would be in line with how EPA is providing lead time for older sources in other rulemakings.[68] Creating a subcategory in the MATS rule for units committing to retire would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, deliberating whether to install controls and continue operation longer than planned to recoup investments in the controls.

Here, EPA should create a retirement subcategory allowing units to continue to meet the existing 0.03 lb/MMBtu fPM standard so long as they opt-in to the retirement subcategory within 18 months after finalization of the rule, with a retirement date no later than December 31, 2035 (and where continued operation after 2035 would later be permitted if (i) the unit is essential to maintain regional grid reliability, as determined by the Western Regional Adequacy Program, Regional Transmission Organizations, Independent System Operators, North American Electric Reliability Corporation, or other similar system reliability authorities; or (ii) or if EPA determines

[67] A unit should qualify for the retirement subcategory as long as it commits to cease burning coal by the proposed deadline of December 31, 2035.
[68] *See e.g.*, Proposed GHG Rule, 88 Fed. Reg. 33,240, 33,245 (May 23, 2023) (near-term retirement units); Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023).

that additional time is required for transition to renewable or clean energy generation).[69] This would provide units another compliance option and needed flexibility.

D. EPA Should Retain the fPM Emission Monitoring Options.

EGUs that do not qualify for the low emitting EGU program currently demonstrate compliance with the fPM standard by conducting quarterly performance testing (*i.e.*, quarterly stack testing), using a PM continuous parameter monitoring system ("CPMS"), or using a PM CEMS.[70] EPA is proposing to eliminate the quarterly stack testing and CPMS options for all coal-fired EGUs — specifically, requiring all coal-fired EGUs to use PM CEMS "[a]fter considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and on the measurement capabilities of PM CEMS, as well as other benefits of using PM CEMS, which include increased transparency and accelerated identification of anomalous emissions."[71] According to EPA, PM CEMS data "supply real-time, quality-assured feedback that can lead to improved control device and power plant operation, which, in turn, can lead to fPM emission reductions."[72]

Talen Montana disagrees with EPA's conclusions and strongly believes that sound engineering approaches using control device operating parameters, such as those found in EPA's required compliance assurance monitoring ("CAM") plans achieve the same ultimate objective of fPM emission reductions. It is unclear how adding another measurement system, particularly given the challenges with PM CEMS as described below, would be cost-effective. Talen Montana urges EPA to retain the option for quarterly stack testing (without any changes to testing frequency) and the CPMS option for all coal-fired EGUs.

1. General Challenges with PM CEMS

EPA should retain the quarterly stack testing and PM CPMS options — particularly if the Agency intends to finalize the proposed 0.010 lb/MMBtu fPM emission limit — to afford entities flexibility in demonstrating compliance with the more stringent limit. Currently, two-thirds of existing EGUs have chosen to demonstrate compliance via the quarterly stack testing approach, and EPA should continue to retain that option in light of the difficulties with using PM CEMS. EPA justifies the proposed requirement to use PM CEMS based on cost, but the Agency understates the costs of PM CEMS and significantly overstates stack testing costs.[73] The costs associated with installing, maintaining, and operating a PM CEMS far outweigh the costs of demonstrating compliance through stack testing, as discussed below.

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[69] It makes sense for units retiring in this time frame to be allowed to continue operations without installation of new controls because the annualized costs for an eight-year period (*i.e.*, installation in the 2027-2028 time period and retirement by the end of 2035) would be excessive. For example, the annualized costs for the reheat FF with an eight-year life would be $76.6M versus $56.5M with a 15-year life.
[70] *See* 40 C.F.R. § 63.10011(b).
[71] *See* 88 Fed. Reg. at 24,857.
[72] *Id.* at 24,872.
[73] *Id*.

