Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

Docket No. EPA-R06-OAR-2015-0189

08/31/2016

List of Public Comments

Docket ID Number (EPA-R06-OAR-2015-0189-xxxx)	Document title number (AR020.xxx)	Commenter Affiliation
0141	AR020.0141	Arkansas Electric Cooperative Corporation (Request for Extension of Comment Period)
0142	AR020.0142	Domtar (Request for Extension of Comment Period)
0143	AR020.0143	Energy and Environmental Alliance of Arkansas (Request for Extension of Comment Period)
0144	AR020.0144	Arkansas Department of Environmental Quality (Request for Extension of Comment Period)
0145	AR020.0145	Arkansas Environmental Federation (Request for Extension of Comment Period)
0146	AR020.0146	
0147	AR020.0147	
0148	AR020.0148	Southwest Electric Power Company (Request for Extension of Comment Period)
0149	AR020.0149	Entergy Arkansas Inc. (Request for Extension of Comment Period)
0150	AR020.0150	Nucor Steel-Arkansas (Request for Extension of Comment Period)
0151	AR020.0151	Arkansas Audubon Society
0152	AR020.0152	Transcript of Public Hearing in Little Rock, Arkansas, April 16, 2015
0153	AR020.0153	
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0155	AR020.0155	Domtar (Request for Extension of Comment Period)
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0160	AR020.0160	Arkansas Department of Environmental Quality
0161	AR020.0161	Domtar A.W. LLC Ashdown Mill
0162	AR020.0162	The Honorable Leslie Rutledge, Attorney General, State of Arkansas
0163	AR020.0163	Nucor Steel-Arkansas and Nucor-Yamato Steel Company

Docket ID Number (EPA-R06-OAR-2015-0189-xxxx)	Document title number (AR020.xxx)	Commenter Affiliation
0164	AR020.0164	Southwest Electric Power Company (AEP-SWEPCO)
0165	AR020.0165	American Chemistry Council, American Coke and Coal Chemicals Institute, American Farm Bureau Federation, American Forest & Paper Association, American Iron and Steel Institute, American Petroleum Institute, American Public Power Association, American Wood Council, Arkansas Asphalt Pavement Association, Arkansas State Chamber of Commerce, Arkansas Environmental Federation, Arkansas Farm Bureau, Arkansas Forest & Paper Council, Arkansas Ready Mixed Concrete Association, Associated Industries of Arkansas Inc., Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resources Council, Gas Processors Association, Industrial Energy Consumers of America, National Association of Manufacturers, National Mining Association, National Oilseed Processors Association, and U.S. Chamber of Commerce (collectively, "the Associations")
0166	AR020.0166	Entergy Arkansas Inc.
0167	AR020.0167	Southwest Electric Power Company (AEP-SWEPCO) (Supplemental Comments submitted on August 7, 2015)
0168	AR020.0168	Entergy Mississippi Inc.
0169	AR020.0169	Arkansas Electric Cooperative Corporation
0170	AR020.0170	Domtar A.W. LLC Ashdown Mill (Supplemental Comments submitted on August 7, 2015)
0171	AR020.0171	Sierra Club, Earthjustice, and National Parks Conservation Association
0172	AR020.0172	Conway Corporation, Jonesboro City Water and Light, West Memphis Utilities, and Osceola Municipal Light and Power

Docket ID Number (EPA-R06-OAR-2015-0189-xxxx)	**Document title number (AR020.xxx)**	**Commenter Affiliation**
0173	AR020.0173	Energy and Environmental Alliance of Arkansas
0174	AR020.0174	Edison Electric Institute
0175	AR020.0175	Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc.
0176	AR020.0176	Utility Air Regulatory Group
0177	AR020.0177	Citizen comments (16)
0178	AR020.0178	Members of Sierra Club (183)
0179	AR020.0179	Members of Sierra Club (38)
0182	AR020.0182	Anonymous comment

Notes:

1. The following public submissions were requests for extensions of the public comment period that are not summarized in this document: EPA-R06-OAR-2015-0189-0141, 0142, 0143, 0144, 0145, 0148, 0149, 0159, 0155, and 0158.

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1. General and Miscellaneous

Comment: (0178) 183 members of the public stated that as Arkansans, they value the Buffalo River, the Caney Creek Wilderness, and the Ouachita Mountains. These are true jewels of "The Natural State," but they are polluted by haze from Arkansas' dirty power plants.

These members of the public stated that they support the EPA's plan to reduce haze pollution in Arkansas. Our parks are a public resource for our families, and shouldn't be sullied by power plant pollution. Our families have long enjoyed our Arkansas parks, as have millions of people from both in and out of our state. Our state parks are a treasure to be passed along to future generations. They are valuable beyond comparison and must be protected. Our parks are also huge economic engines, drawing millions of tourists to experience what Arkansas has to offer. This economic activity will be harmed without strong action to protect and clean up our parks.

One commenter stated that one of the biggest reasons Arkansas is so amazing is its parks, its breathtaking natural surroundings, and its pristine condition. Pollution is destroying the very essence of what makes "The Natural State" so naturally beautiful. Please continue to fight to save our state and preserve its beauty. Another commenter stated that the EPA can make sure that Arkansas' nickname "The Natural State" does not become a joke. The commenter stated it seems the new attorney general opposes EPA rules and it's unclear on whose behalf she is working.

Some commenters stated that EPA's draft regional haze plan makes dirty power plants clean up their act--which is leadership they can get behind. One commenter stated that coal-fired plants not only emit particulates, they also put mercury and other heavy metals into the environment. The haze is just a visible manifestation of the pollution that worsens our health and makes climate change inevitable. Coal plants are endangering our air and consequently are negatively impacting tourism and outdoor activities. The commenters asked EPA to do all we can to stop the increasing air pollution by passing a strong haze bill.

One commenter stated that Arkansas needs to step it up and get serious about coal. Instead the state tries to convince its citizens that coal is essential. The State claims that without coal, the cost of electricity would skyrocket, which is false. Arkansas needs to invest in alternative energy. The folks running the Coop's reap their large incomes off customers. Another commenter stated that protecting our parks also protects our health. Coal isn't "cheap" when you factor in asthma and other illnesses that result from coal plant emissions. Another commenter asked EPA to please ensure that we clean up dirty coal power plants, along with other air polluters.

Some commenters expressed a love of nature and wildlife. They stated that wildlife hinges on the protection of these waterways as habitat, and asked EPA to please respect and protect it from pollution. One commenter stated that they grew up visiting Devil's Den State Park every summer and any time the weather was warm. The commenter stated that they still visit the park in the Spring/Summer months, and that people value the parks in Arkansas.

One commenter stated that not only should strong action be taken to protect our parks, but to also protect our health and ecosystem. The Obama Administration should hold firm and make these

states greatly reduce their emissions. The Turk power plant should NEVER have been built and now Arkansas will justly pay the price. One commenter also stated that the Obama Administration should nationalize even more incentives to encourage folks to shift to solar panels or wind. States such as Arkansas that penalize and place obstacles to using solar should be prohibited from enacting those measures. Thank you for all the work you do and please hold firm to these measures.

One commenter stated that the haze represents filth that not only bothers our eyes, but affects plants and all wildlife. The health of humans is very much affected as seen by many diseases of heart, lungs, and immune system. Another commenter stated that more than the cynical cost-benefit analysis, it is vital to remember that everything we do to nature, we do to ourselves and the generations to come.

Another commenter stated that air pollution also limited their ability to enjoy state parks because, as never-smokers, they are extremely sensitive to particulates.

Many commenters asked EPA to do the right thing and Keep the environment safe and of good quality for the generations to come. Many commenters thanked EPA for working to protect their state of Arkansas. Commenters stated that they are grateful for EPA's efforts to make their parks more enjoyable.

Response: We appreciate the commenter's support of our FIP. We acknowledge these commenters for their support of our proposal.

We appreciate the commenters' concerns regarding the adverse health effects of the air pollutants that also contribute to visibility impairment and the resulting benefits of the air pollution controls we are requiring in our FIP. The emission limitations we are requiring in our FIP are intended to reduce visibility impairing pollutants and thereby improve visibility in Class I areas. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. We agree that our FIP may result in potential ancillary benefits to human health.

We also appreciate the comments regarding the negative impacts that visibility impairing emissions can have on ecosystems and wildlife. We agree that visibility impairing pollutants can have negative impacts on ecosystems and wildlife, and agree that our FIP may result in potential ancillary benefits to ecosystem health.

We also recognize that the reduction of regional haze and the preservation and protection of visibility in national parks and wilderness areas as a result of our FIP may potentially have a positive impact on tourism and the economy. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states.

With regard to the comment that Arkansas needs to invest in alternative energy and that the federal government should nationalize more incentives to encourage a shift to renewable energy forms, we note that such comments are outside the scope of this action and outside the scope of the regional haze program in general.

We take no position on any other specific statements made in the comment.

Comment: (0179) 38 members of the public stated they support the EPAs proposed rule. The commenters stated that they were particularly encouraged by EPA's proposal to crack down on emissions from the two large Entergy coal plants that cloud the skies in Missouri at the Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge. Missourians greatly enjoy the outdoors for family recreation, camping, hiking, and fishing. It is important that these federal lands be protected from air pollution and the commenters encourage EPA to finalize a strong rule that greatly reduces emissions from the coal plants in Arkansas.

One commenter stated that the coal plants in Arkansas also threaten the health in the 240 acre wilderness preserve Christian retreat he founded in the late 1970's, 18 miles southwest of Branson MO, 1 mile north of Arkansas, (where animal factory manure polluted the creeks out of Arkansas since the later 1990's, and antibiotic resistant bacteria/viruses in airborne blown dust from the scattered manure currently threaten additionally - see recent PBS Frontline reports: "The Trouble With Antibiotics" #11 and "Outbreak at National Institute of Health" both Nov. 18, 2014 and "Trouble With Chicken" #1 May 13, 2015).

One commenter stated that Mingo is an important bird stopover for waterfowl, as is nearby Otter Slough. These areas need to be protected as they are important bird areas.

One commenter asked EPA not to punish southwest Missouri for sending Billy Long to Congress. The commenter stated there are many people in this region who want to see saner energy policies than the ones currently exposed by their politicians.

Response: We appreciate the commenter's support of our FIP. We agree that the emission limitations in our FIP will result in large reductions in visibility impairing pollutants and will improve visibility in Arkansas' and Missouri's Class I areas. We take no position on any other specific statements made in the comment.

Comment: (0152) At the public hearing in Little Rock, Arkansas, many people expressed general support for the plan. The speakers at the public hearing included members of various organizations and members of the general public.

Response: We appreciate the commenter's support of our FIP. We acknowledge these commenters for their support of our proposal. We thank those who attended and participated at our public hearing.

Comment: (0177) A commenter expressed gratitude for EPA holding the information sessions and public hearings regarding EPA's proposal. The commenter noted that they will be unable to attend the public hearings and, thus, will be submitting comments electronically. The commenter noted they have read many of the acclaimed accounts (Hunter & Dunbar, Schoolcraft, and Nuttall) of early exploration of Arkansas and have been fascinated by the descriptions of the environment, flora, fauna, soil, rocks, minerals, and water. The commenter states that the rules promulgated in EPA's proposal will help protect the Buffalo National River, Ouachita National Forest, and Caney Creek Wilderness area, which are national and Arkansas treasures. Protecting these treasures will provide both economic and health benefits in the short term and, certainly, in the long term by enhancing tourism and combatting pollution that is hazardous to human health.

Response: We appreciate the commenter's support of our FIP. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health.

EPA also recognizes that the reduction of regional haze and the preservation and protection of visibility in national parks and wilderness areas is expected to have a positive impact on tourism and the economy throughout the state, as noted by the commenter. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states.

Comment: (0177) One commenter stated that they are in favor of the EPA's draft plan to reduce haze pollution in Arkansas. Arkansas's outdoor recreation opportunities in our natural areas, including our national parks and wildlife areas, are one of our greatest assets. Our outdoors are enjoyed by Arkansans and people from all across the country. The quality of these areas must be supported. The EPA's plan would reduce haze pollution and increase the visibility in these prized areas. Hikers, birders, photographers, and others would benefit from this change. It would allow Arkansas's great views to be seen by future generations. I favor the reduction of haze pollution for two reasons. First, my greatest hobbies involve the outdoors. I take two vacations every year. Both of these trips take me to the Buffalo River. I camp, hike, and canoe. I spend my money in Arkansas to spend time in Arkansas. I need my time in this area to be preserved. I hope to take my kids to these places. Second, I work for a conservation non-profit and teach environmental education programs focused on spending time outdoors. I've built a career around encouraging students and their families to responsibly spend time in the outdoors and enjoy activities like birding and hiking. I consider it a part of my job description to make sure natural areas are supported.

Response: We appreciate the commenter's support of our FIP. We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter stated that she is a resident of Little Rock, Arkansas, and is writing in support of the Regional Haze Plan. Requiring the White Bluff and Independence

power plants in our state to reduce pollutants by retrofitting their infrastructure will have fundamental impacts on our public health and protected natural areas, and could speed the transition to a clean energy economy.

My work in environmental justice communities has shown me the terrible effects of industrial pollutants on the poorest residents of our state, who are disproportionately people of color. The waste spewing out of power plants, which includes sulfur dioxide, nitrogen oxides and particulate matter, affects these disadvantaged communities the most, but wind patterns also ensure that these pollutants are carried across our state. Sometimes we even get air pollution from power plants in other states. The effects of this air pollution include difficulty in breathing, and the pollutants can cause or worsen respiratory illnesses such as asthma and bronchitis.

Air pollution also mars the experience of people visiting protected natural areas in our state. Arkansas is known as "the Natural State" and benefits tremendously from tourism around our incredible mountains, lakes, streams, and other scenic places. Many Arkansans, as well as out-of-state tourists, visit the areas that this plan would protect: the Buffalo National River, Ouachita National Forest and Caney Creek Wilderness Area. The plan would improve air quality and visibility in these places, generally having a positive impact on the experiences of their visitors. Some communities nearby these attractions rely on the economic boost of visitors enjoying nature near their towns. However, if air quality continues to decline, the influx of tourists to these areas could be compromised as well.

Finally, the Regional Haze rule could help move Arkansas in the right direction when it comes to our energy future. The retrofit technology that the power plants would have to install would be extremely expensive, which could lead to these dirty plants being shut down sooner. In putting more restrictions on dirty energy sources and potentially moving up the date of retirement for coal plants, the rule could push the state toward more clean, renewable sources such as wind and solar.

Response: We appreciate the commenter's support of our FIP. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health.

EPA also recognizes that the reduction of regional haze and the preservation and protection of visibility in national parks and wilderness areas is expected to have a positive impact on tourism and the economy throughout the state, as noted by the commenter. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states.

Under the Regional Haze regulations we are authorized to require affected sources to meet BART emission limits for visibility impairing pollutants (i.e., SO_2, NO_X, and PM), through the analysis of potential installation of various control technologies. The intent of the regional haze program is not to force affected sources to shut down. However, sources may choose to meet our

emission limits by voluntarily retiring or switching from coal to other fuel types since BART is an emissions limit rather than control requirements.

We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter expressed gratitude to the EPA administrators for holding this hearing on its Draft Regional Haze Plan for Arkansas. The commenter stated that she is a former Vice President of the National Audubon Society and Executive Director of Audubon Arkansas. I am also a member of the Sierra Club. I am here today to support the plan as proposed by the EPA which targets visibility in areas important to tourism in Arkansas; including the Buffalo National River, the crown jewel of our parks, the Caney Creek Wilderness Area and the Ouachita National Forest. Improving the air quality of our parks and wilderness areas can be accomplished by installing retrofit technology on two of Arkansas' largest and dirtiest coal fired plants, namely White Bluff and Independence. The visibility level in all our parks and recreation areas have been reduced by the 30 year unchecked pollution of these dirty, old coal plants. They must be retrofitted or shut down. The Plan, when implemented, will address toxic emissions that are harmful to humans' health. These plants have been operating without minimal safeguards for over three decades. It is time to act. Who has paid the price for the cheap energy provided by these plants? Children, the elderly and all those suffering from bronchitis, asthma and other respiratory illnesses, our local communities, families and hospitals have been footing the bill. It is high time to stop putting the cost of our "cheap energy" on the most vulnerable members of our society and on our environment, especially our irreplaceable national parks and wilderness areas. I support implementation of the Regional Haze plan because it will move Arkansas towards a cleaner and healthier future as the utilities embrace renewable and truly clean energy sources.

Response: We appreciate the commenter's support of our FIP. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health.

We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter stated that she is a supporter of CLEAN air. We need to make sure that industry is reined in and held responsible for pollution. Please make that happen for our "Natural State."

Response: We appreciate commenter's support of our FIP.

Comment: (0177) One commenter stated that he is a native and resident of Little Rock, AR. I'm writing to express my support for the Regional Haze and Interstate Visibility Transport Federal Implementation Plan. The Regional Haze plan will benefit our state's economy, health, and

natural environment. Reducing the amount of haze in the Buffalo River area will make the area more attractive to visitors and ultimately, boost tourism revenue. What's more, the Ozarks and Buffalo River are natural treasures of the Natural State. These areas should be preserved to benefit local residents, visitors, and future generations. In addition, the Regional Haze plan will prevent people in the region from being exposed to harmful pollutants. This plan will reduce the risk of asthma and other health concerns in the Ozarks and surrounding areas. Additionally, the plan will protect natural ecosystems in the region and reduce the effect of pollution on fragile plants, animals, and other living organisms.

Response: We appreciate the commenter's support of our FIP. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health.

We appreciate the comment regarding the negative ecosystem impacts of visibility impairing emissions. We agree that visibility impairing pollutants can have negative impacts on ecosystems. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits related to ecosystem health.

EPA also recognizes that the protection of visibility in national parks and wilderness areas is expected to have a positive impact on tourism and the economy, as noted by the commenter. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states.

We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter stated that she believes that Arkansas companies and agencies should be forced to clean up two of the largest and dirtiest coal-fired power plants: Entergy's White Bluff and Independence plants. The resistance to change our dirty energy policies is so entrenched that it will take a serious effort to slow down the current business as usual mode of operation. As a consumer I am ready to pay more for power. I realize that all Arkansans may not welcome an increase in energy costs but I do believe that all Arkansans want clean air and a healthy environment. Perhaps a way can be found to help out those poor people who cannot afford an increase in costs to pay for their power. Perhaps we should move to a state run energy system. Costs of clean-up of these coal plants can and should be borne by the companies who created the problem in the first place and who have made significant profit by pursuing their dirty coal policies. Climate change is, undeniably, a real threat for the world as we know it. While I am not a scientist, I do understand the implications of continuing to ignore the ominous signs that we are radically changing the climate of the Earth by continuing to use fossil fuels, and especially coal, for energy production. The costs of doing nothing about our reliance on fossil fuels will be staggering and a threat to the future of humanity. We need to act NOW, and not when these companies run out of coal! My husband and I frequently travel in the West and the haze in the national parks is unbelievable. California's central valley is unbelievably polluted with the air visible and shockingly a yellow-grey smog. It is astonishing to see. Pine

bark beetles have devastated the national forests. Alaska had its warmest winter ever. The ice caps are melting. Arkansas is part of the problem and needs to stop relying on fossil fuel for energy. What are we waiting for? I urge you to turn the page on energy policy by supporting clean and renewable forms of energy such as wind and solar. I urge you to close all of the coal fired plants in the country. Please, please do something about this serious issue.

Response: We appreciate commenter's support of our FIP. The purpose of the Regional Haze program is to protect and improve visibility in mandatory Class I Federal Areas. The air pollution control measures we are requiring in our FIP are intended to control emissions of visibility impairing pollutants (i.e., SO_2, NO_X, and PM) and intended to improve visibility conditions in Class I areas. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits related to reduction of greenhouse gases such as carbon dioxide and nitrous oxide that contribute to climate change.

Under the Regional Haze regulations we are authorized to require affected sources to meet emission limits for visibility impairing pollutants (i.e., SO_2, NO_X, and PM), but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to retire or to stop burning fossil fuels. We also are not authorized to require a shift to renewable forms of energy. However, sources may choose to meet our emission limits by voluntarily retiring or switching fuels.

We recognize that it is an unfortunate consequence that the requirement of controls to reduce emissions from power plants often results in electric companies passing on the costs of these controls to ratepayers in the form of increased electricity rates. We are not authorized to prevent companies from doing so. However, we are very sensitive to the ramifications of our actions and we seek to select the most cost-effective options when we propose and finalize these controls.

We appreciate the comment regarding the negative ecosystem impacts of visibility impairing emissions. We agree that visibility impairing pollutants can have negative impacts on ecosystems. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits related to ecosystem health.

We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter stated that she supports the use of EPA authority under the Clean Air Act to reduce carbon emissions and commends the Agency on drafting a plan to clean up haze and visibility problems in some of Arkansas's most treasured natural areas such as the Ozark National Forest, the Buffalo National River corridor and its associated, federally designated wilderness, the Ouachita, Caney Creek Wilderness and similar areas in Missouri. The best solution for our worst air polluting coal-fired power plants, is to retire them and implement clean, renewable and sustainable sources of energy. Arkansas can enjoy better health, robust economic growth and the beauty of our state and national parks and other natural environments.

I support EPA's Option 1 that will reduce emissions of both SO_2 and NO_X. This is the least we can do until all coal-fired power plants are retired. Until they are phased out, they should be required to retrofit with state of the art scrubbers to remove all air pollutants possible.

Reasons to support Option 1: Regional Haze pollution affects visibility in some of our most scenic Arkansas areas. Many Arkansans, as well as out-of-state tourists, visit the areas that the draft Regional Haze plan would protect: the Buffalo National River, Ouachita National Forest and Caney Creek Wilderness Area. The plan would improve air quality and visibility in these places, generally having a positive impact on the experiences of their visitors.

Our parks and wilderness areas boost the economies of the communities in which they're located, attracting tourists and elevating business. However, if air quality continues to decline, the influx of tourists to these areas could be compromised as well. The EPA's draft Regional Haze plan would require some of Arkansas's dirtiest power plants to install retrofit technology in order to reduce pollutants. The power plants affected include Arkansas's two largest and dirtiest coal-fired power plants, Entergy's 1700MW White Bluff and Independence plants.

Coal-fired power plants emit horrendous amounts of pollution that are hazardous to human health. These pollutants include sulfur dioxide, nitrogen oxides and particulate matter, which can lead to difficulty in breathing, and cause or worsen respiratory illnesses such as asthma and bronchitis. These health hazards are particularly dangerous to children, the elderly, and those who already have respiratory problems.

The draft Regional Haze plan could help move Arkansas in the right direction when it comes to our energy future. In putting more restrictions on dirty energy sources and potentially moving up the date of retirement for coal plants, the rule could push the state toward more clean, renewable sources such as wind and solar.

Response: We appreciate commenter's support of our FIP, including our proposed Option 1. For the reasons discussed elsewhere in this document, we are requiring SO_2 and NO_X controls for Independence in our final FIP. The air pollution control measures we are requiring in our FIP are intended to control emissions of visibility impairing pollutants (i.e., SO_2, NO_X, and PM) and improve visibility conditions in Class I areas Under the regional haze regulations, we are authorized to require affected sources to meet emission limits for visibility impairing pollutants (i.e., SO_2, NO_X, and PM), but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to retire or to stop burning fossil fuels. Under the regional haze program, we are also not authorized to implement or force a shift to renewable forms of energy. However, sources may choose to meet our emission limits by voluntarily retiring or switching fuels.

We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health.

EPA also recognizes that the protection of visibility in national parks and wilderness areas is expected to have a positive impact on tourism and the economy, as noted by the commenter. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states, but note that for purposes of this Regional Haze action.

We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter asked EPA to please pass all legislation needed to clean up Entergy's White Bluff and Independence coal plants. The residents of Arkansas are very proud of the quality of our waters and air. We have made great strides in keeping our state clean. Indeed, Little Rock was recently named the 2nd cleanest city in the United States. Please allow the concerned residents of this beautiful state to continue to praise the clean water, air and cities in our state by making Entergy do the right thing and clean up their dirty, polluting power plants that are harming our residents and our state reputation.

Response: We appreciate commenter's support of our FIP.

Comment: (0177) One commenter stated that she has lived in Swain in Newton County Arkansas for the past 40 years, and has increasingly seen the haze increase over this area to where it is very rare to see clearly from Highway Seven above Jasper. Tourism is extremely important to Newton's county's economy, and the increased haze caused by pollution from Arkansas dirty power plants is detrimental to those who come to experience the county's magnificent natural areas, and a health hazard for we who live in this scenic area. The draft Regional Haze plan under consideration could help move Arkansas energy future in the right direction. However, retrofitting the plants and allowing them to continue operation is not a sound solution. The plan needs to more restriction on solar and wind sources and potentially move up retirement dates for coal plants.

Response: We appreciate commenter's support of our FIP. We agree that reducing regional haze will help ensure that views in these parks and wilderness areas are preserved. Based on the context of the comment, it appears that the commenter intended to state that our plan needs to have more emphasis (rather than "more restriction") on solar and wind sources. Under the Regional Haze regulations, we are authorized to require affected sources to meet emission limits for visibility impairing pollutants, but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to retire. However, sources may choose to voluntarily retire or switch fuels to meet our emission limits. We take no position on any other specific statement made in the comment.

Comment: (0177) One commenter stated that she lives on the Little Buffalo River. Living here on the river I spend most of my time outdoors. She is in support of cleaner air for Arkansas and am hoping you will find enough support to implement a plan to help clean up the atmosphere.

