SIERRA
CLUB

RECEIVED
2017 NOV 14 PM 4:16
IDAHO PUBLIC
UTILITIES COMMISSION

November 14, 2017

Via Hand Delivery and U.S. Mail

Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
427 W. Washington St.
Boise, ID 83702-5983
diane.holt@puc.idaho.gov

Re: Case Nos. AVU-E-17-01/AVU-G-17-01: Direct Testimony of Ezra D. Hausman, Ph.D. on Behalf of Sierra Club

Please find enclosed the Direct Testimony of Ezra D. Hausman, Ph.D. on Behalf of Sierra Club in the above mentioned case. The public version of this document was hand delivered and served upon all party representatives for this proceeding via e-mail. The confidential portion of this document was hand delivered and served upon all eligible party representatives via U.S. Mail.

Please do not hesitate to contact me if you have any questions or need other materials. Thank you.

Sincerely,

/s/ Alexa Zimbalist

Alexa Zimbalist
Legal Assistant
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
Phone: (415) 977-5649
alexa.zimbalist@sierraclub.org

CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of November 2017, I delivered true and correct copies of the foregoing DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D. ON BEHALF OF SIERRA CLUB to the following persons via the method of service noted. The public version of this document was served upon parties via email, and the confidential portion of this document was served upon all eligible party representatives via U.S. Mail or FedEx.

Hand Delivery:

Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
427 W. Washington St.
Boise, ID 83702-5983
diane.holt@puc.idaho.gov
(Original and eight copies provided)

Email:

David J. Meyer (C)
Vice President & Chief Counsel, Reg. & Gov't Affairs
Avista Corporation
PO Box 3727
1411 East Mission Avenue
Spokane, WA 99220-3727
david.meyer@avistacorp.com

Kelly Norwood
Vice President - State & Federal Regulation
Avista Utilities
PO Box 3727
1411 East Mission Avenue
Spokane, WA 99220-3727
kelly.norwood@avistacorp.com

Peter J. Richardson (C)
Gregory M. Adams (C)
Richardson Adams PLLC
515 N. 27th Street
P0 Box 7218
Boise. ID 83702
peterrichardsonadams.com
greg@richardsonadams.com

Dr. Don Reading (C)
6070 Hill Road
Boise, ID 83703
dreading@mindspring.com

Carol Haugen (C)
601 W. Riverside Avenue, Suite 1100
Spokane, WA 99201
carol.haugen@clearwaterpaper.com

Marvin Lewallen (C)
MA Lewallen & Associates, LLC
7408 SW Mapleleaf St.
Portland, OR 97223
marv@malewallen.com

Brad M. Purdy
Attorney at Law
2019 N. 17th Street
Boise, ID 83702
bmpurdy@hotmail.com

Nathan Smith (C)
803 Mill Road
Lewiston, ID 83501
nathan.smith@clearwaterpaper.com

john.jacobs@clearwaterpaper.com
david.wrn@clearwaterpaper.com

Matthew A. Nykiel
Idaho Conservation League
PO Box 2308
102 S. Euclid #207
Sandpoint, ID 83864
mnykiel@idahoconservation.org

Ronald L. Williams
Williams Bradbury, P.C.
PO Box 338
Boise, ID 83701
ron@williamsbradbury.com

Dean J. Miller
3620 E Warm Springs Ave.
Boise, ID 83716
deanjmiller@cableone.net

Larry A. Crowley, Director
The Energy Strategies Institute, Inc.
5549 S. Cliffsedge Ave.
Boise, ID 83716
Crowleyla@aol.com

Benjamin J. Otto
Idaho Conservation League
710 N 6th Street
Boise, ID 83701
botto@idahoconservation.org

Brandon Karpen (C)
Deputy Attorney General
Idaho Public Utilities Commission
47 2 West Washington Street
Boise, ID 83702

Dated this 14th day of November, 2017.

/s/ Alexa Zimbalist
Alexa Zimbalist
Legal Assistant
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA 94612
Phone: (415) 977-5649

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE IN IDAHO	)))))))	CASE NOS. AVU-E-17-01 AVU-G-17-01

DIRECT TESTIMONY OF

EZRA D. HAUSMAN, PH.D.

ON BEHALF OF SIERRA CLUB

REDACTED

November 14, 2017

Table of Contents

Exhibit List

Exhibit No. 601	Resume of Ezra D. Hausman, Ph.D.
Exhibit No. 602	Avista's Responses to Sierra Club Production Requests 1-3, 1-5, 3-6 Supplemental 2 and 3-7
Exhibit No. 603	Avista's Confidential Response to Sierra Club Production Request 1-4
Exhibit No. 604	Colstrip Business Plans 2015-2019, 2016-2020, 2017-2021, Avista's Confidential Attachments A-C to Sierra Club Production Request 1-3
Exhibit No. 605	Capital Project Authorization Forms, Avista's Confidential Attachment G to Sierra Club Production Request 1-3 *(excerpt)*
Exhibit No. 606	Colstrip 3&4 Ownership and Operation Agreement, Avista's Confidential Attachment A to Sierra Club Production Request 1-5 *(excerpt)*
Exhibit No. 607	Avista's Confidential Supplemental Attachment A to Sierra Club Supplemental Production Request 3-6
Exhibit No. 608	Protection of Visibility: Amendments to Requirements for State Plans (Final Rule), 82 Fed. Reg. 3078 (Jan. 10, 2017) *(excerpt)*
Exhibit No. 609	Protection of Visibility: Amendments to Requirements for State Plans (Proposed Rule), 81 Fed. Reg. 26942 (May 4, 2016) *(excerpt)*
Exhibit No. 610	Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan, 77 Fed. Reg. 57864 (Sep. 18, 2012) *(excerpt)*
Exhibit No. 611	Montana Department of Environmental Quality, "Regional Haze 5-Year Progress Report," August 2017, Chapter 2 *(excerpt)*
Exhibit No. 612	Washington Utilities and Transportation Commission Dockets UE-170033/UG-170034, Initial Post-Settlement-Hearing Brief of the State of Montana in Support of the Proposed Multiparty Settlement Stipulation and Agreement (Oct. 18, 2017) *(excerpt)*
Exhibit No. 613	Portland General Electric Tariff Schedule 146 - Colstrip Power Plant Operating Life Adjustment

I. Professional Qualifications and Purpose of Testimony

Q. Please state your name, occupation, and business address.

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit Nos. 601-613.

Q. What is your educational and professional background?

A. I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have been involved in analysis of both regulated and restructured electricity markets for approximately 20 years.

I have worked as an independent consultant and expert based on my expertise and experience in energy economics and environmental science since 2014. From 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served most recently as Vice President and Chief Operating Officer. From 1998 through 2004 I served as a Senior Associate at Tabors Caramanis and Associates (TCA) of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates (CRA), where I remained until 2005.

I provide expert consulting services in several areas relating to energy markets and energy market regulation on the state, regional, and federal levels; energy dispatch and planning modeling, quantification of the economic and environmental benefits of displaced emissions; and treatment of energy efficiency and renewable energy in electricity and capacity markets. I have provided testimony and/or appeared before public utility commissions or legislative committees in Arizona, Illinois, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, Nevada, South Dakota, Vermont, and Washington State, as well as at the federal level. I have also provided expert representation for stakeholders at the PJM ISO, the California ISO, the Midwest ISO, and at the FERC. While most of my testimony and analytical work has centered on issues concerning electricity market economics, I have also brought my expertise as a scientist to bear on cases involving energy efficiency programs and greenhouse gas regulation and mitigation in the electric sector.

I have provided a detailed resume as Exhibit No. 601.

Q. Have you previously testified before the Idaho Public Utilities Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is provided in response to both the initial filing by Avista Corporation ("Avista" or "Company") and the proposed multiparty Stipulation and Settlement filed with the Commission on October 20, 2017 ("Settlement Agreement"), I address three issues of relevance to this proceeding concerning the treatment of Avista's shares of Units 3 and 4 of the Colstrip coal-fired electric generating plant in eastern Montana:

1) Avista approved capital expenditures totaling $3,040,933 (Avista's share) to install Smartburn controls for emissions of nitrogen oxides ("NOx") as part of the Colstrip capital budgets in 2015-2017. These capital expenditures at Colstrip were unnecessary and imprudent. The Smartburn projects are not required for any reliability, economic, or regulatory purpose, were the result of poor oversight and management by Avista, and did not result in a significant reduction in NOx emissions at the units. Idaho ratepayers should not be responsible for these unnecessary and imprudent expenditures.

2) Avista's review process for capital projects at Colstrip Units 3 and 4 is fundamentally flawed. Of relevance to this proceeding, Avista provided only a cursory explanation for over $24 million in capital spending at Colstrip that it is seeking to include in rate base. Avista also included in rate base in a prior proceeding capital expenditures for projects that were not in service at the time the relevant rates went into effect.

3) Avista is using an unrealistic end-of-life date for the Colstrip units for depreciation purposes, leading to the likelihood of stranded assets and/or intergenerational inequities in the future.

Q. Is the Settlement Agreement as currently proposed in the public interest?

A. No. The Settlement Agreement is not in the public interest because it fails to remove from rate base capital spending at Colstrip Units 3 and 4 that was unnecessary and imprudent. Although Sierra Club supports the efforts of parties to reach a settlement agreement on the majority of issues presented in the rate case, it is not in the public interest to condone Avista's lax oversight and poor management of capital spending at the Colstrip coal plant in Montana. Unless those practices are addressed and remedied, Idaho ratepayers will be compelled to pay for those imprudent capital expenditures for years to come, and they will be at risk of continued imprudent spending on a coal plant that is nearing the end of its useful life.

Q. What are your recommendations for the Commission in this case?

A. I recommend that the Commission either reject the stipulation or condition its approval on the Parties' acceptance of the following:

1) A finding by the Commission that Smartburn NOx controls installed on Colstrip Units 3 and 4 were unnecessary and imprudent. The Commission should make the following adjustments to Avista's rate base pursuant to this finding:

   a. Remove $1,047,417 from Avista's rate base on a going-forward basis for costs associated with the Smartburn installation on Colstrip Unit 3. There was no economic or regulatory benefit from this capital expenditure, and Idaho ratepayers should not be required to pay for it. Moreover, based on the first months of available emissions data, there appears to be little or no environmental benefit from the project.

   b. Remove $1,993,516 from Avista's rate base on a going-forward basis for costs associated with the Smartburn installation on Colstrip Unit 4, and included in rate base in its prior rate case in Case No. AVU-E-16-03. The Unit 4 Smartburn project should be removed because, as with the Smartburn controls on Unit 3, there was no economic or regulatory benefit from the capital expenditure, and little if any environmental benefit. Furthermore, based on the record in this proceeding, this figure appears to have included at least a portion of the spending on the project at Unit 3, which was not yet used and useful when rates from Case No. AVU-E-16-03 went into effect on January 1, 2017.

2) Direction to Avista to adopt and exercise more rigorous review and approval procedures for future capital expenditures at Colstrip Units 3 and 4. As Colstrip nears the end of its useful life, I recommend that the Commission guard against unnecessary or imprudent spending at Colstrip by requiring Avista to thoroughly review and justify any and all capital projects that increase the plant balance. The Commission should make clear that the company can no longer take a passive role with respect to capital investment decisions in these units, and cannot assume that this Commission will simply rubber-stamp decisions of the Colstrip Owner's Committee without proof that Avista is making its best efforts to act in the interests of Idaho ratepayers.

3) If the Settlement Agreement is rejected, either by the Commission or after modification by the settling parties such that this proceeding returns to litigation, I recommend that the Commission hold open this rate case and consolidate the proceeding with Avista's next depreciation filing. Avista should have included in this proceeding updated end-of-life assumptions for Colstrip Units 3 and 4 that reflect the realities of today's coal and electric industry economics, and the likelihood of future carbon constraints that will adversely or fatally impact coal plants such as Colstrip.

4) If the Commission accepts the Settlement Agreement, the Commission should make clear that nothing in this proceeding precludes further adjustments to rates pursuant to Avista's upcoming depreciation filing.

Q. Are you recommending a change to the revenue requirement proposed by the Settlement Agreement?

A. No. While the changes to rate base that I recommend would normally flow through to reduce annual revenue requirement, I am not recommending a change to revenue requirements or rates in this proceeding. Settlement agreements necessarily represent a compromise among the parties. The majority of issues included in the Settlement Agreement have nothing to do with Colstrip, and therefore I hesitate to disturb a revenue requirement agreement that reflects a balance among the interests of a diverse group of stakeholders.

However, allowing Avista to include its imprudent Colstrip expenditures in rate base would have a much longer-lasting detrimental impact on Idaho ratepayers. If left unchallenged, Avista's wasteful spending on capital projects at Colstrip will stay on the books for years. Implicitly approving those imprudent actions by unconditionally accepting the Settlement Agreement would be against the public interest because it would condone behavior that puts ratepayers at risk of further imprudent spending. The Commission need not disturb the annual revenue requirement agreed upon in the Settlement Agreement, but it should require Avista to remove the outstanding cost of Smartburn at both Colstrip units from rate base for purposes of all future proceedings.

II. Capital Investments in Colstrip Units 3 and 4 Were Imprudent

Q. Please describe the capital expenditures at Colstrip Units 3 and 4 that are at issue in the current rate case.

A. Avista's application included a total of $24.29 million for capital additions at Colstrip for years 2017-2019.[1] In the Settlement Agreement, according to Staff, all of the capital additions budgeted for 2019 and "most" of the proposed additions in 2018 were removed.[2] In addition, Avista requested to add $1,047,417 to rate base for recovery of its share of the cost of installing Smartburn technology on Colstrip Unit 3 that went into service in June 2017.[3]

Q. Does your testimony address other capital projects at Colstrip that were not included in the Company's current filing?

A. Yes. In Avista's previous general rate case (Case No. AVU-E-16-03), Avista sought approval to include $1,993,516 million in rate base for Smartburn technology on Colstrip Unit 4.[4] That case was resolved in a settlement, and the merits of specific capital investments were never adjudicated or deemed prudent

[1] Direct Testimony of Scott J. Kinney at p.31.
[2] Direct Testimony of Randy Lobb at p.10.
[3] Avista Response to SC PR 3-7(b), Exhibit No. 602, page 8 of 8.
[4] Avista Response to SC PR 3-6(b), Exhibit No. 602, page 5 of 8.

by the Commission. However, these past expenditures in 2015 and 2016 on Smartburn projects at Colstrip Unit 4 suffer from the same deficiencies as the later investment at Unit 3.

Q. What are the Smartburn capital projects that you are challenging in this proceeding?

A. Colstrip, like all coal-fired power plants, emits pollution that is harmful to public health and the environment. Smartburn is a form of emissions control technology installed by the Colstrip owners between 2015 and 2017 on Colstrip Units 4 and 3 that purportedly would reduce the emission of oxides of nitrogen, commonly referred to as "NOx", which is harmful to human health and causes visibility impairments in the environment. Smartburn is a far less effective, but also less expensive, means of reducing NOx emissions than installing Selective Catalytic Reduction ("SCR").

Q. When were the Smartburn controls completed at Colstrip Units 3 and 4?

A. According to Avista's responses to Sierra Club's production requests, the installation of Smartburn on Unit 4 was completed on June 30, 2016, and on Unit 3 on June 30, 2017.[5]

Q. How much did the Smartburn projects cost?

A. The Smartburn projects cost a total of [redacted] million on a plant-wide

[5] Avista Response to SC PR 3-6(b) and 3-7(b), Exhibit No. 602, pages 5 and 8 of 8.

basis at Units 4 and 3, respectively.[6] Avista's share for these two projects totaled $3,040,933, "not including any overheads [sic] incurred by Avista."[7]

Q. When were these costs incurred?

A. The following confidential table shows the annual expenditures on each Smartburn project, according to the 2016 Capital Project Authorization forms provided by Avista during discovery.

Confidential Table 1: Annual Cash Flow for Smartburn Capital Projects at Colstrip

	2015	2016	2017
Unit 3 Smartburn	[redacted]	[redacted]	[redacted]
Unit 4 Smartburn	[redacted]	[redacted]	[redacted]

These two projects are summarized in Confidential Exhibit No. 605, which is extracted from Confidential Attachment G to Avista's response to Sierra Club Production Request 1-3.

Q. How much of the capital expenditure is Avista claiming in this rate case?

A. It appears that Avista is only claiming its share of the final year (2017) of capital spending for Smartburn at Unit 3 ($1,047,417).[8] In its previous rate case, Case No. AVU-E-16-03 Avista included nearly two-thirds of its share of the total Smarburn spending for both units, or ($1,993,516).[9] Because The Smartburn controls at

[6] SC PR 1-3C, Confidential Attachment G, p. 41 and 50 of 74, Exhibit No. 605.
[7] Avista Response to SC PR 3-6(b), Exhibit No. 602, page 5 of 8.
[8] Avista Response to SC PR 3-7(b), Exhibit No. 602, page 8 of 8.
[9] Avista Response to SC PR 3-6(b) and 3-7(b), Exhibit No. 602, pages 5 and 8 of 8 (showing that Avista included 66% of total Smartburn expenditures in its 2016 rate case, and 34% in the current 2017 rate case).

Units 3 and 4 should cost roughly the same amount, this suggests that Avista included a portion of spending on Unit 3 Smartburn in rates beginning January 1, 2017. As noted above, the Unit 3 Smartburn did not go into service until June 2017; thus it appears Avista was charging ratepayers for this project before it went into service.

Q. Were the Colstrip owners required to install these projects?

A. No. The projects appear to be completely unnecessary. There were and are no regulatory or statutory compliance obligations that required Colstrip Units 3 and 4 to reduce emissions of NOx in 2016 and 2017. There is no evidence provided by Avista in this docket that these projects improved the economics or production capabilities of Colstrip Units 3 and 4. Finally, the emissions data from Colstrip show that there has been almost no change in the average emissions of NOx from either unit since the installation of the Smartburn controls.

Q. What was the Company's justification for these two projects?

A. Sierra Club specifically asked Avista in discovery the following question about Smartburn controls for each of Unit 3 and Unit 4: "Please provide a narrative description of what Avista understands its regulatory obligations are today that necessitate the installation of [Smartburn NOx controls], including but not limited to compliance deadlines and emissions limit."[10] In response to Sierra Club's data request, Avista provided only a vague and cursory justification for the Smartburn

[10] Avista Response to SC PR 3-6(h) and 3-7(d), Exhibit No. 602, pages 5-6 and 8 of 8.

projects. Avista did not include any specific compliance deadlines, nor did it include any specific NOx emission limits that Colstrip Units 3 or 4 were required to meet.

Instead, Avista included a general description of the Regional Haze Program, which is a regulation under the federal Clean Air Act that is intended to eliminate man-made visibility degradation in Class I areas by the year 2064.[11] However, as discussed in more detail below, there are no enforceable current or planned compliance obligations under the Regional Haze Rule that are applicable to Colstrip Units 3 and 4.

Along with this general reference to the Regional Haze Program, Avista provided the following explanation:

> *Anticipating that Colstrip Units 3 & 4 could be ordered to install Selective Catalytic Reduction (SCR) during the 2017 review period, the Colstrip Owners' proactively installed the Smart Burn technology to reduce the formation of Nitrous Oxides (NOx) in combustion zone for two major benefits:*
> - *Make proactive and verifiable NOx reductions and*
> - *Optimize the size, scope and ammonia use of any future SCR installation.*[12]

Avista also provided several documents as attachments pertaining to various unrelated rules and actions dating back to 2011. Avista then supplemented its response on October 26, 3017 (nearly seven weeks after the original discovery

---

[11] Avista's response included a reference to emissions limitations and pollution controls for Colstrip Units 1 and 2 from a September 18, 2012 Final Implementation Plan (FIP) finalized by EPA. However, Avista does not own any portion of Units 1 and 2, and those units are not at issue in this proceeding.
[12] Avista Response to SC PR 3-6(d), Exhibit No. 602, page 6 of 8.

request and after the Settlement Agreement was filed) to include a series of confidential emails between Avista employees and other Colstrip owners.[13]

Q. Is Avista's explanation reasonable?

A. No. Avista's narrative response suggests that the controls were installed proactively because Colstrip 3 & 4 *could* be required as part of the Regional Haze Program to install a different and much more expensive and more effective type of pollution control –SCR – at some point in the future. However, there is no discussion or explanation as to why or how installing Smartburn in 2016 and 2017 was required. Even if Smartburn-like technology can help to "optimize the size, scope and ammonia use of any future SCR installation" as Avista suggests, it is clearly imprudent to make that investment up to a decade before SCR *may* be required.

Based on the limited explanation provided by Avista, the only plausible rationale for Smartburn controls is that the Colstrip owners believed that somehow installing Smartburn controls in 2016 and 2017 could help avoid the requirement for more effective and expensive controls sometime in the next decade. If this was the strategy Avista and the other owners relied on, it is unlikely to be successful, as the discussion below of regulatory actions related to the "Reasonable Progress" phase of the Regional Haze Rule will demonstrate. Installing the Smartburn controls today is unlikely to have any material impact on any future compliance

[13] SC PR 3-6C, Supplemental Confidential Attachment A, Exhibit No. 607.

obligations at Colstrip Units 3 and 4.

Absent any evidence or support for the Smartburn capital projects at Colstrip Units 3 and 4, the Commission must conclude that these discretionary expenditures were imprudent and remove these costs from rate base. Even if the Commission finds that speculating on future regulatory actions was a reasonable use of ratepayer money, the actual environmental data coming from Colstrip Units 3 and 4 show that the controls have thus far been largely, and predictably, ineffective at reducing NOx emissions.

1) **The Smartburn Projects Were Significant Discretionary Capital Projects that Were Not Required to Meet any Existing Compliance Obligation**

Q. How did Avista describe the Smartburn projects in its filing to the Idaho Public Utilities Commission?

A. Avista did not specifically identify the Smartburn projects in its application or testimony in this proceeding. Instead, it appears that Avista lumped the Smartburn projects in with other capital spending at Colstrip that it describes as "ongoing capital expenditures associated with normal outage activities on Units 3 & 4 at Colstrip."[14] Avista described these costs as "mandatory and compliance" capital projects, including "Environmental Must-Do", a category that that "typically includes projects done for compliance with laws, rules, and contract requirements that are external to the Company (e.g. State and Federal laws, Settlement Agreements, FERC,

[14] Kinney Direct Testimony at p.31.

NERC, and FCC rules, and Commission Orders, etc.)."[15]

Q. Mr. Kinney's direct testimony stated that additional details can be found in Exhibit No. 4, Schedule 3.[16] Did you review that exhibit?

A. Yes. In Exhibit No. 4 at Schedule 3, page 90 of 180, Mr. Kinney provided only a three page "Business Case Justification Narrative" addressing all capital spending at Colstrip Units 3 and 4 for the years 2017 through 2019. The Business Case Justification stated that "Colstrip Capital is required as part of ongoing operations of the facility."[17] That same document included four categories of project: (1) ENVMD- Environmental Must Do, (2) Sustenance, (3) Regulatory, (4) Reliability Must Do.

Q. In your opinion, would you characterize the Smartburn projects as required "Mandatory and Compliance" projects or "Environmental Must Do" projects?

A. Neither. I would describe them as discretionary and ineffective, and at best premature. As discussed in detail below, there was and still is no legal compliance obligation that required Colstrip Units 3 or 4 to reduce NOx in 2016 or 2017, or any future date. The projects should therefore not be considered "Mandatory and Compliance" or "Environmental Must Do" projects and instead should be evaluated as discretionary projects. As such, Avista should have been required to demonstrate that investing the substantial capital resources in Colstrip was

[15] Kinney Direct Testimony at p.30.
[16] Kinney Direct Testimony at p.31.
[17] Kinney, Exhibit No. 4, Schedule 3, page 90 of 180.

somehow in the interests of ratepayers, or should have exercised its right as a participating owner to object to the project and attempt to have it removed from the capital spending plan.

Q. Avista's Exhibit No. 4, Schedule 3 stated that discretionary items are reviewed by Talen (the plant operator) in a hurdle rate analysis.[18] Was a hurdle rate analysis completed for the Smartburn controls?

A. [redacted] In response to Sierra Club's production request 1-3, Avista provided numerous "Capital Project Authorization Forms" for individual projects. [redacted].[19]

Q. Compared to other capital projects, how significant were the Smartburn control projects?

A. The Smartburn controls represented a significant portion of the capital outlays for Colstrip in 2015, 2016 and 2017. The following table shows the annual cash flow for Smartburn at Colstrip compared to the total projected capital costs at Colstrip Units 3 and 4, according to the business plan provided by Avista, for each of the years 2015, 2016, and 2017.

[18] Kinney, Exhibit No. 4, Schedule 3, page 91 of 180.
[19] SC PR 1-3C, Confidential Attachment G, p. 41 and 50 of 74, Exhibit No. 605.

Confidential Table 2: Smartburn Cash Flow as a Percentage of Total Colstrip 3&4 CapEx (millions)

	2015	2016	2017	Total
Total Colstrip 3&4 Capex[20]	[redacted]	[redacted]	[redacted]	[redacted]
Smartburn[21]	[redacted]	[redacted]	[redacted]	[redacted]
Percentage	[redacted]	[redacted]	[redacted]	[redacted]

As can be seen in Table 2, Smartburn accounted for [redacted] to [redacted] of total projected CapEx at Colstrip Units 3 and 4 for each of the years 2015, 2016, and 2017.

Q. What is the Regional Haze Rule referenced by Avista and how does it affect Colstrip Units 3 and 4?

A. Congress established "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1).

In 1990, after finding that the U.S. Environmental Protection Agency ("EPA") and the states had not made adequate progress toward reducing visibility impairment in the nation's Class I areas,[22] Congress amended the Clean Air Act to curb emissions that may reasonably be anticipated to cause or contribute to visibility

---

[20] SC PR 1-3C, Confidential Attachments A-C, Exhibit No. 604. Values shown are for the first year of each capital expenditure plan.

[21] See Table 1 Above. Data from SC PR 1-3C, Confidential Attachment G, p. 41 and 50 of 74, Exhibit No. 605.

[22] Areas designated as mandatory Class I Federal areas (or Class I for short) consist of national parks exceeding 6,000 acres, national wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. See 42 U.S.C. § 7472(a).

impairment at national parks and wilderness areas. *Id.* § 7492.

Congress delegated implementation of the Clean Air Act's visibility program to EPA. In 1999, EPA promulgated the Regional Haze Rule, which requires the states to make incremental, "Reasonable Progress" toward eliminating human-caused visibility impairment at each Class I area by 2064. 40 C.F.R. § 51.308(d)(1), (d)(3). In the 1999 regulations, EPA recognized that visibility impairing pollution was a regional problem that required regional solutions; the regulations create the necessary region-wide scheme to restore Class I areas to natural conditions. Furthermore, the regional haze regulations require evaluation of *all* sources of visibility impairment.