In addition, use of PM CEMS may not be appropriate for all coal-fired units given the challenges associated with: (i) meeting the Quality Assurance-Quality Control ("QA-QC") criteria required under Procedure 2; and (ii) establishing the correlation curve using Performance Specification 11 ("PS-11"). First, when a PM CEMS fails to meet the QA-QC criteria required under Procedure 2, the collected data is considered out-of-control and is no longer considered valid.[74] Because the measured emissions values are dependent upon laboratory analysis, an owner/operator has no real time indication that its EGU might have failed the required QA-QC criteria until several weeks after the testing has been completed. This can result in hundreds of hours of monitor downtime being created retroactively after the QA-QC criteria failure has been identified. Monitor downtime is required to be reported as a deviation under the MATS rule, and most states have minimum data availability requirements that could result in enforcement actions. At the more stringent fPM criteria of 0.010 lb/MMBtu (or 0.006 lb/MMBtu), the likelihood of out-of-control periods increases. This downtime is not reflective of poor maintenance or operation but rather the difficulties associated with the required calibration procedure at such low emission levels. Thus, in conjunction with this rulemaking, EPA should include additional provisions in Appendix C of 40 C.F.R. Part 63, Subpart UUUUU to mitigate the effects of this downtime, such as provisional data periods following a failed RRA or RCA. Moreover, there currently is no calibration procedure available that can accurately verify continuous measuring of fPM at levels as low as 0.010 lb/MMBtu, much less 0.006 lb/MMBtu.[75]

EPA attempts to address these issues by proposing to amend Table 2 of 40 C.F.R. Part 63 Subpart UUUUU to require sample volumes of at least 4 dscm per run, rather than at least 1 dscm per run.[76] While the additional sample volume will reduce measurement uncertainty, it does not address the unit and control device operating variability that occurs during correlation testing that would make it difficult to achieve the distinct PM test conditions required under PS-11 and Procedure 2. In addition, when developing the initial correlation curve or conducting ongoing RCAs, emissions controls are de-tuned to simulate upset conditions and to achieve dust loadings at mid- (25-75% of the maximum expected concentration) and high- (50-100% of the maximum expected concentrations) levels.[77] For units equipped with WFGD systems, expanding the test runs to collect 4 dcsm of sample volume significantly increases the flyash carryover to the scrubber.[78] This off-spec material is then required to be landfilled instead of beneficially reused.

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[74] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.

[75] *See* Nicklin, D. et. al., "Techniques to measure particulate matter emissions from stationary sources: A critical technology review using Multi Criteria Decision Analysis (MCDA)," *Journal of Environmental Management*, 296:18-20 (2021).

[76] *See* MATS RTR Rule Text Redline Strikeout document (final) ("Redline Final"), posted on Apr. 25, 2023, at PDF p. 86, 89, 91, 96, 98, Doc. ID. EPA-HQ-OAR-2018-0794-5831. *See also* 88 Fed. Reg. at 24,873-74.

[77] Trying to simulate different ranges of particulates created for test activities often has unintended consequences on the FGD's performance that can take days to normalize and clean up so that the equipment resumes performing as designed. Any additional ash carryover into the FGD increases the opportunity to blind the FGD such that the only recovery is to shut the unit down to add lime or to dump the ash into a storage tank because the material can no longer be stored in the onsite landfill as the chloride content of the sludge, at that point, has become too high.

[78] Ash reinjection may be not feasible for some sources due to stratification issues or ash drop-out effects.

Furthermore, it can take days to weeks for the scrubber chemistry to again reach optimal, steady-state conditions; and maintaining optimal scrubber chemistry is needed to ensure effective removal of mercury emissions. The increased particulate loading will physically impact the equipment and degrade the scrubber's performance, such as: scaling inside the scrubber vessel; plugging spray headers; causing buildup on mist eliminators; and eroding booster and ID fan blades and absorber recirculating pumps.

Second, PM CEMS require the use of PS-11 to establish a correlation curve.[79] For the PS-11 PM CEMS correlation test, a minimum of 15 sets of reference method testing must be conducted that are evenly spaced over three different levels of PM mass concentration by varying process operating conditions, by varying PM control device conditions, or by means of PM spiking.[80] If it is not possible to obtain three distinct levels of PM concentration, zero point testing may be used to perform correlation testing over the maximum range of PM concentration that is practical for the PM CEMS.[81] Each run requires roughly three to four hours, and most sources conduct 18 to 20 test runs for a robust correlation.[82] Barring unpredictable circumstances, based on the proposed sampling time, PS-11 may require seven to ten days to complete. Additional time likely will be needed to maintain the distinct PM test conditions that are required. Sources also will require accurate, preliminary test results to evaluate each test condition and may even need to obtain final results before concluding the test program, which further extend the length and cost of the tests. These activities increase the cost of MATS compliance and overall EGU operation, as well as disrupt the normal operation of the EGU. Ongoing PM CEMS correlation testing with injection of media in the effluent to artificially raise emission levels costs at least $250,000 per test evolution at one source, and testing is required by MATS once every three years. For Colstrip's Units 3 and 4, PM CEMS would cost approximately $136,000/year, whereas quarterly MATS PM stack testing costs approximately $24,000/year. Thus, EPA may have significantly underestimated annual costs associated with a PM CEMS (from $18,111 to $95,397 depending on type) and overestimated annual costs associated with stack testing ($85,127), particularly when specific control configurations are taken into account.[83] Furthermore, the excessive costs of installing and maintaining PM CEMS become even more onerous if required on a unit with limited remaining life (see earlier discussion on how other rules may force retirement, cessation of coal, or decreased capacity factors, or if an early retirement subcategory is created).