There is nothing more disheartening to begin a beautiful sunny day outside and within a short time be driven inside by noxious odors whether they be from a hog concentrated animal feeding operation (cafo), a chicken house, smoke, coal dust, crop fumigation, etc. It has happened on many occasions and it is sad to think that Arkansas has the education and technology but as a state Arkansas does not use it. It is time to crack the whip, spend the money and make Arkansas stop polluting not only our own citizens' livelihood but all others who may visit or live in areas that the winds travel.

Response: We appreciate commenter's support of our FIP. We take no position on any other specific statements made in the comment.

Comment: (0177) One commenter stated that as a Republican, she stands for a strong America...the greatest nation on Earth. That is why the commenter is very concerned about pollution from coal powered plants in Arkansas. America is already falling behind so many other countries in the areas of literacy, socioeconomic status, security for families and yes, clean air and water. Even China, so massive and backward is moving toward clean power. It's a sad day when a Communist country is addressing its quality of life issues better than we do. The commenter urges EPA to support reduction of pollution from coal powered plants in Arkansas.

Response: We appreciate commenter's support of our FIP. We take no position on any other specific statement made in the comment.

Comment: (0177) One commenter expressed support for the EPA plan to clean up haze in the northwest Arkansas region of the state. The commenter stated that it is past time to clean up our power-generating plants and to switch from burning coal to other technologies that are not polluting and that are sustainable. We cannot continue to pollute our planet without paying the consequences. As a doctor I am concerned about the health consequences of air pollution. I am willing to pay more for energy but I do not think that this argument put forth by the coops is valid. We are paying much more than we realize by continuing to burn coal. The cost is only being measured in terms of producing energy. The energy coops are not including the costs to society of the pollution that is generated by it. These include the health costs, lost productivity, lost tourism revenues, global warming and the weather consequences, the costs of polluting the ground and rivers, etc. Change is difficult but it is inevitable. The coal-fired generating plant is a thing of the past, a relic of an age when we didn't know any better.

Response: We appreciate commenter's support of our FIP. We generally agree that the visibility impairing pollutants our FIP will control also have adverse health impacts and may negatively affect tourism revenue. As our FIP will reduce these emissions, we agree that our FIP may result in potential ancillary benefits to human health. We also agree that our FIP may result in potential ancillary benefits in terms of reducing emissions of greenhouse gases such as carbon dioxide and nitrous oxide.

While our FIP will control emissions from certain coal fired power plants in the state, the intent of our FIP (and the regional haze program in general) is not to force these power plants to cease

coal combustion. Under the Regional Haze regulations we are authorized to require affected sources to meet emission limits for visibility impairing pollutants, but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to cease coal combustion. However, sources may choose to voluntarily retire or switch from coal to other fuels to meet our emission limits. We take no position on any other specific statement made in the comment.

Comment: (0177) One commenter stated she supports bringing Arkansas into compliance. Living in Newton County, Arkansas I have some of the best of Arkansas' scenic and recreational lands easily available for personal use. The Buffalo National River, Koen National Forest, Arkansas Game and Fish and the Ozark National Forest properties surround the privately owned lands of all residents here. I was so excited to find property down on the creek and within 2 years of living here realized how troubling living on a creek can be. Winters can be cloudy and cold, then spring begins and a person is ready to enjoy the fresh spring breezes and feel warm sunshine. I didn't realize that living down in the valley smoke from prescribed burns would cloud the sky and the sun would be shrouded for weeks. The smoke would cause headaches and sore throats and I'd have to shut the windows & doors to try and escape when I was ready to be enjoying the spring and gardening. The black soot that coats the log house and windows some years is thicker than others.

In the year 2012, the Arkansas Department of Environmental Quality very quickly permitted a 6,500 hog factory on one of the largest tributaries to the Buffalo National River. ADEQ director, Teresa Marks, stated hog waste was expected to reach the Buffalo National River. The Buffalo National River has the highest protection in the state under the Clean Water, anti-degradation Act. Hog waste is spread by the millions of gallons from January – November each year. The smell, the haze, manure spreading and run-off of this operation is allowed with no consideration of the community, the Mt Judea School, its children, teachers, and visitors. The school is less than 1/2 air-mile from the hog factory, where the state expects students to concentrate in an environment it has permitted with no consideration. Last week while at the Carver recreation site on the Buffalo River the smell of hogs was strong and annoying. This is not caused by a feral hog running wildly thru the countryside, this is caused by thousands of hogs confined in 2 buildings with open pit lagoons and the constant evaporation of the waste into the air then drifting and settling outside of the hog factory. These are only 2 examples of the state's on-going haze issues. The smell and thickening of air from a hog factory and smoke engulfing the valleys when I wish to enjoy time on the creeks, my garden or outdoor recreation.

An old saying in Arkansas is “If you don't like the weather, wait a few minutes and it will change.” Weather here can go from 70 to 20 in a couple of hours. 20 degree changes are frequent and with that inversions trap air in the steep valleys and along the waterways.

The state of Arkansas has had ample time to comply with EPA rulings. The state continues to subject its residents to unhealthy environments and needs direction and enforcement. Help our state come into compliance and enforce positive goals instead of continuing to subject its residents to capitalistic enterprises which endanger and reduce the health environments of those that live within its borders.

Response: We appreciate commenter's support of our FIP. We take no position on any other specific statement made in the comment.

Comment: Multiple public hearing commenters (0152-5, 0152-7, 0152-8, 0152-12, 0152-13, 0152-16, 0152-17, 0152-18, 0152-19, 0152-20, 0152-21, 0152-22, 0152-23, 0152-24, 0152-25, 0152-27, 0152-29, 0152-31, 0152-40, 0152-43, 0152-44) noted that the visibility impairing pollutants that would be reduced by our FIP also have adverse health impacts and that our FIP would have potential ancillary health benefits.

Response: We appreciate the commenters' concerns regarding the adverse health effects of the air pollutants that also contribute to visibility impairment and the resulting benefits of the air pollution controls we are requiring in our FIP. The emission limitations we are requiring in our FIP are intended to reduce visibility impairing pollutants and thereby improve visibility in Class I areas. We generally agree that the same emissions that cause visibility impairment can also cause health related problems, including adverse effects on breathing, respiratory illness, alterations in pulmonary defenses, and aggravation of existing cardiovascular disease. We agree that our FIP may result in potential ancillary benefits to human health.

Comment: Multiple public hearing commenters (0152-2, 0152-7, 0152-9, 0152-12, 0152-16, 0152-22, 0152-32, 0152-43) who expressed general support for our FIP proposal noted that our FIP would require controls on the two largest coal plants in Arkansas, and some of these commenters also noted that these plants do not currently have air pollution controls. These commenters were in favor of controls on these two plants

Response: We appreciate the commenters' support of our FIP. We agree that our FIP will control SO_2 and NO_X emissions from the two largest point sources in Arkansas, the White Bluff and Independence Power Plants.

Comment: Multiple public hearing commenters (0152-8, 0152-9, 0152-12, 0152-16, 0152-19, 0152-25, 0152-30, 0152-37, 0152-38, 0152-40, 0152-41, 0152-42, 0152-43, 0152-45, 0152-46, 0152-47) noted that they enjoy the outdoors and enjoy spending time at Arkansas' Class I areas and are therefore in support of our FIP.

Response: We appreciate the commenters' support of our FIP.

Comment: Some public hearing commenters (0152-8, 0152-13) specifically expressed support for requiring controls on the Independence plant in our FIP.

Response: We appreciate the commenters' support of our FIP. In our FIP we are requiring both SO_2 and NO_X controls on the Independence plant.

Comment: Multiple public hearing commenters (0152-9, 0152-11, 0152-12, 0152-16, 0152-21, 0152-25, 0152-28, 0152-31, 0152-34, 0152-35, 0152-36, 0152-37, 0152-39, 0152-40) expressed general support for our FIP, but commented that we also need to move away from coal and towards clean, renewable energy. Some of these commenters also indicated that we should work towards retiring/shutting down coal plants.

Response: We appreciate the commenters' support of our FIP. Under the Regional Haze regulations, we are authorized to require affected sources to meet BART emission limits for visibility impairing pollutants (i.e., SO_2, NO_X, and PM), through the analysis of potential installation of various control technologies. The intent of the regional haze program is not to force affected sources to shut down, nor are we authorized to force them to shut down. However, sources may choose to meet our emission limits by voluntarily retiring or switching from coal to other fuel types, since BART is an emissions limit rather than control requirements. We also are not authorized under the CAA provisions for regional haze to require a shift to renewable forms of energy.

Comment: Some public hearing commenters (0152-12, 0152-24) noted that visibility impairing pollutants have adverse impacts on ecosystems and that our FIP would provide ancillary benefits in terms of reduced adverse impacts to ecosystems.

Response: We agree that visibility impairing pollutants can have negative impacts on ecosystems and wildlife, and agree that our FIP may result in potential ancillary benefits to ecosystem health.

Comment: Some public hearing commenters (0152-16, 0152-20, 0152-47) noted that by reducing visibility impairing pollutants and improving visibility in Arkansas' Class I areas, our FIP would have a positive effect on tourism and the economy.

Response: We agree that the reduction of regional haze and the preservation and protection of visibility in national parks and wilderness areas as a result of our FIP may potentially have a positive impact on tourism and the economy. We agree that our Class I areas and other national parks and wilderness areas are a source of jobs and contribute to the economies of their respective states.

Comment: Multiple public hearing commenters (0152-17, 0152-19, 0152-21, 0152-22, 0152-30) generally supported our FIP proposal, noting that the benefits of the controls would outweigh the visibility benefits and the ancillary benefits.

Response: We appreciate the commenters' support of our FIP.

Comment: One commenter asked how is it fair to require these coal plants to spend billions of dollars to make upgrades while China and other countries are not held to the same standards. If

the problem is truly as bad as EPA says, why are they given additional time to meet requirements? Americans are struggling as it is and a higher electric bill could mean no electricity for some people.

Response: We acknowledge the commenter's concerns. Consistent with the CAA, the regional haze program is concerned with remedying existing and preventing future impairment of visibility caused by manmade air pollution in mandatory Class I Federal areas (located in this country). Our action requires particular Arkansas sources to control emissions that impact visibility at Arkansas and Missouri Class I areas. Our action does not in any way expect Arkansas to make up for emissions from international sources. On the other hand, as we discussed in the preamble to the Regional Haze Rule, "the States should not consider the presence of emissions from foreign sources as a reason not to strive to ensure reasonable progress in reducing any visibility impairment caused by sources located within their jurisdiction."[1] While the goal of the regional haze program is to restore natural visibility conditions at Class I areas by 2064, the rule requires only that reasonable progress be made towards the goal during each planning period. In cases where it is not reasonable to meet the rate of progress needed to attain the goal by 2064, the Regional Haze Rule requires a state to demonstrate that this rate of progress is not reasonable, and that the state's selected rate of progress is reasonable for that planning period. While there is no indication at this time that emissions from international sources are anticipated to prevent Arkansas from attaining the goal of natural visibility conditions at its Class I areas, we recognize that in some cases it may not be possible to attain the goal by 2064 because of impacts from new or persistent international emissions sources or impacts from sources where reasonable controls are not available. However, states are still required to demonstrate that they are establishing a reasonable rate of progress that includes implementation of reasonable measures within the state to address visibility impairment in an effort to make progress towards the natural visibility goal during each planning period. We acknowledge the commenter's concern regarding potential increases in electricity rates. While our consideration of cost under the Regional Haze Rule is limited to the direct costs incurred by sources, consistent with the CAA's and Rule's source-specific focus, we are very sensitive to the ramifications of our actions and we seek to select the most cost-effective options when we propose and finalize these controls.

Comment: One public hearing commenter expressed concern for the high cost of the controls in our proposed FIP, noting that Arkansas' ratepayers would ultimately pay the cost in the form of electric rate increases. The commenter noted that the FIP is a visibility requirement, not a health-based requirement. The commenter also noted stated that the FIP is resulting from a lawsuit and expressed concern that there are some procedural issues in the lawsuit that have not been litigated.

Response: As noted in our response to the previous comment, we acknowledge the concern regarding potential increases in electricity rates. While our consideration of cost under the Regional Haze Rule is limited to the direct costs incurred by sources, consistent with the CAA's and Rule's source-specific focus, we are very sensitive to the ramifications of our actions and we seek to select the most cost-effective options when we propose and finalize these controls. We

[1] 64 FR 35755 (July 1, 1999).

agree that the regional haze program is concerned with visibility, and that it is not a health based requirement. With regard to the comment that our FIP is resulting from a lawsuit, we explain in greater detail elsewhere in this document that under the Clean Air Act requirements, under the Clean Air Act, we have an obligation to approve a SIP revision from the State and/or promulgate a FIP within two years of our partial disapproval of the SIP submitted by Arkansas in 2008 to remedy the disapproved portions of the SIP. Two years elapsed and EPA was sued for failing to either approve a SIP or issue a FIP to address the elements we disapproved on the submitted 2008 Arkansas regional haze SIP. With Arkansas as a party, a district court judge ordered EPA to either approve a revised SIP submittal from Arkansas or finalize a FIP for the elements we disapproved by August 31, 2016. It is unclear what procedural issues in the lawsuit the commenter is referring to, but we note that such comment is outside the scope of our proposed action.

Comment: Some public hearing commenters [0152-1, 0152-15] were against our FIP, and expressed concern over the high costs required to comply with the FIP. The commenters also noted that it is their understanding that the FIP underestimates the cost of controls and that it does not allow for costs during construction. One commenter noted that these costs are real world and will have to be passed on to ratepayers.

Response: We appreciate the comments. We note that the issues raised by the commenters are discussed in great detail in the section of this document where we discuss cost issues.

Comment: ADEQ agrees with EPA's determination that the Georgia Pacific Crossett Mill 6A and 9A Power Boilers are not subject-to-BART. [ADEQ (0144) p. 4] ADEQ stated that chapter III.A.1 of the Proposed FIP contains an analysis of whether BART controls will be required at the Georgia Pacific Crossett Mill 6A and 9A Power Boilers.[2] In the Arkansas Regional Haze Approval/Disapproval, EPA disagreed with ADEQ's assertion that the 6A Power Boiler was not BART-eligible and proposed to find that it is BART-eligible.[3]

In the Proposed FIP, EPA conducts a further analysis of these boilers and determines that, whether BART-eligible or not, neither boiler has visibility impacts sufficient to be considered subject-to-BART.[4] ADEQ concurs that neither of these boilers should be subject-to-BART.

Response: We appreciate ADEQ's support of our proposal. We are finalizing our determination that the Georgia Pacific Crossett Mill 6A and 9A Power Boilers are not subject-to-BART.

Comment: [Arkansas Audubon Society (0151) p. 1] The Arkansas Audubon Society stated that it is a statewide organization committed to fostering a greater knowledge of the natural history of Arkansas and promoting conservation of natural resources in Arkansas. We would like to voice our support of the EPA's proposed rule *Promulgation of Air Quality Implementation Plans; State*

[2] 80 FR 18944 at 18947.
[3] 77 FR 14604 at 14605.
[4] 80 FR 18944 at 18948.

of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan (Docket No. EPA-R06-OAR-2015-0189).

Arkansas is known as the Natural State, and as such, we take pride in the quality of our landscapes especially as it pertains to their ecological integrity and our ability as citizens to enjoy these areas. The aforementioned rule would enact regulations to protect the air quality of some of our most precious natural areas including the Buffalo National River, Caney Creek Wilderness, and Ouachita National Forest. We believe that Option 1, which includes the control of both SO_2 and NOx emissions, is the best way forward to reduce haze as well as potentially improve the health of Arkansans who live in the affected areas.

We applaud your move to enforce stricter regulations on emissions in order to reduce their negative impacts in our atmosphere. Thank you for considering our comments on this important matter.

Response: We appreciate the commenter's support regarding our FIP, including support of our proposed Option 1. For the reasons discussed in other sections of this document, we are finalizing both SO_2 and NO_X controls for Independence in our final FIP.

Comment: [Arkansas Public Policy Panel (0154) p. 1-2] The Arkansas Public Policy Panel (APPP) stated that it is a statewide organization dedicated to achieving social, economic and environmental justice by organizing citizen groups around the state, educating and supporting them to be more effective and powerful, and linking them with one another in coalition and networks. The Panel seeks to bring balance to the public policy process in Arkansas.

The APPP supports EPA's proposed Federal Implementation Plan and favors the proposed Option 1 over the proposed Option 2. The draft plan would assist in protecting two of Arkansas' treasured areas, the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The proposal to control SO_2, NO_X, and PM BART for nine units at six facilities in Arkansas will clean up haze problems in these unique areas and help uphold our state motto of "The Natural State."

These Wilderness Areas draw in many visitors both local and out-of-state who contribute significantly to Arkansas' economy. In 2012 tourism in Arkansas accounted for a $5.76 billion positive economic impact and employed 58,452 people.[5] The Buffalo River attracted 1,093,083 visitors who spend $43.78 million in communities surrounding the river.[6] Direct spending from visitors to the Buffalo employed 610 people in 2012.[7] Arkansans pride themselves on the quality of our natural resources and the great outdoors are entrenched in our culture. Preserving the

[5] Arkansas Department of Parks and Tourism Annual Report 2013. http://www.arkansas.com/!userfiles/editor/docs/apt---2013---annual---report.pdf
[6] 2012 National Park Visitor Spending Effects. National Park Service, U.S. Department of the Interior. Natural Resource Report NPS/NRSS/EQD/NRR---2014/765. http://www.nature.nps.gov/socialscience/docs/NPSVSE2012_final_nrss.pdf
[7] *Id.*

natural visibility and air quality of these areas is detrimental to protecting Arkansas' economy, culture and values.

The APPP supports a transition away from coal-fired power and does not find that retrofitting the plants and allowing them to continue operating is a sound solution, especially if those costs are passed on to the ratepayer. However, the draft Regional Haze plan does signal progress in Arkansas to push the state towards cleaner and healthier energy sources.

Response: We appreciate the commenter's general support of our FIP and the commenter's preference of our proposed Option 1. For the reasons discussed elsewhere in this document, we are finalizing both SO_2 and NO_X controls for Independence in our final FIP. Based on the context of the comments, it appears that the commenter intended to state that preserving the natural visibility and air quality of these areas is "important" or "vital" to protecting Arkansas' economy, culture, and values, not "detrimental." We recognize the positive impact that protecting visibility and air quality in national parks and wilderness areas is expected to have on the economy, culture, values, and tourism throughout the state. We agree with the commenter that reducing regional haze will help ensure that views in these parks and wilderness areas are preserved, and is expected to potentially have a positive impact on tourism and the economy.

Under the regional haze regulations we are authorized to require affected sources to meet BART emission limits for visibility impairing pollutants (i.e., SO_2, NO_X, and PM), but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to retire or to stop burning coal. However, sources may choose to voluntarily retire or switch fuels in order to comply with our emission limits. Additionally, we recognize that it is an unfortunate consequence that the requirement of controls to reduce emissions from power plants often results in electric companies passing on the costs of these controls to ratepayers in the form of increased electricity rates. However, we do not have the authority to prevent companies from doing this.

We take no position on any other specific statements made in the comment.

Comment: [Entergy Arkansas Inc. (0166) p. 56] Entergy stated it agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NO_X, and PM. 80 Fed. Reg. at 18,975. Entergy also agrees that 2009-2011 should be used as the baseline period for NO_X for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

Response: We appreciate the commenter's support of our proposal.

Comment: [Entergy Arkansas Inc. (0166) p.56] Entergy Arkansas Inc. stated it agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993. Entergy also agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

Response: We appreciate the commenter's support of our proposal.

Comment: [Entergy Arkansas Inc. (0166) p.56] Entergy Arkansas Inc. stated that if EPA finalizes a source-specific NO_X BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NO_X CEMS with a continuous NO_X analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NO_X analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NO_X correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

Response: We are finalizing the NO_X BART limit we proposed for Lake Catherine Unit 4. After carefully considering this comment, we have determined that it is appropriate to allow the unit to continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit under the Part 75 regulations. As such, the unit may continue to utilize a NO_X correlation curve to estimate NO_X emissions and only monitor heat input and exhaust O_2 concentration. We are revising our proposed section 52.173(c) to reflect this.

Comment: [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 1-2] Nucor stated that it operates electric arc furnace steel mills in Mississippi County, Arkansas, which produce steel products from recycled scrap metal. As a result of mills such as NSA and NYS, Nucor Corporation is one of the largest recyclers in the nation. The cost of electric power is a significant component of the cost of producing steel in an electric arc furnace and the costs of the control technologies required under the Proposed FIP will injure NSA and NYS by increasing the cost of electric power needed to operate their facilities.

NSA and NYS both receive electrical service from Mississippi County Electric Cooperative Corporation ("MCECC"), which is a member co-operative of Arkansas Electric Cooperative Corporation ("AECC"). AECC is either an owner or co-owner of four facilities that are subject to Best Available Retrofit Technology (BART) determinations under EPA's Proposed FIP: Entergy's White Bluff power plant (White Bluff), SWEPCO's Flint Creek power plant (Flint Creek), AECC's Bailey power plant (Bailey), and AECC's McClellan power plant (McClellan). AECC also is a co-owner of Entergy's Independence power plant ("Independence"), for which EPA is proposing additional emission limits and controls under the Proposed FIP. These five facilities provide a large majority of the baseload generating capacity for AECC and its member cooperatives. NSA and NYS's electric power primarily comes from AECC's electric generating resources, and NSA and NYS's electricity costs are dependent on AECC's costs of maintaining and operating those generating resources, including AECC's interest in White Bluff, Independence, and Flint Creek.

Response: We acknowledge the background information provided by the commenter. We address specific comments made by the commenter elsewhere in this document.

Comment: [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 6-9] Nucor stated that Congress first adopted regional haze provisions in 1977 to establish a national goal that would address haze issues in national parks and other federal "Class I areas" by adding Section 169A to the Clean Air Act. See, 42 U.S.C. § 7491. EPA has established three primary components for a state's regional haze SIP: (1) reasonable progress goals for Class I areas in the state; (2) a long-term strategy; and (3) implementation of BART for certain stationary sources. The Clean Air Act requires states to submit SIPs that contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." 42 U.S.C. § 7491(b)(2). The reasonable progress goal "is a goal and not a mandatory standard which must be achieved by a particular date." 64 Fed. Reg. 35,714, 35,733 (July 1, 1999). Further, States have considerable discretion in establishing reasonable progress goals; for instance, the Clean Air Act "requires only that a state establish reasonable progress, not the most reasonable progress." North Dakota v. EPA, 730 F.3d 750, 768 (8th Cir. 2013).

States are required to consider four statutory factors when establishing reasonable progress goals that are "necessary" for Class I areas. 42 U.S.C. §7491(g)(1); 40 C.F.R. § 51.308(d)(1)(i)(A). These factors are: (1) costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. 42 U.S.C. § 7491(g)(1). Furthermore, reasonable progress goals are "interim goals that represent incremental visibility improvement over time." See, USEPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 1, 2007, section 1.2, p. 1-2. The "first planning period" for the Arkansas Regional Haze Rule SIP extends from 2008 to 2018.

To comply with the BART requirements, states must develop "emission limitations representing BART" for a specified set of sources. 42 U.S.C. §7491(b)(2)(A); 40 C.F.R. § 51.308(e). BART determinations must consider five statutory factors: (1) the costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. 42 U.S.C. § 7491(g)(2); *see* 40 C.F.R. §51.308(e)(1)(ii)(A).

Congress enacted the Clean Air Act's regional haze provisions with a long-term goal of returning national parks and certain scenic areas to a state of natural visibility. However, Congress realized such changes could not be fully realized immediately and adopted an approach by which States would make incremental improvements over time. In fact, EPA has approved much longer reasonable progress goals for Class I areas in the State of California. For example, EPA approved almost 300 years for the Desolation Wilderness and Mohalume Wilderness, which must achieve compliance by 2307. 76 Fed.Reg. 34,608 (June 14, 2011); 76 Fed.Reg. 13,951(March 15, 2011). Yet, EPA is attempting in its Proposed FIP to force Arkansas to achieve compliance even earlier than the national goal of 2064.

Despite the fact that real-world, measured air quality demonstrates that Arkansas is on track to meet the visibility improvements contemplated by the Regional Haze Rule,[8] EPA has unreasonably proposed to supplant the State's authority and impose a FIP that would place additional emission control requirements on a handful of sources at significant cost notwithstanding expected further emissions reductions from levels that have achieved the desired target today. Furthermore, EPA has failed to explain how these costly emissions are reasonably certain to achieve actual visibility improvements, as required by the CAA.

Response: We acknowledge the background information provided by the commenter. We take no position on the commenter's synopsis of the visibility program.

To the extent the commenter is alleging that our proposed FIP is inappropriate or unnecessary because Arkansas Class I areas are already projected to be below the URP glidepath, we address such comments elsewhere in this document. We address elsewhere in this document comments contending that our proposed FIP is inconsistent with our approval of the RPGs for other states that are not expected to reach natural visibility conditions until after 2064. We address elsewhere in this document comments contending that ADEQ's Five-Year Progress SIP revision shows that IMPROVE monitor data indicate that Arkansas is on track to meet the state established RPGs for 2018. We address elsewhere in this document comments alleging that we are supplanting the State's authority in promulgating our FIP. We also address elsewhere in this document comments alleging that due to the uncertainty in the CALPUFF model our proposed controls are not expected to achieve actual visibility improvement.