In order to achieve the goal of natural visibility in Class I areas, individual states are subject to implementation plans that must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal." 42 U.S.C. § 7491(b)(2). The Regional Haze Rule includes several interlocking measures designed to make "Reasonable Progress" towards achieving natural visibility by 2064. These measures include requirements to (1) develop Reasonable Progress goals based on the evaluation of any and all sources contributing to visibility impairment; (2) determine baseline and natural visibility conditions; (3) create a long-term strategy for compliance with Reasonable Progress; and (4) implement the best available retrofit technology (BART) for some of the oldest sources of haze-causing pollutants. *Id.*;

40 C.F.R. § 51.308(d), (e).

Q. What actions have the state and EPA taken to implement the Regional Haze Rule in Montana?

A. On September 18, 2012, the EPA issued a final Federal Implementation Plan ("FIP")[23] to address regional haze in Montana.[24] Under the Regional Haze Rule, Colstrip Units 1 and 2 were required to undergo a BART analysis. Units built after 1977 such as Colstrip Units 3 and 4 are not "BART eligible" units,[25] but they still fall under the Reasonable Progress requirement. The Montana FIP addressed both the BART analysis at Colstrip Units 1 and 2, and Montana's obligations under Reasonable Progress that apply to Units 3 and 4.

Q. What subsequent state or federal actions are necessary under the Regional Haze Rule?

A. Under Reasonable Progress, states are required to report in five-year intervals that they are making progress toward achieving natural visibility conditions by 2064. In developing these Reasonable Progress goals and the emission reductions needed to meet them, the state must develop a long-term strategy that considers four factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4)

---

[23] If a state fails to develop its own State Implementation Plan ("SIP"), the EPA develops a Federal Implementation Plan.

[24] 77 Fed. Reg. 57864 (Sep. 18, 2012), Exhibit No. 610.

[25] In response to Sierra Club PR 3-6(f), Avista provided two attachments (SC PR 3-6 A and B) that purportedly discussed a "BART analysis" for Colstrip Units 3 and 4. That analysis was not actually conducted under the Regional Haze Rule, but instead was part of a requirement in Colstrip Unit 3 and 4's prevention of significant deteriorate ("PSD") permit.

the remaining useful life of any potentially affected sources. 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).

States are required to submit periodic plans demonstrating how they have and will continue to make progress towards achieving their visibility improvement goals. The first state plans were due in 2007 and covered the 2008–2018 planning period.[26] The second planning period covers 2018-2028. Prior to 2017, states faced a requirement to submit comprehensive State Implementation Plan ("SIP") revisions in 2018 to address the second planning period. However, a recent Regional Haze Rule changed the deadline for states to submit their next comprehensive Regional Haze Plan SIP revisions from 2018 to 2021.[27] This change gives states more time to submit comprehensive SIP revisions, but otherwise the Reasonable Progress requirements remain the same, including the 2028 end date of the second planning period.[28]

Q. Were any emissions reduction required at Colstrip Units 3 and 4 in 2016 or 2017 under the EPA's FIP implementing the Regional Haze Rule?

A. No. EPA's 2012 Montana FIP, which EPA issued because Montana declined to issue a SIP in 2006, specifically concluded "not to require additional emission controls on Colstrip Units 3 and 4 in the relevant planning period" (i.e. 2008-

[26] *See*, 82 Fed. Reg. 3078, 3080 (Jan. 10, 2017), Exhibit No. 608, page 3 of 4.
[27] 82 Fed. Reg. 3078 at 3080 (Jan. 10, 2017), Exhibit No. 608, page 3 of 4.
[28] *See,* Proposed Amendments to Requirements for State Plans, 81 Fed. Reg. 26942, 26965 (May 4, 2016), Exhibit No. 609, page 3 of 5; *see, also*, 82 Fed. Reg. 3078, 3080 (Jan. 10, 2017), Exhibit No. 608, page 3 of 4 ("Other than the one-time change to the next due date for periodic comprehensive SIP revisions, no change is being made for due dates for future periodic comprehensive SIP revisions").

2018) and that "[w]hether additional emission reductions from reasonable progress sources, including Colstrip Units 3 and 4, are necessary will be re-evaluated in subsequent planning periods."[29] There was no compliance deadline or emissions limit set, or any requirement for additional NOx controls at Colstrip Units 3 or 4, for 2016 or 2017 or any future year.

Q. Did the State of Montana determine that Colstrip Units 3 and 4 were required to install environmental retrofits under the Reasonable Progress requirements for Montana?

A. No. The Montana Department of Environmental Quality (MDEQ) has concluded that nothing further is required from Colstrip Units 3 and 4 during the current evaluation period. In MDEQ's most recent "Regional Haze 5-Year Progress Report" in August 2017, Colstrip Units 3 and 4 are listed among Montana sources "for which the Montana FIP analysis did not result in emission limits."[30] The report goes on to note that while Smartburn was installed on Colstrip units 3 and 4 in 2016 and 2017, this was done "in the absence of regulatory emission limits in the Montana FIP."[31]

Simply put, there was no federal or state requirement for the Colstrip owners to spend [redacted] on NOx pollution controls between 2015 and 2017.

---

[29] 77 Fed. Reg. 57864, 57902 (Sep. 18, 2012), Exhibit No. 610, page 4 of 5.
[30] Regional Haze 5-Year Progress Report, August 2017, at p.2-7, Exhibit No. 611 (full report available at: https://deq.mt.gov/Portals/112/Public/PublicComment/Documents/RegionalHaze_ProgressReport_8-2017.pdf).
[31] *Id.* at p. 2-8.

Q. Have you seen evidence of when the Colstrip co-owners, including Avista, believed Colstrip Units 3 and 4 might require upgrades to reduce NOx emissions under the Reasonable Progress rule?

A. Yes. Avista itself acknowledged in its recently completed 2017 IRP that the Regional Haze Rule will not affect Colstrip Units 3 and 4 at this time. The IRP states, "Colstrip Units 3 and 4 are not currently affected, although the units will be evaluated for Reasonable Progress at the next review period in September 2017. Avista does not anticipate any material impacts on Colstrip Units 3 and 4 at this time."[32]

However, Avista and other Colstrip owners do acknowledge that further controls will likely be required in the next planning period – and have made statements indicating that they expect SCR controls – not Smartburn – will be required in the next planning period (2018-2028). For example, PacifiCorp's 2015 IRP included an assumption that it will incur costs to install SCR at Colstrip 3 and 4 in 2023 and 2022, respectively.[33] Portland General Electric's 2016 IRP assumed that SCR would be required by 2027 in order to meet Reasonable Progress requirements.[34] Avista's own 2017 IRP base scenario assumed an SCR would be necessary in

[32] Avista 2017 IRP at p.7-6 (available at: https://www.myavista.com/about-us/our-company/integrated-resource-planning).

[33] PacifiCorp 2015 IRP, Vol. 1, footnote to Table 7.2 at p. 148: "Colstrip 3&4 SCR 2023/2022" is "common to all scenarios". https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf.

[34] Portland General Electric 2016 IRP, Ch. 3, p.78 (available at: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning).

2028; the Company also evaluated a sensitivity case with SCR in 2023.[35]

Avista provided a series of e-mails on this topic in its confidential supplemental response to Sierra Club Production Request 3-6. It is clear from these e-mails that [redacted]

Q. Given this evidence, how would you characterize the decision by Avista and the other Colstrip owners to install Smartburn technology at Units 3 and 4?

A. It is clear from the record that the Smartburn installations on Units 3 and 4 were elective, as they were not mandated by any federal or state law or rule, and that any investment in technology to reduce NOx emissions at these units in 2016 and 2017 was premature at best.

2) <u>The Installation of Smartburn in 2016-2017 is Unlikely to Avoid SCR in a Future Compliance Period.</u>

Q. Avista states that it "proactively installed Smart Burn technology" because it "Anticipat[ed] that Colstrip Units 3 & 4 could be ordered to install Selective

[35] Avista 2017 IRP at p.12-2 and 12-6.

[36] SC PR 3-6C Supplemental Attachment A, Exhibit No. 607.

Catalytic Reduction (SCR) during the 2017 review period…"[37] Is this approach reasonable?

A. No. Avista appears to be saying that it installed Smartburn in 2016-2017 in order to avoid a possible future requirement to install SCR at some undefined date. Avista provides no analysis whatsoever showing that gambling over $3 million in ratepayer money on this risky and speculative "pre-compliance" strategy is likely to pay off. If this was indeed Avista's strategy, it is a poor one because the Smartburn controls are unlikely to have any material impact on the ultimate control technology that will be required at Colstrip Units 3 and 4.

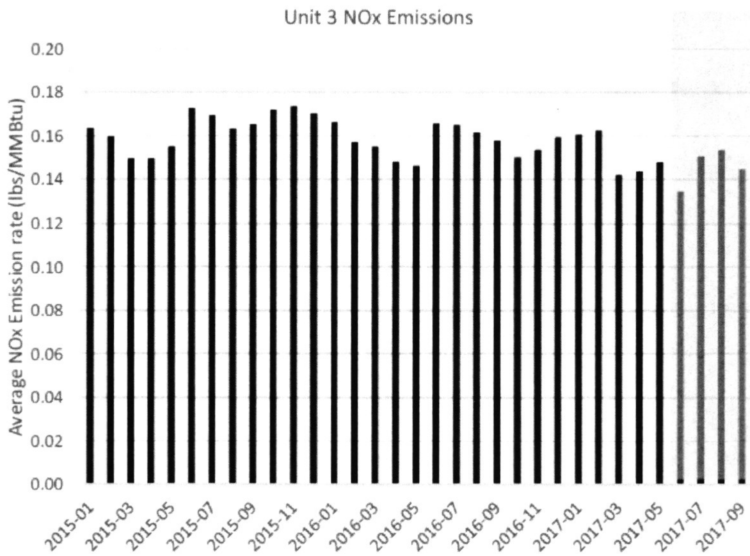
Q. Why do you conclude that installing Smartburn is unlikely to avoid a future SCR requirement?

A. Avista, Talen, and the other co-owners should have known that Smartburn would not be an effective way to achieve meaningful reductions in NOx emissions at Units 3 and 4. Both general industry experience[38] and Talen's own experience at Colstrip Unit 2, demonstrate that in the absence of SCR, Smartburn technology is capable of achieving NO_x emission levels of 0.15 lbs/MMBtu. This is very close to the levels that were already being achieved at Colstrip Units 3 and 4.

As seen in *Figure 1*, there was only a very small reduction in the emission rate at each unit, if any, after the in-service date for Smartburn at Unit 4 (June 30, 2016)

[37] SC PR 3-6(d), Exhibit No. 602, pages 5-6 of 8.
[38] See, for example, Power Engineering, 2003, "Combustion Control Techniques Achieve 0.15 lb/MMBtu NO_x Levels Without SCR." Available at http://www.power-eng.com/articles/print/volume-107/issue-1/features/combustion-control-techniques-achieve-015-lb-mmbtu-nosubx-sub-levels-without-scr html.

and Unit 3 (June 30, 2017). Prior to the installation of Smartburn, both Units 3 and 4 were averaging about 0.16 lbs NOx/mmbtu. After installing Smartburn, based on the data available thus far, the average rate dropped to about 0.15 lbs NOx/mmbtu.



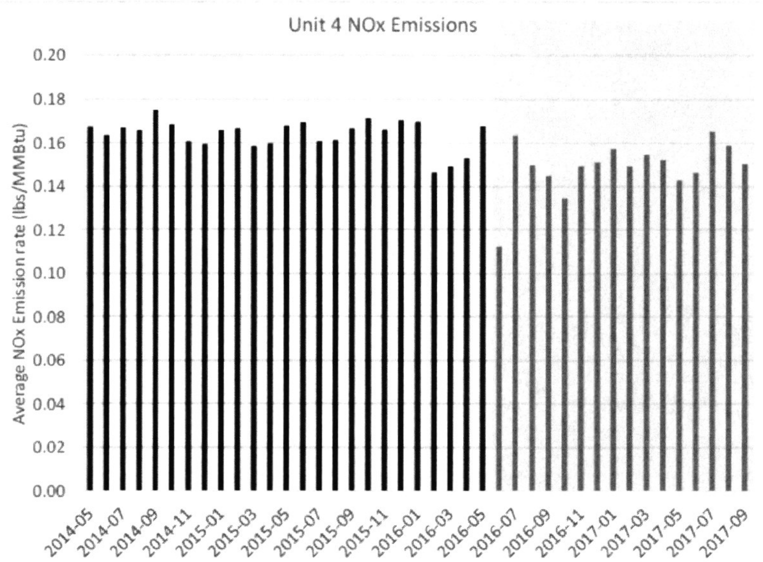


Figure 1. NO_x emission rate at Colstrip Units 3 (top) and 4 (bottom) before and after installation of Smartburn technology. Shaded region is post-installation. Data source: US EPA Air Markets Program Data (AMPD)[39]

[39] Available at https://ampd.epa.gov/ampd/.

Q. Does this decrease in emissions mean that Colstrip will be able to avoid further NOx controls on these units?

A. No. The Smartburn controls achieved only a very small reduction in NOx pollution from Colstrip Units 3 and 4, as shown in *Figure 1*. Other pollution control technologies, such as SCR, are far more effective at reducing the amount of NOx pollution from coal plants such as Colstrip. The EPA will determine at a later date whether further NOx controls will be required on the units, and I have seen no indication that Smartburn technology is an acceptable alternative to more effective and expensive controls such as SCR or SNCR.[40]

Further, Colstrip is by far the largest single source of emissions in Montana. It would be highly unlikely – and essentially noncompliant - for Montana to ignore Colstrip Units 3 and 4 in its long-term strategy. That means Montana will still need to apply the four statutory factors mentioned earlier to determine whether emissions controls, such as SCR, must be installed on Colstrip Units 3 and 4. Nothing about installing Smartburn in 2016-2017 affects any of those factors.

3) <u>Even if Smartburn might be a useful component of a possible future SCR project, it is illogical and imprudent to install it up to a decade in advance.</u>

Q. Avista claimed that the Smartburn controls will "optimize" the installation of SCR at Colstrip in the future. Is this a reasonable justification for the Company's investments in this technology in 2016 and 2017?

[40] Selective Non-Catalytic Reduction

A. No. Part of Avista's explanation for this investment was that it would "optimize the size, scope and ammonia use of any future SCR installation."[41] However, that does not explain why Avista would believe investment in these projects to be prudent in 2016 and 2017. This future compliance obligation is speculative, so it is not known if the Smartburn technology will ultimately be operating in concert with other NOx control technology such as SCR. If SCR is required, it could be up to a decade into the future. It is not prudent to spend ratepayer money today on the chance that it will somehow be a useful component for future technology that may or may not ever be installed.

As noted above, Avista was fully aware that the timing of any requirement to install SCR controls on Colstrip Units 3 and 4 was and remains speculative. Internal Avista emails show that Talen was assuming the cost of SCR on Colstrip Unit 3 alone was [redacted].[42] Given the tenuous economic situation facing Colstrip, it is likely that, were SCR controls required to continue operating these units in the future, a lower cost compliance alternative may well be to forgo combustion of coal at Colstrip. Pursuing a non-coal alternative would mean that any investment in Smartburn technologies installed in 2016 and 2017 would no longer be used or useful in any sense, and would not have been prudent because they were never required for any environmental compliance requirement, did not meaningfully reduce emissions, and were never used to "optimize" anything.

[41] SC PR 3-6(d), Exhibit No. 602, pages 5-6 of 8.
[42] SC PR 3-6C Supplemental Attachment A (page 4 of 9), Exhibit No. 607, page 4 of 9.

Finally, even if SCR is ultimately required, and if today's Smartburn does somehow turn out to be the logical technology for optimizing the SCR controls of the 2020s, Avista has presented no explanation for why it should have been installed in 2016 and 2017. If Smartburn is a prudent and reasonable component of SCR installation, then Avista should have considered it as part of the overall cost of the SCRs, if and when they are required.

Q. Is there an environmental benefit to installing Smartburn controls as soon as possible?

A. Not much. As I have shown, the Smartburn controls on Units 3 and 4 have produced little if any reduction in NOx emissions. Much more effective and expensive SCR technology would be required to achieve significant reductions in NOx emissions as long as Colstrip continues to operate as a coal-fired power plant. An even greater environmental benefit could be realized were Avista and the other co-owners to responsibly plan for the retirement of Colstrip. My client, the Sierra Club, routinely advocates before environmental agencies to require polluting facilities to install stringent pollution controls. But that does not mean it is appropriate to spend tens of millions of dollars on unnecessary and ineffective capital expenditures at coal plants, or even to invest in effective controls when lower cost and lower risk alternatives are available. With the current low price of cleaner and cheaper generating technology, utilities are frequently able to achieve even more environmental benefits at lower cost if they instead rely on other, cleaner alternatives.

III. Avista's Review Process and Request for Recovery of Colstrip Costs is Unreasonable

Q. What is the process by which capital investments such as the Smartburn technology on Units 3 and 4 are approved by Avista and the other co-owners.

A. In response to Sierra Club Production Request 1-5 (Exhibit No. 602), Avista explained as follows:

> *After the first of a given year, Talen updates the existing capital plan to include projects carried forward from a prior year. It also adds in all newly proposed capital projects that were not part of the prior year's 2 year projection. Talen's management team vets all of the projects to ensure that the projects that are included as proposed capital projects are justified and prioritized and included based on a financial analysis or are required for environmental, regulatory, or safety reasons.*[43]

Q. Did Talen provide a financial analysis in support of the Smartburn installations on Units 3 and 4?

A. As noted above, Talen identified these projects as [redacted] even though there was no mandate requiring them and, as far as I have been able to determine, no financial analysis was performed.

Q. Does Avista have veto power over capital projects at the Colstrip plant?

A. No. According to Avista's confidential response to Sierra Club Production Request 1-4 (Exhibit No. 603):

[redacted]

---

[43] SC PR 1-5(c), Exhibit No. 602, pages 3-4 of 8.

[redacted]

Q. Did Avista object to the Smartburn projects at issue here?

A. No. According to the Company, "Avista didn't vote 'no' on any of the Colstrip 3&4 projects included in the rate case application."[45]

Q. To your knowledge, has Avista <u>ever</u> objected to a proposed capital expenditure at Colstrip?

A. No. When asked whether Avista had ever voted "no" on any capital project at Colstrip, Avista responded that it does not keep individual project records, but that it "do[es] not recall an instance at this time."[46]

Q. Why is it important for a minority shareholder like Avista to perform an independent evaluation of capital investments in the Colstrip units?

A. Although Avista is a minority owner of each of the units, the Company does have an opportunity and an obligation to review and, if appropriate, object to capital investments if it believes they are unwarranted or not in the interest of Idaho ratepayers. However, it has never exercised this right, or at least it cannot recall a time that it has objected to any capital spending at Colstrip.

As a regulated utility in the state of Idaho, Avista has an obligation to ensure that ratepayer funds are spent prudently, and that any capital investments are made in the context of least-cost planning to reliably meet customer needs, and subject to

[44] SC PR 1-4(b), Exhibit 603.
[45] SC PR 1-5(d), Exhibit No. 602, page 4 of 8.
[46] SC PR 1-5(f), Exhibit No. 602, page 4 of 8.

known – not speculative – regulatory requirements.[47] This responsibility includes the responsibility to refrain from making imprudent capital investments. As I have demonstrated, the Smartburn pollution controls are a good example of imprudent capital spending. The controls are not required by any state or federal mandate, and they have not been shown to be in the interest of ratepayers, and they have been largely and predictably ineffective at reducing NOx emissions.

Q. Would it be futile for Avista as a minority owner to oppose those capital expenditures?

A. Avista claims that it is not able to veto any specific project by itself. According to the ownership agreement provided by Avista in response to Sierra Club PR 1-5(a), [redacted][48] At a minimum, Avista should have at least identified its concerns and raised them with the other co-owners, particularly Puget Sound Energy, PacifiCorp, and Portland General Electric, who all operate as regulated utilities and have a responsibility to ensure prudent spending on behalf of their ratepayers.

---

[47] *Cf. In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No. IPC-E-13-16, Order No. 32929 at p.9-10 (finding that Idaho Power had presented a sufficient analysis showing that expenditures were the least-cost, least-risk alternative to both reduce environmental effects and allow reliance electric service to continue).

[48] SC PR 1-5C Attachment A, Exhibit No. 606, Section 17 "Project Committee."

Regardless of whether Avista voting "no" would affect the ultimate outcome, the utility still had an obligation to protect the interests of its customers. This responsibility cannot be abdicated, nor should recovery of and on such capital projects be approved, merely because Avista's minority stature does not give it a veto power over such expenditures. The Company should provide a full justification for any such expenditure, including a cost-benefit analysis and a credible analysis of alternatives for meeting its customers' specific needs, exactly as it would were it were the sole owner of the units.

If Avista had voted "no" on the Smartburn capital projects, and despite those objections the other co-owners overruled the Company and installed the projects anyway, then it might be reasonable for the Commission to conclude that Avista's management had acted prudently within the bounds of its authority under the contract. That is not what happened here. Avista was presented with an unnecessary and imprudent project that it affirmatively approved. The costs of that imprudent capital project should therefore be removed from Avista's rate base. The Commission need not reach the question in this proceeding of what it would have done had Avista been overruled, because in this instance Avista never bothered to object to the project.

Q. Do you have any concerns with the timing and manner in which Avista presented the capital costs of Smartburn to the Commission?

A. Yes. In both this proceeding and its prior rate case in AVU-E-16-03, Avista lumped the costs of Smartburn controls in with other more routine capital projects at Colstrip. There was no separate analysis discussing the unique situation that allegedly required the installation of Smartburn. This is troubling because, as discussed above, Smartburn accounted for about [redacted] of Colstrip 3 and 4's annual capital budget each year from 2015-2017. Avista should have called out these costs more explicitly in its application and testimony to allow for a thorough review of those costs, particularly considering that the costs were based on a novel and speculative compliance strategy.

Q. Why was Avista's requested capital expense for Smartburn at Unit 4 in the 2016 rate case nearly twice as expensive ($1,993,516) as the current request for Smartburn controls at Unit 3 ($1,047,417)?

A. Avista appears to have combined some or all of the 2016 project costs for Units 3 with the costs for Unit 4 in the 2016 rate case. [redacted].[49] However, Avista front-loaded recovery of those costs by claiming nearly two-thirds of those costs as part of Unit 4 and the remaining one-third as part of Unit 3.[50]

Q. Do you have any concerns with this discrepancy in timing?

A. Yes. According to the Commission's order approving the 2016 rate case settlement, the test-year for that proceeding was based on a 12-month period

[49] SC PR 1-3C, Confidential Attachment G, p. 41 and 50 of 74, Exhibit No. 605.
[50] Avista Response to SC PR 3-6(b) and 3-7(b), Exhibit No. 602, pages 5 and 8 of 8.

ending December 31, 2015 with rates that became effective on January 1, 2017.[51] That means that the Smartburn project for Colstrip Unit 3 was not complete until a full 18 months after the test year in AVU-E-16-03 and that Idaho ratepayers were paying for the project for a full 6 months before it was in service.

Adjustments to rate base should not be made for plant additions unless and until those projects actually go into service before the higher rates go into effect.[52] While some allowance can be made for capital additions that fall outside the test year, which would account for the 2016 project costs of Smartburn on Unit 4 being included in the last rate case's 2015 test year, this does not justify Avista including expenses for Smartburn Unit 3 in the prior rate case because that project was not expected to be completed until June 2017, six months after rates went into effect.

Q. Are you suggesting that the Commission should revise its prior order approving the 2016 rate case settlement?

A. No. As discussed in more detail below, I am recommending that the Commission remove the total costs from rate base for the Smartburn capital project at both Units 3 and 4. However, I am not suggesting that the Commission try to recover any of the revenues collected by Avista from January 1, 2017 through today. The

---

[51] Order No. 33683, Case No. AVU-E-16-03 (Dec. 28, 2016) at p.1-3.

[52] Order No. 29505, Case No. IPC-E-031-13 (May 25, 2004) ("Once a test year is selected, adjustments are made to test year accounts and rate base to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period **when rates will be in effect**.")(emphasis added)(internal quotations omitted).

revenue requirement in both the 2016 rate case and the current proceeding were the result of a negotiated settlement. There is no need to revisit whether the agreed upon revenue requirement was appropriate.

While I am not recommending that the Commission attempt to claw-back any previously collected revenue, it is nevertheless entirely appropriate to adjust the Company's rate base on a going forward basis now that the presence of imprudent expenditures has been identified. The 2016 rate case proceeding settled without a direct or implicit finding of fact or law regarding the prudence of capital expenditures at Colstrip Unit 4.[53] The Commission would therefore not be overturning any agreed-upon prudence finding related to Smartburn on Unit 4.

In the alternative, if the Commission declines to remove capital costs related to Smartburn on Unit 4, it should at a minimum address the discrepancy in timing whereby Avista claimed twice the costs for Smartburn on Unit 4 than it now claims on Unit 3. The capital costs attributable to Smartburn on each unit should be roughly the same.

I also raise the issue here to provide further evidence that Avista's management of Colstrip expenditures has been deficient. In order to avoid similar problems in the future, the Commission should require a more rigorous review of capital

[53] Paragraph 20 of the 2016 Stipulation expressly provided that "No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation." Mot. for Approval of Stipulation and Settlement, filed Oct. 24, 2016 in Docket AVU-E-16-03.

expenditures at Colstrip in future proceedings.

IV. Useful Life for Colstrip Units 3 and 4

Q. Do you have concerns with the end of life assumptions Avista is making with regard to Colstrip Units 3 and 4?

A. Yes. Avista requested a substantial amount of capital spending ($24.29 million) on Colstrip Units 3 and 4 in its application for the years 2017-2019. While the Settlement Agreement removed all of the capital additions budgeted for 2019 and "most" of the proposed additions in 2018,[54] the overall rate of spending at Colstrip continues to reflect an assumption that the plant will essentially run indefinitely. This is an assumption that is no longer reasonable to make given the current economic environmental facing Colstrip.

Q. How do end-of-life assumptions for Colstrip affect rates in this proceeding?

A. The capital expenditures that Avista requested to include in rate base, and the increases allowed in rate base under the Settlement Agreement, will be paid for by ratepayers based on the depreciation scheduled for each asset. For each capital project, a shorter depreciation schedule generally means a higher depreciation expense, which increases the Company's revenue requirement.