More importantly, EPA has failed to show how correlations can be developed on data sets where the upper end of the emissions testing is capped at 0.010 lb/MMBtu fPM following PS-11 requirements. Emissions levels are supposed to be evenly distributed between the low, mid, and high PM emission levels. Even when allowing for a low-emitting unit to use a zero point in the correlation, a correlation still needs data variation to be a valid regression model. By limiting the

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[79] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.
[80] *See id.*
[81] *See id.*
[82] *See id.*
[83] 88 Fed. Reg. 24,872-73.

dataset — pursuant to the proposed 0.010 lb/MMBtu fPM limit — EPA needs to establish that the PS-11 correlation will still be valid at such low levels.

2. Colstrip's Challenges with PM CEMS

Colstrip has utilized PM CEMS as a particulate control performance indicator in its PM CAM Plan since 2014. The initial PM CEMS were a light scattering technology that encountered times when they did not accurately indicate particulate emissions from the wet venturi scrubber at Colstrip Units 3&4. In September 2020, the PM CEMS were changed to the MSI BetaGuard 3.0 PM CEMS. The BetaGuard PM CEMS has performed better than the light scattering technology at Colstrip; however, it still exhibits variability that would not be acceptable to be used as a continuous compliance monitor. When compared to the quarterly MATS PM compliance test results, the BetaGuard PM CEMS has provided mg/m^3 values that varied from the RM5 mg/m^3 value by -24% to +31%. Talen Montana believes this range of variability with the PM CEMS is not acceptable for use as a compliance monitor, but its use as part of a PM CAM Plan like Colstrip utilizes, is reasonable.

The PM CAM Plan is a requirement under Colstrip's Title V Operating Permit to help ensure compliance to the particulate standard utilizing performance indicators and an operational parameter. The performance indicators include opacity monitoring and PM CEMS, and the operational parameter is scrubber plumb bob delta P.

PM CEMS requirements under Colstrip's PM CAM Plan are robust and include:

- Installation per manufacturer's standards.
- Daily zero and span checks using manufacturer's standards.
- Initial correlation based on three levels (zero, normal operations, and at scrubber operations that increase PM but not at a level that puts Colstrip's Title V requirements at risk). This initial correlation used three RM5 runs at normal operations and two RM5 runs at the higher PM level. This correlation relates PM CEMS mg/m^3 to RM5 mg/m^3.
- A PM CEMS CAM Plan excursion limit in terms of mg/m^3 is established.
- A PM CEMS CAM Plan excursion requires a prompt investigation to identify and correct the condition, followed by a RM5 test to confirm compliance with the particulate standard.
- On a quarterly basis, one RM5 test (comprised of three runs) will be conducted to update the initial correlation. If the result from the average of the three runs differs

from the initial correlation by 25% or more of the CAM Plan excursion limit, then the initial correlation will be repeated.

- An on-going PM CEMS correlation adjustment will be made quarterly based on the correlation from all RM5 test data.

- PM CEMS daily averages are submitted to MDEQ on a quarterly basis.

Given Colstrip's experience with the use of PM CEMS as a performance indicator, which shows that the CEMS results are highly variable and not reliable, EPA should not finalize the CEMS requirement in the Proposed Rule. If EPA does finalize the CEMS requirement, EPA should: (i) carve out units like Colstrip Units 3 and 4 that already have a CAMS plan that utilizes performance indicators and operational parameters to ensure compliance with the particulate standard; and (ii) not require PM CEMS for units that would only be subject to MATS for a limited time after the effective date of the final rule.

IV. CONCLUSION

Talen Montana appreciates the opportunity to submit comments on the Proposed Rule. Talen Montana respectfully requests that EPA consider the recommendations above to ensure that the Agency accounts for Colstrip's unique design and circumstances, as well as to account for the prohibitive costs that Colstrip faces if it were forced to comply with the proposed fPM limit. Colstrip is vital to Montana, and premature retirement could jeopardize Montanans' access to affordable and reliable electricity, especially during extreme weather conditions.