Comment: [Entergy Mississippi Inc. (0168), p. 2] EMI stated that on April 8, 2015, the EPA proposed a FIP for the State of Arkansas for Regional Haze and Interstate Visibility Transport (the "Proposed Rule").[9] Specifically, the Proposed Rule addresses the previously disapproved elements of the Arkansas State Implementation Plan for Regional Haze, including certain BART determinations, RPGs, and long-term strategy ("LTS") necessary to achieve established RPGs, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I federal areas in Arkansas and nearby states. Among other things, the Proposed Rule includes emission limitations based on installation of BART controls for sulfur SO_2 and NO_X at the Entergy White Bluff Plant ("White Bluff") and two proposed alternative options for controlling emissions from the Entergy Independence Plant ("Independence Plant") under the regional haze reasonable progress requirements.

EMI is a corporation organized under the laws of the State of Mississippi and provides electric service in Mississippi. EMI is an electric public utility under the Mississippi Public Utilities Act of 1956, as amended. EMI provides retail electric service in portions of 45 counties in western Mississippi pursuant to certificates of public convenience and necessity issued by the Mississippi Public Service Commission ("MPSC") in Docket U-44 and other Dockets. EMI serves approximately 450,000 retail electric customers in those 45 counties. EMI also provides wholesale partial requirements service to the Municipal Energy Agency of Mississippi, which is

[8] See Arkansas Department of Environmental Quality, "State Implementation Plan Review for the Five-Year Regional Haze Progress Report;" Revised May 2015, pp. 43, 64, attached to Nucor's comments as Exhibit 3.
[9] See 80 Fed. Reg. 18,944 (Apr. 8, 2015).

a state-chartered organization that provides the requirements service to six (6) municipal electric utilities in western Mississippi. EMI acquired a 25% undivided ownership interest in 1981 in each of the two generating units at the Independence Plant, pursuant to, among other things, the approval of the MPSC in Docket U-4873. The Independence Plant provides a significant portion of EMI's baseload generating capacity. As a co-owner of a significant portion of the Independence Plant, EMI has a strong interest in ensuring the proper implementation of the regional haze and interstate visibility requirements of the Clean Air Act for the protection of its customers.

Response: We acknowledge the background information provided by the commenter.

Comment: [Domtar (0161) p. 14] Domtar stated that the preamble of our proposed FIP makes reference to the operations of the Mill's caustic solution system and a set point in the Mill's operational controls for the caustic addition. For clarification purposes, the set point of 0.86 lb/MMBTU for Power Boiler No. 2 is a Mill operating parameter and not an operating requirement.

Response: We acknowledge and appreciate the clarification provided by the commenter regarding background information discussed in our proposal regarding operation of the existing scrubbers on Power Boiler No. 2. We do note that the clarification provided by Domtar does not affect our final BART decision regarding SO_2 BART for Power Boiler No. 2.

Comment: [Edison Electric Institute (0174) p. 9-10] EEI stated that as EPA and states begin to implement the next round of the regional haze program to address reasonable progress requirements in pursuit of the 2064 goal, the Agency should allow states to consider how best to assess and plan additional controls activities, consistent with effective long-term utility planning, and take into consideration the progress made by the electric power and other sectors in improving visibility through the installation of controls to satisfy BART and other regulatory programs.

EEI also stated that it urges EPA to consider the technical comments of both Entergy and Southwestern Electric Power Company regarding unit-specific and other technical and legal concerns.

Response: We acknowledge the commenter's concerns and suggestions with regard to our and the states' work on the regional haze SIPs for future planning periods. However, these types of comments are outside the scope of this rulemaking.

We acknowledge EEI's support of the comments submitted by both Entergy and the Southwestern Electric Power Company (AEP-SWEPCO). Our responses to Entergy's and AEP-SWEPCO's specific comments are provided throughout this document.

Comment: [Entergy Arkansas Inc. (0166) p.1] Entergy Arkansas Inc. stated that on April 8, 2015, the EPA published a proposed Federal Implementation Plan (FIP) to address certain regional haze and visibility transport requirements for the State of Arkansas (80 FR 18944). The proposed FIP would address the requirements of the Regional Haze rule and interstate visibility transport for those portions of Arkansas' SIP that EPA had previously disapproved (77 FR 14604, March 12, 2012). The proposed FIP addresses the requirements for BART for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals, reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states. Entergy Arkansas Inc. owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing SO_2 and NO_X BART limits for White Bluff Units 1 and 2, and SO_2, NO_X, and PM BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NO_X BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NO_X emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

Response: We take no position on Entergy's synopsis of our FIP proposal. We acknowledge that Entergy Arkansas Inc. owns and operates three of the facilities for which we proposed emission limits to meet the Regional Haze Rule requirements in Arkansas.

Comment: [Entergy Arkansas Inc. (0166) p. 1-2] Entergy Arkansas Inc. stated that the Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the CAA as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on Entergy Arkansas Inc.'s customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Response: We disagree with Entergy Arkansas Inc.'s statement that our proposed FIP is inconsistent with the goal of the Regional Haze Program, that it ignores the significant improvements in visibility in Arkansas' Class I areas, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose controls that exceed more than $2 billion in cost without the need for or anticipated benefit from such

controls. These comments are addressed in detail elsewhere in this RTC document. Further, we take no position as to Entergy's characterization of the Regional Haze Program in the comment.

Comment: [Entergy Arkansas Inc. (0166) p. 2-4] Entergy Arkansas Inc. states that it proposes an approach that is more reasonable than EPA's proposed FIP, and is a long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. Entergy provides a summary of its proposed approach, as well as a summary of its comments on EPA's proposed FIP. Entergy states its proposed approach involves the following: (1) achieving early SO_2 reductions by accepting lower interim SO_2 emission rate limitations at both White Bluff and Independence; (2) achieving NOx reductions by installing NOx control technology on all four units within three years of the effective date of EPA's final FIP; and (3) committing to the permanent cessation of coal-fired operations at White Bluff by 2028.

Entergy also provides a summary of its comments, stating that under EPA's current schedule for finalizing the FIP, EPA would require the installation of scrubbers on the four units at White Bluff and Independence by 2021, which would result in a six to seven year amortization period for Entergy Arkansas Inc., which would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Based on modeling conducted by Entergy, which EPA should have conducted but failed to undertake, the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small and does not warrant an investment of over $2 billion in scrubber technology at the plants.

EPA's proposal to require SO_2 and NO_X limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first regional haze planning period because Independence is not a BART-eligible source, and EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. §7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[10] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[11] According to modeling performed by the Central Regional Air Planning Association (CENRAP), all of Arkansas' elevated point sources (including all power plants and large industrial sources)

[10] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[11] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[12] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

Entergy states that EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost-effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine RPGs. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EIA's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

[12] In spite of the Supreme Court decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units ("EGUs"), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, Entergy expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Response: We acknowledge Entergy's summary of its proposed approach and summary of its comments. Entergy's specific comments on its proposed approach and on each of the issues mentioned in its summary and our responses to those comments are provided in other sections of this document.

Comment: [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 3-5] Nucor Steel-Arkansas (NYS) and Nucor-Yamato Steel Company (NSA) stated they disagree with and object to EPA's Proposed FIP. EPA's Proposed FIP does not comply with the requirements of the Clean Air Act ("CAA") because, among other things:

(a) EPA has not demonstrated that its BART determinations for White Bluff and Flint Creek and its Reasonable Progress decision for Independence are necessary,
(b) EPA failed to consider relevant factors in its BART and Reasonable Progress determinations for White Bluff, Flint Creek and Independence,
(c) EPA failed to consider all available control technologies in its BART and Reasonable Progress determinations for White Bluff, Flint Creek and Independence,
(d) EPA's determinations on cost-effectiveness of additional controls for White Bluff, Flint Creek and Independence are not justified, are unreasonable, are inconsistent and are arbitrary and capricious,
(e) EPA's determinations of visibility impacts from White Bluff, Flint Creek, Independence and the other facilities involved in EPA's Proposed FIP are unreasonable and do not support its BART and RP determinations, because the CALPUFF model is unsuitable for EPA's regulatory determinations under these circumstances (thus, EPA has not demonstrated that there is a reasonable certainty that the controls required under its BART and Reasonable Progress determinations will result in an improvement in visibility,
(f) EPA has unduly relied on its cost-effectiveness calculations and has not explained how its cost-effectiveness calculations justify its BART and Reasonable Progress determinations with respect to anticipated visibility improvements; and
(g) EPA has not demonstrated that any of the sources regulated in the Proposed FIP interfere with control measures in any other state's SIP, especially given the overestimation of the CALPUFF modeling results and whether there will be any reasonably certain visibility improvement from EPA's proposed control measures (thus EPA has not demonstrated that these measures are necessary in order to comply with 42 U.S.C. §7410(a)(2)(D)(i)(II)).

In addition, EPA did not explain how it exercised its judgment and balanced and weighed the BART and Reasonable Progress factors in arriving at its BART and Reasonable Progress determinations.

Also, EPA has failed to fully respond to Nucor's Freedom of Information Act (FOIA) requests and has failed to grant Nucor's request to extend the time for comments on the proposed FIP until after EPA has fully complied with those requests.[13] Presumably, the responses to those FOIA requests would be relevant to an explanation of how EPA exercised its judgment in weighing and balancing the BART and Reasonable Progress factors.[14] Finally, under the clear terms of the Clean Air Act, EPA does not have the authority to initiate this rule-making and issue its proposed FIP, because more than two years have passed since EPA disapproved Arkansas's regional haze SIP.

Response: This comment lists a number of issues that are raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments in other sections throughout this document.

We disagree with the comment that the responses to Nucor's FOIA request would be relevant to EPA's exercise of judgement in this rulemaking. The basis for our final action, including our weighing and balancing of the relevant factors, is contained in the record for this rulemaking which is available at regulations.gov. Please see our responses in the legal section regarding EPA's authority to promulgate a FIP more than two years since EPA disapproved Arkansas's regional haze SIP.

Comment: [Entergy Mississippi Inc. (0168) p. 3] EMI stated that Section 169A of the Clean Air Act ("CAA") establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I federal areas. In 1999, EPA promulgated the Regional Haze Rule ("RHR")[15] to address regional haze impairment and establish a comprehensive visibility protection program for Class I areas, which calls for the elimination of man-made visibility impairment at Class 1 federal areas by 2064. The regional haze program was designed this way in recognition of the fact that future advancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost-effective control measures to assure reasonable progress towards the goal of elimination of visibility impairment at Class I areas, and thereby reduce the economic burden of presently installing expensive

[13] See, Nucor FOIA request dated, March 13, 2015; letter response from L. Lane at EPA dated May 19, 2015, and Nucor's counsel's letter to EPA dated July 10, 2015, attached hereto as Exhibits 1A, 1B and 1C, respectively. Nucor reserves the right to submit additional comments in this docket after EPA has fully complied with Nucor's FOIA requests.

[14] In a document dated Feb. 11, 2015 at p. 20 (attached as Exhibit 2), EPA discussed an option for the Reasonable Progress Analysis for SO_2 and NO_X controls at Independence as "No Additional Controls" since the CENRAP modeling showed that all Arkansas areas were on or below the glide path; however, this option was not included in the Federal Register notice and no explanation based on the statutory factors was given why this option was discarded.

[15] 64 Fed. Reg. 35,714 (July 1, 1999), codified at 40 C.F.R. part 51, subpart P.

control measures to meet a purely aesthetic standard.[16] The structure of EPA's rule is designed to require States, through the state implementation plan ("SIP") process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

Despite the long-term nature of Congress' design of the regional haze program and the fact that Arkansas is well ahead of the EPA-approved Uniform Rate of Progress ("URP" or "glide path") for elimination of visibility impairment at its Class 1 areas (and is predicted to remain so for at least a decade to come), the Proposed Rule would mandate emission limitations based on installation of unnecessary and uneconomic controls. Indeed, the Proposed Rule fails to accurately account for the costs of the unnecessary and unjustified controls to the electricity consumers. The cumulative effect of the legal and factual errors is to impose hundreds of millions of dollars of unnecessary expense on Arkansas' utilities, their co-owners, and their customers, including the retail electric customers of EMI.

Although not an Arkansas utility provider, EMI is a co-owner of a significant portion of the Independence Plant and, as such, has particularized concerns about the Proposed Rule's legal and factual errors as they relate to the reasonable progress analysis and determinations in the Proposed Rule. Many of the errors and inaccuracies in the reasonable progress determinations stem from EPA's artificially low assumptions regarding the costs of controls for the White Bluff Plant. Furthermore, the totality of the Proposed Rule fails to account for Entergy's alternative proposal that would yield equivalent visibility improvements at tremendously less cost (over $2 billion). Accordingly, EPA's final rule should reject the proposed reasonable progress determinations for the Independence Plant and instead address Entergy's proposed alternative approach for both the Independence and White Bluff Plants.

Response: The EPA acknowledges the background information provided by the commenter. We take no position with respect to the commenter's synopsis. This comment touches on a number of issues that are raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments.

Comment: Summary of ADEQ's comments. [ADEQ (0144), cover letter and p. 1-2] ADEQ stated that in 1977, Congress amended the Clean Air Act ("CAA") to include the national goal of preventing any future and remedying any existing impairment of visibility at mandatory Class I Federal areas ("Class I areas"). EPA promulgated the Regional Haze Rule in July 1999 to further this national goal and established regulations to eliminate man-made visibility impairment in those areas by 2064. Nationally, there are 156 Class I areas. There are two Class I areas in Arkansas: Upper Buffalo and Caney Creek Wilderness areas.

The Regional Haze Rule and related regulations contain provisions that encourage state, local, and tribal agencies to work cooperatively within regional planning organizations to address visibility impairment. In accordance with the regional haze program requirements outlined in 40 C.F.R. § 51.308, the Arkansas Department of Environmental Quality ("ADEQ") submitted the Arkansas Regional Haze State Implementation Plan ("Regional Haze SIP") to EPA on

[16] *Id.* at 35,714, 35,752.

September 23, 2008. On March 12, 2012, EPA partially approved and partially disapproved the Regional Haze SIP ("the Arkansas Regional Haze Approval/Disapproval").[17]

ADEQ submitted on June 2, 2015, the Five-year Regional Haze Progress Report, which is intended to fulfill the requirement in 40 C.F.R. § 51.308(g) that Arkansas provide periodic reports to EPA evaluating progress towards the Reasonable Progress Goals ("RPGs"). On April 8, 2015, EPA promulgated the Proposed FIP for Arkansas.[18] On May 1, 2015, EPA extended the public comment period for the Proposed FIP until July 15, 2015.[19]

ADEQ stated that Arkansas prides itself on being the Natural State and its ongoing efforts to maintain excellent air quality. The EPA published on April 8, 2015, a proposed Federal Implementation Plan covering Regional Haze and Interstate Visibility Transport for the State of Arkansas ("Proposed FIP"). The Arkansas Department of Environmental Quality (ADEQ) has reviewed the Proposed FIP and has determined that it contains significant flaws and does not accurately reflect the real progress the State has made to fulfill the requirements of the Clean Air Act pertaining to Regional Haze and Visibility. EPA failed to use the proper methodology used in portions of the Proposed FIP. Moreover, the Proposed FIP is lacking in its legal precedence and its analysis appears to be incomplete or lacking in clarity. Furthermore, EPA acted arbitrarily in developing a proposal which is inconsistent with the approach taken in other states.

As a primary example of the Proposed FIP's infirmity, the Entergy Independence Plant is not currently identified as being subject to Best Available Retrofit Technology (BART). Despite this fact, EPA improperly performed its own reasonable progress analysis. EPA indicated this was performed by applying the reasonable progress factors set forth in the Regional Haze Rule to require specific emissions controls for Entergy Independence Units One and Two. This type of improper and unlawful analysis has no basis in the Regional Haze Rule or other relevant law. Moreover, EPA's proposed additional control measures for the Entergy Independence Plant are both unnecessary and arbitrary. The State of Arkansas has demonstrated that it is on track to meet the uniform rate of progress in its Five-Year Regional Haze Progress Report for the first planning period, which ends in 2018. EPA singled out the Entergy Independence Plant through a cursory evaluation of the National Emissions Inventory data, not a reasoned evaluation utilizing the established framework that takes into account, among other factors, the costs of compliance and progress made to date.

Under the Proposed FIP, certain entities that are already complying with portions of the Clean Air Act aimed at reducing interstate transport of air pollution under the Cross-State Air Pollution Rule (CSAPR) would also have to install additional emissions controls to achieve the same goal. This is the case despite EPA's own assertions that CSAPR is more effective in reducing particular emissions during ozone season. Based on EPA's statements that CSAPR provides for greater reasonable progress than source-specific NO_X controls, EPA should determine that

[17] Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze, 77 FR 14604.

[18] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, 80 FR 18944.

[19] Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Extension of Comment Period and Notice of Availability, 80 FR 24872.

facilities included in the Proposed FIP which are already subject to requirements under the CSAPR FIP satisfy BART for NO_X and therefore should not be required to install additional controls.

Additionally, ADEQ finds that EPA's Proposed FIP is inconsistent with the approaches proposed in other states. For example, in developing the Proposed FIP, EPA used a simpler modeling method ignoring crucial factors that would provide a more representative accounting of the emissions in Arkansas. In support of this simpler method, EPA cites to its use in developing reasonable progress goals for Hawaii and Arizona. EPA's decision to utilize this simpler method is not supported in the Proposed FIP. EPA used the CAMx photochemical model in its analysis to develop RPGs for the Texas-Oklahoma FIP. For Arkansas, EPA chose a method of determining RPGs that is admittedly inferior and less sophisticated than the CAMx approach. EPA's inconsistency in methodology is not fully explained and represents arbitrary decision-making that leads to unjustified disparities in treatment among the states.

Furthermore, EPA's metrics used throughout the Proposed FIP are misleading and not supported on a legal or technical basis. For instance, the cumulative visibility effects metric lacks a sound scientific basis and is not supported in the Regional Haze Rule or EPA guidelines. The metric combines slight incremental increases from different locations that do not reflect actual visibility improvement in any single location differently. Ultimately, the metric provides no meaningful information on progress toward meeting visibility goals.

Perhaps most troubling, EPA failed to appropriately assess the costs of the overall impact of the Proposed FIP. Recent concerns have been raised by the United States Supreme Court in the case of *Michigan v. EPA* regarding the rationality of imposing billions of dollars in economic costs in return for a few dollars in health or environmental benefits. Accordingly, EPA should have performed an analysis to properly determine the extent of the impacts of the Proposed FIP in the State of Arkansas.

Finally, it is arbitrary and capricious for EPA to force an emissions source to invest millions, much less billions, of dollars for new technology that will have no appreciable effect on the haze in any Class I Federal area (Class I area). In a recent decision that is further discussed in the attached comments, the United States Court of Appeals for the Ninth Circuit recently issued a decision that called into question the use and reliability of the CALPUFF visibility model as a means of identifying affected facilities when those facilities are more than 200 kilometers from a Class I area and the simulated visibility improvements are both within the margin of error of the model and imperceptible. The Clean Air Act does not require an improvement that cannot be reasonably anticipated.

Response: We acknowledge the background information provided by the State of Arkansas. We take no position with respect to the ADEQ's synopsis of the issues such as the proposed FIP. This comment summarizes the issues raised by the state in its comments. These comments and our responses are found in other sections throughout this document. Please see our responses to those more specific comments.

Comment: [ADEQ (0144) p. 30] ADEQ stated that EPA's Proposed FIP is not a viable option for implementation of the Regional Haze program in Arkansas. The Proposed FIP contains misleading cumulative visibility metrics. EPA arbitrarily requires sources that are subject to the CSAPR Rule to also control NOx emissions as BART. EPA improperly performed the reasonable progress analysis required by the Regional Haze Rule, which resulted in requiring unneeded emissions controls for the Entergy Independence Plant. EPA also chose to forego CAMx photochemical modelling such as that used in Texas in favor of a less accurate algorithm that resulted in inferior RPGs. In addition, EPA has not complied with E.O 12866 and E.O. 13211.

EPA should withdraw the Proposed FIP, and any subsequent plan should address the issues presented in this letter. While ADEQ will continue to work to develop an acceptable SIP for approval by EPA, the harsh deadline of December 15, 2015 proposed in a recently proposed consent decree between EPA and Sierra Club may stifle those efforts. Nonetheless, ADEQ will diligently continue to work towards the resolution of all of the issues raised during the public comment period.

Response: We acknowledge ADEQ's concerns related to our proposed FIP and to our deadline for finalizing the FIP. We do note that EPA did not ask the court to enter the consent decree containing the proposed December 15, 2015 deadline for a final action. Following litigation over the appropriate date for final action on the Arkansas regional haze plan, litigation in which Arkansas participated, the court entered an order establishing a date for final action. We are accordingly subject to a court-ordered deadline to take final action to promulgate a FIP or approve a SIP revision that addresses the deficiencies in the Arkansas RH SIP by August 31, 2016.[20] Although we have not yet seen a revised SIP revision from Arkansas, should the State decide to submit such a plan, we will work expeditiously to review the plan.

This comment touches on issues raised by the ADEQ in more detail elsewhere. Please see our responses to those more specific comments in other sections throughout this document.

Comment: [Domtar (0161) p. 1-2] Domtar stated that it appreciates the opportunity to provide written comments on the EPA's FIP proposal to address certain regional haze and visibility transport requirements for the State of Arkansas. The proposal was published in the April 8, 2015 Federal Register. Domtar stated that the nature of its comments focuses on the proposed BART determinations for the Ashdown Mill Power Boiler 1 and Power Boiler 2. The first section addresses concerns associated with the lack of a statutory basis for imposing BART on the Ashdown Mill, as the purported visibility improvements asserted by the Agency are so insignificant as to fall within the CALPUFF model's Ashdown Mill specific margin of error. As such the purported visibility improvement cannot be reasonably anticipated. *See* 42 U.S.C. § 7491(g)(2); *Nat'l Parks Conservation Ass'n v. EPA*, No. 12-73710, 2015 WL 3559148 (June 9, 2015). (The supporting report and analysis will be submitted during the reopened comment period.) Without waiving the significant legal issues with the BART proposal, the second section of the comments focuses on specific issues and concerns with the proposed BART requirements for the Ashdown Mill. Domtar's comments conclude with a recommendation that the proposed

[20] Sierra Club v. Gina McCarthy, No. 4.14CV00643JLH (ED Ark. Western Div. Nov. 3, 2015).

BART requirements for the Mill not proceed or, alternatively, the Agency defer any action on BART for 5 years until the Mill completes its repurposing project. Based on the actions taken with respect to Power Boilers 1 and 2, BART may be mooted. EPA could review the Mill's status after the full conversion is complete and operational in 5 years at which time it is highly unlikely any BART related action will be necessary.

The Ashdown Mill is part of Domtar Corporation (Domtar). Domtar is a designer, manufacturer, marketer and distributer of a wide variety of wood fiber-based products including communication papers, specialty and packaging papers and absorbent hygiene products. The foundation of Domtar's business is a network of fiber converting assets that produce paper grade, fluff and specialty pulps. While most of our pulp production is consumed internally to manufacture paper and consumer products, we are also one of the United States' largest volume exporters. Domtar is the largest integrated marketer of uncoated freesheet paper in North America. Domtar operates pulp and paper Mills and personal care facilities in the US, Canada, Spain and Sweden. In the US we operate in the following states: Arkansas, Kentucky, Georgia, Michigan, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas and Wisconsin.

The Ashdown Mill operates in very dynamic, changing and competitive global markets. The global marketplace is very competitive, and as such, managing costs is a key component, especially in a business where the ability to pass through costs to customers is limited. Our products are sold on the basis of cost, quality and service. We continue to see increased competition from "lower" cost imports, with about a 20% increase in imports last year alone. In addition, due to the digital revolution, the traditional paper markets continue to shrink rapidly. To a significant extent, the market is transitioning away from traditional, higher profit margin paper products to newer but lower profit margin items. The ability to maintain operational flexibility and be cost effective is essential for the Ashdown Mill to be able to quickly adjust to the changing markets and maintain economic viability.

Response: We acknowledge the background information provided by the commenter. This comment summarizes the issues raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments.

Comment: [AEP-SWEPCO July 15, 2015 comments (0164), p. 1, and August 7, 2015 comments (0167) p. 1-2] Southwestern Electric Power Company (AEP-SWEPCO), an operating company of the American Electric Power system (AEP), stated it appreciates the opportunity to provide comments to the U.S. Environmental Protection Agency (EPA or the Agency) on its proposed FIP to address certain regional haze and visibility transport requirements for the State of Arkansas.[21] Comments were originally due on May 16, 2015.[22] EPA subsequently extended that deadline to July 15, 2015 and at the same time announced the availability in the docket of

[21] 80 *Fed Reg.* 18944 (April 8, 2015).
[22] *Id.*

supplemental modeling.[23] On July 23, 2015, EPA published its notice of the reopening of the comment period until August 7, 2015.[24]

AEP-SWEPCO owns and operates the Flint Creek Power Plant and supports EPA's approval of the SO_2 portions of the Flint Creek BART analysis as submitted. AEP-SWEPCO is a 50% owner of Flint Creek Power Plant along with Arkansas Electric Cooperative Corporation (AECC). AEP-SWEPCO also supports EPA's previous approval of the particulate matter (PM) portions of the Arkansas SIP as submitted.

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis. Although outside of the scope of this rulemaking, we appreciate the commenter's support of our previous action approving a portion of ADEQ's PM BART determinations.

Comment: [AECC (0169) p. 1] AECC stated that it appreciates the opportunity to provide comment on the potential implications of the proposed FIP on its operations and member-owners. AECC is a generation and transmissions cooperative which is owned by 17 electric distribution cooperatives in the State of Arkansas. Together, they provide electricity to approximately 500,000 member-owners covering approximately 62% of the geographical area of the state.

Response: We acknowledge the background information provided by the commenter.