Q. Did Avista propose any changes to its depreciation schedules in this proceeding?

A. No. For Colstrip and other non-transportation assets, Avista relied on depreciation

[54] Direct Testimony of Randy Lobb at p.10.

schedules based on a depreciation study completed nearly seven years ago, on December 31, 2010.[55]

Q. Why is an outdated depreciation study a concern?

A. The depreciation schedules relied on by Avista, particularly with respect to the Colstrip units, are stale. The Company should have studied and revised its depreciation assumptions before submitting its general rate case. That update would have allowed the Commission and other parties a more accurate analysis of revenue requirement based on more up-to-date assumptions. Having failed to update its depreciation schedules, it is now likely that Avista will soon return to the Commission to request yet another rate increase to account for a faster rate of depreciation.

Q. Is it reasonable to require Avista to use an updated depreciation study in this proceeding?

A. Avista's witness, Karen Schuh, stated in her direct testimony that "Avista's next depreciation study is currently underway and is expected to be completed towards the end of 2017."[56] This suggests that Avista had already begun the process of updating its depreciation assumptions. Had Avista finished that study and submitted it along with this proceeding (or at the same time) the Commission could have consolidated multiple issues impacting revenue requirement and rates into a single docket.

[55] Direct Testimony of Karen Schuh at p.10.
[56] Direct Testimony of Karen Schuh at p.9.

Q. How does the Settlement Agreement impact your recommendation that Avista be required to consolidate its general rate case with its upcoming depreciation filing?

A. In my opinion, it may have been premature for parties to agree to a revenue requirement in this proceeding without addressing whether and how rates may change again soon in an upcoming depreciation proceeding. However, I do not want to second-guess the rationale for each party's decision to settle. If the Commission accepts the Settlement Agreement, it should make clear that nothing in this proceeding precludes Avista or any other party from arguing that rates could change to reflect updated depreciation schedules.

If, on the other hand, the Settlement Agreement is not accepted, the Commission should require Avista to file its depreciation study and consolidate that proceeding with this rate case so that the Commission and parties will be better able to understand the full extent of the proposed rate increases.

Q. Why do you conclude that rates are likely to go up in Avista's next depreciation case?

A. As discussed in more detail below, Avista's current depreciation schedules for Colstrip Units 3 and 4 are based on unrealistically long operating life assumptions. If Avista follows the trend of its other Colstrip owners such as Puget Sound Energy, Portland General Electric, and PacifiCorp, it will likely accelerate the depreciation schedule at Colstrip. All else equal, that would lead to an increase in rates.

Q What is Avista's current end-of-life assumption for Colstrip Units 3 and 4 for depreciation purposes?

A. Avista's most recently completed depreciation study was produced in December 2010 by the consulting firm Gannett Fleming, Inc; this study was provided to Sierra Club as Attachment A to Sierra Club Production Request 2-5. The Gannett Fleming study used retirement dates of December 2034 for Colstrip Unit 3 and December 2036 for Colstrip Unit 4.

Q. What was the basis of this projected end-of-life date?

A. According to the Gannett Fleming Study (p.I-4), although there were a number of analytical and judgment-related considerations, "retirement data for the years 1989 through 2010 were used in the actuarial life table computations which were the primary statistical support of the service life estimates."

Q. Is this a reasonable approach? Why or why not?

A. While this approach may have been more reasonable in 2010, it is certainly not reasonable today. The economic and regulatory environment for coal today is manifestly different from the economic conditions during the time period referenced by Gannett Fleming, rendering such a statistical analysis irrelevant to estimating the future lives of the Colstrip units.

Throughout the 20^{th} century and into the first decade of the 21^{st}, there were very few retirements of coal plants, as demand for power grew exponentially and the availability and cost of coal made it more attractive to utilities than alternative energy sources. In addition, the environmental and public health impacts of coal combustion were less well-known than they are today, and/or were considered an acceptable cost of this engine of economic growth. In 1970, the US Congress passed the Clean Air Act and began the process of requiring coal plants to install pollution controls to reduce the environmental and health impacts of their emissions. However, Congress exempted many existing coal plants from strict emissions control requirements. This loophole had the perverse consequence of actually prolonging the life of many coal plants that lacked modern pollution controls, as companies sought to avoid the costs associated with the technology that would be required on new, or substantially refurbished, coal-fired power plants.

Since around 2010 the rate of coal plant retirements has increased dramatically. In much of the country the growth in demand for electricity has slowed or even halted due to factors such as stringent appliance energy efficiency standards, along with utility-run energy efficiency programs. (The US Department of Energy's Annual Energy Outlook (AEO) for 2017 projects a total increase in electricity consumption of just 2.0% in the Western region of the United States by 2035 over 2015 levels, despite an 804% increase in electricity demand for transportation.[57]) More recent environmental regulations have required existing coal-fired plants to reduce their emissions of harmful and haze-inducing pollutants, in addition to better management of their water use, their impact on

[57] US Department of Energy, Energy Information Administration, Annual Energy Outlook for 2017. Available at https://www.eia.gov/outlooks/aeo/.

aquatic life, and disposal of combustion residuals (a.k.a. ash). These mandates often necessitate costly equipment upgrades for plants to continue operating.

At the same time, the availability of natural gas has increased with the development and widespread use of hydraulic fracturing, and the current and expected cost of gas has dropped to the point where it is often cost-preferable to coal as a generation fuel. The cost of renewable energy sources has also plummeted, while the demand for renewable-sourced energy has increased as a result of state Renewable Portfolio Standards and other policies. AEO 2017 projects an increase in renewable generation of 81.2% over 2015 levels by 2035, replacing not just coal (decrease of 77.8%) but also natural gas (decrease of 46.4%.)

Finally, coal-fired plants such as Colstrip are very large point-sources of carbon dioxide (CO_2) and other greenhouse gases, which have well-documented and extremely harmful long-term impacts on the Earth's climate and environment, human health, and economic well-being. The United States currently lags other countries in federal policies to address this threat. However, numerous states, including western states such as Washington, Oregon, and California, are moving aggressively to reduce the greenhouse gas emissions associated with electricity production and other economic activity, transforming the regional electricity market by pushing the generation mix away from high-carbon sources such as Colstrip and towards cleaner generating technologies. There has also been widespread recognition throughout the electric industry that the United States will ultimately implement policies that impose a price on greenhouse gas emissions, as the deleterious effects of global climate change become increasingly difficult to ignore or deny.

These factors have led to conditions where many coal plants cannot compete economically, and even more cannot justify continued investments in either environmental upgrades or other significant capital improvements given their long-term outlook. As a result, coal plants have been retired, or repowered to burn gas, at an unprecedented rate over the last decade. As tallied by the Sierra Club, 732 units at 259 coal plants have retired or committed to retire since 2010, representing almost 50% of 2010 coal capacity in the United States.[58] Today, even larger, younger coal plants are struggling to survive the economic competition from cleaner, cheaper energy sources.[59]

Q. Has the wave of coal plant retirements you describe reached Montana?

A. Yes. The other two Colstrip units, Units 1 and 2, will be retired in 2022. The 2022 retirement date represents a dramatic acceleration of retirement relative to that unit's owners' previous projections – Puget Sound Energy, for example was previously using a retirement date of 2035 for Units 1 and 2, based on a settlement of that company's 2007 rate case. While Units 1 and 2 are older and

[58] http://content.sierraclub.org/coal/.

[59] See, for example, E&E News, April 27, 2017: "Big Young Power Plants are Closing. Is it a new trend?" Available at https://www.eenews.net/stories/1060053677.

less efficient than Units 3 and 4, the newer units are subject to the same regulatory and economic pressures that have rendered the older units uneconomic in the longer term.

Q. What end-of-life assumptions should Avista have used in this proceeding and in its upcoming depreciation study?

A. Based on my analysis, including testimony I recently prepared for the Washington Utilities and Transportation Commission, I believe that Colstrip is likely to go out of service by 2025. In this proceeding and the upcoming depreciation filing, I recommend that Avista *at a minimum* accelerate its end-of-life assumption for both Colstrip Units to 2027. This schedule would match the depreciation schedule recently proposed by Puget Sound Energy and would more closely align with depreciation schedule changes made recently by other co-owners.

Q. What end-of-life considerations affect the other (non-Avista) owners of Colstrip Units 3 and 4?

A. Puget Sound Energy (PSE), which owns 25% of Units 3 and 4, recently reached a settlement agreement before the Washington Utilities and Transportation Commission that requested, among other things, approval of a depreciation schedule that assumed a remaining useful life of Colstrip Units 3 and 4 through December 31, 2027. Several parties, including UTC Staff, industrial customers, Sierra Club and the Montana Attorney General signed on to this settlement in support of a 2027 depreciation date. While the settling parties continue to disagree on a precise retirement date for the units in that proceeding, they all agreed that accelerating depreciation to 2027 was reasonable. The Montana Attorney General's post-hearing brief described the accelerated depreciation date as follows:

> Working to ameliorate cost uncertainty, which the adjusted depreciation schedule for Units 3 & 4 does, is in the public interest generally and the interest of Washington ratepayers specifically. **December 31, 2027, is a lawful and well-supported depreciation date** that arose from thoughtful negotiations among diverse interests.[60]

The Washington UTC's order on the PSE settlement is still pending. In addition, Portland General Electric (PGE) owns 20% of each unit and Pacific Power's parent company PacifiCorp owns 10% of each unit. Both companies serve customers in Oregon and are required by the Oregon Clean Electricity and Coal Transition Act to eliminate coal from their portfolios serving Oregon customers by 2030. While there is a carve-out from the legislation allowing PGE to continue using power from Colstrip until no later than 2035,[61] PGE has nevertheless shortened its depreciable end-of-life assumption for Units 3 and 4 from 2042 to 2030 pursuant to this rule.[62] PacifiCorp also serves customers in Washington, where it recently requested and received permission to set its depreciation rate for the Washington-jurisdictional share of Colstrip Units 3 and 4

---

[60] Washington Utilities and Transportation Commission Dockets UE-170033/UG-170034, Initial Post-Settlement-Hearing Brief of the State of Montana in Support of the Proposed Multiparty Settlement Stipulation and Agreement (Oct. 18, 2017) at p. 7 (emphasis added), Exhibit No. 612, page 6 of 6.
[61] See 78th Oregon Legislative Assembly, 2016 Regular Session, Enrolled Senate Bill 1547 for bill text (https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled) and Oregon Clean Electricity & Coal Transition Plan (SB 1547B) for a summary (https://www.portlandgeneral.com/-/media/public/our-company/news-room/documents/oregon-clean-electricity-plan-summary.pdf).
[62] Schedule 146 of PGE's Oregon tariff, Exhibit No. 613.

using an end of life date of 2032.[63]

Talen Energy, the independent generating company that co-owns and operates Colstrip Units 3 and 4, purchases coal from the Rosebud coal mine adjacent to the plant, owned by Westmoreland Coal. In Westmoreland Coal's most recently-fled SEC Form 10-K,[64] the company reported that the "estimated mine life with current plan" for Rosebud ends in 2024. The same document states that the current contract to supply coal to Colstrip Units 3 and 4 expires in 2019.[65]

Q. Does this support your conclusion that Colstrip is likely to stop operating by 2025?

A. It does in part. I also base my conclusion on the observation that during the last several years coal plants have been trending toward earlier retirements than anticipated, resulting in large undepreciated balances for resources that are no longer used and useful. Colstrip Units 1 and 2 are excellent examples of this phenomenon, and the owners of these units and their regulatory commissions are struggling to accommodate not only large undepreciated balances but also inadequate decommissioning funds. Further, as discussed above, I think it is likely that EPA will require installation of expensive SCR technology on these units in the mid-2020s in order to continue "Reasonable Progress" in reducing regional

---

[63] See final order in Washington Utilities and Transportation Commission Docket No UE-152253, September 1, 2016.

[64] Available at: https://www.sec.gov/Archives/edgar/data/106455/000010645517000012/wlb-123116_10k.htm. See table on page 10.

[65] Ibid., p.34.

haze. Based on the magnitude of costs required for SCR, and the continued improvements in the cost and performance of cleaner energy sources, the units may well shut down rather than install those controls.

While it is certainly possible that the companies and commissions setting end-of-life for Units 3 and 4 closer to 2030 have gotten it right this time around, I find it much more likely that economic pressures and the opportunity to avoid capital improvements and maintenance expenses will lead the co-owners to retire the units several years earlier than that.

Q. Why is it important to use a realistic estimate of end-of-life for depreciation purposes?

A. It is a fundamental principle of utility economic regulation that customers who get the benefit of a resource should be the same customers who pay for it. Although this can rarely be achieved with precision, using a realistic end-of-life date for depreciation purposes ensures that, to the best of anyone's ability, the customers who benefit from the energy and capacity provided by Units 3 and 4 will both pay off the outstanding plant balance, and fully fund the eventual decommissioning of these units. If a utility is allowed to assume an unrealistically long lifetime for depreciation purposes, future ratepayers or utility shareholders will have to make up the shortfall for a resource from which they are receiving no benefit – a phenomenon often called intergenerational inequity.

As Avista witness Karen Schuh noted in her direct testimony, "it is sound accounting practice to periodically update depreciation rates to recognize additions to investment in plant assets and to reflect changes in asset characteristics, technology, salvage, removal costs, life span estimates and other factors that impact depreciation rate calculations."[66] I agree with this assessment; however, Avista should have made those updates <u>before</u> filing its present request to increase rates.

V. <u>Recommendations</u>

Q. What are your recommendations for the Commission in this proceeding?

A. The Commission should conclude that Avista acted imprudently when it agreed to capital expenditures to install Smartburn at Colstrip Units 3 and 4 in the absence of any existing or anticipated compliance obligation, any showing of benefits for ratepayers, and little to no benefit in terms of reducing NOx emissions. These capital expenditures, totaling $3,040,933, should be removed from rate base on a going forward basis.

The Commission should also direct Avista to adopt and exercise more rigorous review and approval procedures for future capital expenditures at Colstrip Units 3 and 4. Avista cannot abdicate its responsibility to act in the best interests of its customers by claiming that it has no control over Colstrip expenditures as a minority owner. Avista should also provide more detailed and specific justification for significant Colstrip capital expenditures rather than simply

[66] Direct Testimony of Karen Schuh at p.10.

combining all capital costs into a single category that it claims is for "Mandatory and Compliance" purposes.

Finally, if the Settlement Agreement is rejected, the Commission should hold open this general rate case until Avista has completed and submitted its pending depreciation study. The Commission should then allow parties an opportunity to address that depreciation study and any impacts that the results will have on rates in this proceeding.

Q. Do your recommendations require the Commission to reject the Settlement Agreement?

A. No. Under Rule 276 of the Commission's Rules of Procedure, the Commission may state additional conditions under which the settlement will be accepted. Adopting my recommendations above need not disturb the agreed upon revenue requirement and rate spread in the Settlement Agreement. The adjustments I recommend to rate base are on a forward-going basis only. That is, the Commission need only issue a determination that the Smartburn capital projects were imprudent and require Avista to exclude those expenditures from rate base in all future proceedings. In doing so, the Commission would protect future ratepayers from harm while still maintaining the benefits of the Settlement Agreement currently before the Commission.

Q. Does this conclude your direct testimony?

A. Yes.

Ezra D. Hausman, Ph.D.

I am an independent consultant in energy and environmental economics.

I have worked for 20 years as an electricity market expert with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, offered expert testimony, led workshops and working groups, made presentations and participated on panels, and provided other support to clients in a number of areas, including:

- Economic analysis, price forecasting, and asset valuation in electricity markets
- Dispatch and planning model analyses, and review of modeling studies
- Electricity and generating capacity market design and analysis
- Demand-side resource program analysis
- Integrated Resource Planning and portfolio analysis
- Economic analysis of environmental and other regulations, including regulation of greenhouse gas emissions, in electricity markets
- Quantification, regulation and mitigation of greenhouse gas emissions associated with the supply and demand sides of the U.S. electricity sector
- Quantification of the economic and environmental benefits of displaced emissions associated with energy efficiency and renewable energy initiatives
- Expert representation/participation in stakeholder processes
- Clean Air Act determinations and enforcement.

I have prepared reports and offered other expert services on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers.

I previously served as Vice President and Chief Operating Officer of Synapse Energy Economics, Inc. of Cambridge, Massachusetts. In addition to my consulting portfolio, this management role entailed responsibility for day-to-day operations of the company including overseeing finance, HR, communications & marketing, quality assurance, client service, and professional development of staff. I had overall responsibility for ensuring that project managers and project teams had the tools, information, and training they needed to successfully serve client's needs and to produce high-quality deliverables on time and on budget. I was also a resource available to any of our clients to address any issues of customer service, quality, or any other issues.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.
I provide research, analysis, expert testimony, and policy support services in regulatory, litigation, and stakeholder processes covering a wide range of electric sector and electriciuty market issues. The focus of my consulting work includes:

- Interaction of air quality and environmental regulations with electricity markets
- Analysis and implementation of the Clean Power Plan and other greenhouse gas rules
- Clean Air Act enforcement support
- Long-term electric power system planning and market design
- Energy efficiency and renewable energy programs and policies
- Avoided emissions analysis
- Regulation and mitigation of greenhouse gas emissions
- Consumer and environmental protection
- Efficient pricing of generating and transmission capacity
- Market power and market concentration analysis in electricity markets
- Economic analysis of electricity industry regulation and restructuring

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – February 2014;
Vice President, July 2009 – February 2014;
Senior Associate, 2005-2009.

- Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Provided expert support and representation in planning, greenhouse gas mitigation, and other stakeholder processes.
- As Vice President and Chief Operating Officer, I was also responsible for day-to-day operations of the company, quality assurance, client service, and professional development of staff.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
As a member of the modeling group, developed and maintained dispatch modeling capability in support of electricity market consulting practice.

Performed modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity
- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the "delivered price test" for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal

and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

> **Harvard University:** *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*
>
> **Wesleyan University:** *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Community Service

Academic Mentor and Athletic Coach, SquashBusters Boston, 2014 - Ongoing
Judge, Cleantech Open innovation competitions, 2015-2016
President, Burr Elementary School Parent Teacher Organization, 2005-2007

EXPERT TESTIMONY AND SERVICES

Washington Utilities and Transportation Commission (Dockets UE-170033 and UG-170034) – Ongoing
Expert witness on behalf of the Sierra Club in Puget Sound Energy (PSE) rate case.

Clean Power Plan Modeling in PJM and MISO – Ongoing
Participation on behalf of the Sustainable FERC Project in ISO initiative to model scenarios for state compliance with federal greenhouse gas mitigation rules.

California ISO/PacifiCorp Market Integration - Ongoing
Technical support to Sierra Club in stakeholder review and participation in all relevant proceedings in California.

New Jersey Board of Public Utilities – 2014-Ongoing
Expert witness on behalf of the New Jersey Division of Rate Counsel, reviewing and providing testimony on cost effectiveness and program design of various New Jersey gas utility energy efficiency programs.

United States Department of Justice – US District Court Dallas, TX Division (U.S. vs. Luminant Generation Company, LLC, and Big Brown Power Company, LLC) – Ongoing
Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

United States Department of Justice – US District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – 2013-2016
Expert witness on behalf of the United States Department of Justice on successful prosecution of clean air act case.

Missouri Public Service Commission (Case No. EO-2015-0084) – 2014-2015
Expert services in support of Sierra Club's participation in integrated resource planning process.

Missouri Public Service Commission (File No. ER-2014-0258) – 2014-2015
Expert witness on behalf of the Sierra Club in Ameren Missouri rate case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – 2014
Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Comission (Docket No. ET-2014-0085) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Comission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013

Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Eastern Interconnect Planning Collaborative (EIPC) – 2012-2013
Expert support on behalf of coalition of NGO stakeholders in transmission and resource planning process, including development and review of modeling assumptions and interim results, and development of comments.

Puget Sound Energy (PSE) – 2012-2013
Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011
Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011
Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011
Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-Present
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – August 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008
Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia

- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005
Presented written and live testimony on whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Utah, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Oregon, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp in a Carbon Constrained Economy, Produced on behalf of the Sierra Club, October 2014.

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, 2013 Carbon Dioxide Price Forecast, Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council, Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update) Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, Will LNG Exports Benefit the United States Economy? Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman, *2012 Carbon Dioxide Price Forecast*, Synapse Energy Economics, October 2012.

Fagan B., M. Chang, P. Knight, M. Schultz, T. Comings, E.D. Hausman, and R. Wilson, *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition, May 2012.

Hausman, E.D., T. Comings, "*Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?* Synapse Energy Economics for Sierra Club, April 2012.

Hausman, E.D., T. Comings, and G. Keith, *Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics for Sierra Club, January 2012.

Keith G., B. Biewald, E.D. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight, *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* Synpase Energy Economics for Civil Society Institute, November 2011.

Chang M., D. White, E.D. Hausman, N. Hughes, and B. Biewald, *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S.* Synpase Energy Economics for Union of Concerned Scientists, October 2011.

Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011.* Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* Synapse Energy Economics for American Public Power Association, June 2011.

Johnston L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. *2011 Carbon Dioxide Price Forecast.* Synapse Energy Economics White Paper, February 2011.

Hausman E.D., V. Sabodash, N. Hughes, and J. I. Fisher, *Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule.* Synapse Energy Economics for New Energy Economy, February 2011.

Hausman E.D., J. Fisher, L. Mancinelli, and B. Biewald. *Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers.* Synapse Energy Economics for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 2009.

Peterson P., E. Huasman, R. Fagan, and V. Sabodash, *Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI*, May 2009.

Schlissel D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, *Synapse 2008 CO_2 Price Forecasts.* July 2008.

Hausman E.D., J. Fisher and B. Biewald, *Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation.* Synapse Energy Economics Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July 2008.

Hausman E.D. and C. James, *Cap and Trade CO_2 Regulation: Efficient Mitigation or a Give-away?* Synapse Enegy Ecomics presentation to the ELCON Spring Workshop, June 2008.

Hausman E.D., R. Hornby and A. Smith, *Bilateral Contracting in Deregulated Electricity Markets.* Synapse Energy Economics for the American Public Power Association, April 2008.

Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers.* Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

Hausman E.D. and K. Takahashi, *The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis.* Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, January 2007.

Hausman E.D., K. Takahashi, D. Schlissel and B. Biewald, *The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives.* Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, March 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies*. Synapse Energy Economics for the Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region*. Synapse Energy Economics for Glebe Mountain Wind Energy, LLC., February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project.* Synapse Energy Economics for Deerfield Wind, LLC., January 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon*. Synapse Energy Economics for the Illinois Citizens Utility Board, October 2005.

Hausman E.D. and G. Keith, *Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives*. Synapse Energy Economics for EPA website 2005

Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, *Loss Hedging Rights: A Final Piece in the LMP Puzzle*. Hawaii International Conference on System Sciences, Hawaii, January, 2005 *(*accepted*).*

Hausman E.D. and R.D. Tabors, *The Role of Demand Underscheduling in the California Energy Crisis*. Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, *The reorganization of the global carbon cycle at the last glacial termination.* Global Biogeochemical Cycles, *13*(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, *Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum.* Paleoceanography, *12,* 15-22, 1997.

Hausman E.D. and M.B. McElroy, *Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation.* Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

American Public Power Association: Invited expert participant in APPA's roundtable discussion of the current state of the RTO-operated electricity markets. October 2013.

California Long-Term Resource Adequacy Summit (Sponsored by the California ISO and the California Public Utility Commission): Panelist on "Applying Alternative Models to the California Market Construct." February 26, 2013.

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO2 Cap-and-Trade." July, 2009.

***NASUCA 2008 Mid-Year Meeting*:** Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

***NASUCA 2007 Mid-Year Meeting*:** Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

***NASUCA 2006 Mid-Year Meeting*:** Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Led a series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated June 2017

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	08/23/2017
CASE NO.:	AVU-E-17-01 / AVU-G-17-01	WITNESS:	Scott Kinney
REQUESTER:	Sierra Club	RESPONDER:	Tom Dempsey
TYPE:	Production Request	DEPARTMENT:	Thermal Operations
REQUEST NO.:	Sierra Club-1-3	TELEPHONE:	(509) 495-4960

REQUEST:

Reference Exhibit No. 4 (Kinney), Schedule 3 pages 90-91. Section 1.1 states: "The current operator provides the annual business plan and capital budgets to the owner group every September."
a. Provide the annual business plan and capital budgets for the past three years (2015, 2016, 2017).
b. Provide the 2018 business plan and capital budget when it is available next month.
c. Provide all "individual project summaries" related to the Colstrip 3&4 Capital Projects.

RESPONSE:

Please see Avista's response 1-3C, which contains **TRADE SECRET, PROPRIETARY** or **CONFIDENTIAL** information and exempt from public view and is separately filed under IDAPA 31.01.01, Rule 067 and 233, and Section 9-340D, Idaho Code.

a. Avista is providing the Colstrip 3&4 business plans and capital budgets for 2015, 2016, and 2017. See SC_PR_1-3C Confidential Attachments A-C. Please note, each business plan received annually provides a 5-year plan i.e. 2015 business plan provides 2015-2019. Therefore, outer years within the 5-year plan are updated annually with each subsequent year.

b. The Colstrip units 3&4 2018 Business Plan and capital budget for 2018 will not be approved and finalized until after November 1st.

c. Avista is providing project summaries for 2015, 2016 and 2017 Colstrip 3&4 capital projects as requested. See SC_PR_1-3C Confidential Attachments D-J.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	08/23/2017
CASE NO.:	AVU-E-17-01 / AVU-G-17-01	WITNESS:	Scott Kinney
REQUESTER:	Sierra Club	RESPONDER:	Tom Dempsey
TYPE:	Production Request	DEPARTMENT:	Thermal Operations
REQUEST NO.:	SC-1-4	TELEPHONE:	(509) 495-4960

REQUEST:

Reference Exhibit No. 4 (Kinney), Schedule 3 pages 90-91. Section 1.1 states: "Avista reviews these individual projects."
a. Provide all documents, emails, communications, memos, or other internal company documents related to Avista's review of the Colstrip 3&4 Capital Projects.
b. Describe in detail the review process, including the individuals who are responsible for review and approval of the individual projects.

RESPONSE:

Please see Avista's response 1-4C, which contains **TRADE SECRET, PROPRIETARY** or **CONFIDENTIAL** information and exempt from public view and is separately filed under IDAPA 31.01.01, Rule 067 and 233, and Section 9-340D, Idaho Code.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	08/23/2017
CASE NO.:	AVU-E-17-01 / AVU-G-17-01	WITNESS:	Scott Kinney
REQUESTER:	Sierra Club	RESPONDER:	Tom Dempsey
TYPE:	Production Request	DEPARTMENT:	Thermal Operations
REQUEST NO.:	Sierra Club-1-5	TELEPHONE:	(509) 495-4960

REQUEST:

Reference Exhibit No. 4 (Kinney), Schedule 3 pages 90-91. Section 1.1 states:
"Ultimately, the business plan is approved in accordance with the Ownership and Operation Agreement for units 3&4 that six companies are party to."
a. Provide the currently applicable Ownership and Operation Agreement.
b. If different than (a), provide the Ownership and Operation Agreement in effect at the time the Colstrip 3&4 Capital Projects at issue in Avista's application were approved by the owners.
c. Describe Avista's understanding of how the decision to include a capital project in the business plan works in practice.
d. Did Avista raise any concerns or vote "no" on the Colstrip 3&4 Capital Projects at issue in this application? If so, please provide any record of those objections or concerns.
e. Did any other Colstrip owner raise any concerns of vote "no" on the Colstrip 3&4 Capital Projects at issue in this application? If so, please provide any record of those objections or concerns.
f. Has Avista ever voted "no" or otherwise not approved an individual capital project? If so, please describe when such a vote occurred and whether the capital project was ultimately included in the business plan.