Dated: June 23, 2023

Respectfully submitted,

Thomas Weissinger
Sr. Director – Environmental
Talen Energy
thomas.weissinger@talenenergy.com

ATTACHMENT A

Please see native Excel file "ATTACHMENT A" accompanying Talen Montana's comments.

ATTACHMENT B

The following table summarizes how the cost effectiveness of installing a new baghouse at Colstrip was calculated using EPA's post-IRA IPM model. The table was prepared by Trinity Consultants, which Talen Montana retained for the purposes of preparing comments on the Proposed Rule.

Colstrip New Baghouse Cost Effectiveness

Scenario	Unit	Heat Input (MMBtu/yr)	Current FPM Emission Factor (lb/MMBtu)	FPM Emissions (tpy)	% Reduction in FPM without Proposed Rule	New Baghouse Cost ($/yr)	FPM Emission Factor with New Baghouse (lb/MMBtu)	FPM Emissions with New Baghouse (tpy)	FPM Emissions Reduction from New Baghouse (tpy)	New Baghouse Cost Effectiveness ($/ton)
EPA Proposed Emission Reductions (Baseload Operation)	3	55,255,556	0.018	497.3		18,992,866	0.0020	54.7	442.6	42,912
	4	55,904,762	0.021	587.0		19,058,306	0.0021	58.7	528.3	36,075
	Total	**111,160,317**		**1084.3**		**38,051,172**		**113.4**	**970.9**	**39,192**
Emission Reductions Using 2040 Base Case	3	42,374,312	0.018	381.4		18,992,866	0.0020	42.0	339.4	55,957
	4	42,925,688	0.021	450.7		19,058,306	0.0021	45.07	405.6	46,982
	Total	**85,300,000**		**832.1**	**23%**	**38,051,172**		**87.0**	**745.1**	**51,071**
Emission Reductions Using 2050 Base Case	3	6,557,338	0.018	59.0		18,992,866	0.0020	6.5	52.5	361,602
	4	6,642,662	0.021	69.7		19,058,306	0.0021	6.97	62.8	303,606
	Total	**13,200,000**		**128.8**	**88%**	**38,051,172**		**13.5**	**115.3**	**330,026**

Scenarios. The scenarios presented for calculating the cost effectiveness of installing a baghouse at Colstrip are: (i) based on the utilization and heat input predicted EPA's post-IRA IPM model from present to 2050;[84] (ii) based on EPA's "baseline" for Colstrip, which represents the 99th percentile of the lowest

[84] Final Version of the RIA [Regulatory Impact Analysis] for the Proposed EGU MATS RTR, Doc ID. EPA-HQ-OAR-2018-0794-5837; Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.

quarter among the 2017, 2019, and 2021 data EPA evaluated;[85] and (iii) based on EPA's assumption that installing a baghouse would "reduc[e] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu.[86]

Heat Input (MMBtu/yr). Heat input is calculated by EPA's Post-IRA 2022 Reference Case.[87]

Current FPM Emission Factor (lb/MMBtu). Current fPM emission factor is EPA's "baseline" for Colstrip, which represents the 99th percentile of the lowest quarter among the 2017, 2019, and 2021 data EPA evaluated.[88]

FPM Emissions (tpy). fPM emissions are calculated by multiplying the Heat Input (MMBtu/yr) by the Current FPM Emission Factor (lb/MMBtu) and diving by 2000 lb/ton.

New Baghouse Cost ($/yr). New baghouse cost is EPA's annualized cost estimate for Colstrip to achieve compliance with the proposed 0.010 lb/MMBtu fPM limit via a new baghouse.[89]

FPM Emission Factor with New Baghouse (lb/MMBtu). fPM emission factor with new baghouse is based on EPA's assumption that installing a baghouse would "reduc[e] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu.[90]

FPM Emissions with New Baghouse (tpy). fPM emissions with new baghouse are calculated by multiplying the Heat Input (MMBtu/yr) by the fPM New Baghouse Emissions factor (lb/MMBtu) and then diving by 2000 lb/ton.

FPM Emissions Reduction from New Baghouse (tpy). fPM emission reduction from new baghouse is calculated by subtracting fPM emissions with new baghouse (tpy) and fPM emissions (tpy).