Comment: UARG provides a summary of EPA's proposed Arkansas Regional Haze FIP. [UARG (0176) p. 1-2] UARG stated that in a March 12, 2012 final rule, the U.S. Environmental Protection Agency (EPA or Agency) disapproved substantial parts of a state implementation plan (SIP) intended to implement the Clean Air Act's (CAA or the Act) regional haze provisions and the Act's interstate transport requirements related to visibility for Arkansas. 77 Fed. Reg. 14,604 (Mar. 12, 2012). On April 8, 2015, EPA published a proposed federal implementation plan (FIP) to address those regional haze provisions and interstate transport requirements that were included in the disapproved parts of the Arkansas SIP. "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan." 80 Fed. Reg. 18,944. The proposed FIP is intended to implement the CAA's best available retrofit technology ("BART") requirements for nine units at six facilities in Arkansas. *Id.* at 18,945-46. It would also impose emission limits based on the Act's reasonable progress requirements for two units at one facility that are not subject to BART. *Id.* at 18,946. In connection with these proposed BART and reasonable progress requirements, the proposed FIP would establish new reasonable progress goals ("RPGs") for the two Class I areas in Arkansas. *Id.* at 18,997-98. The proposed FIP would incorporate its proposed requirements into the long-term strategy ("LTS") for Arkansas, *id.* at 18,998, and would include a determination that the FIP, in combination with the provisions of Arkansas's SIP that EPA approved, would address the visibility-related interstate transport requirements for Arkansas for the 1997 national ambient air

[23] 80 Fed. Reg. 24,872 (May 1, 2015).
[24] 80 Fed. Reg. 43,661 (July 23, 2015).

quality standards ("NAAQS") for ozone and fine particulate matter ("PM2.5"), *id.* at 18,946, 18,998.

Response: We acknowledge the background information provided by UARG. We take no position with regard to UARG's synopsis of our proposed FIP.

Comment: UARG provides background information on the statutory and regulatory regional haze requirements. [UARG (0176) p. 2-4] UARG stated that the CAA's visibility protection provisions establish 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." CAA § 169A(a)(1). The Act directs EPA to promulgate regulations designed "to assure … reasonable progress toward meeting the national goal," *id.* § 169A(a)(4), and to require each state to submit a SIP that "contain[s] such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal," *id.* § 169A(b)(2). Under the Act and EPA's regional haze rules, a plan to implement the regional haze requirements has three main elements: (i) RPGs, which are visibility goals for each mandatory Class I federal area located in the state, 40 C.F.R. § 51.308(d)(1) & (2); (ii) an LTS, which is the state's plan for meeting the RPGs, CAA § 169A(b)(2)(B); 40 C.F.R. § 51.308(d)(3); and (iii) BART requirements for certain large stationary sources, CAA § 169A(b)(2)(A), 40 C.F.R. §51.308(e).

UARG stated that EPA's regional haze rules provide that for each mandatory Class I federal area in a state, the state must establish goals, expressed in deciviews ("dv"), that "provide for reasonable progress towards achieving natural visibility conditions." 40 C.F.R. § 51.308(d)(1). The rules further require that an RPG "provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." *Id.* To establish an RPG, a state must consider 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] the remaining useful life of any potentially affected sources." *Id.* § 51.308(d)(1)(i)(A); CAA § 169A(g)(1). A state must include in its SIP "a demonstration showing how these factors were taken into consideration in selecting the goal." 40 C.F.R. § 51.308(d)(1)(i)(A). In setting RPGs for a Class I area, a state must determine and consider what EPA refers to as the uniform rate of progress ("URP"), which is the rate of improvement in visibility, expressed in dv, that would be needed to attain natural visibility conditions by the year 2064. *Id.* § 51.308(d)(1)(i)(B). A state may establish an RPG for a Class I area that "provides for a slower rate of improvement in visibility" than the URP for that area if the state demonstrates that the URP is not reasonable for that area and that the RPG adopted by the state is reasonable. *Id.* § 51.308(d)(1)(ii). A state makes such a showing by evaluating the four reasonable progress factors as they apply to the Class I area. *Id.*

UARG stated that EPA's regional haze rules also direct each state to submit an LTS to address regional haze in its Class I areas and in Class I areas in other states that are affected by emissions from the state. *Id.* § 51.308(d)(3). The LTS "must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas." *Id.*

In addition, the regional haze rules describe requirements for BART. States determine and require BART for "BART-eligible" sources that are also determined to be "subject to BART" because they "may reasonably be anticipated to cause or contribute" to visibility impairment in a Class I area. CAA § 169A(b)(2)(A). Determining BART for a specific source requires consideration of five factors as they apply to that source. CAA § 169A(g)(2); *see* 40 C.F.R. § 51.301 (definition of BART); *id.* § 51.308(e)(1)(ii)(A).

Arkansas's regional haze SIP addressed these requirements, and states are entitled to significant deference regarding how to implement them in SIPs. Nevertheless, EPA disapproved significant provisions of the SIP and now proposes a FIP to implement EPA's policy preferences in place of those of the state.

Response: We acknowledge the background information provided by UARG. We take no position with regard to UARG's synopsis of the statutory and regulatory regional haze requirements. We address UARG's comment as to deference elsewhere in our responses to comments.

We disagree that the Regional Haze SIP submitted by Arkansas addressed all the regional haze requirements discussed in UARG's comment. In a final rule published in the Federal Register on March 12, 2012, we issued a partial disapproval of the Arkansas Regional Haze SIP.[25] Our final rule and proposed rule, along with all associated TSDs,[26] discussed in detail how the SIP did not fully meet the regional haze requirements and explained that we were therefore partially disapproving the SIP. Therefore, UARG's comments contending that the Arkansas Regional Haze SIP submitted by Arkansas addressed all the regional haze requirements is outside the scope of this rulemaking, as this rulemaking does not take action on the Arkansas Regional Haze SIP. Rather, this rulemaking is a regional haze FIP to correct the parts of the Arkansas RH SIP we disapproved in 2012.

Comment: [The Associations (0165) p. 1-2, 10] The American Chemistry Council, American Coke and Coal Chemicals Institute, American Farm Bureau Federation, American Forest & Paper Association, American Iron and Steel Institute, American Petroleum Institute, American Public Power Association, American Wood Council, Arkansas Asphalt Pavement Association, Arkansas State Chamber of Commerce, Arkansas Environmental Federation, Arkansas Farm Bureau, Arkansas Forest & Paper Council, Arkansas Ready Mixed Concrete Association, Associated Industries of Arkansas, Inc., Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resources Council, Gas Processors Association, Industrial Energy Consumers of America, National Association of Manufacturers, National Mining Association, National Oilseed Processors Association, and U.S. Chamber of Commerce (collectively, "the Associations")[27] stated they appreciate the opportunity to submit comments in response to the EPA's proposed approval of the Arkansas regional haze federal implementation plan ("proposed rule").

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[25] 77 FR 14604.
[26] See 76 FR 64186 and 77 FR 14604.
[27] A description of each Association is included in Appendix A.

The Associations represent the nation's leading energy and manufacturing sectors that form the backbone of the nation's industrial ability to grow our economy and provide jobs in an environmentally sustainable and energy efficient manner. The Associations' members include electric utilities, manufacturers and energy developers that own or operate facilities directly impacted, or could be directly impacted, by the Regional Haze program. In addition to generating electricity, many member companies require reliable and affordable electricity for manufacturing and industry. The Associations are key and necessary stakeholders in any regulation that directly impacts energy providers and which may impact manufacturers directly or indirectly in the future.

As discussed in more detail in the Associations' comments, the Associations urge EPA to withdraw and modify the proposed rulemaking due to numerous deficiencies within it. These deficiencies began with the disapproval of Arkansas' proposed state implementation plan. The Associations believe that EPA is failing to provide the deference due to states that Congress intended when it passed the Regional Haze statute. This has resulted in too many instances where EPA disapproves reasonable state policy determinations and imposes its own policy preferences through a federal implementation plan. Key among these flawed policy preferences are EPA's imposition of costly pollution controls at Independence Steam Electric Station ("Independence plant"), a source not eligible for Best Available Retrofit Technology ("BART") review under the Clean Air Act, without any rational basis, and multiple errors in the White Bluff Electric Power Plant BART analysis. Beyond these specific issues, what most concerns the Associations is that the proposed rule evinces a tendency by EPA to deviate from the Clean Air Act, its own regulations, and guidance to require exorbitant pollution controls that would achieve, at most, negligible visibility benefits. The Clean Air Act's Regional Haze program envisions gradual improvements to Class I area visibility over long periods of time and through cost-effective means. Contrary to EPA's rationale in the proposed rulemaking, it is not a vehicle to further accelerate the retirement of coal-fired power plants. Lastly, the Associations object to EPA justifying additional emission control measures on modeled visibility improvements that are less than CALPUFF's margin of error. To do so means that EPA has no credible evidence showing that visibility improvements would be greater than zero. Such justifications have already been struck down by the U.S. Court of Appeals for the Ninth Circuit and the Associations object to EPA ignoring that court's determination in deciding whether additional emission reductions at stationary sources would provide any visibility improvements at Class I areas.

For the reasons discussed in The Associations' comments, EPA's proposal to issue a Regional Haze Federal
Implementation Plan for Arkansas is unlawful, arbitrary, and capricious. The Associations urge EPA to withdraw the proposed rule and propose a new rule that is consistent with the Clean Air Act and EPA's Regional Haze regulations.

Response: We acknowledge the background information provided by the commenter. This comment summarizes the issues raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments in other sections throughout this document.

Comment: [Conway Corporation et.al. (0172) p. 2-3] Conway Corporation et. al. stated that on April 8, 2015, the U.S. Environmental Protection Agency ("EPA") proposed a Federal Implementation Plan ("FIP") for the State of Arkansas for Regional Haze and Interstate Visibility Transport (the "Proposed Rule").[28] Specifically, the proposed rule addresses the previously disapproved elements of the Arkansas State Implementation Plan for Regional Haze, including certain Best Available Retrofit Technology ("BART") determinations, Reasonable Progress Goals ("RPGs"), and long-term strategy ("LTS") necessary to achieve established RPGs, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states. Among other requirements, the Proposed Rule includes emission limitations based on installation of BART controls for SO_2 and NO_X at the White Bluff Plant ("White Bluff Plant") and two alternative options for controlling emissions from the Independence Plant ("Independence Plant") under the regional haze reasonable progress requirements.

Conway Corporation is a non-profit corporation that operates the city-owned utility system and provides electric, water, wastewater, cable, Internet, and telephone services for the City of Conway, Arkansas, a city of about 64,000 residents. Conway Corporation is dedicated to producing and delivering safe, affordable, reliable, innovative and environmentally sound utility and telecommunication services while enhancing the quality of life of its community. Conway Corporation owns 2% of each unit of the Independence Plant and the White Bluff Plant.

City Water & Light of the City of Jonesboro, Arkansas ("CWL") is a municipal improvement district and consolidated utility district formed by special act of the Arkansas General Assembly (Act 251 of 1921). CWL provides electric, water and wastewater services in Jonesboro, Arkansas for approximately 72,000 residents. CWL strives to provide safe, reliable, and cost-effective services to its customers. Making sound long-term business decisions have supported this customer commitment. CWL's customers made a substantial investment in both the White Bluff and Independence Plants to secure their power needs for the future. CWL currently owns 5% of each unit of the White Bluff Plant, and 5% and 15% of Units 1 and 2 of the Independence Plant, respectively.

West Memphis Utilities ("WMU") is a department of the City of West Memphis, Arkansas, a city of approximately 28,000 residents. There are about 10,500 residential, and 1,700 commercial and industrial customers in WMU's service area, to whom WMU provides electrical, water and wastewater services. WMU strives to deliver safe, reliable, environmentally friendly utilities at an affordable cost to its ratepayers. WMU currently owns 1% of each unit of the Independence and White Bluff Plants.

Osceola Municipal Light and Power ("OML&P") is a non-profit division of the city government that operates the city-owned utility system and provides electric, water, and wastewater, for the City of Osceola, Arkansas, a city of about 8,000 residents. OML&P is committed to delivering safe, affordable, reliable, innovative and environmentally sound utility services while enhancing the quality of life in the community. OML&P owns 0.5% of each unit of the Independence Plant.

[28] *See* 80 Fed. Reg. 18944 (Apr. 8, 2015).

Collectively, Conway Corporation, CWL, WMU and OML&P ("Commenters") are substantial co-owners, with others, of the Independence and White Bluff Plants, which are significantly affected under the Proposed Rule. As such, the Commenters have a strong interest in the reasonable and proper implementation of the regional haze and interstate visibility requirements of the Clean Air Act for the protection of their customers.

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis of our proposed FIP.

Comment: [Conway Corporation et. al. (0172) p. 3-4] Conway Corporation et. al. stated that Section 169A of the Clean Air Act establishes a national goal for the prevention of any future, and the remedying of any existing man-made impairment of visibility in the nation's 156 national parks and wilderness areas designated as mandatory Class I federal areas.2 In 1999, EPA promulgated the Regional Haze Rule ("RHR") to address regional haze impairment and establish a comprehensive visibility protection program for Class I areas. The regional haze program is designed to reduce man-made visibility impairment over time (*i.e.* by 2064)4 and in sequenced planning periods. The long-term planning recognizes that advancements in technology and changes in economic factors will likely provide opportunities for implementing new cost-effective control measures to assure reasonable progress and reduce the economic burden of rushing to install costly control measures to meet a purely aesthetic standard.5 The EPA's rule requires states, through the state implementation plan ("SIP") development process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

Conway Corporation et. al. stated that as discussed in their comments, the Proposed Rule is unreasonable, arbitrary and capricious and not in accordance with law. Most importantly, the Proposed Rule fails to recognize that the visibility improvement at relevant Class I federal areas is well ahead of the approved Uniform Rate of Progress ("URP" or "glide path") necessary to maintain and achieve the national visibility goal, and is projected to remain so for more than a decade. Accordingly, the Proposed Rule unnecessarily imposes significant costs on Commenters and their customers with little or no corresponding visibility benefit. Finally, in developing the Proposed Rule, EPA departed from its own guidance and previous regional haze decisions for other states.

For the reasons discussed in Conway Corporation et. al.'s comments, EPA should abandon the Proposed Rule's determinations regarding reasonable progress determinations for the Independence Plant and
NOx BART determinations for Arkansas' subject-to-BART sources, and prepare a FIP consistent with the requirements of the Clean Air Act and EPA's own regulations.

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis. This comment summarizes the issues raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments in other sections throughout this document.

Comment: [Energy and Environmental Alliance of Arkansas (0173) p. 2] EEAA stated that the Energy and Environmental Alliance of Arkansas ("EEAA") is an ad-hoc collaboration of Arkansas' investor-owned, co-operative, municipal, and independent electric utilities and other energy companies formed to advocate, communicate and encourage energy and environmental policies that promote sound and predictable regulation of Arkansas' utility industry, and support an economically viable and environmentally secure future for all Arkansans, including access to reliable and affordable energy resources.[29] Many of EEAA's members are co-owners of the affected units under the Proposed Rule. EEAA and its members therefore have a strong interest in the appropriate and coherent implementation of the regional haze program in the most economical and reasonable means possible for the benefit of their customers. For the reasons explained herein, EEAA believes that the Proposed Rule is arbitrary and capricious in that it is inconsistent with EPA's previous guidance, regulations, and determinations concerning visibility protection and imposes significant unnecessary and unjustified costs on Arkansas' utilities providers and their customers.

EEAA stated that on April 8, 2015, the EPA published a proposed rule for the State of Arkansas for Regional Haze and Interstate Visibility Transport (hereinafter, the "Proposed Rule") promulgating a Federal Implementation Plan ("FIP") to address those portions of Arkansas' regional haze State Implementation Plan ("SIP") that were disapproved on March 12, 2012.[30] The Proposed Rule includes Best Available Retrofit Technology ("BART") determinations for sulfur dioxide ("SO2"), nitrogen oxides ("NOx") and particulate matter ("PM") impacting nine units at six facilities in Arkansas,[31] and two proposed alternative options for controlling emissions from the Entergy Independence Plant ("Independence Plant") under the regional haze reasonable progress requirements.

Response: We acknowledge the background information provided by the commenter. This comment summarizes the issues raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments.

We take no position with respect to the commenter's synopsis of our proposed FIP.

Comment: [Energy and Environmental Alliance of Arkansas (0173), p. 3-4] EEAA stated that EPA's Proposed Rule is replete with legal and factual errors that vastly underestimate the cost and cost effectiveness of the proposed emissions controls and simultaneously overestimate the necessity and benefit of the controls for maintaining reasonable progress towards the national visibility goal. This has the combined effect of imposing hundreds of millions of dollars of unnecessary expense on Arkansas' utilities and their customers. As discussed elsewhere, the Proposed Rule is inconsistent with EPA's own guidance and the regional haze determinations for

[29] The members of EEAA are: AEP/Southwestern Electric Power Company ("AEP/SWEPCO"), Arkansas Electric Cooperative Corporation ("AECC"), Arkansas Municipal Power Association, Conway Corporation, Empire District Electric Company, Entergy Arkansas, Inc. ("Entergy"), Jonesboro City Water & Light, North Little Rock Electric, Oklahoma Gas & Electric Company, Plum Point Services Company, LLC, and West Memphis Utility Commission.
[30] *See* 80 Fed. Reg. 18944 (April 8, 2015).
[31] The subject-to-BART facilities include AECC Carl E. Bailey and John L. McClellan Generating Stations; AEP Flint Creek Power Plant; and Entergy White Bluff and Lake Catherine Plants. *Id.*

other states, and it fails to account for Arkansas' current progress towards the national visibility goal and the visibility benefits resulting from other programs such as the Cross-State Air Pollution Rule ("CSAPR"). The errors and inconsistencies that infect EPA's BART and reasonable progress determinations render the Proposed Rule arbitrary and capricious. As such, EPA should abandon the approach and analysis utilized in the Proposed Rule and instead prepare a FIP in accordance with the requirements of the Clean Air Act and EPA's own guidance.

Response: This comment summarizes the issues raised by the commenter in more detail elsewhere. Please see our responses to those more specific comments.

Comment: [Edison Electric Institute (0174) p. i-2] EEI stated that it appreciates the opportunity to submit comments on the proposed *Promulgation of Air Quality Implementation Plans* for the state of Arkansas by the EPA in Docket No. EP A-R06-0AR-2015-0189, 80 *Fed. Reg.* 18,944 (Apr. 8, 2015) and 80 *Fed. Reg.* 24,872 (May 1, 2015). EPA proposes to promulgate a Federal Implementation Plan (FIP) for Arkansas to address the requirements of the Regional Haze Rule (RHR) and address interstate visibility transport requirements for portions of Arkansas' State Implementation Plan (SIP) that EPA disapproved in a prior action. *See id.*

EEI is the association that represents all U.S. investor-owned electric utilities, international affiliates and industry associates worldwide. EEI members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $90 billion in annual capital expenditures, the electric power industry is responsible for millions of jobs outside our direct operations. Reliable, affordable and sustainable electricity powers the economy and enhances the lives of all Americans. As generators of electricity and operators of the nation's electric transmission and distribution system, EEI's member companies have a strong interest in any proposed rule that potentially impacts the industry and the ongoing transition of the domestic fleet.

EEI member companies operate facilities directly affected by the Agency's proposed action. As part of the ongoing transition to cleaner sources of generation, the electric power sector generally-and Arkansas electricity generators in particular- have cut emissions significantly in recent years and will continue to do so under many recently finalized EPA regulations, even without the regional haze Federal Implementation Plan (FIP) proposed by EPA for Arkansas. EEI is filing comments to ensure that the Agency allows states to determine how best to consider additional controls, consistent with effective long-term utility planning toward the linked goals of reliable, affordable and increasingly clean electric power. EEI also offers a number of specific comments regarding the proposed FIP, and urges the Agency to consider the technical comments of both Entergy and Southwestern Electric Power Company regarding unit-specific and other technical and legal concerns. EEI looks forward to continued dialogue with Agency officials on this important rulemaking.

Response: We acknowledge the background information provided by the commenter. As to comments that are generally raised here (i.e. proposed FIP comments of Entergy and Electric Power Co.), we address those in other sections throughout this document.

Comment: [Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 1-2] AEEC and AGC stated that they are submitting comments in response to the EPA's "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule" in Docket No. EPA-R06-OAR-2015-189, published at 80 Fed. Reg. 18944 on April 8, 2015 (the "Proposed FIP").[32] AEEC and AGC are non-profit corporations organized under the laws of the State of Arkansas for the purpose of ensuring just and reasonable utility policies and energy rates in the State of Arkansas. The members of AEEC and AGC collectively employ thousands of Arkansans through their engagement in energy- intensive industries such as primary metals manufacturing, chemical production, brick manufacturing, food processing, refining, and wood products manufacturing. The members of AEEC purchase electricity from Entergy Arkansas, Inc. ("EAI"). EAI is either an owner or co-owner of certain power plants regulated by the Proposed FIP. Since the cost of electricity constitutes a major component of the cost of manufacturing the products created by the members of AEEC and AGC, the costs of the various control technologies required under the Proposed FIP will injure the members of AEEC and AGC by increasing the cost[33] of the electricity (and likely natural gas)[34] needed to operate their facilities.

Response: We acknowledge the background information provided by the commenters. We also acknowledge the commenters' concerns. Specific issues raised by the commenter are addressed by us elsewhere in this document. Please see our responses to those more specific comments.

Comment: Summary of the history of the regional haze program. [Sierra Club et. al. (0171) p. 2-3] Sierra Club et. al. stated that since the nation's founding, the United States has valued its diverse and stunning natural scenery. *See, e.g.*, John Copeland Nagle, *The Scenic Protections of the Clean Air Act*, 87 N.D. L. Rev. 571, 576 (2011). In what has been lauded as "America's best idea," Congress first set aside national parks in the 19th century to preserve and celebrate some of the nation's most spectacular scenery. *Id.* With the nation's rapid industrialization, however, these remarkable scenic views became increasingly marred by air pollution. *See id.* at 573. Today, air pollution is "perhaps the greatest threat to national parks," and pollution all too often degrades visibility in these iconic scenic areas. *Id.*

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[32] These comments are timely filed. On July 23, 2015, at 80 Fed. Reg. 43661, the EPA published notice that it would re-open the comment period in this docket until August 7, 2015.

[33] Act 310 of 1980, as amended, which has been codified at Arkansas Code Annotated sections 23-4-501 *et seq.*, allows an Arkansas utility to immediately recover expenditures incurred as a result of regulatory requirements relating to the protection of the environment by imposing a surcharge on its customers. *See* McDaniel v. Arkansas Public Service Commission *et al.*, 2014 Ark. App. 529 (Ark. App. 2014).

[34] Since the enormous costs of implementing the controls required by the Proposed FIP will necessarily render certain coal-fired power plants less economic, the proposed FIP will increase demand for natural gas, thereby placing significant upward pressure on natural gas commodity and transportation prices. Thus, the proposed FIP will injure the members of AGC. *See* Energy Ventures Analysis, Inc., *EPA Clean Power Plan: Costs and Impacts on U.S. Energy Markets*, at 20 (October 2014), http://www.countoncoal.org/assets/Executive-Summary-EPA-Clean-Power-Plan-Costs-Impacts.pdf.

Recognizing the "intrinsic beauty and historical and archaeological treasures" of the national parks and wilderness areas,[35] 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 EPA and the states had not made adequate progress toward reducing visibility impairment in the nation's Class I areas,[36] Congress amended the Clean Air Act ("CAA" or "the Act") to curb emissions that may reasonably be anticipated to cause or contribute to visibility 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 (or EPA where a state fails to act) to make incremental, "reasonable progress" toward eliminating human-caused visibility impairment at each Class I area by 2064. 64 Fed. Reg. 35,714, 35,746 (July 1, 1999), codified at 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.

In order to achieve the goal of natural visibility in Class I areas, implementation plans must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting 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 the 2064 natural visibility goal. These measures include requirements to (1) develop reasonable progress goals based on the evaluation of any and all sources contributing to visibility impairment; (2) create a long-term strategy for achieving the reasonable progress goals; and (3) require installation and operation of the best available retrofit technology ("BART") for some of the oldest and dirtiest sources of haze-causing pollutants. *Id.*; 40 C.F.R. § 51.308(d), (e).

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis.

Comment: Summary of the statutory and regulatory requirements associated with RPGs. [Sierra Club et. al. (0171) p. 3] Sierra Club et. al. stated that one of the main features of the Regional Haze Rule is the establishment of "goals (expressed in deciviews)[37] that provide for reasonable progress towards achieving natural visibility conditions." 40 C.F.R. § 51.308(d)(1). In developing these "reasonable progress goals" and the emission reductions needed to meet them, the state must consider 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) the remaining useful life of any potentially affected sources. 42 U.S.C. § 7491(g)(1); 40 C.F.R. §

[35] H.R. Rep. No. 95-294, at 203-04 (1977), *reprinted in* 1977 U.S.C.C.A.N 1077, 1282.

[36] 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).

[37] A deciview is a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. 40 C.F.R. § 51.301.

51.308(d)(1)(i)(A). In contrast to the definition of best available retrofit technology ("BART"), the statute does not list visibility improvement as a fifth factor in the reasonable progress analysis. *Compare* 42 U.S.C. § 7491(g)(1) *with id.* § 7491(g)(2).

For each Class I area within its borders, a state must determine the uniform rate of progress ("URP"), which is the amount of progress that, if kept constant each year, would ensure that natural visibility conditions are achieved in 2064. *See* 40 C.F.R. § 51.308(d)(1)(i)(B). If a state selects a reasonable progress goal that achieves a slower rate of progress than the URP, the state must demonstrate, based on the four reasonable progress factors, "that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal adopted by the State is reasonable." *Id.* § 51.308(d)(1)(ii).