RESPONSE:

Please see Avista's response 1-5C, which contains **TRADE SECRET, PROPRIETARY** or **CONFIDENTIAL** information and exempt from public view and is separately filed under IDAPA 31.01.01, Rule 067 and 233, and Section 9-340D, Idaho Code.

a. See SC_PR_1-5C Confidential Attachment A for the current Colstrip Ownership and Operation Agreement.

b. The current Colstrip Ownership and Operation Agreement provided in question SC 1-5a was in effect at the time the projects included in Avista's application were approved.

c. Engineering, equipment condition assessment, and all other daily operational activities and capital planning are provided by Talen as operator of Colstrip 3&4. The following is a general description of Talen's process:

   After the first of a given year, Talen updates the existing capital plan to include projects carried forward from a prior year. It also adds in all newly proposed capital projects that were not part of the prior year's 2 year projection. Talen's management team vets all of the projects to ensure that the projects that are included as proposed capital projects are justified and prioritized and included based on a financial analysis or are required for environmental, regulatory, or safety reasons.

d. Avista didn't vote "no" on any of the Colstrip 3&4 projects included in the rate case application. With respect to projects occurring in 2018 and beyond, no such approval process has started yet- with the exception of those projects that are multiyear projects starting in 2017 or prior that continue on into 2018 and beyond.

e. As a matter of general practice, Avista does not maintain records of other companies' voting positions.

f. **Objection:** Avista objects to this data request on the ground that it does not include any defined timeframe and, therefore, the request is overly broad and unduly burdensome. Without waiving its objections, Avista provides the following response.

   Avista doesn't maintain any formal documentation regarding previous individual project approval discussions. If a project that Talen proposed was rejected by the committee it would be eliminated from the budget. With respect to an instance where Avista objected to a project that was ultimately included in the budget, we do not recall an instance at this time.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	10/31/2017
CASE NO:	AVU-E-17-01/AVU-G-17-01	WITNESS:	Scott Kinney
REQUESTER:	Sierra Club	RESPONDER:	Thomas Dempsey
TYPE:	Production Request	DEPARTMENT:	Thermal Operations
REQUEST NO.:	Sierra Club - 3-6 Supplemental 2	TELEPHONE:	(509) 495-4960

REQUEST:

Reference Avista's response to SC 1-3, Confidential Attachment E, page 33 of 38.

a. What is the construction and operation status of [confidential] ("Project ID 10022111")? If it has not been completed, when (month and year) does Avista anticipate it will be completed?

b. Please provide the dollar amount, if any, from Project ID 10022111 that Avista included in its rate base request in this proceeding AVU-E-17-01?

c. On what date does Avista anticipate Project ID 10022111 was or will be "used and useful"?

d. The project description states: [confidential] What is the status of the [confidential] referenced in this project authorization?

e. On what date did the [confidential] referenced by this document come into effect? If that date has not yet occurred, what date does Avista anticipate they will come into effect?

f. Please provide all memos, reports, emails, or other documents prepared by, reviewed by, or made available to Avista that support the conclusion that [confidential].

g. Please provide all memos, reports, emails, or other documents prepared by, reviewed by, or made available to Avista between 2015 and today that discuss any changes to the referenced [confidential] and/or the referenced [confidential].

h. Please provide a narrative description of what Avista understands its regulatory obligations are today that necessitate the installation of Project ID 10022111, including but not limited to compliance deadlines and applicable emissions limits.

RESPONSE:

a. Project ID 10022111 has been completed and is in service.
b. This project was completed in June of 2016, included and approved in Avista' prior 2016 GRC (Case No. AVU-E-16-03), and is therefore currently included in base rates as of January 1, 2017. Therefore this project is not included in the Company's current base request in this proceeding. The total cost from Talen for this project is $1,993,516. This total does not include any overheads incurred by Avista.
c. 6/30/2016

d. The Regional Haze Program set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make "reasonable progress" to maintain the proper glide-path of pollutant reductions to achieve the 2064 goal. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana which included both emission limitations and pollution controls for Colstrip Units 1 & 2.

   Anticipating that Colstrip Units 3 & 4 could be ordered to install Selective Catalytic Reduction (SCR) during the 2017 review period, the Colstrip Owners' proactively installed the Smart Burn technology to reduce the formation of Nitrous Oxides (NOx) in combustion zone for two major benefits:

   Make proactive and verifiable NOx reductions and
   Optimize the size, scope and ammonia use of any future SCR installation.

   Colstrip Units 3 & 4 are currently being evaluated as part of the State of Montana Regional Haze 5-Year Progress Report (please see: https://deq.mt.gov/Portals/112/Public/Air/ProgressReport_DRAFT_7-2017.pdf) for more information.

e. See answer to "d"
f. The following attachments are provided:
   - SC_PR_3-6 Attachment A – PPL - PPL response letter to EPA dated Jan. 31, 2011 to request for information (Nov. 5, 2010) for additional Reasonable Progress information for Colstrip Units 3 & 4.
   - SC_PR_3-6 Attachment B –Executive - NOx Control supplement to Attachment 2 of PPL.pdf . This attachment includes additional information in regards to NOx provided by PPL.
   - SC_PR_3-6 Attachment C –Earth J -Earth Justice, Montana Environmental Information Center, Sierra Club and National Parks Conservation Association comment letter to EPA dated August 22, 2011
   - SC_PR_3-6 Attachment D –Regional Haze - Colstrip Owners presentation to EPA dated Nov. 1, 2011
   - SC_PR_3-6 Attachment E –Federal Reg - EPA issued the Federal Implementation Plan (FIP) for Montana dated Sept. 18, 2012
   - SC_PR_3-6 Attachment E –EPA - EPA issued general principles for next review period for reasonable progress reports

   The Company is in the process of searching for additional material and will supplement this response with relevant information if and when available.

g. See "f"
h. See answer to "d"

SUPPLEMENTAL RESPONSE:

Please see Avista's response 3-6C, which contains **TRADE SECRET, PROPRIETARY** or **CONFIDENTIAL** information and exempt from public view and is separately filed under IDAPA 31.01.01, Rule 067 and 233, and Section 9-340D, Idaho Code.

Please see SC_PR_3-6C Supplemental Confidential Attachment A for additional material to part f.

SUPPLEMENTAL 2 RESPONSE:

Please see Avista's response 3-6C Supplemental 2, which contains **TRADE SECRET, PROPRIETARY** or **CONFIDENTIAL** information and exempt from public view and is separately filed under IDAPA 31.01.01, Rule 067 and 233, and Section 9-340D, Idaho Code.

The spreadsheet attachment to the email (Gordon Criswell to Tom Dempsey and others) was inadvertently left out of the previous response (ICNU_PR_3-6C Supplemental). Please see SC_PR_3-6C Supplemental 2 Confidential Attachment A for additional material to part f.

AVISTA CORPORATION
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	IDAHO	DATE PREPARED:	09/22/2017
CASE NO:	AVU-E-17-01/AVU-G-17-01	WITNESS:	Scott Kinney
REQUESTER:	Sierra Club	RESPONDER:	Thomas Dempsey
TYPE:	Production Request	DEPARTMENT:	Thermal Operations
REQUEST NO.:	Sierra Club - 3-7	TELEPHONE:	(509) 495-4960

REQUEST:

Reference Avista's response to SC 1-3, Confidential Attachment G, page 50 of 74.

a. What is the construction and operation status of the ("Project ID 10023705")? If it has not been completed, when (month and year) does Avista anticipate it will be completed?

b. Please provide the dollar amount, if any, from Project ID 10023705 that Avista included in its rate base request in this proceeding AVU-E-17-01?

c. On what date does Avista anticipate Project ID 10023705 was or will be "used and useful"?

d. Please provide a narrative description of what Avista understands its regulatory obligations are today that necessitate the installation of Project ID 10023705, including but not limited to compliance deadlines and applicable emissions limits.

e. Please provide all memos, reports, emails, or other documents prepared by, reviewed by, or made available to Avista that support the conclusion that any regulation, statute, or other requirement requires the installation of Project ID 10023705.

RESPONSE:

a. Project ID 10023705 has been completed and is in service.
b. The total project costs billed from Talen are $1,047,417. This total does not include any overheads incurred by Avista.
c. 6/30/17.
d. See the Company's response to SC_PR_3-6 (d).
e. See the Company's response to SC_PR_3-6 (d).
f. See Avista's response to SC_PR_3-6 (f)
g. See Avista's response to SC_PR_3-6 (f)
h. See the Company's response to SC_PR_3-6 (d).

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA–HQ–OAR–2015–0531; FRL–9957–05–OAR]

RIN 2060–AS55

Protection of Visibility: Amendments to Requirements for State Plans

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions to requirements under the Clean Air Act (CAA) for state plans for protection of visibility in mandatory Class I Federal areas in order to continue steady environmental progress while addressing administrative aspects of the program. In summary, the revisions clarify the relationship between long-term strategies and reasonable progress goals (RPGs) in state implementation plans (SIPs) and the long-term strategy obligation of all states; clarify and modify the requirements for periodic comprehensive revisions of SIPs; modify the set of days used to track progress towards natural visibility conditions to account for events such as wildfires; provide states with additional flexibility to address impacts on visibility from anthropogenic sources outside the United States (U.S.) and from certain types of prescribed fires; modify certain requirements related to the timing and form of progress reports; and update, simplify and extend to all states the provisions for reasonably attributable visibility impairment, while revoking most existing reasonably attributable visibility impairment federal implementation plans (FIPs). The EPA also is making a one-time adjustment to the due date for the next periodic comprehensive SIP revisions by extending the existing deadline of July 31, 2018, to July 31, 2021.

DATES: This final rule is effective on January 10, 2017.

ADDRESSES: The EPA established Docket ID No. EPA–HQ–OAR–2015–0531 for this action. All documents in the docket are listed in the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically in *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For general information regarding this rule, contact Mr. Christopher Werner, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541–5133 or by email at *werner.christopher@epa.gov;* or Ms. Rhea Jones, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541–2940 or by email at *jones.rhea@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Preamble Glossary of Terms and Acronyms

The following are abbreviations of terms used in this document.

AQRV Air quality related value
BART Best available retrofit technology
b_{ext} Light extinction
CAA Clean Air Act
CFR Code of Federal Regulations
EGU Electric generating unit
EPA Environmental Protection Agency
FIP Federal implementation plan
FLM or FLMs Federal Land Manager or Managers
ICR Information collection request
IMPROVE Interagency monitoring of protected visual environments
NAAQS National Ambient Air Quality Standards
NSR New Source Review
NO_X Nitrogen oxides
OMB Office of Management and Budget
PM Particulate matter
$PM_{2.5}$ Particulate matter equal to or less than 2.5 microns in diameter (fine particulate matter)
PM_{10} Particulate matter equal to or less than 10 microns in diameter
PRA Paperwork Reduction Act
RHR Regional Haze Rule
RPG Reasonable progress goal
RPO Regional planning organization
SIP State implementation plan
SO_2 Sulfur dioxide
TAR Tribal Authority Rule
URP Uniform rate of progress

B. Entities Affected by This Rule

Entities potentially affected directly by this rule include state, local and tribal [1] governments, as well as FLMs responsible for protection of visibility in mandatory Class I federal areas.[2] Entities potentially affected indirectly by this rule include owners and operators of sources that emit particulate matter equal to or less than 10 microns in diameter (PM_{10}), particulate matter equal to or less than 2.5 microns in diameter ($PM_{2.5}$ or fine PM), sulfur dioxide (SO_2), oxides of nitrogen (NO_X), volatile organic compounds and other pollutants that may cause or contribute to visibility impairment. Others potentially affected indirectly by this rule include members of the general public who live, work or recreate in mandatory Class I areas affected by visibility impairment. Because emission sources that contribute to visibility impairment in Class I areas also may contribute to air pollution in other areas, members of the general public may also be affected by this rulemaking.

C. Obtaining a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of this **Federal Register** document will be posted at *http://www.epa.gov/visibility.* A "track changes" version of the full regulatory text that incorporates and shows the full context of the changes in this final action is also available in the docket for this rulemaking. In addition to the final and regulatory text documents, other relevant documents are located in the docket, including technical support documents referenced in this preamble.

[1] The EPA's visibility protection regulations may apply, as appropriate under the Tribal Authority Rule (TAR) in 40 CFR part 49, to an Indian tribe that receives a determination of eligibility for treatment as a state for purposes of administering a tribal visibility protection program under section 169A of the CAA. No tribe has applied for such status, and so at present the EPA is responsible for implementation of the visibility protection regulations in areas of tribal authority. This responsibility includes, but is not limited to, implementation of the reasonable progress requirements of 40 CFR 51.308(f), as necessary or appropriate. These rule changes may impact the development and approvability of tribal implementation plans that tribes may wish to submit in the future. We encourage states to provide outreach and engage in discussions with tribes about their regional haze SIPs as they are being developed.

[2] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. CAA section 162(a). In accordance with section 169A of the CAA, the EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. CAA section 162(a). Although states and tribes may designate as Class I additional areas that they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." CAA section 302(i). When we use the term "Class I area" in this action, we mean any one of the 156 "mandatory Class I Federal areas" where visibility has been identified as an important value, unless the context makes it clear that additional non-mandatory Federal Class I areas are also meant to be included.

D. Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 13, 2017. Under CAA section 307(d)(7)(B), any such judicial review is limited to only those objections that were raised with reasonable specificity in timely comments. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for purposes of judicial review, extend the time in which a petition for judicial review may be filed, or postpone the effectiveness of the rule. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

*E. Organization of This **Federal Register** Document*

The information presented in this document is organized as follows:

F. Background on This Rulemaking

On May 4, 2016, the EPA proposed revisions to the 1999 Regional Haze Rule (RHR),[3] which include clarifications and modifications to the requirements that states (and, if applicable, tribes) have to meet as they implement programs for the protection of visibility in mandatory Class I Federal areas, under sections 169A and 169B of the CAA. The EPA held public hearings on May 19, 2016, in Washington, DC and on June 1, 2016, in Denver, Colorado. States, industry, private citizens and non-governmental organizations submitted over 180,000 comments. Based on EPA's review of the comments, we are finalizing most of the proposed revisions, but are also making some changes to respond to the concerns raised by commenters. These include: Changes to the proposed terminology used to refer to emissions inventories; changes to the proposed definitions and terminology related to how days are selected for tracking progress; changes to the proposed fire-related definitions and terminology; changes to the proposed required content of progress reports; changes to the proposed deadline for a state response to a reasonably attributable visibility impairment certification; the addition of a requirement for FLMs to consult with states prior to making a reasonably attributable visibility impairment certification; and minor changes to the requirements for FLM consultation on SIPs and progress reports. The EPA is issuing this final rule under section 307(d) of the CAA. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. CAA section 307(d)(1) clarifies that: "The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies." Thus, section 553(d) of the APA does not apply to this rule. The EPA has nevertheless considered the purposes underlying APA section 553(d) in making this rule effective upon publication. The primary purpose of the 30-day waiting period prescribed in section 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Notably, there are no specific obligations in the first thirty days of this regulatory action, and all obligations are established as of a date certain, rather than being tied to the effective date.

In addition, section 553(d) allows an effective date less than 30 days after publication for a rule that "grants or recognizes an exemption or relieves a restriction." An important aspect of this rule is the 3-year extension for state planning obligations. This extension is comparable to the grant of an exemption or relief from a restriction because it provides more time for states to meet a regulatory requirement. It is thus reasonable to make this action effective upon publication because states do not require an additional 30 days to adjust their behavior and prepare for the rule going into effect, and in fact will gain additional time to meet their planning obligations.

II. Executive Summary

The CAA's visibility protection program, implemented through the rules at 40 CFR 51.300 through 51.309, helps to protect clear views in national parks, such as Grand Canyon National Park, and wilderness areas, such as the Okefenokee National Wildlife Refuge.

[3] Here and elsewhere in this document, the terms "Regional Haze Rule," "1999 Regional Haze Rule" and "1999 RHR" refer to the 1999 final rule (64 FR 35714), as amended in 2005 (70 FR 39156, July 6, 2005), 2006 (71 FR 60631, October 13, 2006) and 2012 (77 FR 33656, June 7, 2012).

Vistas in these areas are often obscured by visibility-impairing pollutants caused by emissions from numerous sources located over a wide geographic area. States are required to submit periodic plans demonstrating how they have and will continue to make progress towards achieving their visibility improvement goals. The first state plans were due in 2007 and covered the 2008–2018 planning period.

The EPA is making changes to the requirements that states (and, if applicable, tribes) have to meet for the second and subsequent implementation periods as they develop programs for the protection of visibility in mandatory Class I areas, consistent with CAA requirements. Implementation of the EPA's RHR (during the first implementation period) resulted in significant reductions in emissions and associated improvements in visibility in many Class I areas (*see* Section III.B of this document). This final rule supports continued environmental progress by retaining much of the 1999 RHR, clarifying or revising certain provisions of the visibility protection rules in 40 CFR part 51, subpart P, and removing rule provisions that have been superseded by subsequent developments. An overview of the revisions is provided later, with additional details throughout this document.

The EPA is clarifying the relationship between long-term strategies and RPGs in state plans and the long-term strategy obligations of all states. We are reiterating that the CAA requires states to consider the four statutory factors (costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts and remaining useful life) in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class I area. The rate of progress in some Class I areas may be meeting or exceeding the uniform rate of progress (URP) that would lead to natural visibility conditions by 2064, but this does not excuse states from conducting the required analysis and determining whether additional progress would be reasonable based on the four factors. The EPA is revising the RHR to address a number of issues, as discussed in the proposal, including: The way in which a set of days during each year is to be selected for purposes of tracking progress towards natural visibility conditions; aspects of the requirements for the content of progress reports; updating, simplifying and extending to all states the provisions for reasonably attributable visibility impairment and revoking FIPs adopted in the 1980s that require the EPA to assess and address any existing reasonably attributable visibility impairment situations in some states; and revising the requirement for states to consult with FLMs. Other changes address administrative aspects of the program in order to reduce unnecessary burden. These include the following: The EPA is finalizing a one-time adjustment to the due date for the next SIPs (from 2018 to 2021); revising the due dates for progress reports; and changing the requirement that progress reports be submitted as formal SIP revisions to documents that need not comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103 and Appendix V to Part 51—Criteria for Determining the Completeness of Plan Submissions. All of these changes apply to periodic comprehensive state implementation plans developed for the second and subsequent implementation periods and to progress reports submitted subsequent to those plans. These changes do not affect the development and review of state plans for the first implementation period or the first progress reports due under the 1999 RHR.

The rationale for these changes is described more fully in the descriptions of each change detailed later in this action as well as in the preamble to the proposed rule.[4] The revisions being finalized are informed by approximately 15 years of implementation of the CAA, numerous outreach sessions and stakeholder feedback regarding the regional haze program, and the many constructive comments we received on the proposal. The clarifications regarding the relationship between RPGs, long-term strategies and the long-term strategy obligation of all states are intended to ensure appropriate and consistent understanding of these requirements as states prepare their plans for the second implementation period. These clarifications reflect EPA's long-standing interpretation of the RHR, and are now being codified. The rule revisions related to how days are selected for visibility progress tracking will provide the public and state officials more meaningful information on how existing and potential new emission reduction measures are contributing or could contribute to reasonable progress in reducing man-made visibility impairment. Changes to FLM consultation requirements will help ensure that the expertise and perspective of these officials are brought into the state plan development process early enough that they can meaningfully contribute to the state's deliberations. Collectively, the changes being finalized now will ensure that the regional haze program is implemented consistent with CAA obligations, and ensure successful implementation during the second planning period and beyond.

With regard to the extension of the deadline of July 31, 2018, to July 31, 2021, for states' comprehensive SIP revisions for the second implementation period, this one-time change will benefit states by allowing them to obtain and take into account information on the effects of a number of other regulatory programs that will be impacting sources over the next several years. The change will also allow states to develop SIP revisions for the second implementation period that are more integrated with state planning for these other programs, an advantage that was widely confirmed in early discussions with states and in comments submitted to the docket for this rulemaking. We anticipate that this change will result in greater environmental progress than if planning for these multiple programs were not as well integrated. The end date for the second implementation period remains 2028, as was required by the 1999 RHR. Other than the one-time change to the next due date for periodic comprehensive SIP revisions, no change is being made for due dates for future periodic comprehensive SIP revisions.

The changes related to progress reports are intended to make the timing of progress reports more useful as mid-course reviews, to clarify the required content of progress reports for aspects on which there has been some confusion, and to allow states to conserve their administrative resources and make submission of progress reports more timely by removing the requirement that they be submitted as formal SIP revisions. We are retaining a requirement that states consult with FLMs on their progress reports, and that states offer the public an opportunity to comment on progress reports before they are finalized, which are two of the steps that applied to progress reports when they were required to be SIP revisions, and which will help ensure ongoing accountability for progress reports. Please note that while the proposed rule included identical FLM consultation periods for progress reports and periodic comprehensive SIP revisions, FLM consultation requirements for SIP revisions and progress reports will differ going forward. This issue is described more fully in Section IV.K of this document.

[4] 81 FR 26942 (May 4, 2016).

Finally, the 1999 RHR's provisions related to reasonably attributable visibility impairment required a recurring process of assessment and planning by the states. Experience since these provisions were promulgated suggests that situations involving reasonably attributable visibility impairment occur infrequently and therefore that an "as needed" approach for initiating a state planning obligation would be a more efficient use of resources. The EPA is finalizing its proposal to replace the recurring process of assessment of reasonably attributable visibility impairment with an as-needed approach. The change to an as-needed approach only applies to reasonably attributable visibility impairment—periodic planning for purposes of regional haze will continue. In addition, in light of our increased understanding of the interstate nature of visibility impairment, we are expanding the applicability of the requirement to address reasonably attributable visibility impairment from only states with Class I areas to all states. If a situation exists or arises in which a source or a small number of sources in a state without any Class I area causes reasonably attributable visibility impairment at a Class I area in another state, this mechanism will ensure adequate visibility protection.

III. Overview of Visibility Protection Statutory Authority, Regulation and Implementation

A. Visibility in Mandatory Class I Federal Areas

Reduction in visibility caused by emissions of PM_{10}, $PM_{2.5}$ (*e.g.*, sulfates, nitrates, organic carbon, elemental carbon and soil dust) and their precursors (*e.g.*, SO_2, NO_X and, in some cases, ammonia and volatile organic compounds) can take the form of either visibly distinct layers or plumes of pollution or more uniform "regional haze." Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which along with directly emitted PM_{10} and $PM_{2.5}$ impairs visibility by scattering and absorbing light. This light scattering reduces the clarity, color and visible distance that one can see. Particulate matter can also cause serious health effects in humans (including premature death, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and increased respiratory symptoms) and contribute to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that at the time the RHR was finalized in 1999, visibility impairment caused by air pollution occurred virtually all the time at most national park and wilderness areas. The formally defined average visual range [5] in many Class I areas in the western U.S. was 62–93 miles. In some Class I areas, these visual ranges may have been impacted by natural wildfire and dust episodes in addition to anthropogenic impacts. In most of the eastern Class I areas of the U.S., the average visual range was less than 19 miles.[6]

Based on visibility data through 2014, the visual range has increased 10 to 20 miles (4 to 7 deciviews) [7] since the year 2000 in eastern Class I areas on the 20 percent haziest days. Some western Class I areas have also experienced visual range increases of 5 to 10 miles (1 to 4 deciviews) on the 20 percent haziest days. However, in some areas, such as Sawtooth Wilderness area in Idaho, improvements from reduced emissions from man-made sources have been overwhelmed by impacts from wildfire and/or dust events. There are also some western areas where visibility has improved only by a slight amount or made no progress.

B. Reasonably Attributable Visibility Impairment

In section 169A of the 1977 Amendments to the CAA, Congress enacted a program for protecting visibility in the nation's national parks, wilderness areas and other Class I areas due to their "great scenic importance." [8] Section 169A(a) of the CAA establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

In 1980, the EPA promulgated regulations to address visibility impairment in Class I areas, including but not limited to impairment that is "reasonably attributable" to a single source or small group of sources, *i.e.*, "reasonably attributable visibility impairment." [9] These regulations, codified at 40 CFR 51.300 through 51.307, represented the first phase in addressing visibility impairment from existing sources. They also addressed potential visibility impacts from new and modified major sources already subject to permitting requirements for purposes of protection of the National Ambient Air Quality Standards (NAAQS) and preventing significant deterioration of air quality.

Notably, not all states were subject to the 1980 reasonably attributable visibility impairment requirements. Under the 1980 rules, the 35 states and one territory (Virgin Islands) containing Class I areas were required to submit SIPs addressing reasonably attributable visibility impairment. The 1980 rules required states to (1) develop, adopt, implement and evaluate long-term strategies for making reasonable progress toward remedying existing and preventing future impairment in the mandatory Class I areas through their SIP revisions; (2) adopt certain measures to assess potential visibility impacts due to new or modified major stationary sources, including measures to notify FLMs of proposed new source permit applications, and to consider visibility analyses conducted by FLMs in their new source permitting decisions; (3) conduct visibility monitoring in mandatory Class I areas, and (4) revise their SIPs at 3-year intervals to assure reasonable progress toward the national visibility goal. In addition, the 1980 regulations provided that an FLM may certify to a state at any time that visibility impairment at a Class I area is reasonably attributable to a single source or a small number of sources. Following such a certification by an FLM, a state was required to address the requirements for best available retrofit technology (BART) for BART-eligible sources considered to be contributing to reasonably attributable visibility impairment. Also, the appropriate control of any source certified by an FLM, whether BART-eligible or not, would be specifically addressed in the long-term strategy for making reasonable progress toward the national goal of natural visibility conditions. *See* the

[5] Visual range is the greatest distance, in kilometers or miles, at which a certain dark object can be discerned against the sky by a typical observer under certain defined conditions. Visual range defined in this highly controlled manner is inversely proportional to light extinction (b_{ext}) by particles and gases and is calculated as: Visual Range = $3.91/b_{ext}$ (Bennett, M.G., The physical conditions controlling visibility through the atmosphere; Quarterly Journal of the Royal Meteorological Society, 1930, 56, 1–29). Light extinction has units of inverse distance (*i.e.*, Mm^{-1} or inverse Megameters (mega = 10^6)). Under conditions other than those defined in this reference, people's ability to discern landscape features may vary and be different than implied by the value of the visual range as calculated from light extinction using this formula.