New baghouse cost effectiveness ($/ton). New baghouse cost effectiveness is calculated by dividing new baghouse cost ($/yr) by fPM emissions reduction from new baghouse (tpy).

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[85] *See* Technical Memo at PDF p. 4.
[86] *See id.* at PDF p. 10.
[87] Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.
[88] *See id.* at PDF p. 4.
[89] Appendix D, *id.* at PDF p. 80.
[90] *See id.* at PDF p. 10.

ATTACHMENT C

BURNS McDONNELL

June 23, 2023

Mr. Gordon Criswell
Talen Montana
580 Willow Ave, PO Box 38
Colstrip, MT 59323

Re: Talen Energy Colstrip/ Mercury and Air Toxics Standards (MATS) Analysis

Dear Mr. Criswell:

Talen Montana, LLC (Talen) engaged Burns & McDonnell Engineering Company, Inc. (BMcD) to assist it in evaluating the potential cost impacts of complying with the potential particulate limits in EPA's proposed MATS rule. The scope of work included the following:

1. Evaluate the proposed filterable particulate matter limit of 0.01 lb fPM/mmBtu and evaluate what particulate control technologies could maintain the limit at Colstrip.
2. Provide an AACE Class 5 estimate of the necessary capital improvements and operations/maintenance costs.

Background Information

The Colstrip units being evaluated are two approximately 740 MW units (net) that fire PRB coal and utilize a plumb bob wet scrubber to simultaneously remove filterable particulate and sulfur dioxide (SO_2) from the flue gas. This approach has the advantage of using the alkalinity inherent to PRB fly ash as reagent to help remove SO_2. However, this control technology is not as effective at removing fine particulate matter (fPM) as more modern particulate control technologies. The system was originally designed to achieve an emission rate of 0.05 lb fPM/mmBtu at a plumb bob pressure drop of 17".

Over the years the Colstrip plant has worked with scrubber consultants and engineers to improve the fPM removal ability of the scrubber. Changes and upgrades have increased the pressure drop to the system maximum across the scrubber's plumb bob, optimized mist eliminators, and installed flow distribution plates to optimize scrubber performance. Beyond the scrubber, Colstrip has made operational changes to improve the fPM removal including improving boiler wall cleaning to impact the size of the fPM and increase removal across the scrubber, implemented a combustion optimization system, and performed preventative maintenance on the coal mills to maintain the coal grind size and thus the resulting fPM size. However, even with these previous scrubber upgrades, operational changes and maintenance practices focused on fPM removal, the best single quarterly fPM compliance test the unit has achieved (not maintained) is 0.017 lb/mmBtu.

The upgraded system typically operates between 0.020 and 0.027 lb fPM/mmBtu. The average quarterly fPM compliance tests for 2022 was 0.022 lb/mmBtu. These rates are in compliance with the current limit of 0.030 lb fPM/mmBtu but would not be in compliance with the proposed MATS rule. The proposed MATS rule would reduce the fPM limit to 0.010 lb fPM/mmBtu.

Particulate Control Technology Discussion

Potential Particulate Control Options to Achieve New MATS fPM Limit

BMcD evaluated several options to reduce fPM at Colstrip. These options include dry/wet electrostatic precipitators (ESP) and baghouses/fabric filters (FF). The traditional location for a dry ESP or FF is between the air heater outlet and the scrubber. A wet ESP would be located after the scrubber systems while the flue gas is saturated. Colstrip Units have a feature that is uncommon at wet scrubbed United States power plants. After each scrubber vessel there is a reheat system that warms the flue gas approximately 60°F which results in a 'dry' (non-saturated) flue gas. This situation creates the opportunity to utilize an ESP or FF downstream of the scrubber provided that the reheat system is operational.

Burns & McDonnell (BMcD) discussed these different conditions with Southern Environmental Inc. (SEI) – an equipment supplier – and requested budgetary pricing for each option as SEI can supply all of these technologies. SEI indicated they believe that all of these options can achieve the proposed 0.010 lb fPM/mmBtu emission rate. However, guaranteeing that these rates can be continuously maintained at the stack is not certain for all technologies. We identify a few technological challenges to consider when evaluating these technologies below:

ESP/FF Located Upstream of Scrubber

If the fPM control device is installed upstream of the scrubbers, there is a question of whether the scrubbers will remove or re-introduce fPM into the flue gas. An ESP or FF upstream of the scrubber can be guaranteed to maintain 0.010 lb fPM/mmBtu at the particulate control device outlet. Nearly all of the fPM passing through the scrubber is particulate smaller than 2.5 microns ($PM_{2.5}$) as the scrubber is excellent at removing larger particulates but not great at removing smaller particulates. If an ESP or FF is installed upstream of the scrubber, all of the PM entering the scrubber will be $PM_{2.5}$and the scrubber will do little to reduce the $PM_{2.5}$ concentrations. Also, since the existing scrubbers use the alkalinity inherent to PRB fly ash as reagent to help remove SO_2, fly ash that is collected in the ESP/FF would have to be reintroduced to the scrubber for SO_2 removal and this fly ash could be re-emitted as particulate after the scrubber. Therefore, this evaluation has assumed that additional lime will be used in lieu of fly ash to control SO_2 emissions. This does not eliminate the risk the scrubbers could re-emit fPM but does reduce the risk.

Wet ESP

A wet ESP downstream of the scrubber can be guaranteed to maintain 0.010 lb fPM/mmBtu at the particulate control device outlet/stack inlet. However, the flue gas entering the scrubber must be saturated and the stack is not designed for wet flue gas. The flue gas would need to be captured prior to the existing reheat system, routed to the wet ESP and then either routed back to the existing reheat system or through a new reheat system and fan. Because of the complexity of the tie in and the fact the wet ESP and reheat system would need to be made out of high alloy to address corrosion; the cost estimate demonstrates this is the most expensive option.

ESP/FF Located Downstream of Scrubber

An ESP or FF downstream of the scrubber is expected to maintain 0.010 lb fPM/mmBtu. A FF can be guaranteed to maintain 0.010 lb fPM/mmBtu if the flue gas is maintained at least 30° above the dew point. This is critical because if the bags in the fabric filter become wetted for even a short period, the bags could be damaged catastrophically and fail to perform. This requirement could be challenging if there is an upset in the reheat system or any time steam may not be available.

An ESP can likely be guaranteed to maintain 0.010 lb fPM/mmBtu; however, there is some concern due to the fPM particle size in this location. ESP systems can remove $PM_{2.5}$ and smaller particles. However, it is more difficult to remove the smaller particles than the larger particles. Further evaluation or testing maybe required for a guarantee to be provided. The advantage of a dry ESP in this location is a dry ESP is not as susceptible as a FF to wet flue gas conditions. The dry ESP cannot operate in saturated flue gas, and continuous operation in saturated conditions would damage the ESP, but short-lived incidents with exposure to saturated flue gas are not expected to catastrophically damage the ESP.

Cost Estimate for Particulate Control Technology

Burns & McDonnell produced AACE Class 5 estimates for these control technologies based on the 'flange to flange' budgetary price information SEI shared and BMcD's previous experience in building up the fully-installed cost of such projects. The estimated costs are intended to include new ductwork, foundations, support steel, insulation, ash piping, electrical upgrades, new ash silos, new carbon injection systems, and (as applicable) new lime silos and feed systems. The costs do not include new fans, stack modifications, taxes, water treatment, or significant demolition. The Class 5 estimates presented here include: indirects, engineering, escalation during the project, and contingency. The cost estimating method favored by the EPA differs from typical industry cost estimates. Key differences of the EPA cost estimating method include removal of indirect costs and all escalation, and reducing the contingency to 10%. The Class 5 estimates we prepared, and the EPA cost estimates do not include Owners costs or an EPC fee.

The capital cost estimates provided are considered AACE Class 5 feasibility estimates and are provided in 2023 dollars unless indicated otherwise. The estimates were built up using heavy construction cost data from RSMeans, vendor input for major equipment, and in-house information from other projects. Engineering, Construction Management, Start-Up, and Contingency are based on percentages of the total direct cost for these Class 5 estimates. All sales taxes are excluded from the estimates. Talen should not use these estimates to establish the project budget as they are only intended to assist in selecting the preferred solution(s) at the site. The selected alternative(s) should be investigated further, with additional design and more detailed quantity buildup completed along with soliciting local contractors for labor pricing prior to establishing the project budget.

BMcD's estimates, analyses, and recommendations contained in this email are based on professional experience, qualifications, and judgment. BMcD has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analyses, and recommendations. Therefore, BMcD makes no guarantee or warranty (actual, expressed, or implied) that actual results will not vary, perhaps significantly, from the estimates, analyses, and recommendations contained herein.