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the Sierra Club et. al synopsis of the statutory and regulatory requirements associated with the RPGs. We address elsewhere in this document comments contending that the statute does not list visibility improvement as a fifth factor in the reasonable progress analysis.

Comment: Summary of the long-term strategy requirements. [Sierra Club et. al. (0171) p. 4] Sierra Club et. al. stated that a regional haze implementation plan must include, among other things, emission limits, schedules of compliance, and any other measures necessary to achieve the reasonable progress goals—this collection of enforceable measures is called the long-term strategy. 40 C.F.R. §51.308(d)(3)(ii). Given the statutory goal to eliminate all haze caused by "manmade air pollution," 42 U.S.C. § 7491(a)(1), states must consider all air pollution sources that contribute to impairment in Class I areas. In developing a long-term strategy, a state must look beyond major stationary sources to area, mobile, and minor sources, *id.* § 51.308(d)(3)(iv), as well as a number of other sources of impairment such as construction, agricultural, and forestry practices. *Id.* § 51.308(d)(3)(v). The long-term strategy must achieve reasonable progress for both the Class I areas within a state's borders as well as the out-of-state areas affected by the state's emissions. *Id.* § 51.308(d)(3). To ensure that each state does its part to address regional haze, a state that contributes to impairment at another state's Class I area must consult with the state that is home to the Class I area. *Id.* § 51.308(d)(3)(i).

Consultation proceeds based in part on analyses of how much impairment at a given Class I area is due to emissions from each state. Each state then must document the technical basis by which it determines its share of the emissions reductions necessary to make reasonable progress at a Class I area. *Id.* § 51.308(d)(3)(iii). After fulfilling the procedural requirements for consultation, a state must ensure that its haze plan satisfies the primary substantive requirement for a long term strategy: to include the enforceable measures necessary to meet the reasonable progress goals for each Class I area affected by the state's emissions. *Id.* § 51.308(d)(3). In determining whether each state's haze plan satisfies the statutory mandate to make reasonable progress, EPA reviews whether the state followed the consultation requirements set forth in 40 C.F.R. § 51.308(d)(3)(i) and reasonably considered the four statutory factors for reasonable progress. 40 C.F.R. § 51.308(d)(1)(iii).

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the Sierra Club et. al. synopsis.

Comment: Summary of the BART requirements. [Sierra Club et. al. (0171) p. 4-5] Sierra Club et. al., stated that BART controls are one element of making progress towards the natural visibility goal. BART controls are required at fossil fuel-fired power plants and other major stationary sources that "may reasonably be anticipated to cause or contribute to any impairment of visibility in any such [mandatory Class I Federal] area," and were in existence in 1977, but were not in operation before 1962. 42 U.S.C. § 7491(b)(2)(A); *see* 40 C.F.R. § 51.308(e). The term "major stationary source" is defined to include any source that has the potential to emit 250 tons per year or more of any pollutant, and falls within one of 26 categories of industrial sources defined by the Act. 42 U.S.C. § 7491(g)(7). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the *best* system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." 40 C.F.R. § 51.301 (emphasis added).

When determining BART, the states and EPA must analyze "the best system of continuous emission control technology available" by taking into consideration five factors: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) existing pollution controls at the source, (4) the remaining useful life of the source, and (5) the degree of visibility improvement from pollution controls. *Id.* § 51.308(e)(1)(ii)(A). BART is an essential component of the regional haze program because Congress largely grandfathered these antiquated sources into many of the Clean Air Act's other requirements. *See* 70 Fed. Reg. 39,104, 39,111 (July 6, 2005). BART compels these older, disproportionately-polluting sources to install up-to-date and cost-effective pollution controls.

BART is a mandatory measure that must be implemented as part of a plan to achieve reasonable progress toward restoration of natural visibility conditions. The Clean Air Act expressly requires states to adopt SIPs that contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal . . . *including*" the installation and operation of BART at eligible sources that emit any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any Class I area. 42 U.S.C. § 7491(b)(2) (emphasis added), § 7491 (b)(2)(A). The only permissible exemption from BART is when EPA, by rule promulgated with sufficient notice and opportunity for public comment, determines that (1) the source does not "by itself or in combination with other sources" cause or contribute to significant visibility impairment at a Class I area; (2) if the power plant has a design capacity of 750 megawatts or greater, the owner or operator must demonstrate to EPA that the plant is located at such a distance from all Class I areas that it does not "by itself or in combination with other sources" emit pollution that may reasonably be anticipated to cause or contribute to significant visibility impairment at a Class I area; and (3) the affected Federal Land Managers concur with the BART exemption. *Id.* §7491(c).[38] No such determination has

[38] *See also* 40 C.F.R. § 51.308(e) (requiring BART for each eligible source "that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area, unless the State demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions.").

been proposed or made here, nor could it be given the significant visibility impacts that the Flint Creek, Lake Catherine, and White Bluff facilities have on Class I Areas in Arkansas and Missouri.

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis.

Comment: Discussion of the Class I areas affected by emissions from Arkansas sources. [Sierra Club et. al. (0171) p. 7-8] Sierra Club et. al. stated that in finalizing the proposed FIP for Arkansas, EPA has a unique opportunity—and an obligation—to improve air quality in multiple states, including Arkansas and Missouri. Emissions from Arkansas sources impact two in-state Class I areas: Caney Creek Wilderness Area and Upper Buffalo Wilderness Area. Both wilderness areas are located in northwestern Arkansas and offer beautiful hiking opportunities, natural landscapes, and varied scenery.

Caney Creek Wilderness straddles two different sections of the Ouachita Mountains in western Arkansas. The Fourche Mountain subsection is characterized by "deep slices [carved by streams] out of the ridges" and areas of "large rock flows" and "sandstone bluffs."[39] The Central Ouachita Mountains subsection is "richest in terms of plant community diversity" with "seeps and springs" supporting "stands of American beech and umbrella magnolia in coves, on north-facing slopes, and on stream terraces."[40] Over seventeen miles of hiking trails wind through the area and ambitious hikers can climb to the top of several mountains for views of the surrounding peaks.[41]

The Upper Buffalo Wilderness Area in the Ozark Mountains provides visitors the opportunity to "be among the headwaters of the extraordinarily pretty Buffalo National River, which flows down the center of this Wilderness through a rough forested land of steep slopes that descend into deep valleys."[42] The Whitaker Point Trail winds its way to the top of Hawksbill Crag,[43] a scenic rocky outcropping which is one of the most photographed places in Arkansas.[44]

Air pollution from Arkansas sources mars the unique scenery outside of the state too, including in Missouri's Hercules Glades Wilderness and Mingo National Wildlife Refuge. The Hercules Glades Wilderness spans 12,413 acres of some of the "most scenic and unique country in the Midwest" with "[i]ts combination of open grassland, forested knobs, steep rocky hillsides, and

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[39] "Wilderness Stewardship Challenge: Air Quality Values Monitoring Plan for Ouachita National Forest, Arkansas And Oklahoma," p. 17 (Sep. 30, 2009) *available at:* http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprd3811710.pdf.
[40] *Id.*
[41] "Caney Creek Wilderness Trails," *available at:* http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fsm9_039458.pdf.
[42] "Upper Buffalo Wilderness," Wilderness.net, *available at:* http://www.wilderness.net/NWPS/wildView?WID=621&tab=General (last visited July 8, 2015).
[43] "Upper Buffalo Wilderness Area," *available at:* http://www.fs.usda.gov/recarea/osfnf/recreation/camping-cabins/recarea/?recid=43499&actid=34
[44] "Adventure Arkansas: Hawksbill Crag," *available at:* http://5newsonline.com/2014/05/24/adventure-arkansas-hawksbill-crag/

narrow drainages offers unusual beauty."[45] The area contains 32 miles of maintained trails for visitors to explore.[46]

The 21,592-acre Mingo National Wildlife Refuge "provide[s] food and shelter for migratory waterfowl and . . . protect[s] the bottomland hardwood forest," while providing enjoyment for people visiting.[47] Along with migratory waterfowl, the refuge is also a wintering ground for bald eagles.[48] People travel to the Mingo National Wildlife Refuge for hiking, birding, canoeing, and kayaking opportunities.[49]

Response: We acknowledge the background information provided by the commenter.

Comment: A handful of point sources emit the overwhelming majority of haze-causing pollutants in Arkansas. [Sierra Club et. al. (0171) p. 8-9] Sierra Club et. al. stated that a handful of point sources, mostly electric generating units ("EGUs"), emit the overwhelming majority of haze-causing pollutants in Arkansas. Of these pollutants, sulfates and nitrates contribute most significantly to the visibility problem in Arkansas's Class I areas.[50] Three EGUs—the Flint Creek, Independence, and White Bluff power plants—emitted approximately 84% of Arkansas SO2 point-source emissions and 55% of state-wide NOx point source emissions in 2011. 80 Fed. Reg. at 18,991. In 2011, Arkansas EGUs accounted for 78.4% of Arkansas's total SO2 emissions (*i.e.*, emissions from both point and non-point sources).[51]

Flint Creek Unit 1 is a 558 megawatt ("MW") coal-fired electric generating station that burns mostly western subbituminous low-sulfur coal and is operated by Southwestern Electric Power Company (a subsidiary of American Electric Power ("AEP")). Flint Creek currently has no post-combustion SO2 controls. Early generation low-NOx burners have been installed and an electrostatic precipitator ("ESP") is installed to control particulate matter. According to emissions data in EPA's Clean Air Markets Database, in 2011, Flint Creek was the third-largest point source of emissions of both SO2 (8,620 tons) and NOx (5,326 tons) in the state. 80 Fed. Reg. at 18,991, Table 59. Flint Creek contributes significantly to visibility impairment at all four Class I areas modeled by EPA, with the largest impacts at Upper Buffalo (98th percentile impairment of .965 dvs) and Caney Creek Wilderness Areas (98th percentile impairment of 0.963 dvs). *See* 80 Fed. Reg. at 18,965, Table 25.

Lake Catherine Unit 4 is a 558 MW electric generating station operated by Entergy. The unit is currently permitted to burn natural gas and No. 6 fuel oil, but it has not burned fuel oil for over a

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[45] "Hercules Glades Wilderness," *available at:* http://www.fs.usda.gov/recarea/mtnf/recreation/recarea/?recid=21754&actid=51
[46] *Id.*
[47] "Mingo National Wildlife Refuge," U.S. Fish and Wildlife Service *available at:* http://www.fws.gov/uploadedFiles/Mingobrochure(3).pdf.
[48] *Id.*
[49] *Id.*
[50] ADEQ, "State Implementation Plan Review for the Five-Year Regional Haze Progress Report," Revised May 2015, at 17, Figure 2.2, *available at*: http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.
[51] *Id.* at 18, Figure 2.3.

decade. 80 Fed. Reg. at 18,975. Lake Catherine Unit 4 contributes significantly to visibility impairment at all four Class I areas modeled by EPA, with the largest impacts at Caney Creek Wilderness Area (98th percentile impairment of 1.371 dvs). *See* 80 Fed. Reg. at 18,976, Table 40.

The Independence plant is a 1,800 MW coal-fired electric generating station operated by Entergy. The plant consists of two nearly identical 900 MW units which burn subbituminous coal. The Independents units began operation in 1983 and 1984, respectively, and as such are not BART eligible. The Independence units currently have no SO2 or NOx controls. The units are equipped with ESPs to control PM emissions. According to emissions data in EPA's Clean Air Markets Database, in 2011, the Independence plant was the second-largest point source of both SO2 (30,398 tons) and NOx (13,411 tons) emissions in the state. 80 Fed. Reg. at 18,991, Table 59. The Independence plant contributes significantly to visibility impairment at all four Class I areas modeled by EPA, with the largest impacts at Caney Creek Wilderness Area (98th percentile impairment of 2.412 dvs), Upper Buffalo Wilderness Area (98th percentile impairment of 1.764 dvs), and Mingo National Wildlife Refuge (98th percentile impairment of 1.704 dvs).

The White Bluff plant is a 1,700 MW coal-fired electric generating facility operated by Entergy. The plant consists of two nearly identical 850 MW tangentially fired boilers that burn subbituminous coal. 80 Fed. Reg. at 18,969. White Bluff Units 1 and 2 currently have no SO2 or NOx controls, but are equipped with ESPs to control PM emissions. According to emissions data in EPA's Clean Air Markets Database, in 2011, the White Bluff plant was the largest point source of emissions of both SO2 (31,684 tons) and NOx (16,013 tons) emissions in the state. 80 Fed. Reg. at 18,991, Table 59. White Bluff Units 1 and 2 contribute significantly to visibility impairment at all four Class I areas modeled by EPA, with the largest impacts at Caney Creek Wilderness Area (98th percentile impairment of 3.323 dvs), Upper Buffalo Wilderness Area (98th percentile impairment of 2.325 dvs), and Hercules-Glades Wilderness Area (98th percentile impairment of 2.101 dvs). *See* 80 Fed. Reg. at 18,970, Table 31.

Response: We acknowledge the background information provided by the commenter. We take no position with respect to the commenter's synopsis of our proposed FIP.

2. Entergy's Proposed Strategy for White Bluff and Independence

Comment: Since Entergy proposes to cease coal-fired operations at White Bluff by 2028 as part of a long-term, multi-unit Regional Haze Plan, EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

[Entergy Arkansas Inc. (0149) p. 5-6, 13-14] Entergy Arkansas Inc. (Entergy) stated that EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to ADEQ in October 2013 ("Revised White Bluff BART Analysis"),[52] which assumed White Bluff Units 1 and 2 would continue to

[52] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969.

combust coal for the foreseeable future. However, as part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect. As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the now reduced remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost-effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

Entergy stated that the CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.[53]

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

Entergy stated that BART controls that may be cost-effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

Entergy stated that EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost-effectiveness at Unit 1 of $2,227/ton and at Unit 2 of $2,101/ton. 80 Fed. Reg. at 18,971, Table

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The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[53] Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[54] Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[55] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[56]

Entergy stated that in addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the permitted SO_2 emission rates for White Bluff Units 1 and 2 and Independence Units 1 and 2. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018. NO_X BART for all EGUs in Arkansas, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NO_X BART limits in the final FIP, Entergy proposes that the four units at White Bluff and Independence meet a rolling 30-boiler operating day average NO_X limit of 1,342.5 lb NO_X/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[57] *See* 79 Fed. Reg. at 18,974-75. Although the cost-effectiveness of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the White Bluff units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

Entergy stated that this combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional

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[54] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[55] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[56] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

[57] This limit is different from the limit that Entergy proposed as NO_X BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator (MISO) and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NO_X control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary to ensure that the White Bluff units can comply with the NO_X limit at the lower loads that have become a more common operating condition for the units.

controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

[Conway Corporation et. al. (0172) p. 13, 14, and EEAA (0173) p. 6, 8] Conway Corporation et. al. and EEAA both stated that EPA's proposed FIP fails to properly account for the remaining useful life of the White Bluff Plant, which renders EPA's cost analysis useless for assessing the real costs of the proposed controls for them and their customers.

Conway Corporation et. al. and EEAA stated that the CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.[58] Thus, BART controls that may be cost-effective using the standard amortization period (typically 20-30 years) may no longer be cost-effective when remaining useful life is properly factored into the analysis.[59] EPA's cost estimates for proposed controls at the White Bluff Plant were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited.[60] However, the Commenters understand that Entergy proposed to commit to cease coal-fired operation at the White Bluff Plant by 2027-2028. In light of this proposal, EPA should revise its BART analysis to take the remaining useful life of the units into account. Using the 2027 and 2028 timeline, the amortization period is shortened to approximately six to seven years. This significantly impacts the cost calculation, resulting in much higher costs as compared to the emissions reductions achieved. When appropriate costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of the proposed controls at the
White Bluff Plant increases to amounts that are far too high to constitute BART.

[Edison Electric Institute (0174) p. 2, 7-8, 10] EEI stated that EPA concluded that dry flue gas desulfurization (FGD) controls are BART for Entergy's White Bluff Units 1 and 2 given their visibility impacts and average cost effectiveness at Unit 1 of $2,227/ton and at Unit 2 of $2,101/ton. *See* 80 *Fed. Reg.* at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, which is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. However, Entergy proposes in its own comments to agree to an enforceable commitment to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year. Accordingly, in light of Entergy's proposal, EPA should revisit its proposed BART determination for White Bluff Units 1 and 2 to address the remaining useful life of the units accurately.

EEI stated that Entergy's proposal to cease coal-fired operation at White Bluff by 2027-2028—coupled with a final BART determination in early 2016 (which would result in the proposed dry FGD controls being installed and operational no earlier than 2020)—shortens the amortization period from EPA's assumed 30 years to 6-7 years instead. Entergy's comments contain a revised dry FGD cost analysis from Sargent & Lundy (S&L) that takes into account current costs for dry

[58] *See* 79 Fed. Reg. at 74818, 74837 and 40 C.F.R. Part 51, App. Y, Section IV.D.4.k. .
[59] *Id.*
[60] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.

FGD installation and finds the total costs to install and operate dry FGD at White Bluff will be in excess of $1 billion. Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six or seven years would result in a cost effectiveness several times higher than EPA estimates and above costs that EPA has previously determined on numerous occasions to be too expensive to constitute BART.[61]

EEI stated that in summary, it is unreasonable for EPA to impose a $1 billion control system for units that will utilize that system for only six or seven years. Instead of the proposed costly dry FGD control, Entergy believes that a combination of Low NO_X Burner/Separated Over-Fire Air controls coupled with the use of low sulfur coal through the remaining useful coal-fired life of the White Bluff units should be BART. No additional controls are justified given the limited number of years of coal-fired operation of White Bluff given that the regional haze program allows for firm refueling commitments to satisfy regulatory requirements.

Response: In our FIP proposal, we solicited comment on alternative SO_2 and NO_X control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period.[62] In several instances, after EPA has proposed or finalized a BART determination in a FIP, a source has requested that EPA instead adopt an alternative to BART or otherwise adjust the assumptions underlying the BART analysis based on commitments to shut down or repower.[63] We requested comment on alternative measures in part to determine whether Entergy in particular would be interested in an alternative path. Given the alternatives proposed by owners and operators of other power plants in other states, we stated that an alternative could include, but is not limited to, a combination of early shutdowns of units and other emission control measures that would achieve greater reasonable progress than the BART and reasonable progress controls that we proposed for these four units. Entergy's comments propose a multi-unit strategy as an alternative to the proposed FIP.[64] We note that we do not interpret Entergy's comments submitted during the public comment period as suggesting that we adopt the elements in its alternative that are unique to White Bluff as an alternative to our proposed BART emission limits at the facility unless we also conclude that the remaining elements address any reasonable progress requirements for Independence. After carefully considering the comments we received specifically on this issue, we do not believe the comprehensive multi-unit strategy as presented by the company has potential to satisfy the BART requirements for White Bluff Units 1 and 2 and the reasonable progress requirements for Independence Units 1 and 2.

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[61] *See* 79 *Fed. Reg.* at 9,331-33 (Proposed Arizona Regional Haze FIP), 79 *Fed. Reg.* 52,420 and 426 (Final Arizona Regional Haze FIP), 77 *Fed. Reg.* 23,988 and 24,047 (Proposed Montana Regional Haze FIP), 77 *Fed. Reg.* 57,864-66 (Final Montana Regional Haze FIP), 76 *Fed. Reg.* 58,630 (Proposed North Dakota Regional Haze FIP) and 77 *Fed. Reg.* 20,894-96 (Final North Dakota Regional Haze FIP).

[62] 80 FR at 18997.

[63] "Repower" means to change the fuel type for the boiler from coal to natural gas or fuel oil.

[64] As discussed in our final rule, Entergy also submitted a comment after the close of the comment period, indicating that Entergy intends that a second alternative described in the late comment, involving only White Bluff, is a replacement for the multi-unit alternative previously described in its timely comments. Because the late comment is not a basis for our decision making in this final rule, we are responding in this RTC document and in our final rule to the alternative proposal described in the comments that Entergy filed during the comment period.

We do believe that the elements of the strategy Entergy has presented in its comments that apply specifically to White Bluff have potential merit with respect to addressing the BART requirements for White Bluff Units 1 and 2, if they were not linked to our action on Independence. Our detailed analysis of Entergy's alternative strategy is discussed below and elsewhere in this document. A chief element of Entergy's alternative is its proposal to cease coal combustion at White Bluff Units 1 and 2. It is unclear from the comments submitted whether this would mean the shutdown or the repowering of White Bluff Units 1 and 2. Regardless of this ambiguity, a number of commenters have argued that because of Entergy's proposal, we should use a shorter remaining life in assessing the costs of controls at White Bluff. Entergy too suggests that EPA must take into account a shorter remaining useful life based on its "proposed commitment." If we were to assume that Entergy were proposing changes at White Bluff regardless of our action regarding Independence, we could include in our final FIP an enforceable requirement for the shutdown (or repowering) and take that change into consideration as part of a BART determination. The BART Guidelines state that where unit shutdown affects the BART determination, the shutdown date should be assured by a federally or state-enforceable restriction preventing further operation.[65] Given the long-life of coal-fired power plants such as White Bluff, it would be unreasonable to assume that such shutdowns will occur without an enforceable requirement. Although we could include such a requirement in our FIP, there is no evidence in the comments submitted by Entergy during the comment period that it intends to cease coal combustion at White Bluff Units 1 and 2 at this time absent a broader agreement on appropriate controls for both White Bluff and Independence. As such, we do not consider it appropriate to include a requirement to cease coal combustion at White Bluff Units 1 and 2 in our rule unless we were to also accept the Entergy proposal as meeting all requirements with respect to Independence. Therefore, we are assuming a remaining useful life of 30 years for White Bluff Units 1 and 2 when determining BART for these units.

We discuss elsewhere in this document (in our response to the next set of comments) the merits of Entergy's proposed strategy as an alternative approach for both meeting the BART requirement of section 308(e) for White Bluff and meeting the requirements of sections 308(d)(1) and 308(d)(3) regarding reasonable progress, which implicate all sources in Arkansas including Independence.

We do note that if Arkansas submits a RH SIP revision to replace our FIP, the State has the discretion to consider an approach to address the BART requirements for White Bluff that involves ceasing coal combustion at Units 1 and 2 by a date certain, but the SIP revision is required to also include consideration and evaluation of dry sorbent injection (DSI) as a possible interim BART control option. We discuss this issue in more detail in our response to the next set of comments. With respect to Independence, as we stated above, a strategy that includes controls for Independence similar to what the company has proposed for White Bluff (i.e., interim SO_2 controls, ceasing coal combustion, and NO_X controls) would also have potential merit with respect to addressing the reasonable progress requirements for Independence Units 1 and 2. The state has the discretion to consider submitting a SIP revision that includes such a strategy for Independence to replace our FIP.

[65] See Appendix Y to 40 CFR Part 51- Guidelines for BART Determinations Under the Regional Haze Rule, section IV.D.4.k.

We address comments stating that we used outdated costs in our BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation, in the section of this document where we discuss cost issues. As discussed there, we have revised our cost calculations for White Bluff Units 1 and 2 in response to the comments received on our initial cost analysis. Based on this revised analysis, we have determined that dry scrubbers are estimated to cost \$2,565/SO_2 ton removed at Unit 1 and \$2,421/SO_2 ton removed at Unit 2. Many EGUs have installed and operated this type of controls successfully, and our cost analysis indicates that dry scrubbers at White Bluff would be cost effective and well within the range of cost of controls found to be reasonable by EPA and the States in their BART determinations. We address Entergy's detailed comments regarding the White Bluff cost analysis in the section of this document where we discuss cost issues.

With regard to the comment that NO_X BART for all EGUs in Arkansas should be compliance with CSAPR given that EPA determined that CSAPR is better than BART, we discuss elsewhere in this document why we are not relying on CSAPR to satisfy the NO_X BART requirement for Arkansas EGUs in this rulemaking. We are instead requiring source specific NO_X BART controls. We also address elsewhere in this RTC document Entergy's comments regarding the NO_X emission limits for White Bluff and Independence.

Regarding the comment that in our analysis of BART controls for White Bluff we made references to AEP that made it unclear whether we actually relied on Entergy's revised White Bluff BART Analysis in our proposal, we confirm that we reviewed and based our analysis on Entergy's 2013 Revised White Bluff BART analysis.[66] The reference we made to AEP's modeling and assumptions at 80 FR 18969 was a typographical error; we mistakenly referenced materials from AEP, but did not use AEP's modeling and assumptions in our BART determination for White Bluff. This typographical error did not affect our proposed BART decision for White Bluff Units 1 and 2.