[6] 64 FR 35715 (July 1, 1999).

[7] The deciview haze index (discussed in more detail in Section III.B.3 of this document) is logarithmically related to light extinction and is used by the regional haze program because it describes uniform differences in visibility across a range of visibility conditions.

[8] H.R. Rep. No. 294, 95th Cong. 1st Sess. at 205 (1977).

[9] 45 FR 80084 (December 2, 1980).

FEDERAL REGISTER

Vol. 81 Wednesday,
No. 86 May 4, 2016

Part IV

Environmental Protection Agency

40 CFR Parts 51 and 52
Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA–HQ–OAR–2015–0531; FRL–9935–27–OAR]

RIN 2060–AS55

Protection of Visibility: Amendments to Requirements for State Plans

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing amendments to requirements under the Clean Air Act (CAA) for state plans for protection of visibility in mandatory Class I federal areas (Class I areas) in order to continue steady environmental progress while addressing administrative aspects of the program. The EPA amendments would clarify the relationship between long-term strategies and reasonable progress goals in state plans, and the long-term strategy obligation of all states. The amendments would also change the way in which some days during each year are to be selected for purposes of tracking progress towards natural visibility conditions to account for events such as wildfires; change aspects of the requirements for the content of progress reports; update, simplify and extend to all states the provisions for reasonably attributable visibility impairment and revoke existing federal implementation plans (FIPs) that require the EPA to assess and address any existing reasonably attributable visibility impairment situations in some states; and add a requirement for states to consult with Federal Land Managers (FLMs) earlier in the development of state plans. The EPA also proposes to address administrative aspects of the program by making a one-time adjustment to the due date for the next state implementation plans (SIPs), revising the due dates for progress reports and removing the requirement for progress reports to be SIP revisions.

DATES: *Comments.* Written comments on this proposal must be received on or before July 5, 2016. *Public hearing.* The EPA is holding a public hearing concerning the proposed rule on May 19, 2016, in Washington, DC. The last day to pre-register to speak at the hearing is May 17, 2016. Please refer to **SUPPLEMENTARY INFORMATION** for additional information on submitting comments and the public hearing. *Information collection request.* Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 3, 2016.

ADDRESSES: *Comments:* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2015–0531, at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, Cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/comments.html. Public hearing:* A public hearing will be held at William Jefferson Clinton East building (WJC East), Room 1117A, in Washington, DC. Identification is required. If your driver's license is issued by American Samoa, Illinois or Missouri, you must present an additional form of identification to enter. Enhanced driver's licenses from Minnesota and Washington are acceptable. Please refer to **SUPPLEMENTARY INFORMATION** for additional information on the public hearing and location requirements.

FOR FURTHER INFORMATION CONTACT: For general information on this proposed rule and Information Collection Request (ICR), contact Mr. Christopher Werner, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541–5133 or by email at *werner.christopher@epa.gov*; or Ms. Rhea Jones, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541–2940 or by email at *jones.rhea@epa.gov.* For information on the public hearing or to register to speak at the hearing, contact Ms. Pamela Long, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541–0641 or by email at *long.pam@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Preamble Glossary of Terms and Acronyms

The following are abbreviations of terms used in this document.

AQRV Air quality related value
BART Best available retrofit technology
b_{ext} Light extinction
CAA Clean Air Act
CFR Code of Federal Regulations
EGU Electric generating unit
EPA Environmental Protection Agency
FIP Federal implementation plan
FLM or FLMs Federal Land Manager or Managers
ICR Information collection request
IMPROVE Interagency monitoring of protected visual environments
NAAQS National ambient air quality standards
NO_X Nitrogen oxides
OMB Office of Management and Budget
PM Particulate matter
$PM_{2.5}$ Particulate matter equal to or less than 2.5 microns in diameter (fine particulate matter)
PM_{10} Particulate matter equal to or less than 10 microns in diameter
PRA Paperwork Reduction Act
PSD Prevention of significant deterioration
RPO Regional planning organization
SIP State implementation plan
SO_2 Sulfur dioxide
TAR Tribal Authority Rule
URP Uniform rate of progress

B. Does this action apply to me?

Entities potentially affected directly by this proposed rule include state, local and tribal [1] governments, as well as FLMs responsible for protection of visibility in mandatory Class I areas. Entities potentially affected indirectly by this proposed rule include owners and operators of sources that emit particulate matter equal to or less than 10 microns in diameter (PM_{10}), particulate matter equal to or less than 2.5 microns in diameter ($PM_{2.5}$ or fine

[1] The Regional Haze Rule may apply, as appropriate under the Tribal Authority Rule (TAR) in 40 CFR part 49, to an Indian tribe that receives a determination of eligibility for treatment as a state for purposes of administering a tribal visibility protection program under section 169A of the CAA. No tribe has applied for such status, and so at present the EPA is responsible for implementation of the Regional Haze Rule in areas of tribal authority. This responsibility includes, but is not limited to, implementation of the reasonable progress requirements of 40 CFR 51.308(f) in instances where potentially affected sources are located on tribal land, as necessary or appropriate. The proposed rule changes may impact the development and approvability of tribal implementation plans that tribes may wish to develop in the future. We encourage states to provide outreach and engage in discussions with tribes about their regional haze SIPs as they are being developed.

changes to maintain consistency with other sections of the Regional Haze Rule and with the CAA. The first change involves § 51.307(b)(1) concerning integral vistas, for which we are proposing deletion of obsolete language regarding the now-expired identification period for integral vistas. Instead, the newly proposed addition of a listing of integral vistas in § 51.304(b) will be referenced. In section § 51.307(b)(2), the deletion of a reference to specific sections of the CAA is proposed in order to remove unnecessary language, as the EPA believes a reference simply to section "107(d)(1)" is sufficient.

I. Changes to FLM Consultation Requirements

The EPA believes that state consultation with FLMs is a critical part of the creation of quality SIPs. As mentioned earlier, the EPA is proposing to extend the FLM consultation requirements of § 51.308(i)(2) to progress reports that are not SIP revisions. In addition, the EPA believes further edits to § 51.308(i)(2) are necessary because the current requirement for consultation at least 60 days prior to a public hearing may not occur sufficiently early in the state's planning process to meaningfully inform the state's development of the long-term strategy. This proposed rule change would add a requirement that such consultation occur early enough to allow the state time for full consideration of FLM input, but no fewer than 60 days prior to a public hearing or other public comment opportunity. A consultation opportunity that takes place no less than 120 days prior to a public hearing or other public comment opportunity would be deemed to have been "early enough."

Finally, the EPA notes that pursuant to the existing provisions of § 51.307(a), the SIP for every state must require the new source permitting authority to consult with FLMs regarding new source review of any new major stationary source or major modification that would be constructed in an area that is designated attainment or unclassified that may affect visibility in any Class I Federal area. As required by the regulations, that consultation must include sharing with the FLMs a copy of all information relevant to the permit application for the proposed new stationary source or major modification. The regulations also specify that this material must be provided within particular time frames. Also, under § 51.307(b)(2), a proposed new major source or major modification locating in a nonattainment area is subject to review if it may have an impact on visibility in any mandatory Class I area. Two EPA guidance documents interpret the consultation requirement, particularly with regard to evaluating whether a proposed new major source or major modification may affect visibility in a Class I area and thus consultation is required.[47] The EPA regional offices can provide additional assistance to states in ensuring that their permitting programs meet the regulations and that the appropriate consultation is being conducted for affected permits. No changes are being proposed to these consultation requirements.

J. Extension of Next Regional Haze SIP Deadline From 2018 to 2021

The EPA is proposing to amend § 51.308(f) to move the compliance deadline for the submission of the next periodic comprehensive SIP revisions from July 31, 2018, to July 31, 2021. Under this proposal, states would retain the option of submitting their SIP revisions before July 31, 2021. Regardless of the date on which a state chooses to submit its periodic comprehensive SIP revision, the EPA would evaluate that SIP using the same criteria. The EPA is proposing to leave the end date for the second implementation period at 2028, regardless of when SIP revisions are submitted. We are proposing this change as a one-time schedule adjustment. Periodic comprehensive SIP revisions for the third planning will be due on July 31, 2028, with future periodic comprehensive SIP revisions due every 10 years thereafter.

We are proposing this extension of the due date for periodic comprehensive SIP revisions to allow states to coordinate regional haze planning with other regulatory programs, including but not limited to the Mercury and Air Toxics Standards,[48] the 2010 1-hour SO_2 NAAQS,[49] the 2012 annual $PM_{2.5}$ NAAQS,[50] and the Clean Power Plan.[51] With this one-time extension, states would be able to gather more information on the effects of these programs and develop periodic comprehensive SIP revisions that are more integrated with state planning for these other programs, an advantage that was widely confirmed in our discussions with states. The Regional Haze Rule requires states to address the impacts of other regulatory programs when developing their regional haze SIPs. A number of other regulatory programs will be taking effect in the coming years, which presents an excellent opportunity for states to coordinate their strategies to address significant sources of emissions. The EPA expects this cross-program coordination to lead to better overall policies and enhanced environmental protection.

K. Changes to Scheduling of Regional Haze Progress Reports

The EPA is proposing to amend the requirements in 40 CFR 51.308(g) and (h) regarding the timing of submission of reports evaluating progress towards the natural visibility goal. Under the current rule, regional haze progress reports are required to be submitted 5 years after submission of periodic comprehensive SIP revisions. Because states submitted these first SIP revisions on dates spread across about a 3-year period, many of the due dates for progress reports currently do not fall mid-way between the due dates for periodic comprehensive SIP revisions, as the EPA initially envisioned that they would. Looking forward, the current Regional Haze Rule would in many cases require a progress report shortly before or shortly after a periodic comprehensive SIP revision, at which time it could not be expected to have much utility as a mid-course review of environmental progress or much incremental informational value for the public compared to the data contained in that SIP revision.

Complementing the proposed amendments to 40 CFR 51.308(f) regarding the deadlines for submittal of periodic comprehensive revisions, we propose to amend 40 CFR 51.308 (g) and (h) such that second and subsequent progress reports would be due by January 31, 2025, July 31, 2033, and every 10 years thereafter, placing one progress report mid-way between the due dates for periodic comprehensive SIP revisions. The EPA believes that this timing provides a good balance between allowing the implementation of the most recent SIP revision to have proceeded far enough since its adoption for a review to be possible and worthwhile and having enough time

[47] New Source Review Workshop Manual—Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft), October 1990, available at: *https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf;* and Appendix A of Timely Processing of Prevention of Significant Deterioration (PSD) Permits when EPA or a PSD-Delegated Air Agency Issues the Permit, October 2012, available at: *https://www.epa.gov/sites/production/files/2015-07/documents/timely.pdf.*

[48] 77 FR 9304, February 16, 2012.

[49] 75 FR 35520, June 22, 2010.

[50] 78 FR 3086, January 15, 2013.

[51] 80 FR 64,662, October 23, 2015. The compliance deadlines in the Clean Power Plan have been stayed by the Supreme Court. Order in Pending Case, *West Virginia* v. *EPA,* No. 15A773 (Feb. 9, 2016).

remaining before the next comprehensive SIP revision for state action to make changes in its rules or implementation efforts, if necessary, separately from the actions in that next SIP.

Regarding the concept of a progress report also being useful at or near the time of submission of a periodic comprehensive SIP revision, as the EPA envisioned in the 1999 Regional Haze Rule, we note that although they are expressed with somewhat different terminology, in practical terms a progress report would provide little additional information beyond that required to be addressed in a periodic comprehensive SIP revision. The only significant additional information required in a progress report but not explicitly required in a periodic comprehensive SIP revision is the requirement to report on the trend in visibility over the whole period since the baseline period of 2000–2004. While the EPA believes that a state should be aware of, and share with the public, information on the trend in visibility over the whole period since the baseline period of 2000–2004, we believe it would be inefficient to require the preparation of a separate progress report for this purpose. Therefore, we are proposing to limit the requirement for separate progress reports to the one due mid-way between periodic comprehensive SIP revisions, and to add to the requirement for periodic comprehensive SIP revisions a requirement to include this trend information. The EPA believes this approach would substantially reduce administrative burdens and make progress reports of more informational use to the public, with no attendant reduction in environmental protection. The EPA solicits comment on this and any alternative approaches to progress report scheduling.

L. Changes to the Requirement That Regional Haze Progress Reports Be SIP Revisions

The EPA is proposing to amend 40 CFR 51.308(g) regarding the requirements for the form of progress reports. Under the current regulations, progress reports must take the form of SIP revisions that comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103 and Appendix V to Part 51—Criteria for Determining the Completeness of Plan Submissions. The EPA included the requirements for progress reports in the Regional Haze Rule primarily with an emphasis toward ensuring that the states remain on track during the 10 years between periodic comprehensive SIP revisions. By requiring progress reports to be in the form of SIP revisions, the 1999 Regional Haze Rule ensured an opportunity for public input on the progress reports, while specifically pointing out that the EPA "intends for progress reports to involve significantly less effort than a comprehensive SIP revision." 64 FR 35747 (July 1, 1999). For all SIP revisions, however, the state must provide public notice and a public hearing if requested, and it must conform to certain administrative procedural requirements and provide various administrative material. Also, the submission must be made by an official who is authorized by state law to submit a SIP revision. As a required SIP revision, a finding by the EPA that a state has not submitted a complete progress report by the deadline would start a "clock" for the EPA to prepare, take public comment on, and issue a progress report like the state was required to submit.

We are proposing that progress reports need not be in the form of SIP revisions, but that states must consult with FLMs and obtain public comment on their progress reports before submission to the EPA. We are also proposing that the SIP revision that would be due in 2021 must include a commitment to prepare and submit these progress reports to the EPA according to the proposed revised schedule (*see* previous section). These progress reports would be acknowledged and assessed by the EPA, but our review of these reports would not result in a formal approval or disapproval of them.

The EPA is proposing these changes because it believes these reports are not the kind of state submissions for which the formality of a SIP revision, and the accompanying requirement for the EPA to have to prepare the report within 2 years of finding that a state has failed to do so, are warranted. It is important to note that as part of the EPA's review of the report, we will follow up with the state on any appropriate next steps. There are also additional remedies, such as undertaking a less formal assessment of the results of the implementation of the previously submitted SIP, that are available to the EPA in the event a state fails to properly submit a progress report. These changes have been widely supported by state air agencies in our pre-proposal consultations because they would allow more efficient use of state resources. This option would relieve states of the obligation to follow the procedural requirements of 40 CFR 51.102 and 51.103. States have expressed concern that these procedural requirements are resource-intensive, and increase the burden on states by requiring formal procedures be followed when submitting progress reports. By avoiding the specific formal steps required for a SIP revision, including requirements imposed by state law that may involve time-consuming steps beyond those required by the EPA, this proposal may also reduce the time between the completion of the technical analysis in the progress report and when the final report becomes available to the EPA and the public. Thus, progress reports could contain fresher information on the environmental progress being made by a state. Removing the requirement that progress reports be submitted as SIP revisions is consistent with regulatory requirements for similar reports from states for progress reporting or planning purposes where control requirements are not imposed, such as annual monitoring plans required for planning and maintenance of state monitoring networks.[52]

The EPA invites comment on whether it should finalize this proposed change. Also, the EPA invites comment on changing the progress report scheduling as described in the previous section without making any change to the requirement that progress reports take the form of SIP revisions, and vice versa.

It is important to note that under this option, states would still be required to include the required progress report elements listed in 40 CFR 51.308(g)(1) through (g)(6). Also, § 51.308(h) would continue to require that at the same time the state is required to submit a progress report, it must also take one of four listed actions concerning whether the SIP is adequate to achieve established goals for visibility improvement. Where a state determines that its own SIP is or may be inadequate to ensure reasonable progress due to emissions from sources within the state, the state will continue to have an obligation to revise its SIP to address the plan's deficiencies within 1 year of its submission of such a determination.

Upon receipt of such progress reports, the EPA would review the reports. In addition, the EPA intends to create a system of logging progress reports as they are received, and making them available to the public. In addition to putting the public on notice that a progress report was received by the EPA, this system would provide the public an opportunity to view the contents of the progress report. Although the EPA would not formally approve or disapprove a progress report,

[52] *See* 40 CFR 58.10(a)(1) and (2).

the EPA would still have discretion to assess the adequacy of the SIP, relying in part on the information in the progress report. Under the CAA, a discretionary determination that the SIP is inadequate would create a non-discretionary duty for the EPA to issue a SIP call requiring the state to correct the inadequacy. A failure by the state to submit a progress report could be determined by the EPA to constitute failure to implement the regional haze SIP, given that we are proposing that every regional haze SIP include a commitment to submit the required progress reports (*see* next paragraph).

We are proposing that the next periodic comprehensive SIP revisions (currently due in 2018 but proposed to be due in 2021) would need to include a commitment for states to provide progress reports. The 1999 Regional Haze Rule does not require such a commitment because the current requirement for progress reports to be submitted in the form of SIP revisions makes such a commitment superfluous. The EPA solicits comment on this or alternative approaches to ensuring that states continue to provide progress reports.

M. Changes to Requirements Related to the Grand Canyon Visibility Transport Commission

Section 51.309 has limited applicability going forward because its provisions apply only to 16 Class I areas covered by the Grand Canyon Visibility Transport Commission Report, and only to the first regional haze implementation period (*i.e.,* through 2018). Nevertheless, certain conforming amendments at this time are appropriate to avoid confusion going forward. Section 51.309(d)(4)(v) is proposed to be amended to correctly refer to the new § 51.302(b) (in lieu of (e), which no longer exists in the proposed section § 51.302) and to delete the reference to BART since it does not appear in § 51.302(b). The title of § 51.309(c)(10), Periodic implementation plan revisions, is proposed to be amended to include "and progress reports" at the end. This insertion would complement the proposed amendments that will no longer require progress reports be considered SIP revisions by making clear from the title of the section that it applies to both SIP revisions and progress reports. Within § 51.309(c)(10), amendments are proposed that would preserve the existing requirement that the progress reports due in 2013 were to take the form of SIP revisions, but direct the reader to the provisions of § 51.308(g) for subsequent progress reports. In similar fashion, § 51.309(c)(10)(i) and (ii) would be amended to specifically refer to the 2013 progress reports, while § 51.309(c)(10)(iii) would point to § 51.308(g) for subsequent progress reports. Section 51.309(c)(10)(iv) is proposed to be added to indicate that subsequent progress reports are subject to the requirements of § 51.308(h) regarding determinations of adequacy of existing SIPs.

A final change in section 51.309 appears in § 51.309(g)(2)(iii). This change is purely to correct a typographical error and the EPA will therefore not consider comments on this subsection.

V. Environmental Justice Considerations

The EPA believes this action would not have disproportionately high and adverse human health, well-being or environmental effects on minority, low-income or indigenous populations because it would not negatively affect the level of protection provided to human health, well-being or the environment under the CAA's visibility protection program. When promulgated, these proposed regulations will revise procedural and timing aspects of the SIP requirements for visibility protection but will not substantively change the requirement that SIPs provide for reasonable progress towards the goal of natural visibility conditions. These SIP requirements are designed to protect all segments of the general population.

The EPA acknowledges that the proposed delay in submitting SIP revisions from 2018 to 2021 might cause delays in when sources must comply with any new requirements. However, because neither the CAA nor the existing Regional Haze Rule set specific deadlines for when sources must comply with any new requirements in a state's next periodic comprehensive SIP revision, states have substantial discretion in establishing reasonable compliance deadlines for measures in their SIPs. Given this, we expect to see a range of compliance deadlines in the next round of regional haze SIPs from early in the second implementation period to 2028, depending on the types of measures adopted, whether or not these proposed rule changes are finalized. Thus, the EPA believes the delay in the periodic comprehensive SIP revision submission deadline from 2018 to 2021 will not meaningfully reduce the overall progress towards better visibility made by the end of 2028 and will not meaningfully adversely affect environmental protection for all general segments of the population.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the OMB for review because it raises novel policy issues. Any changes made in response to OMB recommendations have been documented in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned the EPA ICR number 2540.01. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0421. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The EPA is proposing these amendments to requirements for state regional haze planning to change the requirements that must be met by states in developing regional haze SIPs, periodic comprehensive SIP revisions, and progress reports for regional haze. The main intended effects of this rulemaking are to provide states with additional time to submit regional haze plans for the second implementation period and to provide states with an improved schedule and process for progress report submission. Further reductions in burden on states include this proposal's removal of the requirement for progress reports to be SIP revisions, clarifying that states are not required to project emissions inventories as part of preparing a progress report, and relieving the state of the need to review its visibility monitoring strategy within the context of the progress report. With all of these proposed changes considered, the overall burden on states would represent a reduction compared to what would otherwise occur if the provisions of the current rule were to stay in place. Total estimated burden is estimated to be reduced from 10,307 hours (per year) to 5,974 hours (per year), and total estimated cost is expected to be reduced from $510,498 (per year) to $295,876 (per year). All states are required to submit regional haze SIPs and progress reports under this rule.

Respondents/affected entities: All state air agencies.

Respondent's obligation to respond: Mandatory, in accordance with the

FEDERAL REGISTER

Vol. 77 No. 181
Tuesday, September 18, 2012

Part III

Environmental Protection Agency

40 CFR Part 52

Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan; Final Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2011–0851, FRL 9719–9]

Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating a Federal Implementation Plan (FIP) to address regional haze in the State of Montana. EPA developed this FIP in response to the State's decision in 2006 to not submit a regional haze State Implementation Plan (SIP) revision. The FIP satisfies requirements of the Clean Air Act (CAA or "the Act") that require states, or EPA in promulgating a FIP, to assure reasonable progress towards the national goal of preventing any future and remedying any existing man-made impairment of visibility in mandatory Class I areas. In addition, EPA is approving one of the revisions to the Montana SIP submitted by the State of Montana through the Montana Department of Environmental Quality on February 17, 2012, specifically, the revision to the Montana Visibility Plan that includes amendments to the "Smoke Management" section, which adds a reference to Best Available Control Technology (BACT) as the visibility control measure for open burning as currently administered through the State's air quality permit program. This change was made to meet the requirements of the Regional Haze Rule. EPA will act on the remaining February 17, 2012 revisions in the State's submittal in a future action.

DATES: This final rule is effective October 18, 2012.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–R08–OAR–2011–0851. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov,* or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, 1595 Wynkoop Street, Denver, Colorado 80202–1129. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Scott Jackson, Air Program, Mailcode 8P–AR, Environmental Protection Agency, Region 8, 1595 Wynkoop Street, Denver, Colorado 80202–1129, (303) 312–6107, or *Jackson.Scott@epa.gov.*

SUPPLEMENTARY INFORMATION:

Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

- The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.
- The initials *A/F* mean or refer to air-to-fuel.
- The initials *ALM* mean or refer to Ammonia Limiting Method
- The initials *ARM* mean or refer to Administrative Rule of Montana.
- The initials *ARP* mean or refer to the acid rain program.
- The initials *ARS* mean or refer to Air Resources Specialists.
- The initials *ASOFA* mean or refer to advanced separated overfire air.
- The initials *BACT* mean or refer to Best Available Control Technology.
- The initials *BART* mean or refer to Best Available Retrofit Technology.
- The initials *CAA* mean or refer to the Clean Air Act.
- The initials *CAM* mean or refer to compliance assurance monitoring.
- The initials *CAMD* mean or refer to EPA Clean Air Markets Division.
- The initials *CAMx* mean or refer to Comprehensive Air Quality Model.
- The initials *CBI* mean or refer to confidential business information.
- The initials *CCM* mean or refer to EPA Control Cost Manual.
- The initials *CCOFA* mean or refer to close-coupled overfire air system.
- The initials *CDS* mean or refer to circulating dry scrubber.
- The initials *CGA* mean or refer to gas cylinder audit.
- The initials *CELP* mean or refer to Colstrip Energy Limited Partnership.
- The initials *CEMS* mean or refer to continuous emissions monitoring systems.
- The initials *CEPCI* mean or refer to Chemical Engineering Plant Cost Index.
- The initials *CFAC* mean or refer to Columbia Falls Aluminum Company.
- The initials *CFB* mean or refer to circulating fluidized bed.
- The initials *CKD* mean or refer to cement kiln dust.
- The initials *CMAQ* mean or refer to Community Multi-Scale Air Quality modeling system.
- The initials *CPMS* mean or refer to continuous parametric monitoring system.
- The initials *CO* mean or refer to carbon monoxide.
- The initials *CPI* mean or refer to Consumer Price Index.
- The initials *CRF* mean or refer to Capital Recovery Factor.
- The initials *CSAPR* mean or refer to Cross-State Air Pollution Rule.
- The initials *DAA* mean or refer to Dry Absorbent Addition.
- The initials *DPCS* mean or refer to digital process control system.
- The initials *D-R* mean or refer to Dresser-Rand.
- The initials *DSI* mean or refer to dry sorbent injection.
- The initials *EC* mean or refer to elemental carbon.
- The initials *EGU* mean or refer to Electric Generating Units.
- The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.
- The initials *ESP* mean or refer to electrostatic precipitator.
- The initials *FCCU* mean or refer to fluid catalytic cracking unit.
- The initials *FGD* mean or refer to flue gas desulfurization.
- The initials *FGR* mean or refer to flue gas recirculation.
- The initials *FIP* mean or refer to Federal Implementation Plan.
- The initials *FLMs* mean or refer to Federal Land Managers.
- The initials *HAR* mean or refer to hydrated ash reinjection.
- The initials *HDSCR* mean or refer to high-dust selective catalytic reduction.
- The initials *HC* mean or refer to hydrocarbons.
- The initials *gr/scf* mean or refer to grains per standard cubic foot.
- The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.
- The initials *IPM* mean or refer to Integrated Planning Model.
- The initials *IWAQM* refer to Interagency Workgroup on Air Quality Modeling.
- The initials *LDSCR* mean or refer to low-dust selective catalytic reduction.
- The initials *LEA* mean or refer to low excess air.
- The initials *LNBs* mean or refer to low NO_X burners.