In the preparation of this, information provided by Talen was used by BMcD to make certain assumptions with respect to conditions that may exist in the future. While BMcD believes the assumptions made are reasonable for the purposes of this study, BMcD makes no representation that the conditions assumed will, in fact, occur. In addition, while BMcD has no reason to believe that the information provided by Talen, and on which this report is based, is inaccurate in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Cost Summary

We prepared the following cost summary of the various options. Table 1 is a summary of key assumptions while Tables 2-5 are the costs summarized and levelized to dollars per ton. Tables 2 and 4 assume the baseline is the 2022 average emission rate of 0.022 lb fPM/mmBtu while Tables 3 and 5 assume the average emission rate the EPA used in the MATS evaluation of Colstrip (0.0195 lb fPM/mmBtu).

Table 1: Summary of Capital and O&M Costs

Capacity Factor:	85%
Life, years	15
Cost of Money, %	8.25
Capital Recovery Factor	0.118619
Property Taxes, Insurance	0
Disposal cost, $/ton	15
Power cost, $/MW	45
Lime cost, $/ton	200

Table 2: Summary of Capital, O&M and Levelized Costs for Class 5 Estimate Method, 2022 Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
	PM	**Emissions**				**Economic Impacts**			
PM-10 Control Alternative (Ranked by PM-10 Rate)	**Removal Efficiency** % (Note B)	Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	54.55	0.010	152	566	679	486.0	29.8	87.4	128,700
Upstream FF	54.55	0.010	152	566	679	404.9	29.9	78.0	114,900
Wet ESP	54.55	0.010	152	566	679	744.5	16.6	104.9	154,500
Reheat ESP	54.55	0.010	152	566	679	263.5	10.5	41.8	61,600
Reheat FF	54.55	0.010	152	566	679	351.2	14.9	56.5	83,200
2022 Baseline (Scrubber)		0.022	334	1245		N/A	N/A	N/A	N/A

Table 3: Summary of Capital, O&M and Levelized Costs for Class 5 Estimate Method, EPA Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency** % (Note B)	**Emissions**				**Economic Impacts**			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	48.72	0.010	152	566	538	486.0	29.8	87.4	162,500
Upstream FF	48.72	0.010	152	566	538	404.9	29.9	78.0	145,000
Wet ESP	48.72	0.010	152	566	538	744.5	16.6	104.9	195,000
Reheat ESP	48.72	0.010	152	566	538	263.5	10.5	41.8	77,700
Reheat FF	48.72	0.010	152	566	538	351.2	14.9	56.5	105,000
2022 Baseline (Scrubber)		0.0195	296	1103		N/A	N/A	N/A	N/A

Table 4: Summary of Capital, O&M and Levelized Costs for EPA Estimate Method, 2022 Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency %** (Note B)	**Emissions**				**Economic Impacts**			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	54.55	0.010	152	566	679	406.1	29.8	78.0	114,900
Upstream FF	54.55	0.010	152	566	679	338.3	29.9	70.1	103,200
Wet ESP	54.55	0.010	152	566	679	622.2	16.6	90.4	133,100
Reheat ESP	54.55	0.010	152	566	679	220.2	10.5	36.6	53,900
Reheat FF	54.55	0.010	152	566	679	293.4	14.9	49.7	73,200
2022 Baseline (Scrubber)		0.022	334	1245		N/A	N/A	N/A	N/A

Table 5: Summary of Capital, O&M and Levelized Costs for EPA Estimate Method, EPA Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
	PM	Emissions				Economic Impacts			
PM-10 Control Alternative (Ranked by PM-10 Rate)	Removal Efficiency % (Note B)	Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	48.72	0.010	152	566	538	406.1	29.8	78.0	145,000
Upstream FF	48.72	0.010	152	566	538	338.3	29.9	70.1	130,300
Wet ESP	48.72	0.010	152	566	538	622.2	16.6	90.4	168,000
Reheat ESP	48.72	0.010	152	566	538	220.2	10.5	36.6	68,000
Reheat FF	48.72	0.010	152	566	538	293.4	14.9	49.7	92,400
2022 Baseline (Scrubber)		0.0195	296	1103		N/A	N/A	N/A	N/A

We appreciate the opportunity to assist in this evaluation. Should you have any questions or wish to schedule a follow-up meeting, please contact Doug Randall at (816) 822-3455.

Sincerely,

Burns & McDonnell Engineering Company, Inc.

Douglas Randall
Associate Controls Specialist