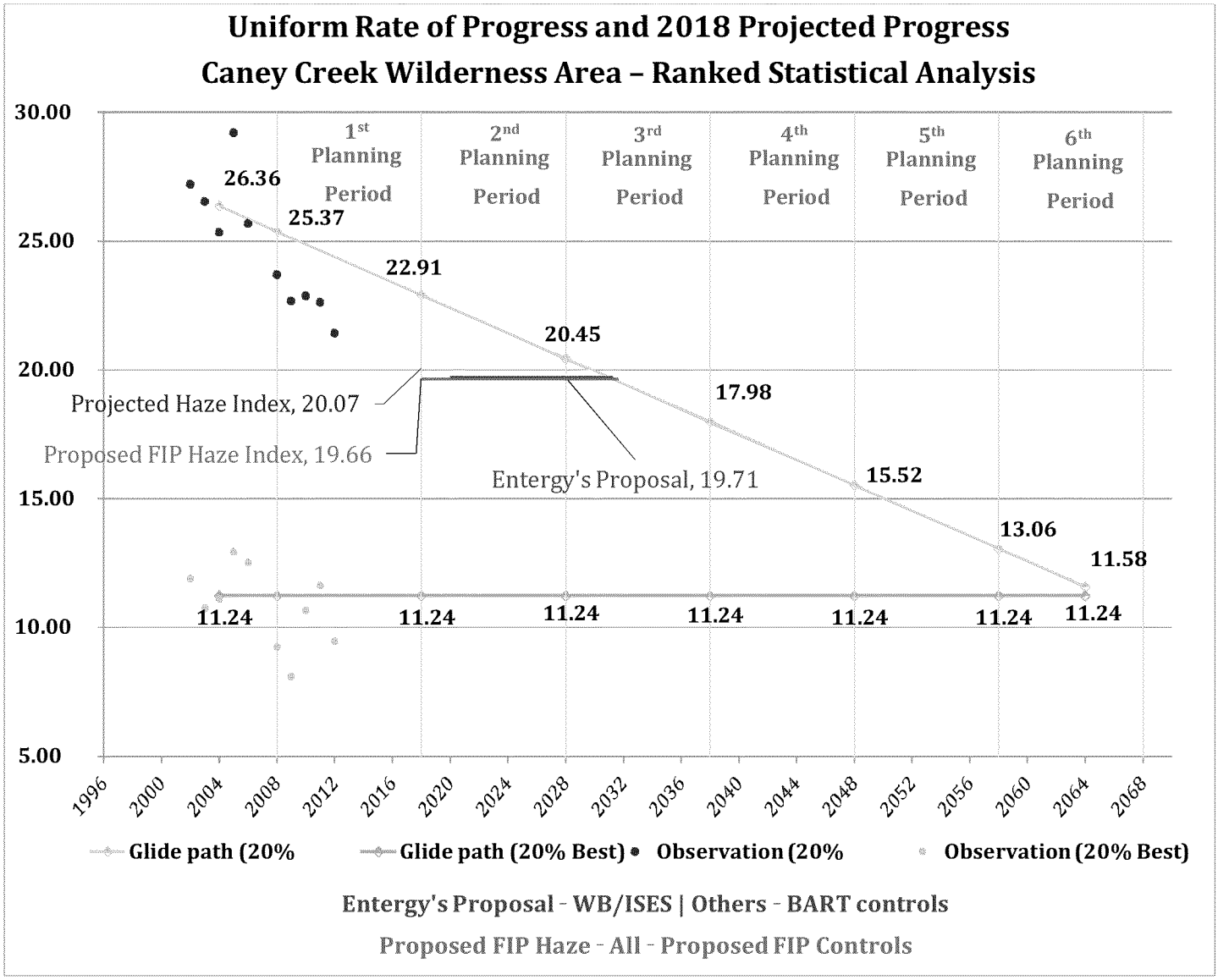
Comment: EPA's final FIP should include Entergy's proposed multi-unit approach for White Bluff and Independence, which achieves virtually identical visibility benefits as EPA's proposal for over \$2 billion less.

[Entergy Arkansas Inc. (0166) p. 45-49] Entergy stated that it is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy is proposing to meet lower SO_2 emission rates at White Bluff Units 1 and 2 and Independence Units 1 and 2 by 2018, and is willing to install LNB/SOFA at all four units and meet a 30-day rolling average NO_X emission rate of 1,342.5 lb NO_X/hr, within three years after the effective date of the final FIP as part of its multi-unit approach. This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's proposal but at a cost of over \$2 billion less than the proposal. *See* the figures below, which compare the projected 2018 haze index at each Arkansas Class I area based on a Ranked Statistical Analysis, to the deciview improvements projected for the following scenarios (1)

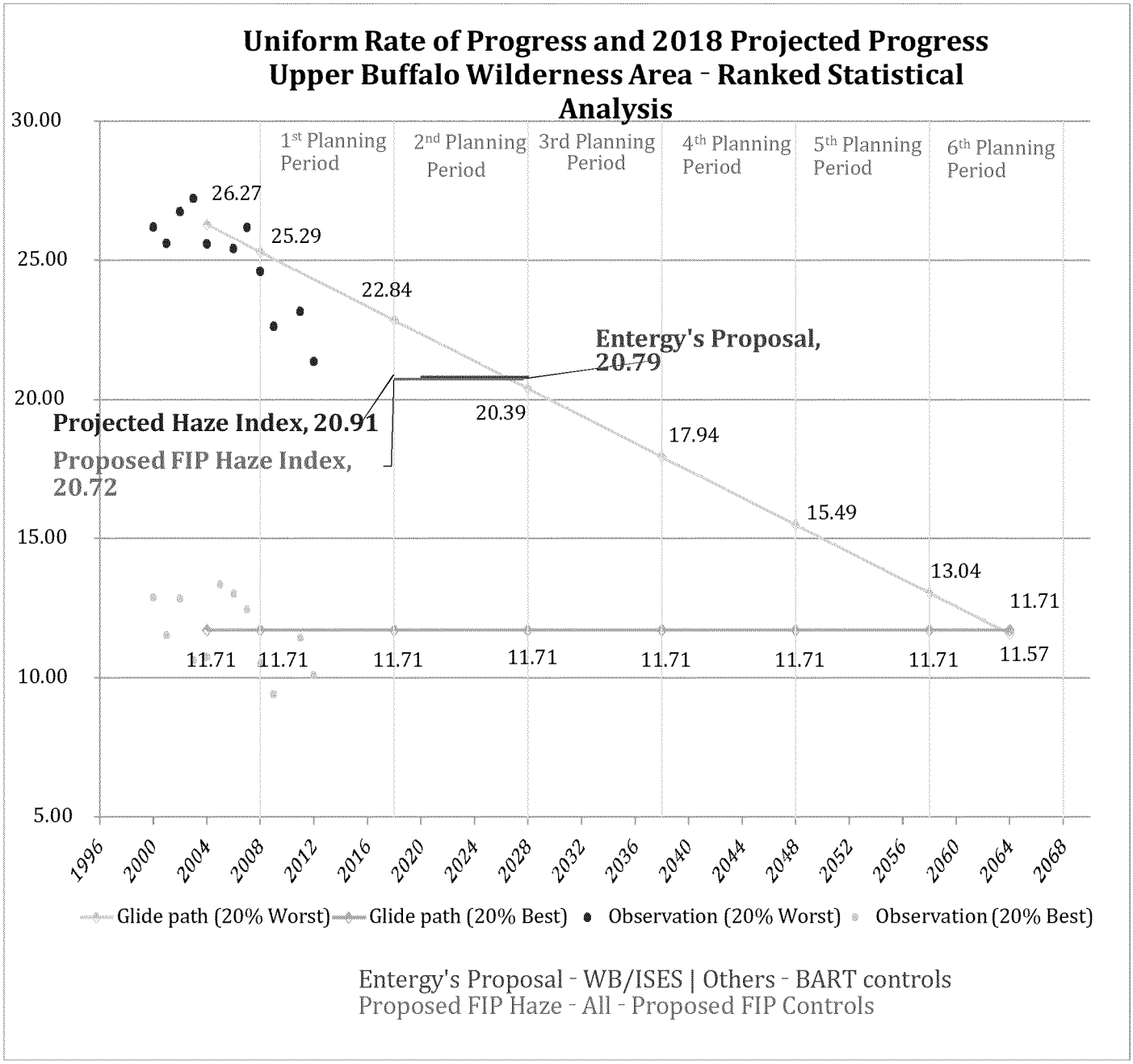
[66] "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc.

Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of EPA's proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 dv at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

"Uniform Rate of Progress and 2018 Projected Progress for Caney Creek- Ranked Statistical Analysis"
(provided by Entergy as Figure 13 to AR020.0166)



"Uniform Rate of Progress and 2018 Projected Progress for Upper Buffalo Wilderness Area- Ranked Statistical Analysis"
(provided by Entergy as Figure 14 to AR020.0166)



Entergy stated that its proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state

currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 of Entergy's comments. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NO_X, SO_2, and PM heading into the third planning period.

Entergy stated that ultimately, its approach would achieve 170,000 tons of NO_X reductions from White Bluff more than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NO_X would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NO_X and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_{2e}. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

Entergy stated that it opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. Controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

[Entergy Mississippi Inc. (0168) p. 14 and Conway Corporation et. al. (0172) p. 15] Entergy Mississippi Inc. (EMI) and Conway Corporation et. al. both stated that EPA requested public comment on any alternative SO_2 and NO_X control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA proposed for the first planning period.

[Entergy Mississippi Inc. (0168) p. 14] EMI stated it understands that Entergy Arkansas Inc. is proposing the cessation of coal combustion at White Bluff by 2028, the installation of LNB/SOFA at White Bluff Units 1 and 2 and Independence Plant's Units 1 and 2, and to meet lower SO_2 emission rates at all four units by 2018. This combination of controls and lower SO_2 emission rates ensures that the relevant Class I areas achieve virtually the same reasonable progress as EPA's proposed rule but at a significantly lower cost to EMI and its customers.

[Conway Corporation et. al. (0172) p. 15] Conway Corporation et. al. stated it understands that Entergy is proposing to cease burning coal at the White Bluff Plant by 2028, and to install LNB/SOFA at Independence Units 1 and 2, and to meet lower SO_2 emission rates at all four units by 2018. Conway Corporation et. al. support this proposed approach, which ensures that the

Class I areas achieve virtually the same reasonable progress as EPA's proposal but at significantly less cost to commenters and their customers.

[Entergy Mississippi Inc. (0168) p. 14 and Conway Corporation et. al. (0172) p. 15] EMI and Conway Corporation et. al. both stated they strongly encourage EPA to amend the proposed rule as described in Entergy's comments and to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure comparable or superior, long-term visibility benefits than the proposed FIP for $2 billion less. It also would deliver important non-haze environmental benefits, including a dramatic decrease in greenhouse gas emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NO_X emissions.

Response: After carefully considering the comments we received, we have determined that Entergy's alternative proposal[67] is not a better than BART alternative, does not meet the BART requirements for White Bluff Units 1 and 2, does not meet the reasonable progress requirements, and does not provide for the same visibility benefits as the FIP while delaying a majority of the visibility benefits until several years later than the FIP. The details of our assessment of the merits of Entergy's proposed strategy as an alternative approach for both meeting the BART requirement of section 308(e) for White Bluff and meeting the requirements of sections 308(d)(1) and 308(d)(3) regarding reasonable progress, which implicate all sources in Arkansas, including Independence, are as follows.

First, we note that Entergy does not appear to be proposing that we apply the provisions of sections 308(e)(2) and 308(e)(3) to determine that its multi-unit strategy is an alternative to BART that provides more reasonable progress than BART by the end of the first implementation period, which is December 31, 2018. To the extent that this is Entergy's proposal, those provisions clearly would not allow Entergy's multi-unit plan to be approved as an alternative to BART because it does not meet the requirements of section 308(e)(2)(ii) that "all necessary emission reductions take place during the period of the first long-term strategy for regional haze." Moreover, Entergy does not argue that its alternative would provide for "greater" reasonable progress, only that its proposal would result in "virtually the same" visibility benefits. Thus, our analysis considers only the requirements of section 308(e)(1), which contains the source-specific BART requirements, in considering the provisions of Entergy's alternative proposal applicable to White Bluff. (We address elsewhere in this document the issue of whether our FIP should apply the provisions of section 308(e)(4) for purposes of meeting the BART requirement for NO_X emissions for EGUs in Arkansas.)

Next, we also note that Entergy does not appear to be requesting in the comments submitted during the comment period that we adopt the elements in its alternative proposal that are unique to White Bluff as an alternative to our proposed BART emission limits at the facility unless we

[67] As discussed in our final rule, Entergy also submitted a comment after the close of the comment period, indicating that Entergy intends that a second alternative described in the late comment, involving only White Bluff, is a replacement for the multi-unit alternative previously described in its timely comments. Because the late comment is not a basis for our decision making in this final rule, we are responding in this RTC document and in our final rule to the alternative proposal described in the comments that Entergy filed during the comment period.

also conclude that the remaining elements address any reasonable progress requirements for Independence. In other words, Entergy's comments provide no indication that it is willing to accept a binding requirement to cease coal combustion at White Bluff by 2027/2028, unless we also accept the elements of its alternative proposal that are applicable to Independence as satisfying the reasonable progress requirements. As we discuss below, we conclude that the elements of Entergy's alternative proposal that are specific to Independence do not satisfy the reasonable progress requirements. Even if we had interpreted Entergy's comments as requesting that we adopt the particular elements in its alternative proposal that apply to White Bluff as an alternative to our proposed BART emission limits at the facility without these elements being linked to the remaining elements addressing the reasonable progress requirements for Independence, we conclude that we would not be able to incorporate the Entergy alternative proposal into the final FIP as a way of meeting the BART requirements for White Bluff because, as we discuss below, Entergy's alternative proposal does not satisfy the source-specific BART requirements of section 308(e)(1) for White Bluff.

Entergy's alternative strategy would achieve minimal SO_2 emission reductions over the next 10 to 11 years. Entergy proposes that White Bluff Units 1 and 2 would meet an SO_2 interim emission limit of 0.6 lb/MMBtu on a rolling 30-day average beginning in 2018 through 2027/2028 when coal combustion at the two units would cease.[68] We note that the 0.6 lb/MMBtu interim emission limit is only slightly lower than the units' current SO_2 emission rates. We have no basis to assume that future emissions would be lower than these current rates in the absence of new SIP or FIP requirements, and so these current emission rates are the appropriate baseline for comparing strategies, rather than the currently permitted emission rates, which are higher; Entergy does not appear to dispute this point. The maximum monthly SO_2 emission rates for White Bluff Units 1 and 2 in 2009-2013 were 0.653 lb/MMBtu and 0.679 lb/MMBtu, respectively.[69] Thus, under Entergy's alternative proposal, the White Bluff units would continue to operate for the remainder of the first planning period at near the current emission rate and throughout most of the second planning period with only a slight actual reduction in SO_2 emissions. Entergy has provided no analysis to show that there is no more effective measure for White Bluff for this interim period that is needed to make reasonable progress. Section 308(e)(1) and the BART guidelines require that a subject-to-BART source install and operate the best available emission reduction technology based on the five statutory factors, and it is therefore necessary to consider whether there are any additional SO_2 control measures, such as dry sorbent injection (DSI), that constitute BART during this interim period. Entergy has argued that with this limited remaining period of coal combustion, the cost per ton of SO_2 emissions reduction for scrubbers would be too high for scrubbers to be selected as BART for White Bluff. While we agree that a shorter remaining useful life might result in a conclusion that dry scrubbers are not cost effective, as part of the BART analysis, technically feasible control technologies beyond the interim SO_2 emission limit the company has proposed must be evaluated to determine if they are

[68] Although not specified in Entergy's written comments, the company met with us and confirmed that the interim SO_2 emission limit would be achieved by combusting lower sulfur coal. See file titled "Record of Meeting_October 27 2015," which is found in the docket for this rulemaking.

[69] 80 FR at 18970; see also the spreadsheet titled "White Bluff_R6 cost revisions2," which is found in the docket for this rulemaking.

cost effective for use in the period before coal combustion ceases.[70] In particular, DSI has a relatively low capital cost and may be cost effective even if operated for a short period of time.[71] Under Entergy's proposed strategy, White Bluff Units 1 and 2 would cease coal combustion towards the end of the second planning period. Therefore, it would be necessary to consider and evaluate DSI as a possible interim BART control option for White Bluff Units 1 and 2. Because Entergy has provided no analysis or any pertinent information or documentation to demonstrate that there is no more effective interim SO_2 control that would constitute BART for White Bluff, the company's proposed strategy is not adequate to ensure that the BART requirements for White Bluff Units 1 and 2 will be met.

Further, even if it were not necessary to evaluate DSI or if we were to determine that DSI is not cost effective for use at White Bluff in the interim period before coal combustion ceases, Entergy's alternative proposal would still not satisfy the BART requirements for White Bluff because the alternative proposal does not include SO_2 and NO_X emission limits after coal combustion ceases or otherwise propose adopting a binding requirement to burn only natural gas or completely shut down the units. Entergy proposes to cease coal combustion at White Bluff Units 1 and 2 in 2027/2028, but its comments do not specify the operating conditions of White Bluff Units 1 and 2 after coal combustion ceases. The type of fuel White Bluff is permitted to burn after ceasing coal combustion will impact the emissions reductions actually achieved under Entergy's alternative proposal. Exhibit C to Entergy's comments indicates that the company assumes in its visibility modeling that SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under the company's alternative proposal (i.e., "Entergy's proposed controls" scenario).[72] If Entergy's alternative proposal had included accepting a binding requirement to burn only natural gas at White Bluff Units 1 and 2 after coal combustion ceases, or a binding requirement to completely shut down the units, then we would agree that it would be appropriate to assume that SO_2 emissions from White Bluff will be zero beginning in 2027/2028. Similarly, if Entergy's alternative proposal had included accepting a binding requirement to completely shut down White Bluff or included a NO_X emissions limit, then we would agree that it would be appropriate to assume that NO_X emissions from White Bluff will be zero beginning in 2027/2028. However, Entergy's alternative proposal does not specify any such binding requirements that would ensure SO_2 and NO_X emissions from White Bluff are appropriately controlled after coal combustion ceases.

With regard to Independence, we note that Entergy's proposal to cease coal combustion at White Bluff does not change our conclusion that it is necessary to control Independence under the reasonable progress requirements. Under Entergy's proposed approach, Independence Units 1 and 2 would be subject to an SO_2 emission limit of 0.6 lb/MMBtu on a rolling 30-day average

[70] As discussed elsewhere in this response, the SO_2 interim emission limit of 0.6 lb/MMBtu proposed by the company for White Bluff Units 1 and 2 is only slightly less than the units' current SO_2 emission rates, meaning that only slight actual SO_2 emissions reductions are expected to take place as a result of the interim emission limit.
[71] For example, Florida evaluated a shutdown option by December 31, 2020 for two BART units. After reviewing the Florida Regional Haze SIP, we concluded that the State should have evaluated DSI as a as a possible interim BART control option during the interim before the units shut down. We ultimately approved Florida's determination after evaluating the cost-effectiveness of DSI and concluding that such controls were not cost-effective in light of the remaining useful life of the units. See 78 FR at 53261.
[72] See "Regional Haze Modeling Assessment Report," dated August 4, 2015, submitted as Exhibit C to Entergy Arkansas Inc.'s comments.

beginning in 2018.[73] This emission limit is only slightly lower than the current SO_2 emission rates from Independence Units 1 and 2. The maximum monthly SO_2 emission rates for Independence Units 1 and 2 in 2009 – 2013 were 0.631 lb/MMBtu and 0.612 lb/MMBtu, respectively.[74] We have no basis to assume that future emissions would be different from current rates in the absence of new SIP or FIP requirements, and so these current emission rates are the appropriate baseline for comparing strategies, rather than the currently permitted emission rates, which are higher. As such, under Entergy's proposal these units would continue to operate with minimal SO_2 emissions reductions. Unlike Entergy's proposed approach with respect to White Bluff, the proposed SO_2 limit for Independence would not be an interim emission limit. The company's alternative proposal does not include any further SO_2 controls for Independence Units 1 and 2, such as DSI or the eventual cessation of coal combustion. In light of the minimal SO_2 emissions reductions that would be achieved at Independence under the company's proposed strategy, we expect that there would be correspondingly minimal visibility improvement with respect to the SO_2 controls it proposes for Independence. SO_2 emissions are the primary driver of regional haze in Arkansas' Class I areas on the 20% worst days and Independence is the second largest source of SO_2 in the State of Arkansas.[75] As explained in our proposal, the preamble to our final action, and elsewhere throughout this document, our consideration of the four reasonable progress factors and consideration of the visibility impacts and visibility improvement of controls for Independence revealed that dry scrubbers are needed on both units to make reasonable progress. Additionally, we received CAMx source apportionment modeling from Entergy during the comment period that estimates the average visibility impairment from Independence during the 20% worst days. As we discuss in the section of this document where we discuss modeling issues, the results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. As such, Entergy's proposal to cease coal combustion at White Bluff does not change our conclusion that it is necessary to control Independence under the reasonable progress requirements. Since Entergy's alternative proposal includes minimal SO_2 control for Independence, thus omitting controls that we found to be cost effective and that are anticipated to result in considerable visibility benefits at Arkansas' Class I areas, we conclude that the elements of Entergy's alternative proposal that are specific to Independence do not satisfy the reasonable progress requirements for Independence.

Although, as we have already established, Entergy's alternative proposal cannot constitute a BART alternative because all necessary emission reductions will not take place during the first implementation period and the alternative proposal also does not satisfy the source-specific BART requirements of section 308(e)(1) for White Bluff and the requirements of sections

[73] Although not specified in Entergy's written comments, the company met with us and confirmed that this emission limit would be met by combusting lower sulfur coal. See file titled "Record of Meeting_October 27 2015," which is found in the docket for this rulemaking.
[74] See the spreadsheet titled "White Bluff_R6 cost revisions2," which is found in the docket for this rulemaking.
[75] CENRAP CAMx modeling shows that on most of the 20% worst days in 2002, total extinction is dominated by sulfate at both Caney Creek and Upper Buffalo. Therefore, SO_2 emissions are considered the primary driver of haze in Arkansas' Class I areas. However, as discussed elsewhere in this RTC document, we consider both SO_2 and NO_X to be key visibility impairing pollutants in Arkansas' Class I areas. See Arkansas RH SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas RH SIP.

308(d)(1) and 308(d)(3) regarding reasonable progress, in response to Entergy's comment that its alternative proposal would achieve almost the same level of visibility benefit as the FIP, we compared the potential impacts of Entergy's proposal to our FIP. Despite the ambiguity in the comments submitted by Entergy regarding its alternative proposal, for purposes of assessing the visibility impacts of the company's proposed approach we have assumed that post-2028 SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under Entergy's alternative proposal. In the Table below, we compare the total annual SO_2 emissions reductions that would result under our FIP and under Entergy's alternative proposal when the alternative proposal is fully implemented in 2028 (i.e., when coal combustion has ceased at White Bluff).[76] For consistency and to allow for direct comparison to our FIP proposal, in estimating the SO_2 emissions reductions anticipated to result from Entergy's alternative proposal we have assumed the same SO_2 baseline emissions we used for White Bluff and Independence in our proposal.[77]

Comparison of Annual SO_2 Emissions Reductions from White Bluff Units 1 and 2 and Independence Units 1 and 2 (Post-2028)

Unit	SO_2 Baseline Emissions (tpy)	FIP proposal- Annual SO_2 reductions[1]	Entergy alternative proposal- Annual SO_2 reductions[2]	Additional SO_2 Emissions Reductions achieved by FIP proposal
White Bluff Unit 1	15,816	14,363	15,816	(1,453)
White Bluff Unit 2	16,697	15,221	16,697	(1,476)
Independence Unit 1	14,269	12,912	1,291[3]	11,621
Independence Unit 2	15,511	13,990	1,399[3]	12,591
Total- All four units combined (SO_2 tpy)	62,293	56,486	35,203	21,283

[1] These SO_2 reductions will begin taking place no later than 5 years from the effective date of this final FIP.

[2] This takes into account the full SO_2 reductions that would take place under Entergy's alternative proposal; a small amount of SO_2 reductions would begin taking place in 2018, but the majority of these SO_2 reductions would begin taking place in 2027/2028.

[3] As Entergy's proposed SO_2 emission limit for Independence Units 1 and 2 is one order of magnitude greater than our proposed SO_2 emission limit (i.e., 0.6 lb/MMBtu vs. 0.06 lb/MMBtu), we have accordingly estimated that the SO_2 emissions from Independence under the Entergy alternative would be one order of magnitude greater than under our FIP. Thus, we estimated SO_2 emissions reductions of 1,291 tpy and 1,399 tpy from Units 1 and 2 under the Entergy alternative. However, even if we were to accept Entergy's estimate of SO_2 reductions at Independence of 2,104 tpy at Unit 1 (14,258 – 12,154= 2,104 tpy) and 2,245 tpy at Unit 2 (15,407 – 13,162= 2,245 tpy), this does not change our conclusion that substantially greater SO_2 emissions reductions would be achieved at Independence under our FIP proposal. See Appendix A of "Regional Haze Modeling Assessment Report," dated August 4, 2015, submitted as Exhibit C to Entergy Arkansas Inc.'s comments.

[76] The SO_2 emissions reductions expected to result from our FIP will take place several years earlier than any significant SO_2 reductions under Entergy's alternative proposal. However, for purposes of comparing the long-term emissions reductions under the FIP and under the Entergy alternative, we are assessing the annual emissions reductions that will take place beginning in 2028, when the Entergy alternative would be fully implemented.

[77] In our proposal, for purposes of estimating the annual SO_2 emissions reductions due to controls on White Bluff Units 1 and 2 and Independence Units 1 and 2, we assumed an SO_2 emissions baseline that was determined by examining annual SO_2 emissions for the years 2009-2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years. See 80 FR at 18971 and 18992.