• The initials *LSD* mean or refer to lime spray drying.
• The initials *LSFO* mean or refer to limestone forced oxidation.
• The initials *LTS* mean or refer to Long-Term Strategy.
• The initials *MACT* mean or refer to maximum achievable control technology.
• The initials *MATB* mean or refer to Montanan's Against Toxic Burning.
• The initials *MDEQ* mean or refer to Montana's Department of Environmental Quality.
• The initials *MDF* mean or refer to medium density fiberboard.
• The initials *MISO* mean or refer to Midwest Independent Transmission System Operator.
• The initials *MDU* mean or refer to Montana-Dakota Utilities Company.
• The initials *MEL* mean magnesium-enhanced lime.
• The initials *MKF* mean or refer to mid-kiln firing of solid fuel.
• The words *Montana* and *State* mean the State of Montana.
• The initials *MSCC* mean or refer to Montana Sulphur and Chemical Company.
• The initials *NAAQS* mean or refer to National Ambient Air Quality Standards.
• The initials *NC* mean or refer to North Carolina.
• The initials *ND* mean or refer to North Dakota.
• The initials *NEI* mean or refer to National Emission Inventory.
• The initials *NESHAP* mean or refer to National Emission Standards for Hazardous Air Pollutants.
• The initials NH_3 mean or refer to ammonia.
• The initials NO_X mean or refer to nitrogen oxides.
• The initials *NP* mean or refer to National Park.
• The initials *NPS* mean or refer to National Parks Service.
• The initials *NSCR* mean or refer to non-selective catalytic reduction.
• The initials *NSPS* mean or refer to New Source Performance Standards.
• The initials *NWR* mean or refer to National Wildlife Reserve.
• The initials *OMB* mean or refer to the Office of Management and Budget.
• The initials *OC* mean or refer to organic carbon.
• The initials *OFA* mean or refer to overfire air.
• The initials *PC* mean or refer to pulverized coal.
• The initials *PH/PC* mean or refer to preheater/precalciner.
• The initials *PM* mean or refer to particulate matter.
• The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers (fine particulate matter).
• The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers (coarse particulate matter).
• The initials *PMCD* mean or refer to particulate matter control device.
• The initials *ppb* mean or refer to parts per billion.
• The initials *ppm* mean or refer to parts per million.
• The initials *PRB* mean or refer to Powder River Basin.
• The initials *PSAT* mean or refer to Particulate Matter Source Apportionment Technology.
• The initials *PSD* mean or refer to Prevention of Significant Deterioration.
• The fraction *Q/D* means quantity of emissions over distance.
• The initials *RAA* mean or refer to relative accuracy audit.
• The initials *RATA* mean or refer to relative accuracy test audit.
• The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.
• The initials *RICE* mean or refer to Reciprocating Internal Combustion Engines.
• The initials *RMC* mean or refer to Regional Modeling Center.
• The initials *ROFA* mean or refer to rotating opposed fire air.
• The initials *RP* mean or refer to Reasonable Progress.
• The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).
• The initials *RPOs* mean or refer to regional planning organizations.
• The initials *RRI* mean or refer to rich reagent injection.
• The initials *RSCR* mean or refer to regenerative selective catalytic reduction.
• The initials *SCOT* mean or refer to Shell Claus Off-Gas Treatment.
• The initials *SCR* mean or refer to selective catalytic reduction.
• The initials *SDA* mean or refer to spray dryer absorbers.
• The initials *SIP* mean or refer to State Implementation Plan.
• The initials *SMOKE* mean or refer to Sparse Matrix Operator Kernel Emissions.
• The initials *SNCR* mean or refer to selective non-catalytic reduction.
• The initials SO_2 mean or refer to sulfur dioxide.
• The initials *SOFA* mean or refer to separated overfire air.
• The initials *SRU* mean or refer to sulfur recovery unit.
• The initials *TAC* mean or refer to Texas Administrative Code.
• The initials *TESCR* mean or refer to tail-end selective catalytic reduction.
• The initials *TCEQ* mean or refer to Texas Commission on Environmental Quality.
• The initials *tpy* mean tons per year.
• The initials *TSD* mean or refer to Technical Support Document.
• The initials *URP* mean or refer to Uniform Rate of Progress.
• The initials *USFWS* mean or refer to U.S. Fish and Wildlife Service.
• The initials *VOC* mean or refer to volatile organic compounds.
• The initials *WA* mean or refer to Wilderness Area.
• The initials *WEG* mean or refer to WildEarth Guardians.
• The initials *WEP* mean or refer to Weighted Emissions Potential.
• The initials *WETA* mean or refer to Western Environmental Trade Association.
• The initials *WRAP* mean or refer to the Western Regional Air Partnership.
• The initials *YELP* mean or refer to Yellowstone Energy Limited Partnership.

Table of Contents

environmental impacts of compliance; and remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). As also explained in other responses, we also considered potential visibility improvement in a general sense by considering the potential reduction in haze causing pollutants and also the distance from the source to the nearest Class I area. For Colstrip 3 and 4, we also considered visibility modeling results and have explained the reasoning for that decision in another response.

J. Comments on Colstrip Units 3 and 4

Comment: Some commenters agreed with EPA's conclusion not to require additional emissions controls at Colstrip Units 3 and 4. Commenters asserted that, given the aggressive pollution control technologies already in place, EPA properly concluded that additional controls for Reasonable Progress are not appropriate.

Response: We acknowledge the commenters' support for our decision not to require additional emission controls on Colstrip Units 3 and 4 in this planning period. Whether additional emission reductions from reasonable progress sources, including Colstrip Units 3 and 4, are necessary will be re-evaluated in subsequent planning periods.

Comment: Various commenters stated that we underestimated the costs of SNCR for Colstrip Units 3 and 4.

Response: We disagree that we underestimated the costs of SNCR for Colstrip Unit 3 and 4. For a further explanation, see our response to similar comments made in relation to SNCR costs for Colstrip Unit 1 and 2.

Comment: Commenters stated that they disagree with EPA's cost analysis for NO_X control technologies for Colstrip Units 3 and 4. In particular, commenters stated that we underestimated the capital costs and cost-effectiveness of these controls. Commenters referenced cost estimates submitted by PPL in September 2011 and February 2012, which show much higher capital costs and cost-effectiveness than those estimated by EPA.

Response: We disagree. We have rejected PPL's cost estimates for NO_X control options for Colstrip Units 3 and 4 for the same reasons that we rejected them for Colstrip Units 1 and 2. See previous responses to comments.

Comment: NPS stated that EPA modeled baseline visibility impacts at five Class I areas from Colstrip Units 3 & 4 using 2008–2010 emissions, while PPL modeled visibility impacts using 2001–2003 emissions. NPS agreed with the PPL modeling approach because it is consistent with EPA guidance to use the 2001–2003 pre-control emissions.

Response: See our response to a similar comment made in regard to the baseline emissions used for Colstrip Units 1 and 2.

Comment: NPS stated that after EPA concluded its statutory four-factor analysis of Colstrip 3 and 4, it created a new, "Optional Factor: Modeled Visibility Impacts" fifth factor, only for Colstrip 3 & 4. NPS further stated that this "optional" fifth factor is not required by statute or regulation, and that EPA only used it on one reasonable progress source (2 units) and did not explain what criteria it used to evaluate it.

Response: As we explained elsewhere, our RP Guidance allows for consideration of additional factors such as visibility impacts or benefits. Given the large annual emissions of NO_X and SO_2 from Colstrip Units 3 and 4 compared to other reasonable progress sources, we found that it was reasonable to model the visibility benefits and consider them when evaluating controls.

Comment: NPS stated that EPA has not provided criteria used in making the determination of what "Costs of Compliance" are reasonable, and its determinations vary significantly across Montana facilities.

Response: As we have explained elsewhere, while the Regional Haze Rule and BART Guidelines allow states to establish thresholds for cost-effectiveness, we are not required to do so and have not done so for this action. Also, our Reasonable Progress determinations were made based not just on the cost of compliance, but with consideration of the four factors along with additional information that was pertinent.

Comment: EarthJustice stated that EPA must set NO_X emission limits for Colstrip Units 3 and 4 based on SCR to help achieve reasonable progress. EarthJustice stated that EPA's analysis is skewed to underestimate the benefits of SCR, both in terms of control effectiveness and visibility improvement, and overestimates the costs. EarthJustice made claims regarding our cost analysis for Colstrip Units 3 and 4 that were very similar to the claims they made regarding Colstrip Units 1 and 2.

Response: We disagree. Below we address each of EarthJustice's arguments that support their assertion that SCR must be required for Colstrip Units 3 and 4.

Comment: EarthJustice stated that EPA underestimated the control effectiveness of SCR.

Response: See our response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

Comment: EarthJustice stated that EPA overestimated the cost of SCR.

Response: See our response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

Comment: EarthJustice claimed that the visibility benefit of SCR on Units 3 and 4 is substantial and therefore SCR should be required. EarthJustice noted that EPA modeled visibility benefits of SNCR and SCR and found a visibility benefit of 0.273 dv per unit from application of SCR. EarthJustice stated that application of SCR at both units would approximately halve the units' emissions of visibility impairing pollutants and would reduce the number of days of visibility impairment at Theodore Roosevelt NP to just 2 days and would eliminate visibility impairment caused by Units 3 and 4 at four other Class I areas. EarthJustice stated that, in light of this, we lacked a basis for our determination to not impose SCR at Colstrip Units 3 and 4. EarthJustice noted that, in North Dakota, we imposed LNB on two units at Antelope Valley Station based on a combined visibility benefit of 0.39 deciview, which we stated was significant even on a unit-by-unit basis of 0.2 deciview.

Response: We disagree that SCR should be required based solely on the modeled visibility benefits. As we explained in our proposal, we considered the four factors and the modeled visibility benefits of controls and determined that no additional controls should be required for this planning period. 77 FR 24066. Also, we stated that specifically, for SCR, the modeled visibility benefits (0.273 deciview and 0.260 deciview) were not sufficient for us to consider it reasonable to impose SCR in this planning period. 77 FR 24066. In making this determination, we noted that SCR was the more expensive option ($4,574/ton at Unit 3 and $4,607/ton at Unit 4). The cost of compliance is one of the four statutory factors, and EarthJustice has not provided a reason why it should be ignored. For the same reason, we reject the comparison with our North Dakota action. There, the cost-effectiveness of LNB at Antelope Valley Station was $586/ton for Unit 1 and $661/ton at Unit 2. 76 FR 58631. We explicitly considered these costs in making our determination to impose LNB. Here, the cost-effectiveness of SCR at Colstrip Units 3 and 4 is far above the cost-effectiveness of LNB at Antelope Valley Units 1 and 2. Thus, the comparison gives us no basis to change our determination that SCR should not be required in this planning period.

Comment: EarthJustice stated that EPA should set more stringent SO_2 emission limits at Colstrip Units 3 and 4 to help achieve reasonable progress. EarthJustice stated that EPA incorrectly found that no additional upgrades are feasible and that 98% SO_2 removal to meet an SO_2 emission limit of 0.05 lb/MMBtu at Units 3 and 4, which is readily achievable at little expense using MEL.

Response: EarthJustice cites a 1984 paper presented at the American Power Conference to support their argument of a lower emission rate. Colstrip 3 had only started operation in 1984 and Colstrip 4 did not commence operation until 1986,[63] the data cited by EarthJustice cannot be more than short-term tests of Unit 3 that are not representative of longer term performance. Annual emissions from 1985 and 1990 emissions from CAMD can be found in the docket. At the time these scrubbers were built, wet MEL scrubbers and wet caustic scrubbers were the only scrubbers that could deliver high capture rates (over 90%) with reasonable reliability. Scrubber technology has improved and other, less expensive, reagents are now preferred. Although Colstrip Units 3 & 4 used MEL in the past, MEL is not readily available in the region near the Colstrip plant. MEL is produced from a blending of dolomitic lime with high calcium lime to achieve a lime with a magnesium content of 3–6% or so. The lime is produced by calcination of limestone. Dolomitic limestone is limestone with a significant amount of dolomite, or calcium magnesium carbonate. Because there are no dolomitic limestone deposits near the Colstrip plant, the dolomitic lime must be sourced from remote locations. This increases the cost of the lime (that is made from the dolomitic limestone). According to Carmeuse, a supplier of MEL, the closest source of dolomitic lime is 1,000 miles away from the Colstrip plant and transportation would cost $0.12 per mile per short ton plus a 24% fuel surcharge to transport,[64] or close to $150/short ton just for transportation of the reagent. Because the lime would be blended in closer to the plant with high calcium lime at perhaps an 8:1 ratio (reducing magnesium content from about 40% to about 4–5% this would result in an increased reagent cost of $15–$20 per ton. Assuming a high-calcium lime cost of about $95/ton,[65] this raises the cost of reagent by close to 20% assuming constant reduction. Reagent use might be improved somewhat for a given reduction level, but considering this is a unique scrubber design, it is difficult to assess what the impact may be. Regardless, reliance on a reagent source that is 1,000 miles away may cause operating risks during the winter months if delivery was interrupted.

We also note that EarthJustice did not provide site-specific cost information, for us to evaluate MEL. The cost of compliance is one of the factors required to be considered by CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). Based on all four factors, we continue to find that the level of performance of the current SO_2 removal system for Colstrip Units 3 and 4 is satisfactory for this planning cycle. We will re-evaluate additional SO_2 controls for Colstrip Units 3 and 4 in the next planning cycle.

Comment: PPL stated that EPA properly concluded that RPGs do not require additional emissions controls on Colstrip Units 3 and 4 and that existing emissions controls at Units 3 and 4 already limit emissions to levels below the presumptive BART limit. PPL stated that EPA's RP conclusion should not be affected by EPA's ultimate determination with respect to BART requirements for Colstrip Units 1 and 2 and that no further controls are warranted based on conclusions regarding the extent of existing emissions controls and the cost-ineffectiveness of further controls.

Response: PPL did not provide specific information for us to consider in making a change to our FIP. In any case, we have not required additional controls for Colstrip Units 3 and 4 in our final FIP.

K. Comments on Devon Energy

Comment: MDEQ stated that we failed to provide information or analysis of any visibility benefit that would result from the application of NSCR for Devon Energy. MDEQ suggested that we must consider visibility benefits as part of the Devon Energy reasonable progress analysis, as the BART Guidelines include evaluation of visibility impacts "which would also appear to be required under the reasonable progress guidelines."

Response: The four reasonable progress factors are the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). Our Reasonable Progress Guidance states: "In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant." [66] As stated in our proposal at 77 FR 24069, for Devon, we considered Q/D and potential reductions in Q/D, which are relevant to the goal of the Regional Haze Rule, improving visibility.

Comment: MDEQ commented that EPA should review the NO_X limit for Devon with respect to its averaging time and compliance determining method for practical enforceability.

Response: In the final FIP, we have made changes to the language in 40 CFR 52.1396 to clarify the requirements for Devon Energy.

L. Comments on Montana-Dakota Utilities

Comment: Montana-Dakota Utilities (MDU) commented that the company did not disagree with our Reasonable Progress determination. MDU stated that, for EPA's reference, paragraph 3 on page 1 of the Sargent & Lundy IPM model method document cautions as follows with respect to the application of the model to smaller units:

> The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. The older units which comprise a large proportion of the plants in this range generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor and therefore new fans may be required.

MDU stated that Lewis & Clark Station is a small, 52 MW net capacity unit. In addition, MDU believes that the fan margin is not present at Lewis & Clark Unit 1 to overcome the pressure drop as discussed in the Sargent & Lundy guidance.

Response: MDU has not provided the information that would be necessary for

---

[63] See EIA Form 860 data.

[64] Email from Bob Roden, Carmeuse, to Jim Staudt, Andover Technologies, July 31, 2012.

[65] Sargent & Lundy, "IPM Model—Revisions to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology FINAL", Prepared for US EPA, August 2010 see table 2.

[66] Reasonable Progress Guidance, p. 5–1.

STATE OF MONTANA

REGIONAL HAZE
5-YEAR PROGRESS REPORT

DEQ
Montana Department
of Environmental Quality

AUGUST 2017

Table of Contents

Chapter 2. Status of Implementation of Control Measures

This chapter focuses on anthropogenic (manmade) emission sources. The following sections describe the status of the control measures that were included in the Montana FIP to achieve reasonable progress goals for visibility improvement at mandatory Federal Class I Areas in Montana and neighboring states.[9] Title 40 of the Code of Federal Regulations (CFR), part 51.308(g)(1) requires "[a] description of the status of implementation of all measures included in the implementation plan for achieving" reasonable progress goals at Class I Areas both within and outside the State that are influenced by emissions from Montana sources.[10]

In the Montana FIP, the Environmental Protection Agency (EPA) relied upon the implementation of the Best Available Retrofit Technology (BART) at select facilities. In addition, the Montana FIP relied on continual emissions reductions over time resulting from both federal and state measures in existence at the time the Montana FIP was developed. These additional measures have contributed to an ongoing reduction in emissions since the baseline period. They were taken into account in projecting an emissions inventory for the year 2018 to determine whether Montana was forecast to achieve reasonable progress during the initial implementation period.[11]

In the years since 2012, when the Montana FIP was promulgated, further reductions have occurred or will occur through additional federal and state programs not otherwise identified in the Montana FIP, such as periodic updates to the National Ambient Air Quality Standards (NAAQS) and plant closures. The status and associated benefits of these regulations and activities are also discussed in this chapter.

2.1. Montana's BART & Reasonable Progress Measures

For certain large industrial facilities that had the potential to contribute to visibility impairment, the Regional Haze Rule (RHR) required states, tribes, or EPA to conduct an analysis to determine whether additional pollution controls must be installed. Specifically, facilities were considered eligible for such analysis if they (1) had the potential to emit 250 tons a year or more of a visibility-impairing pollutant, (2) were in existence by August 7, 1977, but were not operating before August 7, 1962, and (3) fell into one of 26 different source categories, such as utility and industrial boilers, and large industrial plants like pulp mills, refineries, and smelters.[12] Facilities that met these definitions were considered to be "BART-eligible."

[9] EPA, Approval and Promulgation of Implementation Plans; State of Montana; Regional Haze Federal Implementation Plan, Final Rule, 77 Fed. Reg. 57863 (18 Sep. 2012), https://www.federalregister.gov/d/2012-20918. See also: Proposed Rule at 77 Fed. Reg. 23987 (20 Apr. 2012), https://www.federalregister.gov/d/2012-8367.

[10] EPA, 40 CFR § 51.308(g) (2016), https://www.gpo.gov/fdsys/pkg/CFR-2016-title40-vol2/xml/CFR-2016-title40-vol2-sec51-308.xml.

[11] Marty Wolf and Paula Fields, Technical Memorandum - Final, WRAP PRP18b Emissions Inventory – Revised Point and Area Source Projections (29 Apr. 2009, rev. 16 Oct. 2009), http://www.wrapair.org/forums/ssjf/documents/Pivot_Tables/PRP18b/Final_PRP18b_point_area_source_memo_erg_101609_revised.pdf.

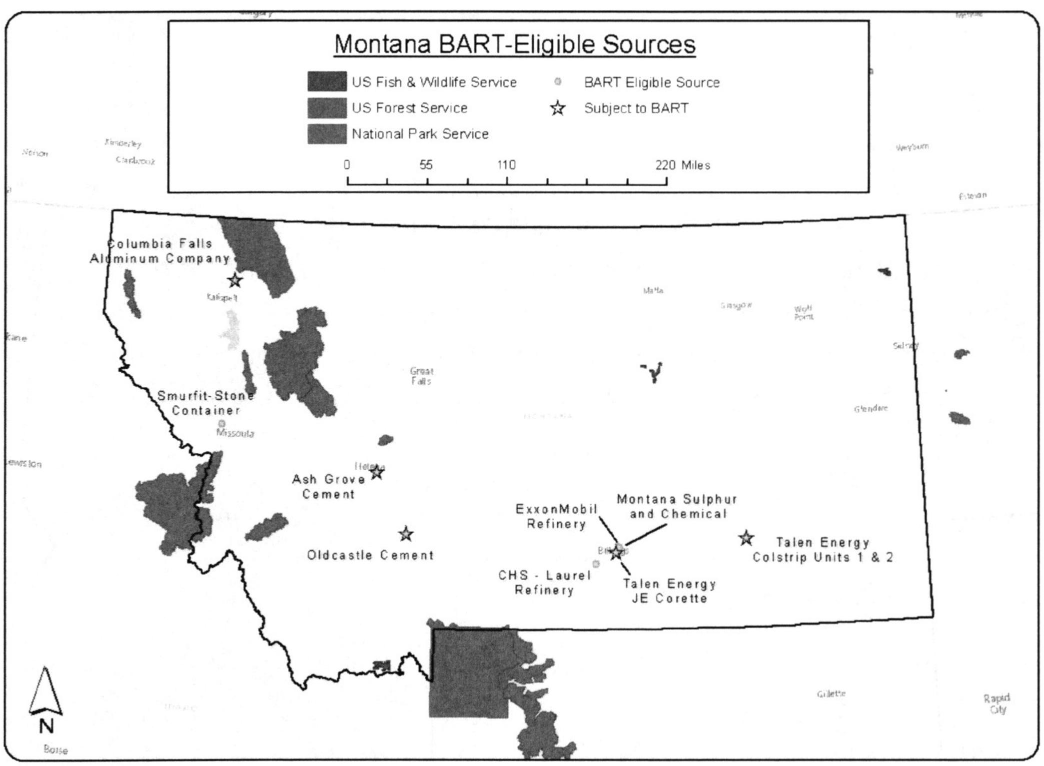
[12] These source categories are listed in section 169A(g)(7) of the federal Clean Air Act.

In the Montana FIP, EPA analyzed nine large stationary sources determined to be BART-eligible. These BART-eligible sources, listed in Table 2-1, included coal-fired electric generating units, refineries, cement plants, and other large industrial facilities. These sources are also mapped below.

TABLE 2-1. LIST OF BART-ELIGIBLE SOURCES IN MONTANA

BART-Eligible Source	BART Source Category
Ash Grove Cement Company	Portland Cement Plants
Cenex Harvest States Cooperatives, Laurel Refinery	Petroleum Refineries
Columbia Falls Aluminum Company, LLC	Primary Aluminum Ore Reduction Plants
ExxonMobil Refinery & Supply Company, Billings Refinery	Petroleum Refineries
Montana Sulfur & Chemical Company	Chemical Process Plants
Oldcastle Cement (formerly Holcim (US), Inc.)	Portland Cement Plants
Smurfit-Stone Container Enterprises Inc., Missoula Mill	Kraft Pulp Mills and Fossil Fuel Boilers of more than 250 million British Thermal Units (BTUs) per hour Heat Input
Talen Energy– Colstrip Steam Electric Station Units 1 & 2 (formerly PPL Montana, LLC)	Fossil-Fuel Fired Steam Electric Plants of more than 250 BTUs per hour Heat Input
Talen Energy – JE Corette Steam Electric Station (formerly PPL Montana, LLC)	Fossil-Fuel Fired Steam Electric Plants of more than 250 BTUs per hour Heat Input

FIGURE 2-1. MAP OF MONTANA BART-ELIGIBLE SOURCES



EPA used air quality modeling conducted by the Western Regional Air Partnership (WRAP) to estimate daily visibility impacts above natural conditions at each Class I Area within 300 kilometers (km), or about 186 miles, of these nine BART-eligible facilities. EPA used a threshold of 1.0 deciview of impact to determine which sources "cause" and a threshold of 0.5 deciview of impact to determine which sources "contribute" to visibility impairment. Following modeling, only five operating units were determined to cause or contribute to visibility impairment and thus only these five were subject to BART.

The Montana FIP included BART determinations for these units, which resulted in new emissions limits for emissions of visibility-impairing pollutants. The Montana FIP included emissions limits for Ash Grove Cement; Oldcastle Cement; Talen Energy Colstrip Steam Electric Station Units 1 and 2; and Talen Energy JE Corette Steam Electric Station. Not all of the facilities determined to be subject to BART were required to install additional controls for visibility-impairing pollutants. According to the federal Clean Air Act, five factors had to be considered in determining whether and what controls must be applied at each individual facility. These factors included:

1) cost of the controls;
2) impact of controls on energy availability or any non-air quality environmental impacts;
3) remaining useful life of the equipment to be controlled;
4) any existing pollution controls already in place; and
5) visibility improvement that would result from controlling the emissions.[13]

In some cases, the minimal visibility improvement expected to result from the use of pollutant-specific add-on controls did not justify proposing additional controls. Instead, EPA proposed emission limits that could be met within the existing operation of the unit.[14] Prior to BART, many of these facilities had not been subject to federal pollution control requirements for this particular set of pollutants.

Columbia Falls Aluminum Company (CFAC) was determined to be subject to BART; however, the facility did not receive emission limits because it was not in operation at the time the Montana FIP was published and is now permanently closed. The JE Corette plant in Billings, a coal-fired electric generating unit, was also determined to be subject to BART and received BART limits. However, the facility ceased operation in April 2015. In both of these cases, the corresponding Montana Air Quality Permits (MAQPs) have been revoked. A sixth facility (Blaine County #1 Compressor Station) also received emission limits in the Montana FIP. This facility was determined to be subject to reasonable progress controls, not BART. However, as further discussed below, the determination was in error, and the source should not have received emission limits.

Table 2-2 provides a summary of the BART emission limits, the corresponding control technology prescribed in the Montana FIP, compliance dates, and the status of each control or limit.

---

[13] EPA, 40 CFR 51.308(e) (2016), https://www.gpo.gov/fdsys/pkg/CFR-2016-title40-vol2/xml/CFR-2016-title40-vol2-sec51-308.xml.

[14] EPA, 40 CFR 52.1396(c) (2016), https://www.gpo.gov/fdsys/pkg/CFR-2016-title40-vol4/xml/CFR-2016-title40-vol4-sec52-1396.xml.

TABLE 2-2. MONTANA BART CONTROLS AND CURRENT STATUS

	Particulate Matter (PM)				Nitrogen Oxides (NO_x)				Sulfur Dioxide (SO_2)			
	Limit	Control	Compliance Date	Status	Limit	Control	Compliance Date	Status	Limit	Control	Compliance Date	Status
Colstrip (Units 1&2)	0.10 lb/mmBtu	NA	11/17/2012	In Compliance	0.15 lb/mmBtu	SOFA & SNCR	10/18/2017	*	0.08 lb/mmBtu	Lime injection	10/18/2017	*
Oldcastle Cement	0.77 lb/ton clinker	NA	11/17/2012	In Compliance	6.5 lb/ton clinker	SNCR	10/18/2017	**	1.3 lb/ton clinker	NA	4/16/2013	In Compliance
Ash Grove Cement	***	NA	11/17/2012	In Compliance	8.0 lb/ton clinker	SNCR & LNB	10/18/2017	In Compliance	11.5 lb/ton clinker	NA	4/16/2013	In Compliance

* Emission limits for Colstrip Units 1 and 2 were vacated by the U.S. Court of Appeals for the 9th Circuit, as discussed further below.

** Oldcastle installed SNCR during a plant shutdown in April 2017. However, the company contacted EPA Region 8 in mid-2016 to express concern that the existing NOx limit may not be achievable even with the successful operation of SNCR. EPA reviewed the documentation and, on April 14, 2017, proposed a revision to the NOx limit in the Montana FIP.

*** If the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10P_{0.67}$, where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0P_{0.11-40}$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour.

Lime Injection – Injecting limestone creates a chemical reaction with sulfur dioxide to create a calcium sulfite solid, removing the SO2 from the flue gas.

LNB – Low NOx burners are configurations intended to prevent the formation of NOx by using air staging of combustion air and fuel rich environments.

SOFA – Separated Over-Fire Air is the process where combustion air is generally staged within the combustion device. Air for combustion is initially limited to below stoichiometric conditions to prevent NOx formation, and then required remaining combustion air is "injected" above the burners. SOFA is a form of a low NOx burner design.

SNCR – Selective Noncatalytic Reduction is another process to prevent NOx formation. It uses a reagent such as ammonia or urea to react with the nitrogen oxides to form nitrogen and water byproducts.

The following sections provide further discussion of BART control technology and implementation status.

2.1.1. Colstrip Steam Electric Station Units 1 and 2

On June 9, 2015, the United States Court of Appeals for the Ninth Circuit vacated the emission limits for Talen Energy Colstrip Units 1 and 2 (and Corette), after the court found the NO_x and SO_2 limits to be arbitrary and capricious, and remanded the determination back to EPA.[15] As of this submittal, EPA has not yet acted on the remand. However, the plant operator did install separated overfire air controls on Units 1 and 2 and SmartBurn[R] technology on Unit 2 before the original BART limits were vacated.

In the summer of 2016, an agreement was reached between Sierra Club and the owners of the Colstrip facility. As part of the agreement, Colstrip Units 1 and 2 must shut down no later than July 1, 2022. In addition, the owners agreed that Units 1 and 2 would comply with the following NO_x and SO_2 emission limits until such time as the units cease operation:

- Unit 1 NO_x limit – 0.45 lb/mmBtu (30-day rolling average)
- Unit 2 NO_x limit – 0.20 lb/mmBtu (30-day rolling average)
- Units 1 and 2 SO_2 limit – 0.40 lb/mmBtu (30-day rolling average)

This Consent Decree is binding and, as such, these emission limits will continue to be beneficial for emission reductions until such time as Colstrip Units 1 and 2 cease operation, at which time all emissions associated with these units will permanently cease.[16] Emission levels currently being achieved by Colstrip Units 1 and 2 are discussed in Chapter 3.

2.1.2. JE Corette

The BART limits for the JE Corette facility were also remanded under the same court proceeding as discussed above. That remand however, has since been made moot by the shutdown of Corette and demolition of the facility. The facility ceased operation in April 2015 and it has been fully decommissioned since that time.

2.1.3. Ash Grove Cement

The Montana FIP required Ash Grove to achieve an SO_2 limit of no more than 11.5 lb/ton of clinker no later than April 16, 2013, and a NO_x limit of no more than 8.0 lb/ton of clinker no later than October 18, 2017. The NO_x limit was established assuming the application of Selective Noncatalytic Reduction (SNCR) and low NO_x burners. The facility installed an SNCR system and made modifications to the kiln burners to be able to meet the NO_x limit.

Under a Consent Decree, initiated by EPA pursuant to violations of Sections 113(b) and 167 of the Clean Air Act, Ash Grove agreed to achieve a lower SO_2 limit at the Montana City Plant. Ash Grove also agreed

---

[15] National Parks Conservation Association (NPCA) v. U.S. Environmental Protection Agency (EPA), No. 12-73710, United States Court of Appeals for the Ninth Circuit (2015), http://caselaw.findlaw.com/us-9th-circuit/1703871.html.
[16] Sierra Club v. Talen Montana, LLC et al., No. 1:13-cv-00032-DLC-JCL, D. Mon. (2016), doc. 316-1.

to achieve the NO_x limit on a faster timeline, and determine a potentially more stringent NO_x limit based on process and control equipment optimization. The settlement required the facility to achieve an SO_2 limit of no more than 2.0 lb/ton (30-day rolling average), required by April 8, 2015 (described as the 210th day after September 10, 2014), and an initial NO_x limit of no more than 8.0 lb/ton (30-day rolling average), required 30 days after September 10.[17]

Following the process optimization requirements contained in Appendix A of the Consent Decree, Ash Grove demonstrated the ability to meet an even lower NO_x emission limit of 7.5 lb/ton.[18] This permit limit was finalized by EPA on December 29, 2016, when EPA issued an acceptance letter for an Ash Grove Demonstration Report, which had been submitted by Ash Grove to EPA on August 25, 2016.[19] This new limit is now in effect and is in the process of being added to Ash Grove's Title V permit.

Although not specifically required by the Consent Decree, Ash Grove installed baghouse control technology on the kiln exhaust to comply with the Portland cement manufacturing industry National Emission Standards for Hazardous Air Pollutants (NESHAP) filterable particulate limit of 0.07 lb/ton of clinker (based on a 30-day rolling average during kiln operation).

Ash Grove is currently achieving emission levels below limits from the BART determination. The associated emission reductions are presented in Chapter 3.

2.1.4. Oldcastle Cement

Oldcastle is currently meeting both the PM and the SO_2 emissions limits. The facility has engaged a design/build contractor for the application of SNCR to achieve the NO_x limit, and has been preparing to commission and optimize the system before the limit becomes effective on October 18, 2017. A plant shutdown occurred in April 2017 to complete the SNCR installation. As of the drafting of this report, Oldcastle is in the process of integrating the system into the plant's control system and optimizing performance.

The facility entered talks with EPA in mid-2016 to revisit the BART determination based on a request submitted to the Acting Air Director of EPA Region 8. Oldcastle expressed concerns to EPA that the original NO_x limit of 6.5 lb/ton of clinker may not be able to be achieved consistently, particularly without a visible detached plume at the site.[20] Based on past experience, the facility expressed that any visible plume from the site is likely to cause significant concern from area residents. As part of the request to EPA, Oldcastle prepared a revised BART analysis in which the facility requested a revised NO_x limit of 8.3

[17] Consent Decree, United States v. Ash Grove Cement Company, No. 2:13-cv-02299-JTM-DJW, D. Kan. (2013), doc. 27 as amended by doc. 28, https://www.courtlistener.com/docket/4267857/united-states-of-america-v-ash-grove-cement-company/.

[18] Department of Justice, Montana City NOx Demonstration Report and Data, No. 90-5-2-1-08221 Ash Grove Cement Co (25 Aug 2016 approved 29 Dec. 2016).

[19] Ibid.

[20] In the manufacture of Portland cement, clinker occurs as lumps or nodules, usually 3 millimetres (0.12 in) to 25 millimetres (0.98 in) in diameter, are produced by sintering (fusing together without melting to the point of liquefaction) limestone and alumino-silicate materials such as clay during the cement kiln stage.

lb/ton of clinker. EPA reviewed the submitted information and, on April 14, 2017, published a proposed revision to the Montana FIP raising the Oldcastle NO_x limit from 6.5 to 7.6 lb/ton of clinker.[21]

2.1.5. Blaine County #1 Compressor Station

At the time of the Montana FIP, the Blaine County #1 Compressor Station was operated by Devon Energy (Devon) and is now operated by Northwestern Energy. In 2012, Devon provided comments to EPA on the Montana FIP limits and four-factor analysis. In setting the Reasonable Progress portion of the Montana FIP, a Q/D analysis threshold calculation was made. In this analysis, Q represents the actual total tons of NO_x and SO_2, and D is the distance in kilometers from the facility to the nearest Class I Area. In the calculation used by EPA's contractor, a distance of 107 kilometers was used for the Blaine County facility, when in fact the distance to the nearest Class I Area is 133 kilometers. This correction would drop the calculated value to a Q/D of 8.7, well below the screening threshold of 10 used in the Montana FIP. The proper calculation would have prevented inclusion of the Blaine County #1 Compressor Station in the Montana FIP.

Additionally, the EPA contractor used emission levels from the 2002 EPA National Emission Inventory. Devon Energy has argued that year 2002 data was not representative of current conditions and over-stated the emissions, further inflating the Q/D calculation. Further, while the original engines were rich-burn engines, they were converted to lean-burn engines in the 1990s. Therefore, the Reasonable Progress determination of nonselective catalytic reduction (NSCR) for engines that are actually lean-burn is not technically feasible.

In the April 14, 2017, proposed revision to the Montana FIP, discussed above, EPA corrected the errors related to the Blaine County #1 Compressor Station. Should the rule be finalized as proposed, the facility would no longer be subject to the NO_x emission limit of 21.8 lb/hr.

2.1.6. Improvements at Other Sources Referenced in the Montana FIP

As discussed above, the main control measure included in the Montana FIP was the application of BART at large facilities where retrofit technology was expected to result in reductions of visibility-impairing emissions. However, by definition, only a narrow set of sources were considered "BART-eligible" and, of those eligible sources, only a handful were eventually given emission limits. The same is true of Reasonable Progress sources, of several that were analyzed in the Montana FIP, only the Blaine County #1 Compressor Station was prescribed emission limits. The group of sources for which the Montana FIP analysis did not result in emission limits includes the following:

- CHS, Laurel Refinery
- Colstrip Energy Limited Partnership
- Colstrip Steam Electric Station, Unit 3
- Colstrip Steam Electric Station, Unit 4
- Columbia Falls Aluminum Company
- ExxonMobil, Billings Refinery
- Montana-Dakota Utilities Lewis & Clark Station
- Montana Sulfur & Chemical Company
- Plum Creek Manufacturing
- Roseburg Forest Products
- Smurfit-Stone Container
- Yellowstone Energy Limited Partnership

[21] EPA, Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan, Proposed Rule, 82 Fed. Reg. 17948 (14 Apr. 2017), https://www.federalregister.gov/d/2017-07597.

It would be a mistake to assume that, in the absence of regulatory emission limits in the Montana FIP, these remaining sources have not installed controls or improved efficiency over the years since the Montana FIP was promulgated. Notable emissions-reducing improvements include the installation of SmartBurn^R NO_x reduction technology on Units 3 and 4 at the Colstrip Steam Electric Station in 2016 and 2017, respectively. According to facility operator Talen Energy, these new controls are expected to improve NO_x removal from 80% to 86%.[22]

In addition, although the Montana FIP did not set reasonable progress emission limits for Montana-Dakota Utilities (MDU) Lewis & Clark Station, a coal-fired power plant located in Sidney, MT, the facility was upgraded in early 2016 to comply with other federal and state regulations. Upgrades included a mist eliminator retrofit and installation of sieve trays to reduce filterable PM, which also resulted in a significant reduction in SO_2 emissions.[23]

2.2. Adjacent States' BART Implementation

In addition to emission reductions at Montana facilities, reductions of emissions in neighboring states may affect visibility in Montana. The following summaries briefly discuss implementation of BART controls in other states in the region.

2.2.1. Idaho

Idaho has five (5) Class I Areas, including Hells Canyon Wilderness, Craters of the Moon Wilderness, Sawtooth Wilderness, and two that are shared with Montana: Selway-Bitterroot Wilderness and Yellowstone National Park. According to Idaho's Regional Haze documentation, Idaho had one BART source, Amalgamated Sugar Company, LLC (TASCO Riley Boiler located in Nampa, Idaho), which was required to install new emission controls by July 22, 2016.[24] This facility was required to install and operate low NO_x burners after it was determined that Selective Catalytic Reduction (SCR) was not technically feasible for the specific process at this facility. There are also two other boilers at this facility referred to as B&W Boilers 1 and 2 that also ended up as part of a BART Alternative Controls option that resulted in a combined NO_x limit for the three boilers. The initial performance test for the new BART limits was required by December 20, 2016.

As part of the BART determination, three non-BART pulp dryers were also shut down at the facility in an effort to provide the necessary SO_2 reductions. The rationale behind this is that the approach provided more improvement in visibility than otherwise would have occurred from the original BART determination. A second facility in Soda Springs, Idaho, went through a BART analysis but EPA determined that no additional control was required.

---

[22] Conversation with Gordon Criswell, Environmental and Compliance Director for Talen Energy (11 May 2017).
[23] Correspondence with the facility (30 May 2017).
[24] Idaho Department of Environmental Quality, "Regional Haze Plan" (8 Oct. 2010), http://www.deq.idaho.gov/air-quality/air-pollutants/haze/.

2.2.2. North Dakota

North Dakota has two Class I Areas, including the Lostwood Wilderness and Theodore Roosevelt National Park, each located in the western third of the state. To make visibility progress during the first implementation period, North Dakota primarily relied on NO_x and SO_2 emission reductions resulting from controls at existing electric generating units (EGUs). These controls include BART at Coal Creek Station (2 units), Leland Olds Station (2 units), Milton R. Young Station (2 units), and Stanton Station, as well as Reasonable Progress controls at Antelope Valley Station (2 units), Coyote Station, and R.M. Heskett Station.[25] The BART emission limits were required to be met by no later than May 7, 2017. On April 6, 2012, EPA took action to partially approve and partially disapprove the state's Regional Haze SIP and finalize a FIP addressing disapproved portions.[26] On September 23, 2013, the U.S. Court of Appeals for the 8th Circuit ruled that EPA's refusal to consider the existing pollution control technology at the Coal Creek Station was arbitrary and capricious.[27] The court vacated the FIP requiring SNCR at the facility.

2.2.3. Oregon

Oregon has twelve mandatory Class I Areas. According to the Regional Haze Update Plan for Oregon, a total of five facilities were impacted by BART determinations. Four facilities chose the option of a federally enforceable permit condition exempting them from BART determinations by reducing visibility impacts below 0.5 deciviews. The PGE Boardman (Boardman) facility BART determination required controls and must cease burning coal by December 31, 2020. Boardman completed installation of BART SO_2 controls consisting of a semi-dry flue gas desulfurization system in early 2014 and is required to further reduce SO_2 emissions in 2018.[28] Boardman is being evaluated to run on biomass so its future emissions are uncertain.

2.2.4. South Dakota

EPA approved South Dakota's Regional Haze State Implementation Plan on April 26, 2012. South Dakota is home to two of the nation's 156 mandatory federal Class I Areas: Badlands National Park and the Wind Dave National Park. Each is located in the southwest corner of South Dakota. South Dakota has only one BART source, which is the Big Stone I coal-fired power plant located in the northeastern corner of South Dakota. Air pollution controls and limits for this source, established under the BART determination, must be installed and implemented within five years of EPA's approval of South Dakota's Regional Haze SIP (April 26, 2017).

The BART determination made in 2010 required selective catalytic reduction (SCR) and separated over-fire air for NO_X control, a dry flue gas desulfurization system for SO_2 control, and a fabric filter for PM

---

[25] State of North Dakota, "Regional Haze State Implementation Plan Periodic Progress Report" (Jan. 2015).

[26] EPA, Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze, 77 Fed. Reg. 20894 (06 Apr. 2012), https://www.federalregister.gov/d/2012-6586.

[27] State of North Dakota v. U.S. Environmental Protection Agency (EPA), Nos. 12-1844, 12-1961, 12-2331, United States Court of Appeals for the Eighth Circuit (2013).

[28] Oregon Department of Environmental Quality, "Oregon Regional Haze Plan 5-Year Progress Report and Update" (Feb. 2016), http://www.deq.state.or.us/aq/haze/docs/2016ORRegHazeUpdate.pdf.

control. The control system was completed in December 2015, well ahead of the 2017 deadline. Emission reductions for SO_2 and NO_x associated with the control equipment are expected to result in approximately an 86% and 89%, reduction in NO_x and SO_2, respectively.[29]

2.2.5. Wyoming

Wyoming has seven Class I Areas including Yellowstone National Park, a portion of which is located in Montana. On Janaruy 30, 2014, EPA published a Regional Haze FIP for Wyoming, approving the state-proposed BART limits for PM and/or NO_x for 17 units. The majority of these limits do not take effect until future years, extending as late as December 31, 2022. EPA also disapproved the State's proposed NO_x limits for five units and developed new BART limits as part of the FIP for these sources. The compliance date for these five sources is March 4, 2019. Portions of EPA's final action were appealed and are still pending a final determination. Most of the BART derminations require SCR and Continuous Emission Monitoring Systems (CEMS) for NO_x control.[30]

2.3. State & Federal Programs relied on in the Montana FIP

EPA's 2013 guidance for the five-year progress report requests that, in addition to describing the status of specific control measures that were applied in the Montana FIP, the state should also describe additional measures that were relied upon to meet the requirements of the Regional Haze program.[31] This section describes the existing SIP-approved state programs and federal programs that were included in the projected 2018 future year emissions estimate and that have contributed to emissions reductions required to meet BART limits and Reasonable Progress Goals (RPGs).

There are numerous existing programs that are responsible for a continual decline in emissions from industrial sources. Most of the existing federal measures were incorporated into the WRAP's 2018 projected emission inventory. These measures should continue to reduce visibility-impairing pollutants over time and are part of Montana's long-term strategy for reaching its progress goals.

2.3.1. Minor Source Permitting Program

EPA granted authority to the State to implement the state's minor source permitting program, located in the Administrative Rules of Montana Chapter 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources. The primary purpose of the permitting program is to assure compliance with ambient air standards set to protect public health, assure that Best Available Control Technology (BACT) is utilized to reduce or eliminate air pollution emissions, and to prevent deterioration of clean air areas.

---

[29] South Dakota Department of Environment and Natural Resources, "South Dakota's Regional Haze State Implementation Plan" (rev. 18 Aug. 2011), http://denr.sd.gov/des/aq/aqnews/RegionalHaze.aspx.

[30] EPA, Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 79 Fed. Reg. 5031 (30 Jan. 2014) https://www.federalregister.gov/d/2014-00930.

[31] EPA, "General Principles for the 5-Year Regional Haze Progress Reports" (Research Triangle Park, North Carolina, April 2013), https://www.epa.gov/sites/production/files/2016-03/documents/haze_5year_4-10-13.pdf.

As part of Montana's SIP, all new emission sources that are required to obtain a Montana Air Quality Permit (MAQP) must use BACT. According to Administrative Rules of Montana (ARM) 17.8.752, the owner or operator of a new or modified emitting unit or emitting unit for which a Montana air quality permit is required shall install on the new or modified facility or emitting unit the maximum air pollution control capability that is technically practicable and economically feasible.[32] This provides that permitted emission rates are generally consistent across source categories and that emission rates are minimized.

By requiring BACT even on minor sources, lower emission levels associated with newer equipment, which replaces older equipment over time, serves to provide emission reductions on a continuing and long-term basis. While the Minor Source Permitting Program did not directly influence the 2018 project emission inventory, use of BACT limits emissions increases from modifications as new permitted equipment (such as engines) will generally have lower emission rates than the older units being replaced.

2.3.2. Prevention of Significant Deterioration

In addition to serving other air quality priorities, Montana's Prevention of Significant Deterioration (PSD) program also serves to limit visibility impairment from proposed major stationary sources or major modifications to existing facilities. Montana's PSD program has been successfully implemented since 1983 and is fully approved by EPA.[33] The PSD program requires sources (that meet the definition of new or major modifications) to model the emissions impacts on Class I Areas within 10 km of the source to determine if the change in emissions would exceed maximum allowable increases over the minor source baseline concentrations for $PM_{2.5}$, PM_{10}, SO_2 and NO_2. The PSD New Source Review (NSR) permitting program is described in ARM Chapter 17.8, Subchapter 8. The PSD program also did not directly influence the projected 2018 emission inventory but served to reduce the growth in new emissions by preventing large increases that could cause significant decline in the Class I Areas.

2.3.3. New Source Performance Standards – 40 CFR Part 60 and National Emission Standards for Hazardous Air Pollutants – 40 CFR Part 63

Montana administers a delegated Clean Air Act Part 70, or Title V, Operating Permit Program, thereby providing Montana with a mechanism to receive automatic delegation to implement the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs in the State.[34] Annually, the State undergoes rulemaking to incorporate by reference the most recent versions of these standards. Within the NSPS and NESHAP programs are numerous measures that have reduced visibility-impairing emissions nationally over time. As new standards continue to be developed, additional emission decreases will be realized. Although in some source categories,

[32] All Administrative Rules of Montana discussed in this report can be accessed through the Montana Secretary of State web portal at http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=17%2E8
[33] EPA, Approval and Promulgation of State Implementation Plans – Revision to the Montana Prevention of Significant Deterioration Regulations, 48 Fed. Reg. 20231 (5 May 1983), http://www.heinonline.org/HOL/Page?handle=hein.fedreg/048088&size=2&collection=fedreg&id=23.
[34] EPA, Clean Air Act Full Approval of Operating Permit Program; State of Montana, 65 Fed. Reg. 37049 (13 Jun. 2000), https://www.federalregister.gov/d/00-14768.

Montana does not have many affected facilities, sources in neighboring states that contribute to visibility impairment in Montana may be affected, resulting in some visibility benefit.

2.3.4. Montana Smoke Management Program

Montana implements an EPA-approved Smoke Management Plan (SMP) to regulate open burning and prescribed fire activities. The SMP consists of Montana's official open burning rules, as written in the Administrative Rules of Montana, Title 17, Chapter 8, Subchapter 6.[35] The SMP considers smoke management techniques and the visibility impacts of smoke when developing, issuing or conditioning permits, and when making dispersion forecast recommendations. The SMP incorporates BACT as the visibility control measure to meet the requirements of the RHR. The State works closely with the Montana/Idaho Airshed group to coordinate burning activities conducted by the large, major open burners and federal land managers.[36] Major burners in Montana are defined as "any person, agency, institution, business, or industry conducting any open burning that, on a statewide basis, will emit more than 500 tons per calendar year of carbon monoxide or 50 tons per calendar year of any other pollutant."[37] Examples of major open burners in Montana include the U.S. Forest Service and the Bureau of Land Management.

During the fall and winter burn seasons, Montana's open burn coordinator and meteorologist are actively involved in day-to-day burn decisions, and evaluate burn type, size, and location using dispersion forecasts. Through this coordination and the required minor burn permitting included in the SMP, anthropogenic smoke emissions are closely monitored and regulated. In addition, as mentioned above, burners must follow BACT, which aims to limit smoke impacts due to burning. A full list of BACT requirements for burners can be found in ARM 17.8.601. During open burn season (March through August) Montana is not involved in the day-to-day decisions of burners, although all other aspects of the Montana open burning rules still apply, including BACT. The SMP, as represented by our open burning rules, is included as Appendix A of this document.

2.3.5. National Petroleum Refinery Initiative

EPA's national Petroleum Refinery Initiative is an enforcement and compliance strategy to address air emissions from the nation's petroleum refineries.[38] Since 2000, EPA has entered into 17 settlements with U.S. companies that refine over 75% of the nation's petroleum.

The initiative has resulted in emission decreases at Montana refineries, including Calumet, Phillips66, CHS, Inc., and ExxonMobil. Emission reductions projected to be achieved at these sources were taken into account in the projected 2018 emission inventory and will continue to provide for emissions reductions going forward.

---

[35] Montana Department of Environmental Quality (DEQ), ARM Title 17, Chapter 8, Subchapter 6 – Open Burning, http://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-06.pdf.
[36] Montana/Idaho Airshed Group, Airshed Management System: http://www.smokemu.org/.
[37] ARM 17.8.601(5), www.mtrules.org/gateway/RuleNo.asp?RN=17%2E8%2E601.
[38] EPA, Petroleum Refinery National Case Results, https://www.epa.gov/enforcement/petroleum-refinery-national-case-results.

2.3.6. Federal Mobile Source Regulations

The Federal Motor Vehicle Control Program has already realized large emissions reductions in NO_x, SO_x, volatile organic compounds (VOCs), and particulate matter (PM). The Federal Tier II vehicle emissions and fuel standards reduced the sulfur content of diesel fuel from 500 to 15 parts per million (ppm) (Ultra Low Sulfur Diesel) in 2006.[39] The reduction in sulfur content allowed diesel engines to be fitted with diesel oxidation chambers to reduce particulates. Fuel standards for offroad diesel similarly reduced allowable sulfur content. In 2007, offroad diesel was required to meet a maximum sulfur content of 500 ppm, which was further reduced to 15 ppm in 2010. Additional programs include the following:

Federal onroad measures

- Tier 3 vehicle emission standards and federal low-sulfur gasoline
- National low-emission vehicle standards
- Heavy-duty diesel standards

Federal offroad measures

- Lawn and garden equipment
- Tier 3 heavy-duty diesel equipment
- Locomotive engine standards
- Compression ignition standards for vehicles and equipment
- Recreational marine engine standards

2.4. Additional Federal Measures

In addition to the state and federal measures that were anticipated in the Montana FIP, new measures have been promulgated and implemented, in whole or in part, since the development of the Montana FIP and the projected 2018 emissions inventory. Any reduction that will occur or has already occurred as a result of these new measures will further reduce emissions beyond what was projected toward Montana's reasonable progress goals. This section details several new federal measures.

2.4.1. Mercury and Air Toxics Rule

On February 16, 2012, EPA finalized national standards to reduce mercury and other toxic air pollution from coal and oil-fired power plants as part of 40 CFR 63, Subpart UUUUU – National Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, also referred to as the Mercury and Air Toxics Standards (MATS).[40] The final rule established power plant emission standards for mercury, acid gases, and non-mercury metallic toxic pollutants. EPA projected 2015 emissions with the standards in place – emissions of mercury, $PM_{2.5}$, SO_2, and acid gas will be

[39] EPA, Diesel Fuels Standards and Rulemakings, https://www.epa.gov/diesel-fuel-standards/diesel-fuel-standards-rulemakings.

[40] EPA, National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 77 FR 9304 (16 Feb. 2012), https://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.

reduced by 75, 19, 41, and 88%, respectively, from coal-fired EGUs greater than 25 megawatts (MW).[41] Compliance with MATS was required by April 16, 2015. Emission reductions that occur as a result of MATS, both in the form of particles and gases that may form aerosols, will reduce the amount of light extinction and reduce anthropogenic causes of haze.

Montana had previously adopted rules to control mercury in response to the proposed federal rulemaking known as the Clean Air Mercury Rule (CAMR), under which states were originally required to adopt a set of federal market trading standards for mercury or develop their own "equivalent" standard. Montana adopted its own mercury standard referenced as the Montana Mercury Rule.[42] The Montana Mercury Rule (ARM 17.8.771) was adopted effective October 27, 2006, and required compliance with mercury emission limits by January 1, 2010.[43] Although CAMR was vacated by the District of Columbia Court of Appeals in 2008, the Montana Mercury Rule was already in place by the time MATS was finalized.

There were five affected coal-fired facilities under the Montana Mercury Rule and MATS. These included the Colstrip Steam Electric Station, J.E. Corette Steam Electric Station, Montana-Dakota Utilities (MDU) Lewis & Clark Plant, Colstrip Energy Limited Partnership, and Rocky Mountain - Hardin.