As shown in the Table above, although Entergy's alternative proposal would, after 2027/2028, achieve slightly greater SO_2 reductions at White Bluff Units 1 and 2 than our FIP proposal, it would achieve substantially lower SO_2 reductions at Independence Units 1 and 2. Thus, considering the four units combined, we estimate that our FIP proposal would achieve emissions reductions of 21,283 SO_2 tpy more than Entergy's alternative proposal. With regard to the visibility benefits, Entergy does not assert that its alternative proposal would provide equal of greater visibility benefits relative to our proposed FIP once the alternative is fully realized in the period after 2027/2028. Entergy states only that its alternative proposal would provide almost the same visibility benefit as our proposed FIP post-2027/2028. We conclude that not even this assertion is adequately supported, and that the long-term visibility benefits of the Entergy alternative proposal would be significantly smaller than those of the proposed and final FIP. As we explained above, Entergy assumes in its visibility improvement projections that SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under the company's alternative proposal. The assumption of zero SO_2 emissions from White Bluff after coal combustion ceases would be appropriate only if Entergy's alternative proposal involves accepting a binding requirement to burn only natural gas or permanently shut down after coal combustion ceases.[78] With respect to NO_X emissions from all four units of White Bluff and Independence, Entergy's multi-unit strategy includes the same level of NO_X control as our FIP proposal prior to the cessation of coal combustion at White Bluff in 2027/2028. Since Entergy's explanation of its alternative proposal does not specify the operating conditions of White Bluff Units 1 and 2 when coal combustion ceases in 2027/2028, we find that the assumption of zero NO_X emissions is also not adequately supported. However, even if we accept Entergy's assumption that SO_2 and NO_X emissions from White Bluff will be zero after coal combustion ceases and that its alternative proposal would thus achieve greater NO_X reductions compared to our FIP proposal, given the dominance of visibility impact from sulfate compared to nitrate at the affected Class I areas in Arkansas, the higher visibility impacts due to sulfate under the Entergy alternative proposal would more than outweigh any extra nitrate-related visibility benefit. Entergy's own CAMx modeling shows that even assuming zero SO_2 and NO_X emissions from White Bluff once it ceases coal combustion, its multi-unit alternative proposal would achieve less visibility benefit than the FIP controls at Arkansas' Class I areas, most significantly at Upper Buffalo where the benefit from Entergy's proposal is approximately only 66% of the benefit from the FIP (i.e., 1.54 dv visibility benefit from the FIP compared to 0.97 dv from Entergy's alternative proposal). Thus, we have determined that Entergy's alternative proposal would not achieve "virtually the same" level of reasonable progress in Arkansas' Class I areas as our FIP proposal, and that it would delay a majority of the visibility benefits until several years later than the FIP. We address elsewhere in this document specific comments regarding Entergy's photochemical modeling of visibility benefits from the controls in our proposed FIP and Entergy's alternative multi-unit strategy, as well as Entergy's ranked statistical analysis.

We agree that ceasing coal combustion at White Bluff Units 1 and 2 could result in additional PM emissions over our FIP proposal. But since actual PM emissions from the units are already

[78] On the other hand, if White Bluff Units 1 and 2 are permitted to burn fuel oil after coal combustion ceases, it is not appropriate to assume that SO_2 emissions will be "0" under the company's proposed approach. In fact, if the units will be permitted to burn high sulfur fuel oil after coal combustion ceases, we expect that the SO_2 emission rate under the company's proposed approach would be even higher than the SO_2 emission rate under our proposed FIP.

very low because the units are equipped with electrostatic precipitators (ESPs), we do not expect that the additional PM emissions reductions from ceasing coal combustion would be considerable. Additionally, because PM emissions from White Bluff contribute very little to haze at Arkansas' Class I areas, we do not believe that the additional PM reductions that would be achieved would provide a significant visibility benefit at the Class I areas.[79] We also recognize that ceasing coal combustion at White Bluff Units 1 and 2 could result in greater nonair environmental benefits and in more emission reductions of mercury and other hazardous air pollutants and CO_2/CO_{2e} than our proposed FIP. However, in assessing Entergy's alternative proposal, we do not find it necessary to weigh the nonair quality environmental benefits with the other statutory factors since we ultimately find that we cannot accept Entergy's alternative proposal because it does not satisfy the requirements of the Regional Haze Rule. As discussed earlier in our response, we conclude that Entergy's proposal does not satisfy the requirements to be considered a better-than-BART alternative under sections 308(e)(2) and 308(e)(3); does not satisfy the source-specific BART requirements under section 308(e)(1) for White Bluff; does not satisfy the reasonable progress requirements under section 308(d)(1); and does not provide for the same visibility benefits as the FIP, while delaying a majority of the visibility benefits until several years later than the FIP. For these reasons, we cannot adopt Entergy's alternative approach in lieu of our FIP.

With regard to Entergy's comment regarding the cost to install dry FGD, we note that we have revised our cost calculations of SO_2 controls for White Bluff Units 1 and 2 in response to the comments received on our initial cost analysis. Based on our revised cost analysis, we have found that dry scrubbers on White Bluff are estimated to cost \$2,565/SO_2 ton removed at Unit 1 and \$2,421/SO_2 ton removed at Unit 2. After revising our cost estimates for dry scrubbers on White Bluff, we continue to believe that dry scrubber controls and LNB/SOFA controls are cost effective at White Bluff Units 1 and 2 and would result in significant visibility improvement at Arkansas' Class I areas based on our CALPUFF modeling of the 98th percentile visibility impacts from the facility.[80] Based on our consideration of the five BART factors, we have determined that controls consistent with dry scrubber and LNB/SOFA installation are BART for White Bluff Units 1 and 2. We address Entergy's comments regarding the cost to install dry FGD in the section of this document where we address cost issues.

As we discuss in our final rule, based on our consideration of the four reasonable progress factors and of the visibility impacts and visibility improvement of controls on Independence, we have determined that dry scrubbers and LNB/SOFA controls on Independence Units 1 and 2 are necessary to make reasonable progress at Arkansas' Class I areas. We have also revised our cost calculations of SO_2 controls for these units in response to the comments received on our initial cost analysis. Based on our revised cost analysis, we have found that dry scrubbers on Independence are estimated to cost \$2,853/SO_2 ton removed at Unit 1 and \$2,634/SO_2 ton removed at Unit 2. After revising our cost estimates for dry scrubbers on Independence, we

[79] "Since we have found that the visibility impact of the source [White Bluff] due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and subbituminous coal firing scenarios is the existing PM emission limit for [White Bluff] Units 1 and 2." 76 FR 64205.

[80] See 80 FR at 18972. Our FIP proposal provides a detailed discussion of the visibility improvement of these controls based on our CALPUFF modeling.

continue to believe that both dry scrubber and LNB/SOFA controls are cost effective. We also find that these controls on Independence would provide significant visibility improvement as projected by our CALPUFF modeling that focuses on the 98th percentile impacts from the facility.[81] Additionally, the CAMx photochemical modeling submitted by Entergy shows that the contribution to visibility impairment due to baseline emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the average 20% worst days in 2018 at each Arkansas Class I area. We consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources. The results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30 – 40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days.[82] We expect that installation of cost-effective NO_X controls on Independence would provide visibility improvement on this portion of the 20% worst days, and as such, are requiring both SO_2 and NO_X controls under the reasonable progress requirements.

We do note that if Arkansas submits a regional haze SIP revision to replace our FIP, the state has the discretion to consider an approach to address the BART requirements for White Bluff that involves ceasing coal combustion at Units 1 and 2 by a date certain, but an approvable SIP revision must also include consideration and evaluation of DSI as a possible interim BART control option. With respect to Independence, a strategy that includes controls for Independence similar to the elements of Entergy's alternative proposal that are specific to White Bluff (i.e., interim SO_2 controls, ceasing coal combustion in the near future, and NO_X controls) would also have potential merit with respect to addressing the reasonable progress requirements for Independence Units 1 and 2. The state may consider submitting a SIP revision that includes such a strategy for Independence to replace our FIP.

With regard to the numeric RPGs we are finalizing, we note that we proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo of 22.27 dv and 22.33 dv, respectively, that reflected the anticipated visibility conditions resulting from the combination of control measures from the approved portion of the 2008 Arkansas Regional Haze SIP and our FIP proposal. We received comments on our proposal indicating that our proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo improperly incorporated visibility improvements that would not occur until after 2018. After considering these comments, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented, and we are therefore revising the RPGs we proposed. This approach is consistent with the purpose of RPGs and the direction provided in our 2007 Reasonable Progress Guidance.[83]

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[81] 80 FR 24872.

[82] This means 2 out of the 21 days that are the 20% worst of the days with IMPROVE monitoring data.

[83] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," dated June 1, 2007.

Section 169B(e)(1) of the CAA directed the Administrator to promulgate regulations that "include[e] criteria for measuring 'reasonable progress' toward the national goal." Consequently, we promulgated 40 CFR 51.308(d)(1) as part of the Regional Haze Rule. This provision directs states to develop RPGs for the most and least impaired days to "measure" the progress that will be achieved by the control measures in the state's long-term strategy "over the period of the implementation plan."[84] The current implementation period ends in 2018. RPGs "are not directly enforceable" like the emission limitations in the long-term strategy.[85] Rather, they fulfill two key purposes: (1) allowing for comparisons between the progress that will be achieved by the state's long-term strategy and the URP,[86] and (2) providing a benchmark for assessing the adequacy of a state's SIP in 5-year periodic reports.[87] Consequently, in our 2007 Reasonable Progress Guidance, we indicated that states could consider the "time necessary for compliance" factor by "adjust[ing] the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018."[88] In other words, RPGs need not reflect the visibility improvement anticipated from all of the control measures deemed necessary to make reasonable progress (as a result of the four-factor analysis) and included in the long-term strategy.
In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due. As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021. Because RPGs are only unenforceable analytical benchmarks, we think that it is appropriate to follow the recommendation in our 2007 Reasonable Progress Guidance and finalize RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018. These RPGs are listed in the table below:[89]

Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I area	2018 RPG 20% Worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

We note that the RPGs we are finalizing are very similar to the ones that we disapproved in the Arkansas Regional Haze SIP. The reason for this is that Arkansas' RPGs were calculated using the 2018 CENRAP CAMx modeling completed in 2006/2007, which assumed that Flint Creek would install scrubbers to meet the presumptive SO_2 BART limit of 0.15 lb/MMBtu, that Flint Creek and White Bluff would install low NOx burners to satisfy NOx BART, and that AECC Bailey and Entergy Lake Catherine would be shut down by 2018. In contrast, our RPGs reflect a

[84] 40 CFR 51.308(d)(1).
[85] 40 CFR 51.308(d)(1)(iv).
[86] 40 CFR 51.308(d)(1)(ii).
[87] 40 CFR 51.308(g)-(h).
[88] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," at 5-2.
[89] These RPGs are calculated using the same methodology described in our proposal and TSD.
See "CACR UPBU RPG analysis 2018.xlsx" for additional information on the calculation of the RPGs.

more stringent SO_2 emission limit of 0.06 lb/MMBtu at Flint Creek and the installation of low NO_X burners at Independence in addition to Flint Creek and White Bluff, but also the continued operation of AECC Bailey and Entergy Lake Catherine. In other words, our RPGs reflect additional emission reductions from Flint Creek and Independence, but more emissions from AECC Bailey and Entergy Lake Catherine.

The fact that the RPGs we have calculated are very close to those originally submitted by Arkansas does not undermine the reasonableness of our action. We disapproved Arkansas' RPGs in part because Arkansas failed to conduct a four-factor analysis, as required by the CAA and the Regional Haze Rule. Without a four-factor analysis, we were unable to verify whether any additional control measures were necessary to make reasonable progress—the core requirement of the CAA's visibility program.[90] After conducting a full four-factor analysis, we have determined that controls at the Independence plant are cost-effective and reasonable and therefore necessary to make reasonable progress. The visibility benefits of the SO_2 controls at Independence, along with benefits of the SO_2 BART controls at White Bluff, and additional BART controls at AECC Bailey, AECC McClellan, Entergy Lake Catherine, and the Domtar Ashdown Mill will be fully realized in 2021, and we expect Arkansas to properly take these benefits into account when developing RPGs for 2028.

With regard to the comment that Entergy's alternative multi-unit strategy would ensure that Arkansas' Class I areas remain below the URP glidepath, we discuss elsewhere in this RTC document that being below the URP glidepath does not mean that the regional haze requirements are automatically satisfied or that no controls are necessary under the reasonable progress requirements. We also address comments regarding Arkansas' Five-Year Progress Report and comments regarding the URP glide path elsewhere in this RTC document.

We also address Entergy's specific comments regarding its proposed NO_X emission limits for White Bluff and Independence elsewhere in this RTC document.

3. Reasonable Progress Goals/ Reasonable Progress Analysis

3.a. EPA did not perform an adequate Reasonable Progress Analysis

Comment: EPA should allow time to determine the impacts of other regulatory programs and allow for better defined and more cost-effective decisions, especially considering there will be future opportunities to re-evaluate the RPGs and URPs.

[Entergy Mississippi Inc. (0168) p. 13; AEP-SWEPCO July 15, 2015 comments (0164) p. 3-5, and August 7, 2015 comments (0167) p. 4-5] EMI and American Electric Power/Southwest Electric Power Company (AEP-SWEPCO) both stated that EPA failed to consider the full improvements in visibility at Class I areas that will result from other emission reduction programs currently being implemented and, therefore, underestimated the likely overall visibility improvement in those areas. EPA determined CSAPR to be better than BART but did not quantify the added benefit that would result from that trading program over and above the site-

[90] CAA section 169A(b)(1) and (g)(1).

specific BART NO_X controls currently in the FIP. Implementation of the Mercury and Air Toxics Standards rule (MATS) will, in many cases, result in PM rates well below current emissions rates than those approved in Arkansas's SIP providing additional benefits not quantified in the RPG analysis. Additionally, implementation of the MATS rule and several other Clean Air Act programs, including CSAPR, the 1-hour SO_2 National Ambient Air Quality Standard (NAAQS), and the ozone NAAQS will, in many cases, also result in additional reductions in visibility-impairing pollutants beyond those relied upon when analyzing impacts at Arkansas' Class I Federal areas.[91] Time should be allowed for evaluating the emission reductions and visibility improvement impacts resulting from these programs before requiring the installation of expensive controls that may not achieve significant additional visibility benefits.

[AEP-SWEPCO July 15, 2015 comments (0164) p. 6, and August 7, 2015 comments (0167) p. 7-8] AEP-SWEPCO stated that imposing costly controls in the first planning period is unwarranted in such a long term goal program and that the obligation to consider costs is not only related to quantity but also timing. A much more prudent approach would be to allow time to determine the impacts of CSAPR, MATS, and other programs before requiring costly controls on a facility that will soon also need to reevaluate options related to the 111(d) program. Waiting until that program's requirements are better defined will allow for more cost-effective decisions.

AEP-SWEPCO stated that considering that the visibility improvements of these programs have not yet been quantified, and the gradual progress anticipated in establishing such a long term goal, EPA should be patient and not take such aggressive action in overriding a reasonable state SIP and imposing additional controls at this time. The regional haze program is not for the purpose of addressing health issues and the added visibility improvement associated with the controls proposed for the Independence facility do not indicate an urgent need to take this action. There will be many future opportunities for EPA to reevaluate the RPG and URP and the controls being contemplated could be added in later planning periods, if needed.

[Conway Corporation et. al. (0172) p. 11-12 and EEAA (0173) p. 15] Conway Corporation et. al. and EEAA stated that in proposing to require the installation of still more controls, EPA has again failed to consider the full improvements in visibility to Class I areas that will result from other emission reduction programs currently being implemented and has, therefore, underestimated the likely overall visibility improvement to those areas. EPA has determined CSAPR to be better than BART and has not quantified the added benefit that would result from that trading program over the site-specific BART NO_X controls currently in the FIP. Furthermore, implementation of the Mercury and Air Toxics Standards (MATS) rule will, in many cases, result in PM rates well below current emissions rates and those approved in Arkansas's SIP, providing additional benefits not quantified in the RPG analysis.[92]

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[91] Although the MATS rule was remanded by the U.S. Supreme Court in *Michigan et al. v* EPA, 135 S.Ct. 2699 (2015), EMI anticipates that, even if the rule is stayed or vacated while EPA undertakes its cost analysis in compliance with the Court's decision, MATS and its associated emission reductions will go forward by the end of the first planning period.

[92] Although the MATS rule was remanded by the U.S. Supreme Court in *Michigan et al. v EPA* (June 29, 2015), Commenters anticipate that even if the rule is stayed or vacated while EPA undertakes its cost analysis in compliance with the Court's decision, MATS and its associated emission reductions will go forward by the end of the first planning period.

Conway Corporation et. al. and EEAA stated that given that Arkansas' Class I areas are ahead of the URP necessary to obtain the national visibility goal even before implementation of BART, EPA should allow more time for evaluating the emission reductions and visibility improvement impacts resulting from these programs before requiring installation of expensive controls that may not achieve perceptible visibility benefits.

[EEAA (0173) p. 15-16] EEAA stated that in spite of the visibility benefits from other emission reduction programs (over and above currently documented visibility improvement), EPA is pushing forward with a proposal for additional controls under the guise of reasonable progress. EEAA disagrees with EPA's conclusion that additional controls are necessary to meet reasonable progress. A much more prudent approach would be to allow time to determine the impacts of CSAPR, MATS and other programs before requiring costly controls on a facility that will soon also need to reevaluate options related to the 111(d) program. Waiting until that program's requirements are better defined will allow for more reasonable, cost-effective decisions; and, the design and intent of the regional haze program is consistent with such a thoughtful and deliberative planning approach. Considering that the visibility improvements of these programs have not yet been quantified and the Regional Haze Rule's design for long-term gradual progress, EPA should be patient and should not take such unreasonable and aggressive action to impose costly controls that yield imperceptible visibility benefits.

Response: We disagree that EPA should delay implementation of this FIP to allow time for evaluating the emission reductions and visibility improvement impacts resulting from other EPA programs. Congress added the visibility provisions in section 169A of the CAA in 1977; Congress later amended the Act in 1990 tasking EPA to carry out its regulatory responsibilities under 169A. EPA issued the Regional Haze Rule in 1999 requiring states to submit regional haze SIPs by 2007. At this point, we do not consider it appropriate to further delay implementation of measures to improve visibility in Class I areas. In addition to the many delays in addressing visibility, we note that a significant portion of our FIP addresses the requirements for BART. Given the statutory and regulatory requirements for BART, we cannot put off implementation of these measures to see what other improvements to visibility might happen through the implementation of other programs. We further do not agree that the emission limitations for the Independence plant should be delayed. As explained elsewhere in this document, we have determined that the measures in the FIP applicable to Independence are cost-effective, will have a meaningful impact on visibility in Class I areas, and are appropriate for ensuring reasonable progress.

We also note that EPA has an obligation to promulgate a FIP within 2 years of disapproving a SIP in whole or in part, unless the State corrects the deficiency and EPA approves the plan. There is no authority in the CAA for EPA to further delay our action for the reasons provided by the commenter. The fact that we let two years elapse without fully approving a regional haze SIP led a district court in Arkansas to order EPA to finalize a RH rulemaking by a date certain (August 31, 2016).[93]

The Regional Haze Rule requires states to estimate 2018 emission inventories as part of the planning process. EPA approved Arkansas' estimates of its 2018 emissions inventory and those

[93] Sierra Club v. Gina McCarthy, No. 4.14CV00643JLH (ED Ark. Western Div. Nov. 3, 2015).

of its neighboring states.[94] Each state included projected emissions inventories for 2018 in its SIP. As explained in our review of the Arkansas Regional Haze SIP, CENRAP with assistance from Arkansas developed an emissions inventory for 2018 "by projecting 2002 emissions and applying reductions expected from federal and state regulations affecting the emissions of the visibility-impairing pollutants NO_X, PM, SO_2, and VOCs." EPA approved Arkansas' 2018 emissions inventory in its final action on the SIP. We are not revisiting our prior approval of these emissions inventories in today's rulemaking.

With regard to the comment that we have underestimated the likely overall visibility improvement in Arkansas' Class I areas by ignoring recent regulatory requirements, we agree that there have been a number of regulatory changes over the years since the emission inventories for Arkansas and the surrounding states were developed. As noted above, we approved these inventories when we took action on Arkansas' Regional Haze SIP as valid estimations of 2018 emissions inventories. We note that Arkansas is required to update these inventories in its next regional haze SIP, due at this time in just over two years.[95] For the near term, we do not expect significant changes in emissions from Arkansas sources between now and 2018. More significantly, the commenters' suggestions that EPA should further delay the implementation of measures to improve visibility while assessing the visibility improvements that will result from other existing programs relies on the conclusion that there is a specific rate of improvement that constitutes reasonable progress. The reasonable progress goals are not enforceable goals, but rather provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP. That Arkansas is meeting the glidepath, largely due to emission reductions in other states, does not support the conclusion that the most significant sources of visibility impairment in Arkansas should be left for later.

It appears that the improvements in visibility in Class I areas in Arkansas projected by CENRAP were due largely to projected emission reductions from other states. The emissions inventories for Arkansas show that the state expected its emissions of every visibility pollutant but for NO_X to increase over the first planning period, notwithstanding the reductions expected from federal regulations. Thus, for example, SO_2 emissions were expected to increase by 6,000 tons per year.[96] In terms of changes in emissions inventories in Arkansas, we do not expect significant changes in emissions from Arkansas sources between now and 2018.

The relevance of the comment that EPA determined CSAPR to be better than BART but did not quantify the added benefit that would result from that trading program over and above the site-specific BART NO_X controls currently in the FIP is unclear. In determining that CSAPR provides for greater reasonable progress than BART, EPA assessed the visibility benefits across

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[94] See 76 FR at 64212-13 and 77 FR 14604 for our approval of Arkansas' estimates of its 2018 emissions inventory. See 76 FR at 16189 and 76 FR 81728 for our approval of Oklahoma's estimates of its 2018 emissions inventories but for its inclusion of reductions from the OG&E and AEP/PSO coal fired units that were not ultimately required by Oklahoma; the Oklahoma BART FIP we promulgated addressed this deficiency. See 77 FR at 11971 and 77 FR 38007 for our approval of Missouri's estimates of its 2018 emissions inventory. See 79 FR at 74858-74861 and 81 FR 296 for our approval of Texas' estimates of its 2018 emissions inventory.

[95] EPA has proposed to give the states an additional three years to submit the next update to their regional haze SIP, but as of the date of today's final action, has not yet taken final action on that proposal.

[96] 76 FR at 64213.

the entire continental United States and found that *on average* across all Class I areas, CSAPR provided for greater visibility improvement than BART. To make this determination, EPA made broad assumptions as to what controls would constitute BART based on the presumptive BART limits in the BART Guidelines. CSAPR requires significant SO_2 and NO_X reductions in many states; in Arkansas, however, the state is subject only to an ozone season NO_X budget requirement. The commenters have presented no evidence that CSAPR will result in any added benefit over and beyond the site-specific BART controls in the FIP at the Class I areas impacted by Arkansas, but if the commenters' point is that a program requiring hundreds of thousands of tons of reductions in SO_2 and NO_X across a broad region will achieve greater visibility improvement than the modest BART NO_X controls in the Arkansas FIP, then we would have to agree. To the extent the commenter is arguing that our revised reasonable progress goals do not account for the improvement that will result from implementation of CSAPR, we note that the states assumed the implementation of CAIR in setting their goals but that CAIR has now been replaced by CSAPR.

With regard to the comment that EPA should not "take such aggressive action in overriding a reasonable state SIP," we point out that our proposed partial approval and partial disapproval of the Arkansas RH SIP submitted to us in 2008 was published in the Federal Register on October 17, 2011.[97] We held a 66 day public comment period and our final action was published on March 12, 2012.[98] In our final action, we determined that the Arkansas RH SIP does not meet certain elements of the Federal regional haze requirements and partially approved and partially disapproved the Arkansas RH SIP. While we did receive adverse comments on that proposal, no petitions were filed for judicial review of the final rule, and the rule became effective on April 11, 2012. Therefore, the comment that we are "overriding a reasonable state SIP" is not germane to the proposed action we solicited comments on and is outside the scope of this action.

We address in other sections of this document comments contending that requiring controls on the Entergy Independence Plant is not expected to achieve significant additional visibility benefits or perceptible visibility benefits. We also address elsewhere in this section of the document comments contending that additional controls are not necessary at this time to make reasonable progress because Arkansas' Class I areas are projected to be below the URP glidepath.

Comment: EPA failed to perform the analysis required to establish RPGs and instead arbitrarily required emissions controls for Entergy Independence.

[ADEQ (0160) p. 8-13] ADEQ stated that EPA improperly performed the reasonable progress analysis by applying the reasonable progress factors set forth in the Regional Haze Rule to require specific emissions controls for Entergy Independence Units 1 and 2. Despite the fact that Entergy's Independence Plant is not identified as subject to BART, EPA requires specific emissions controls for the plant in the proposed FIP under an analysis using four factors intended to aid in establishing unenforceable numerical goals for reducing regional haze, called

[97] 76 FR 64186.
[98] 77 FR 14604.

"reasonable progress goals." This type of analysis has no basis in the Regional Haze Rule or other relevant law.

ADEQ stated that EPA is required to engage in "reasoned decision-making."[99] Not only must an agency's decreed result be within the scope of its lawful authority, "but the process by which it reaches that result must be logical and rational."[100] *In Michigan v. E.P.A.,* the Supreme Court of the United States explained that "agency action is lawful only if it rests 'on a consideration of the relevant factors.'"[101] In the proposed FIP, EPA has disregarded the framework in the Regional Haze Rule and failed to consider the factors required for establishing Arkansas' Reasonable Progress Goals (RPGs).