Colstrip Steam Electric Station

Colstrip's four electric generating units use subbituminous coal and its mercury limit under the Montana Mercury Rule is 0.9 pounds per trillion British thermal units (lb/TBtu) on a 12-month rolling average. Colstrip is required to meet a MATS limit of 1.2 lbs/TBtu on a 30-day rolling average. The compliance date for Colstrip was April 16, 2015, but the facility was granted a one-year extension to April 16, 2016. The extension provided a full one year grace period for all required MATS limits, but upgrades were completed for particulate on Colstrip scrubbers to improve particulate removal.

Particulate matter (PM) emissions may be used as a surrogate for actual heavy metal emissions to meet the heavy metal limits in the MATS rule. Reductions in PM emissions reflect a broad category of particulate and gaseous species that contribute to the PM category. The mercury control system installed at Colstrip to meet Montana's Mercury Rule also allowed Colstrip to meet the MATS requirements for mercury capture and removal. In addition, existing controls on all four units adequately remove acid gases covered by the MATS rule (using SO_2 as a surrogate). Upgrades were done on the Unit 1 and 2 scrubbers (sieve trays installed) for additional PM control and resulted in the secondary benefit of significant SO_2 reduction. Theses controls at Colstrip have resulted in significant emission reductions from the facility.

J.E. Corette Steam Electric Station

The J.E. Corette facility was also subject to MATS, but opted not to install the required control equipment, resulting in its shutdown in April 2015.

---

41 Ibid. p. 9424.
42 EPA, Clean Air Mercury Rule, https://www3.epa.gov/airtoxics/utility/utiltoxpg.html.
43 ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units, http://www.mtrules.org/gateway/RuleNo.asp?RN=17%2E8%2E771.

MDU Lewis & Clark Plant

The MDU Lewis & Clark Plant burns lignite coal, a different type of coal than the Colstrip Steam Electric Station, and therefore has different limits than Colstrip. For this facility, the Montana Mercury Rule requires a limit of 1.5 lb/TBtu on a rolling 12-month average, and MATS requires 4.0 lb/TBtu on a rolling 30-day average. MDU Lewis & Clark upgraded the existing scrubber and installed sieve trays to satisfy the non-mercury metals emission standard of 0.03 lbs/MMBtu for filterable PM in 2015. The system was fully operational in early 2016. These additional controls have resulted in further particulate reductions plus a co-benefit of significant SO_2 emission reductions.

Rocky Mountain Power – Hardin

Also known as the Hardin Generating Station, this facility consists of a single coal-fired boiler with single steam turbine rated at 116 gross megawatts. Hardin must achieve a 0.9 lb/TBu mercury limit on a 12-month rolling average to comply with the Montana Mercury Rule, and a limit of 1.2 lb/TBtu on a 30-day average to comply with MATS. Hardin installed carbon injection controls to meet the limit in the Montana Mercury Rule.

Colstrip Energy Limited Partnership (CELP)

This facility often is referred to as the Rosebud Power Plant and also uses coal from the same geographic area as the Colstrip Steam Electric Station but is able to utilize a lower grade coal sometimes referred to as "waste coal". The facility has a single coal-fired boiler rated for 39 gross megawatts. CELP began planning for their compliance with the Montana Mercury Rule as early as December 2008, when Montana DEQ received an application to modify their Montana Air Quality Permit. CELP is meeting the same limits as Hardin, 0.9 lb/TBtu mercury limit on a 12-month rolling average and a MATS limit of 1.2 lb/TBtu on a 30-day average.

2.4.2. Revised National Ambient Air Quality Standards

According to EPA, the primary NAAQS serve to protect public health, including "the health of 'sensitive' populations such as asthmatics, children, and the elderly." In addition, secondary NAAQS protect public welfare, "including protection against decreased visibility and damage to animals, crops, vegetation, and buildings."[44] As EPA continues to revise NAAQS, the standards put pressure on states to manage pollution sources, often resulting in emissions decreases, including of pollutants responsible for visibility impairment.

The following NAAQS revisions have occurred since the baseline period (2000-2004) for the Regional Haze program. Each of these standards must be taken into account when permitting new or modified major sources, including fossil fuel-fired power plants, boilers, and a variety of other operations. Any reductions in SO_2, NO_x, or $PM_{2.5}$ brought about by these revised standards will enhance protection of visibility in Montana Class I Areas.

---

[44] EPA, "NAAQS Table" (last updated 20 Dec. 2016), https://www.epa.gov/criteria-air-pollutants/naaqs-table (accessed 14 Apr. 2017).

2010 SO_2 NAAQS

On June 2, 2010, EPA strengthened the SO_2 NAAQS by revising the primary SO_2 standard to 75 parts per billion (ppb) 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum SO_2 concentrations. This short-term standard is significantly more stringent than the revoked standards of 0.140 parts per million (ppm) averaged over 24-hours and 0.030 ppm averaged over a calendar year.

On August 21, 2015, EPA released the 2010 SO_2 Data Requirements Rule (DRR), which instructs states to evaluate areas surrounding facilities with 2000 tons/year or more SO_2 emissions.[45] In Montana, all units at the Colstrip Steam Electric Station were modeled under the DRR since the facility exceeds the 2000 ton/year threshold. As a result, Montana requested to designate Rosebud County as "attainment" for SO_2. Montana had one area in Yellowstone County that was designated as nonattainment. The area was redesignated to attainment under a maintenance plan effective on June 9, 2016.[46]

2010 NO_2 NAAQS

Effective on April 12, 2010, EPA established a new 1-hour primary standard to supplement the existing annual standard. This 1-hour standard was set at a level of 100 ppb, based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations.[47] Along with the new standard, EPA set new requirements to monitor NO_2 levels near major roadways. Montana does not have a population center with a density high enough to warrant or trigger the near-roadway monitoring requirement. In 2012, EPA designated every county in Montana as Unclassifiable/Attainment for the 2010 NO_2 NAAQS.[48]

2012 $PM_{2.5}$ NAAQS

On January 15, 2013, EPA published a final rule strengthening the annual NAAQS for fine particles ($PM_{2.5}$) from 15.0 micrograms per cubic meter ($\mu g/m^3$) to 12.0 $\mu g/m^3$.[49] According to EPA, "Emission reductions from EPA and states rules already on the books will help 99 percent of counties with monitors meet the revised $PM_{2.5}$ standards without additional emission reductions."[50] These rules include many of

---

[45] EPA, Data Requirements Rule for the 2010 1-Hour Sulfur Dioxide (SO2) Primary National Ambient Air Quality Standard (NAAQS); Final Rule, 80 FR 51052 (21 Aug. 2015), https://www.gpo.gov/fdsys/pkg/FR-2015-08-21/html/2015-20367.htm.
[46] EPA, Designation of Areas for Air Quality Planning Purposes; Redesignation Request and Associated Maintenance Plan for Billings, MT 2010 SO2 Nonattainment Area, 81 FR 28718 (10 May 2016), https://www.gpo.gov/fdsys/pkg/FR-2016-05-10/html/2016-10451.htm.
[47] EPA, Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Final Rule, 75 FR 6474 (9 Feb. 2010), https://www.gpo.gov/fdsys/pkg/FR-2010-02-09/pdf/2010-1990.pdf. See also EPA, "Nitrogen Dioxide (NO2) Pollution," last updated 23 Dec. 2016, https://www.epa.gov/no2-pollution/2010-primary-national-ambient-air-quality-standards-naaqs-nitrogen-dioxide.
[48] EPA, Air Quality Designations for the 2010 Primary Nitrogen Dioxide (NO2) National Ambient Air Quality Standards; Final Rule, 77 FR 9532 (17 Feb. 2012), https://www.federalregister.gov/d/2012-3150.
[49] EPA, National Ambient Air Quality Standards for Particulate Matter, 78 FR 3086 (15 Jan. 2013), https://www.gpo.gov/fdsys/pkg/FR-2013-01-15/pdf/2012-30946.pdf.
[50] EPA, "Overview Of EPA's Revisions to the Air Quality Standards for Particle Pollution (Particulate Matter)," https://www.epa.gov/sites/production/files/2016-04/documents/overview_factsheet.pdf (accessed 24 Apr. 2017).

the regulations discussed above, such as clean diesel rules for vehicles and fuels, and rules to reduce pollution from power plants.

2.5. Additional State Measures

In addition to BART and the federal and state programs discussed previously, there are other state measures and noteworthy changes that will influence the achievement of Montana's 2018 RPGs. As set forth in detail below, some noteworthy changes in Montana since the Montana FIP submittal include a power plant closure, two previously planned coal-fired facilities that were not constructed, stronger renewable energy portfolio requirements, and attainment of the NAAQS throughout the state.

2.5.1. Closure/Cancellations & Derating

The WRAP projected 2018 emissions estimate included emissions from a number of large sources that have closed, were never built, or are operating at different levels than originally planned. These sources include a power plant that has been closed (Corette, discussed in Section 1.1.2), a power plant that was constructed but at a smaller size than originally planned (Rocky Mountain Power - Hardin), and two coal-fired power plants that were planned but never constructed (Bull Mountain/Roundup Power Project and Southern Montana Electric, or SME). The latter two permits were eventually permanently revoked.

The Hardin facility was originally designed as 160 megawatts (MW), but was eventually permitted at 113 MW; therefore, emissions associated with this facility were over-stated by the equivalent of 47 MW. The Bull Mountain/Roundup plant, with a capacity of around750 MW per the WRAP inventory, was never constructed, and SME was permitted and constructed but never came on-line. Adjusting the 2018 projected emissions inventory to reflect these changes will further reduce emissions toward the RPGs.

2.5.2. Montana Renewable Portfolio Standard

The Montana Renewable Power Production and Rural Economic Development Act or the Montana Renewable Portfolio Standard (RPS), was approved by the Montana Legislature in 2005. The RPS required public utilities to obtain a percentage of their retail customer sales from renewable resources. Starting in 2008, a public utility was required to acquire renewable energy equal to 5% of its retail sales of electricity in Montana. That percentage increased to 10% in 2010 and to 15% in 2015.[51] While new sources of renewable energy do not directly replace electricity from fossil fuel-fired electric generating plants, they accommodate growth in electricity demand without increasing emissions.

The new sources of generation in Montana are shown in Table 2-3, although not all of the power generated is consumed in Montana. Many of the projects are able to help meet the RPS, but not all were constructed specifically to meet the requirements of this Act.

---

[51] Montana Code Annotated 2015, Title 69, Chapter 3, Part 20, Renewable Power Production and Rural Economic Development, http://leg.mt.gov/bills/mca_toc/69_3_20.htm.

TABLE 2-3. NEW AND PROPOSED RENEWABLE GENERATION IN MONTANA AS OF NOVEMBER 2016[52]

COMPANY	PLANT	COUNTY	SOURCE	INITIAL OPERATION	CAPACITY (MW)
NWE Portfolio (winter) - Tiber Montana, LLC	Tiber Dam	Liberty	Water	2004	7.5
NWE QF - Two Dot Wind	Martinsdale Colony	Wheatland	Wind	2004	0.8
NWE Portfolio - Invenergy Wind	Judith Gap	Wheatland	Wind	2005	135.0
NWE QF - United Materials of Great Falls, Inc.	UMGF	Cascade	Wind	2006	9.0
Montana-Dakota Utilities	Diamond Willow	Fallon	Wind	2007	30.0
NWE QF - Two Dot Wind	Martinsdale Colony S.	Wheatland	Wind	2007	2.0
NaturEner	Glacier 1 & 2	Toole	Wind	2008	210.0
Flathead Electric Cooperative	Landfill Gas to Energy	Flathead	Landfill Methane	2009	1.6
NWE Portfolio - Turnbull Hydro LLC	Turnbull Hydro	Teton	Water	2011	13.0
NaturEner	Rimrock	Toole	Wind	2012	189.0
NorthWestern Energy (NWE)	Spion Kop	Judith Basin	Wind	2012	40.0
NWE QF - Oversight Resources	Gordon Butte	Meagher	Wind	2012	9.6
F.H. Stoltze	Land & Lumber Co-Gen	Flathead	Biomass	2013	2.5
NWE QF - Granite County	Flint Creek Dam	Granite	Water	2013	2.0
NWE QF - Goldwind Global	Mussellshell 1 & 2	Wheatland	Wind	2013	20.0
NWE Portfolio - NJR Clean Energy Ventures	Two Dot Wind Farm	Wheatland	Wind	2014	9.7
NWE QF - WINData LLC	Fairfield Wind	Teton	Wind	2014	10.0
GreenField Wind	Greenfield Wind	Teton	Wind	2017	25.0
				Total	**716.7**

2.5.3. State Implementation Plans

The State Implementation Plans (SIPs) for nonattainment and maintenance areas contain control measures that may also contribute to the reduction of visibility-impairing pollution. Table 2-4. Existing Montana Nonattainment Areas shows the status of all of the existing nonattainment areas and maintenance areas in the state of Montana. For each nonattainment area, the State has drafted a SIP with control measures to bring the area back into attainment with the associated NAAQS. Currently, most nonattainment areas (primarily PM_{10}) in Montana are meeting the NAAQS standards based on ambient monitoring data. A few of these areas have been redesignated to attainment and are now in compliance with maintenance plans. Others have been granted a "determination of attainment," indicating that the area is attaining the standard even though it has not yet been redesignated.

In these areas, control measures (such as fugitive dust regulations, oxygenated fuel programs, transportation control measures, residential wood burning regulations, woodstove replacement programs, and winter sanding and sweeping regulations) ensure there are no large emission increases (without emissions offsets) and serve to return the areas to attainment/unclassifiable. These measures often also reduce pollutants that contribute to haze.

[52] Montana DEQ, Energy Bureau, "Table E1. Electric Power Generating Capacity by Company and Plant as of August 2016." Received 7 Nov. 2016.

TABLE 2-4. EXISTING MONTANA NONATTAINMENT AREAS

Pollutant	Standard Violated	Community	Current Standard	2016 Design Value (With EE)ǂ	2016 Design Value (Without EE)ǂ	Nonattainment	Attainment/ Maintenance
Sulfur Dioxide	1971 (24-hr)	Laurel	75 ppb	38*	NA	3/3/1978	
		East Helena		No Monitor	NA	11/15/1990	
	2010 (1-hr)	Billings		53	NA		6/9/2016[53]
Particulate (PM2.5)	1997 (Annual)	Libby	12 μg/m³	9.8	NA	4/5/2005	
Particulate (PM10)**	1987 (24-hr)	Kalispell	150 μg/m³	87, 84	87, 84	11/15/1990	
		Columbia Falls		45, 44	45, 44	11/15/1990	
		Whitefish		106, 98	106, 98	10/19/1993	
		Libby		58, 57	45, 45	11/15/1990	
		Missoula		74, 65	74, 65	11/15/1990	
		Thompson Falls		135, 97	97, 89	1/20/1994	
		Butte		52, 51	52, 45	11/15/1990	
Carbon Monoxide	1971 (8-hour)	Billings	9 ppm	NA	NA		4/22/2002[54]
		Great Falls		NA	NA		7/8/2002[55]
		Missoula		NA	NA		9/17/2007[56]
Lead	1978 (Cal. Qtr.)	East Helena	0.15 μg/m³	0.06		1/6/1992	

* 2014 Design Value, monitoring ceased in June 2015.
** PM_{10} Design Values are the 2016 1st and 2nd high values, only PM_{10} flagged events removed above 150.
ǂ Exceptional Events (EE) – EE are natural or unusual events that can affect air quality but that are not reasonable controllable using the techniques that air agencies use to attain or maintain the NAAQS. Additional information on Montana nonattainment areas, including designation references and current EPA status of areas, can be found at https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mt_areabypoll.html

2.6. Conclusion

In summary, this chapter has described the implementation status of measures from the Montana FIP, including the status of control measures to meet BART requirements, the status of significant measures resulting from EPA and state regulations, as well as measures and facility changes that have occurred since the WRAP analyses were completed for the Montana FIP. Since the Montana FIP was promulgated in 2012, further reductions have already occurred or will occur as a result of additional federal and state programs not otherwise identified in the Montana FIP, such as periodic updates to the NAAQS and plant closures. As discussed in this chapter, these actions and others have led to substantial reductions in both the actual and projected emissions of visibility-impairing pollutants from Montana sources. The following chapter further assesses emissions reductions resulting from these measures.

---

[53] EPA, Designation of Areas for Air Quality Planning Purposes; Redesignation Request and Associated Maintenance Plan for Billings, MT 2010 SO2, 81 Fed. Reg. 28718 (10 May 2016), https://www.federalregister.gov/d/2016-10451.
[54] EPA, Approval and Promulgation of Air Quality Implementation Plans; State of Montana; Billings Carbon Monoxide Redesignation to Attainment and Designation of Areas for Air Quality Planning Purposes, 67 Fed. Reg. 7966 (21 Feb. 2002), https://www.federalregister.gov/d/02-4062.
[55] EPA, Approval and Promulgation of Air Quality Implementation Plans; State of Montana; Great Falls Carbon Monoxide Redesignation to Attainment and Designation of Areas for Air Quality Planning Purposes, 67 Fed. Reg. 31143 (9 May 2002), https://www.federalregister.gov/d/02-11448.
[56] EPA, Approval and Promulgation of Air Quality Implementation Plans; State of Montana; Missoula County Carbon Monoxide Redesignation to Attainment, Designation of Areas for Air Quality Planning Purposes, and Approval of Related Revisions, 72 Fed. Reg. 46161 (17 Aug. 2007), https://www.federalregister.gov/d/E7-15784.

BEFORE THE STATE OF WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-170033/UG-170034 (*Consolidated*)

Initial Post-Settlement-Hearing Brief of
the State of Montana in Support of
the Proposed Multiparty Settlement Stipulation and Agreement

October 18, 2017

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

Statutes

Other Authorities

fiscally responsible way and will prevent or reduce rate shock to PSE ratepayers. In short, the proposed Settlement addresses those of Montana's interests that the Commission has power to address while also meeting this Commission's standards for settlement approval.[16]

B. The proposed Settlement's depreciation schedule balances the magnitude of rate increases associated with Colstrip depreciation expenses against a measure of certainty that ratepayers will not pay for Colstrip Units 3 & 4 for longer than is fair, just, and reasonable.

14 For accounting purposes only,[17] the proposed Settlement establishes an accelerated depreciation schedule for Colstrip Units 3 & 4 ("Units"). That schedule will not force Washington ratepayers to bear an inordinate rate increase, but it does provide assurance that the depreciation expense for the Units will be fully and predictably funded.[18] Similarly, as other Settling Parties have recognized through a general consensus of diverse opinions, the adjusted depreciation schedule minimizes future intergenerational inequities that might arise from the imprecise science of setting depreciation dates.

15 Further, by clarifying that the stipulated depreciation schedule for the Units is for accounting purposes only and does not set a retirement date for them, the Settlement preserves operational flexibility for an important source of reliable, low-cost baseload power for PSE customers while implicitly acknowledging that any decision regarding the Units' eventual retirement must be jointly made by all six of the Units' owners. This operational flexibility

[16] Because the proposed Settlement resolves each issue implicating Montana's interests in these consolidated rate proceedings, Montana's initial post-hearing brief focuses solely on the issue of whether the Commission should adopt the proposed Settlement. Accordingly, Montana's initial post-hearing brief does not address any of the issues remaining to be litigated. Further, because the proposed Settlement resolves issues other than those that implicate Montana's interests, Montana's initial post-hearing brief focuses its support of the proposed Settlement solely on issues that implicate Montana's interests.

[17] As PSE correctly observed in joint testimony supporting the proposed Settlement, the proposed Settlement's 2027 depreciation date does not equate to a retirement date. Joint Testimony of Puget Sound Energy, Exh. PSE-1JT at 7:4-12 (Sept. 15, 2017).

[18] Settlement ¶¶ 24-27; *see also* Settlement Ex. B n.2 & Joint Memorandum in Support of Multiparty Partial Settlement ¶ 13.

mitigates cost uncertainty that PSE would otherwise face–e.g., the cost of replacement baseload power–if the proposed Settlement equated the Units' depreciation life with their operational life.[19]

16 Public Counsel's witness Roxie M. McCullar disagrees that December 31, 2027, is a reasonable depreciation date for Colstrip Units 3 & 4.[20] Ms. McCullar observes that 2027 is a number that falls between 2025 and 2035, stating that December 31, 2027 "seems early."[21] But Ms. McCullar's only response is circular and conclusory–i.e., the depreciation date should be later.[22] Ms. McCullar does not acknowledge that depreciation is an imprecise science–as Mr. Douglas H. Howell noted on behalf of Sierra Club's full support of the proposed Settlement, "certainty of retirement dates is not required–nor is it advisable–in setting a depreciation date."[23] Regulatory uncertainty, particularly in a cyclical industry such as energy, counsels in favor of a more conservative depreciation end-date in order to avoid intergenerational inequities.

17 Further, Ms. McCullar mischaracterizes Mr. Bradley G. Mullins' testimony in support of the proposed Settlement in her own effort to support Public Counsel's approach to setting a depreciation date for Colstrip Units 3 & 4. Specifically, Ms. McCullar focuses on to Mr. Mullins' remark that ICNU would have preferred a 2030 depreciation year for Colstrip Units 3 & 4,[24] but Ms. McCullar ignores the crucial next sentence of Mr. Mullins' testimony: "However, ICNU was willing to agree to a [December 31, 2027] depreciation date for Units 3 & 4 as part of a broader

[19] Montana maintains that any reading of the proposed Settlement as purporting to establish a retirement date for Colstrip Units 3 & 4 would not be lawful, because it would be outside this Commission's authority. Accordingly, by clarifying that depreciation does not equal retirement, the proposed Settlement appears to avoid any question of legality in that regard.
[20] Ms. McCullar's testimony opposing the proposed Settlement also incorrectly states that December 31, 2027, is a retirement year. Testimony of Roxie M. McCullar, Exh. RMM-12T at 6:12-13 (Sept. 22, 2017).
[21] *Id.* at 6:13.
[22] *Id.* at
[23] Testimony of Douglas H. Howell, Exh. DHH-1T at 11:5-6 (Sept. 15, 2017).
[24] Testimony of Bradley G. Mullins, Exh. BGM-17T at 4; *see* RMM-12T at 7-8.

settlement package."[25] This is the Settling Parties' general sentiment regarding the settlement as a whole, which includes the adjusted depreciation date for Units 3 & 4.[26] Public Counsel's opposition essentially amounts to a preference for a different depreciation date for Units 3 & 4 rather than the date reached in the Settlement among PSE and stakeholders of notably diverse interests.[27]

18 Working to ameliorate cost uncertainty, which the adjusted depreciation schedule for Units 3 & 4 does, is in the public interest generally and the interest of Washington ratepayers specifically. December 31, 2027, is a lawful and well-supported depreciation date that arose from thoughtful negotiations among diverse interests. The depreciation date for Units 3 & 4 satisfies this Commission's standards for settlement approval. Public Counsel's opposition does nothing to aid the Commission's decision process regarding this component of the proposed Settlement. The Commission should adopt the December 31, 2027, depreciation date for Units 3 & 4 as part of an unconditional approval of the proposed Settlement.

C. The proposed Settlement's payment arrangements for decommissioning and remediation of Colstrip Units 1 & 2 are lawful, supported by the record, and serve the public interest.

19 The proposed Settlement outlines a lawful use of hydro-related Treasury Grants and Production Tax Credits ("PTCs") which is supported by the record, because those assets will be split between (1) a dedicated retirement account pursuant to RCW 80.04.350 to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 & 2 and (2) a non-

---

[25] BGM-17T at 4.
[26] *See, e.g.*, Testimony of Ali Al-Jabir, Exh. AZA-7T at 2-3 (FEA witness characterizing the proposed Settlement as a "reasonable compromise" among the Settling Parties).
[27] Notably, Ms. McCullar did not review workpapers supporting depreciation rates for Colstrip Units 3 & 4. RMM-12T at 8:20-21. Literally, then, Public Counsel has stated no real basis to oppose the proposed Settlement's negotiated depreciation date for Units 3 & 4.

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the revenue requirement effect of the change in the Colstrip Power Plant Units 3 and 4 and associated common facilities currently assumed end of depreciable life year from 2042 to 2030 as specified in 2016 Oregon Laws, Chapter 28 (SB 1547), Section 1. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495 and 576R.

ADJUSTMENT RATES

Schedule 146 Adjustment Rates will be set based on an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate	
7	0.035	¢ per kWh
15/515	0.028	¢ per kWh
32/532	0.032	¢ per kWh
38/538	0.030	¢ per kWh
47	0.038	¢ per kWh
49/549	0.037	¢ per kWh
75/575		
Secondary	0.030	¢ per kWh
Primary	0.029	¢ per kWh
Subtransmission	0.029	¢ per kWh
83/583	0.032	¢ per kWh
85/585		
Secondary	0.031	¢ per kWh
Primary	0.030	¢ per kWh
89/589		
Secondary	0.030	¢ per kWh
Primary	0.029	¢ per kWh
Subtransmission	0.029	¢ per kWh

SCHEDULE 146 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/590	0.028	¢ per kWh
91/591	0.028	¢ per kWh
92/592	0.028	¢ per kWh
95/595	0.028	¢ per kWh

DETERMINATION OF ADJUSTMENT AMOUNT

Any revision to this schedule's Adjustment Rates requires Commission authorization (by order, approval of a filing, acknowledgement of an Integrated Resource Plan's Action Plan, or approval of a depreciation study) to revise for rate setting and accounting purposes, the end of depreciable life assumption of 2042 for the Colstrip Power Plant Units 3 and 4 and associated common facilities. The revised Adjustment Rates will be set to recover an Adjustment Amount reflecting the change in depreciation revenue requirements.

The Adjustment Amount is the difference between the Colstrip Power Plant Units 3 and 4 and associated common facilities depreciation/amortization revenue requirement for the year 2017 as determined in UE 294 that reflects a plant end of depreciable life date of 2042, and the same depreciation/amortization revenue requirement determination using a plant end of depreciable life assumption of 2030. The depreciation/amortization revenue requirement change computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return, and return on equity rates. Only changes to depreciation expense, amortization expense and related Schedule M and rate base adjustments as of the date of the filing revisions to this rate schedule are included in the depreciation/amortization revenue requirements.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 depreciation revenue requirement, if the Company has not incorporated the revised depreciable life into base rates in a general rate case or other proceeding.

The docket reference numbers and dates in this schedule will be revised as necessary to a subsequent docket if no change to the Colstrip Power Plant Units 3 and 4 and associated common facilities depreciable life occurs prior to a subsequent general rate case order.

TERM

This schedule will terminate at the date that base rates include the revised end of life assumption or when all remaining investment in the Colstrip Power Plant Units 3 and 4 and associated facilities have been recovered.