ADEQ stated that EPA's Regional Haze Rule primarily addresses visibility impairment from point sources by requiring BART for certain existing stationary sources.[102] In contrast to the BART requirements, which are specific to point sources, EPA also requires states to develop broad RPGs to be expressed in deciviews that each state must set based on the URP and the following four factors ("reasonable progress 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) the remaining useful life of any potentially affected sources.[103]

ADEQ stated that the Regional Haze Rule uses the imperative "must" in reference to consideration of both the URP and the reasonable progress factors.[104] Based on these considerations, either the state, or EPA in the case of a FIP, must set specific numerical goals in deciviews - the RPGs which are intended to ensure that a state is making progress toward achieving natural visibility conditions.[105] The Regional Haze Rule requires a state, or EPA, to consider both the reasonable progress factors and the URP in setting the RPGs.[106] However, EPA completely disregards its own framework in the proposed FIP. Instead of utilizing the four reasonable progress factors in conjunction with the URP to set numerical goals measured in deciviews, EPA applies the reasonable progress factors in order to require emissions controls for Independence Plant Units 1 and 2, which it refers to as a "reasonable progress source." Effectively, EPA has applied the reasonable progress factors to the Independence Plant as if it were a BART analysis. Rather than considering the URP in conjunction with the reasonable progress factors, EPA completely dismisses the URP, which Arkansas is on track to meet in the

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[99] *See* State of AR, ADEQ, State Implementation Plan Review for the Five-Year Regional Haze Progress Report (April 2014) attached as Exhibit 1, at 56.
[100] Id.
[101] *Id.* (citing *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43, 103 S.Ct. 2856, 77 L.Ed.2d 443 (1983) (internal quotation marks omitted)).
[102] 40 C.F.R. § 51.308
[103] 40 C.F.R. § 51.308(d)(1)(i)
[104] 40 C.F.R. § 51.308 (d)(1)(i)(A)(" the State *must*: … (A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources" (emphasis added)); 40 C.F.R. § 51.308 (d)(1)(i)(A) ("In establishing the reasonable progress goal, the State *must* consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plant" (emphasis added))
[105] 40 C.F.R. § 51.308(d)(1)
[106] 40 C.F.R. § 51.308(d)(1)(i)

first planning period, by stating that "the URP does not establish a 'safe harbor' for the state in setting its progress goals."[107]

ADEQ stated that furthermore, EPA fails to explain how factors required to be considered in setting specific numerical targets, which are themselves not enforceable, could somehow be used to require specific enforceable limits for a single plant. In 40 C.F.R. § 51.308(d)(1)(v), the Regional Haze Rule states that "[t]he reasonable progress goals established by the State are not directly enforceable." There is simply no legal justification for the analysis EPA has performed using the reasonable progress factors set out in 40 C.F.R. § 51.308(d)(1)(A). EPA cites no legal authority for identifying and requiring emissions controls for "reasonable progress sources." The term "reasonable progress source" does not itself appear in the Regional Haze Rule or related guidance documents.

ADEQ stated that the state, or EPA in the case of a FIP, is required to "include a demonstration showing how these [reasonable progress] factors were taken into consideration in selecting the goal."[108] EPA has not performed this task in the proposed FIP. EPA meticulously presents its analysis under headings with each reasonable progress factor clearly marked, but this analysis does not explain how those factors were taken into consideration in selecting numerical goals in deciviews as required by the Regional Haze Rule. In fact, EPA makes no mention of the factors required for consideration under 40 C.F.R. § 51.308(d)(1)(A) except in relation to the analysis of "Entergy Independence Plant Units 1 and 2."[109]

ADEQ stated that EPA's arbitrary use of the reasonable progress factors to evaluate the Entergy Independence Plant resulted in EPA foregoing a proper analysis of the reasonable progress factors in relation to the RPGs. Critically, EPA has failed to consider the "costs of compliance" with the RPGs in the proposed FIP. Although all of the reasonable progress factors are required to be considered in setting the RPGs, the Supreme Court of the United States recently reiterated the importance of considering cost in relation to electric generating units such as the two units at the Entergy Independence Plant. In *Michigan v. E.P.A.*, the Supreme Court held that it was unreasonable for EPA to interpret the phrase "appropriate and necessary" as not including an analysis of costs in implementing the Mercury and Air Toxics Standards (MATS) for power plants.[110] In doing so, the Supreme Court stated that "[o]ne would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."[111] EPA's decision to forego any type of analysis involving the reasonable progress factors in relation to setting the RPGs is particularly troublesome in light of the Supreme Court's concerns about costs in *Michigan v E.P.A.*

ADEQ stated that EPA asserts that it is appropriate to evaluate Entergy's Independence Plant "because it is a significant source of SO_2 and NO_X … even though Arkansas's Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet

[107] *See* Exhibit 1.
[108] 40 C.F.R. § 51.308(d)(1)(i)(A).
[109] 80 FR 18944 at 18992-18998
[110] *Michigan v. E.P.A.,* No. 14-46, 2015 WL 2473453, at *7 (U.S. June 29, 2015).
[111] Id.

URP for the first planning period."[112] In fact, Arkansas is projected to meet the URP despite none of the controls specified in the SIP or the proposed FIP having been installed to date. The additional control measures for the Entergy Independence Plant are especially unnecessary in light of Arkansas being on track to meet the Uniform Rate of Progress (URP) for the first planning period, which ends in 2018.[113] EPA singled out Entergy's Independence Plant through a cursory evaluation of the National Emissions Inventory data that ADEQ provides to EPA annually, which EPA then used in modeling for potential visibility impacts.[114] In doing so, EPA has ignored its own framework for establishing reasonable progress goals and requiring specific emissions controls for a point source. EPA should have considered the four factors in 40 C.F.R. § 51.308(d)(1)(A) along with the URP as set forth in 40 C.F.R. § 51.308(d)(1)(B) in setting numerical RPGs.

ADEQ stated that in the Arkansas Regional Haze Approval/Disapproval, EPA rejected Arkansas's RPGs because the state relied on the URP rather than both the URP and the reasonable progress factors to propose its RPGs. EPA stated that "[u]ntil the State conducts a proper evaluation of the four statutory factors … we will not know whether different RPGs are appropriate for Arkansas's Class I areas."[115] Just as EPA was unable to determine whether Arkansas's RPGs were appropriate, ADEQ cannot determine whether the RPGs presented by EPA are appropriate because EPA has failed to perform an analysis of its RPGs using the factors in 40 C.F.R. §51.308(d)(1) and instead applied those factors to an assessment of controls for Entergy's Independence Plant. Therefore, EPA should withdraw the proposed FIP, and ensure a proper analysis is included in any subsequent plan.

[Arkansas Attorney General (0162) p. 3-4] The Attorney General for the State of Arkansas stated that the States must establish Reasonable Progress Goals (RPGs) for each Federal Class I area in the state to provide incremental visibility improvements toward he ultimate goal of reaching natural background conditions by 2064. 40 C.F.R. § 51.308(d). EPA disapproved Arkansas's RPGs in 2012; however, EPA approved the State's commitment to submitting periodic progress reports. Based on a May 2015 progress report, EPA is aware that Arkansas is meeting the Uniform Rate of Progress (URP), which is a "glide path" for reaching the 2064 goal. *See* State Implementation Plan Review for the Five-Year Regional Haze Progress Report, Revised May 2015, Arkansas Department of Environmental Quality, found at: https://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

The Attorney General stated that 40 C.F.R. § 51.308(d)(1) requires the States to "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions." In setting a reasonable progress goal, the State must "consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, *and include a demonstration showing how these factors were taken into consideration in selecting the goal.*" 40 C.F.R. § 51.308(d)(1)(i)(A) (emphasis added). In *North Dakota v. EPA*, 730 F.3d

[112] 80 FR 18944 at 18992.
[113] *See* State of Arkansas, ADEQ, State Implementation Plan Review for the Five-Year Regional Haze Progress Report (April 2014), attached as Exhibit 1 to ADEQ's comments, at 56.
[114] *Id. at* 18991-18992.
[115] 77 FR 14604 at 14621.

750 (2013), the Eighth Circuit Court of Appeals held that EPA was bound to follow the same regulatory requirements as the State when promulgating a FIP.

The Attorney General stated that thus, if EPA proposes RPGs in a FIP it must set those goals using the regulatory factors, including a demonstration of how those factors were applied. Then EPA *may* determine that additional measures are necessary to meet the goals. The law clearly states that "reasonable progress goals…are not directly enforceable." 40 C.F.R. §51.308(d)(1)(v). However, EPA uses the guise of setting RPGs to unlawfully apply a BART-type analysis to the Entergy Independence electric generating unit ("Independence"). Independence is not subject to the BART requirements because it was not constructed between 1962 and 1977. Its construction commenced after this time period. EPA uses a "reasonable progress analysis for point sources" to shoehorn Independence into the use of emission controls without a legal basis for doing so. This action is outside the scope of the Clean Air Act and its implementing regulations.

The Attorney General stated that as cited above, the law clearly sets forth the process for RPGs. EPA must begin by setting a RPG and then conduct an analysis of whether additional controls are necessary. However, EPA turns this process on its head. First, EPA looked at the emissions from Independence as a point source. It then uses the regulatory factors for setting a RPG to justify a "cut and paste" of its BART analysis for Entergy White Bluff and calls it a "reasonable progress analysis for point sources." There is no authority for this procedure in the law. This is a textbook example of regulatory overreach to achieve a policy goal. Only after completing its BART-like analysis for Entergy Independence does EPA discuss the establishment of RPGs. In direct contravention of 40 C.F.R. § 51.308(d)(1)(i)(A), EPA fails to demonstrate how the regulatory factors were used to set the goals. Its discussion of those factors as it relates to Entergy Independence is unlawful and cannot be substituted for the demonstration required by law.

The Attorney General stated that EPA's proposed "reasonable progress" action clearly exceeds its authority under the Clean Air Act and is arbitrary and capricious.

Response: We disagree with the commenters on all issues raised. As an initial matter, the commenters appear to have a misunderstanding of the process for establishing RPGs. One commenter contends that the law clearly sets forth that EPA must begin the process for [establishing] RPGs by setting the RPGs using the regulatory factors, and only after that may EPA determine that additional measures are necessary to meet that goal. The commenter further contends that EPA's analysis was flawed because we turned this process on its head by first completing an analysis of the reasonable progress factors for the Independence Plant and then discussing establishment of the RPGs. This is incorrect. The CAA requires reasonable progress determinations to be based on consideration of "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 existing source subject to such requirements." CAA section 169A(g)(1). The regional haze regulations under 40 CFR 51.308(d)(1)(i) also require consideration of these four statutory factors in establishing the RPGs:

> (i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:

> (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

The statute and regulations are clear that in establishing the RPGs, states (or EPA in standing in the shoes of the state and promulgating a FIP) must conduct an analysis of the four statutory factors to determine whether additional controls (i.e., beyond those required under BART and other "on the books" controls) are necessary to make reasonable progress. These statutory factors are only relevant in the context of considering specific possible emission reduction measures for specific sources or groups of sources. A state or EPA determines the rate of progress that is reasonable for a Class I area after taking into account these factors -- as applied to specific sources or groups of sources – to determine what additional controls should be required in its regional haze SIP or FIP. The fact that under 40 CFR section 51.308, section 308(d)(1) on setting RPGs appears before section 308(d)(3) on long-term strategy requirements does not change this fact and does not mean that RPGs can or must be set prior to consideration of specific control measures for specific sources under the reasonable progress requirements.

This approach to setting RPGs was understood and used by the states and the RPOs (including Arkansas and CENRAP), which took into account the anticipated emission reductions from specific measures adopted to improve visibility as well as from other CAA requirements in calculating 2018 emission inventories and then established RPGs based on the anticipated changes in emissions over the planning period of the SIP. A description from last year by EPA of the design of the regional haze program and how states established reasonable progress goals provides a useful overview of how the program has worked in practice, based on these regulatory requirements:

> The Regional Haze Rule, which was promulgated not long after the 1997 revisions to the ozone and fine particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS), was explicitly designed to facilitate the coordination of emissions management strategies for regional haze with those needed to implement the NAAQS. *See* 64 FR 35713, 35719–35720 (July 1, 1999). More generally, the Regional Haze Rule requires states to include all air quality improvements that will be achieved by other CAA programs and state air pollution control requirements when assessing changes in emissions and visibility to be expected during the period of their regional haze SIP. 64 FR at 35733. This is made clear in the haze regulations which prohibit states from adopting RPGs that represent less visibility improvement than is expected to result from the implementation of other CAA requirements during the planning period. 40 CFR 51.308(d)(1)(vi). Given this requirement, states included in their regional haze SIPs a number of Federal regulations for mobile and stationary sources that had or were expected to come into effect after the baseline period and that were anticipated to result in

> reductions of visibility impairing pollutants. These regulations included NAAQS implementation measures as well as other CAA requirements, such as mobile source rules or Maximum Achievable Control Technology (MACT) standards issued under section 112 of the CAA. . .
>
> Thus, states took into account the anticipated emission reductions from a wide range of measures in setting RPGs. To model the visibility conditions in 2018, states used projected emission inventories based on the best information before them. Given the significance of emissions from EGUs to haze, these projections were based, among other things, on expected changes in energy demand affecting capacity utilization of power plants. States also sometimes included an emissions buffer to account for the possible construction of new power plants or other types of facilities. States also took into account, as described above, anticipated reductions in emissions resulting from recent Federal rules addressing non-visibility-related requirements, as well as consent decrees, significant measures adopted by nearby states, and specific measures to address the requirements of the visibility program. Thus, in forecasting future visibility conditions, states by design took into account to the extent possible ''outside forces'' and a host of overlapping requirements.[116]

Because the reasonable progress analysis and the BART analysis share some regulatory requirements, the commenters argue that we performed "a BART analysis" for Independence. States and EPA have generally taken very similar approaches to analyzing BART and reasonable progress controls during the first planning period, as the relevant factors to be considered overlap to a large degree: Compare section 169A(g)(1) ("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 existing source subject to such requirements") with section 169A(g)(2) ("the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology"). The type of source-specific analysis undertaken for Independence is a careful and thorough analysis that by its nature tends to require cost-effective controls on only the largest contributors to visibility impairment. It is both logical and rational and is based on consideration of the relevant statutory factors.

The commenter's suggestion that because the RPGs are not themselves enforceable we cannot require specific enforceable limits for a single plant is not consistent with the requirement that each regional haze SIP or FIP include enforceable emissions limitations as necessary to ensure that the SIP or FIP will provide reasonable progress toward the national goal of natural visibility conditions. While our FIP does consider and ultimately apply controls on an individual source basis to assure reasonable progress, this is consistent with the CAA, our regulations, and past EPA guidance. The four statutory factors under CAA Section 169A(g) and 40 CFR 51.308(d)(1)(i)(A) are directed to the listed possible features or consequences of potential emission control measures for sources, including individual stationary sources. The CAA and the

[116] 80 Fed. Reg. 32019, 32021 (June 5, 2015)(emphasis added).

Regional Haze regulations expressly set forth that the reasonable progress analysis must consider the "compliance" time and costs for "potentially affected sources." A state determines the rate of progress that is reasonable for a Class I area after taking into account the four statutory factors--as applied to specific sources or groups of sources – to determine what additional controls should be required in its regional haze SIP. Thus, individual stationary sources may be subject to emission limits and source specific analysis when determining whether additional controls are necessary to make reasonable progress. We accordingly disagree with the argument that EPA should not include enforceable emission limits for an individual source in our FIP to ensure reasonable progress. Further, we discuss elsewhere in this document that the numeric RPGs established by the state or EPA represent the best estimate of the degree of visibility improvement that will result in 2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP or EPA in a regional haze FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[117] Thus, the RPGs are intended to provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP. But the RPGs themselves are not enforceable.[118] EPA cannot enforce an RPG in the sense of seeking to apply penalties on a state for failing to meet the RPG or obtaining injunctive relief to require a state to achieve its RPG. However, the long-term strategy can and must contain emission limits and other control measures that apply to specific sources under the reasonable progress requirements, and that are themselves enforceable. The fact that the RPGs are not enforceable does not mean that we cannot conduct a source-specific evaluation of the reasonable progress factors or require source-specific emission limits under the reasonable progress requirements.

Furthermore, if the CAA's requirements were such that only sources subject to controls for BART could be looked to for emission reductions to promote reasonable progress, then States, or EPA acting as necessary in the place of a State, would have little to no room for additional progress and even less need for sequential planning periods to build on past progress. Source-specific emission limitations, as promulgated in our FIP, are manifestly envisioned by the statute. While reasonable progress is not required to be demonstrated on a source-by-source basis (or via "source-specific analysis"), this emphatically does not mean that individual sources are free from any possibility of required new or stricter controls as part of establishing reasonable progress goals or what is necessary as part of a long-term strategy. In other words, an appropriately focused and detailed analysis using a so-called category based approach may (and in some cases manifestly should) result in a determination that source-specific controls are needed to make reasonable progress. To conclude otherwise vitiates the statutory purpose and asks for an entirely ineffectual analysis which could not result in possible emission limitations as expressly envisioned in the statute. See CAA Section 169A(b)(2); 40 CFR 51.308(d)(1) and (3). We also note that even though we are required to prepare our own analysis to do a FIP, this does not mean our analysis and conclusions are precisely what Arkansas would itself conclude in its SIP to meet the CAA requirements.

The commenter states that we make reference to "reasonable progress sources" in our FIP proposal, and states that this term does not appear in the RH rule or related guidance. The

[117] 64 FR 35733.
[118] See 51.308(d)(1)(v).

commenter contends that we cite no legal authority for identifying and requiring emissions controls for "reasonable progress sources." Where we used the term "reasonable progress sources" in our FIP proposal, we used it as shorthand to refer to sources that we are controlling or evaluating for controls under the reasonable progress requirements.

In our Arkansas FIP, we have conducted the requisite analysis to determine what controls are necessary to make reasonable progress by considering those sources and source categories with the most significant impact on visibility impairment. We explained in our FIP proposal that our reasonable progress analysis focused on the point source category since the other source categories each contribute a much smaller proportion of the total light extinction at each Class I area in Arkansas based on the CENRPAP modeling.[119] For example, the point source category contributed 81.04 Mm^{-1} out of a total light extinction of 133.93 Mm^{-1} for the 20% worst days in 2002 at Caney Creek, or approximately 60.5% of the total light extinction. Similarly, the point source category contributed 77.80 Mm^{-1} out of a total light extinction of 131.79 Mm^{-1} for the 20% worst days in 2002 at Upper Buffalo, or approximately 59% of the total light extinction. In comparison, area sources, which are the source category with the next highest contribution to the total light extinction at each Class I area, contributed approximately 13.3% of the total light extinction at Caney Creek and 15.5% at Upper Buffalo. The remaining source categories each contributed less than 6% of the total light extinction at each Class I area.[120] Therefore, we found it is appropriate for our reasonable progress analysis to focus on the point source category.

We also note that the CENRAP CAMx modeling shows that on most of the 20% worst days in 2002, total extinction is dominated by sulfate at both Caney Creek and Upper Buffalo.[121] Additionally, total extinction at Caney Creek is dominated by nitrate on four of the 20% worst days in 2002, and a significant portion of the total extinction at Upper Buffalo on two of the 20% worst days in 2002 is due to nitrate.[122] Therefore, we consider both SO_2 and NO_X to be key pollutants that contribute to visibility impairment at Arkansas' Class I areas and considered both SO_2 and NO_X controls in our reasonable progress analysis.

We explained in our FIP proposal that as a starting point in our analysis to determine whether additional controls on Arkansas point sources are reasonable in the first regional haze planning period, we examined the most recent SO_2 and NO_X emissions inventories for point sources in Arkansas. Our examination of the emissions inventory revealed that the magnitude of emissions from the Independence Plant warranted further evaluation to determine if the source is a significant contributor to regional haze in Arkansas' Class I areas and whether controls at the source are needed under the reasonable progress requirements. Specifically, the Independence Plant is the second largest source of SO_2 and NO_X point source emission in the state, contributing approximately 36.2% of the total SO_2 point source emissions in the state (i.e.,

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[119] See 80 FR at 18989.

[120] Please see our FIP proposal and associated TSDs for a thorough discussion of contributors to visibility impairment at Arkansas Class I areas and our rationale for focusing on point sources

[121] See Arkansas RH SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas RH SIP.

[122] See Arkansas RH SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas RH SIP.

30,398 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons, based on the 2011 NEI) and approximately 21.3% of the total NO_X point source emission in the state (i.e., 13,411 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons).[123]

Our examination of the emissions inventory also revealed that other large point sources emitting SO_2 and NO_X are already being controlled under the BART requirements (i.e., White Bluff and Flint Creek) and that further controls during this planning period are not necessary for these sources. After White Bluff, Independence, and Flint Creek, the remaining point sources in the state have much lower SO_2 and NO_X emissions than these facilities. In other words, the magnitude of SO_2 and NO_X emissions from point sources in Arkansas drops off considerably after the top 3 emitters. For example, the point source with the fourth highest SO_2 emissions (after White Buff, Independence, and Flint Creek) is Future Fuel Chemical Company, which contributes approximately 4.1% of the total SO_2 point source emissions in the state (i.e., 3,420 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons). The point source with the fourth highest NO_X emissions is the Natural Gas Pipeline Company of America #308, which contributes approximately 5.1% of the total NO_X point source emission in the state (i.e., 3,194 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons). Based on the much smaller magnitude of these sources' emissions, we determined that the remaining point sources in the state are less likely to be significant contributors to regional haze, and thus did not warrant closer evaluation under reasonable progress in this planning period. As such, we found that it is appropriate to evaluate Independence for controls under reasonable progress. The claim that we arbitrarily singled out Independence and that we provided no explanation as to why we did not evaluate other point sources under the reasonable progress requirements is incorrect.

In one part of the comment, the commenter contends that we have failed to conduct any type of analysis involving the reasonable progress factors in relation to setting the RPGs for Arkansas Class I areas, but another part of the comment contends that while we did apply the reasonable progress factors in our analysis, we did not consider the URP in setting the RPGs. We disagree that we failed to consider the reasonable progress factors and we also disagree that we did not consider the URP in setting the RPGs. Our analysis and consideration of the reasonable progress factors under section 51.308(d)(1)(i)(A) is presented in our FIP proposal.[124] To the extent the commenter suggests that our reasonable progress analysis is inappropriate or insufficient because we applied the reasonable progress factors to an individual source (the Independence Plant), we discussed above why individual sources may be subject to controls and source specific analysis when establishing RPGs. With regard to our consideration of the URP in establishing RPGs for Arkansas' Class I areas, we explained in our Reasonable Progress analysis that:

> The preamble to the Regional Haze Rule also states that the URP does not establish a "safe harbor" for the state in setting its progress goals. 64 FR 35732. If the state determines that the amount of progress identified through the URP analysis is reasonable based upon the statutory factors, the state, or us in the case of a FIP, should identify this amount of progress as its

[123] See NEI 2011 v1. A spreadsheet containing the emissions inventory is found in the docket for our proposed rulemaking.
[124] 80 FR at 18989.

> reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the state or we determine that additional progress is reasonable based on the statutory factors, that amount of progress should be adopted as the goal for the first long-term strategy.[125]

That Arkansas' Class I areas are below the URP glidepath does not divest us from our authority and obligation to conduct an analysis of the four statutory factors. The URP is an analytical requirement created by regulation to ensure that states consider the possibility of setting an ambitious reasonable progress goal. Its purpose is to complement, not usurp, the reasonable progress analysis. Based on the analysis of the four statutory factors required under the CAA and Regional Haze regulations, a state (or EPA in a FIP) may determine that a greater or lesser amount of visibility improvement than what is reflected in the URP is necessary to demonstrate reasonable progress.[126] Based on our analysis of the four statutory factors, along with consideration of the visibility improvement of controls, we determined that there are reasonable controls available for Independence that would be cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas. Because we have identified that additional progress (beyond the amount reflected in the URP) is reasonable based on the statutory factors and our consideration of the visibility impacts, we are required to adopt that amount of progress under the reasonable progress requirements. It is for this reason that we are requiring controls for Independence under the reasonable progress requirements.

With regard to the comment alleging that we did not include a demonstration showing how the reasonable progress factors were taken into consideration in establishing the RPGs, the commenter is incorrect. Our FIP proposal explained in detail how we took the factors into consideration in evaluating controls under reasonable progress.[127] Based on consideration of the four reasonable progress factors, we determined that there are reasonable controls available for Independence Units 1 and 2. With regard to the comment that we took a "cut and paste" approach in our evaluation of controls for Independence Units 1 and 2, we explained in our FIP proposal that we verified that White Bluff and Independence are sister facilities with nearly identical units by constructing a master spreadsheet that contains information concerning ownership, location, boiler type, environmental controls, and other pertinent information.[128] The cost of compliance is a factor that is required for consideration under both a BART and a reasonable progress analysis. Due to the similarities in the facilities and the identical requirement for consideration of the cost of controls under reasonable progress and BART, our use of the total annualized costs of controls on White Bluff Units 1 and 2 in our cost analysis for Independence Units 1 and 2 was a reasonable approach. We do note that in calculating the cost effectiveness ($/ton removed) of controls for Independence Units 1 and 2, we used actual emissions data from Independence Units 1 and 2 to estimate the emission reductions expected to take place from the controls we evaluated. In our reasonable progress analysis, we took into consideration the cost of controls on Independence and we also considered the other reasonable

[125] 80 FR at 18992.
[126] 64 FR 35732.
[127] 80 FR at 18989.
[128] 80 FR at 18992.

progress factors (time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources), as well as the visibility impacts of Independence and improvement due to controls on the facility. We modeled both the baseline visibility impacts from the Independence facility and the visibility benefit of controls using CALPUFF dispersion modeling. Based on our consideration of the four reasonable progress factors and the modeled visibility improvement of controls, we determined that reasonable controls for SO_2 and NO_X are available for Independence Units 1 and 2 that are cost effective and would result in a large amount of visibility improvement in Arkansas' Class I areas in terms of the 98th percentile impacts from the source, and are therefore necessary to make reasonable progress.[129]

After determining that reasonable controls are available for Independence Units 1 and 2, we proposed RPGs for Caney Creek and Upper Buffalo that are consistent with the combination of control measures from the approved portion of the 2008 Arkansas RH SIP and our proposed Arkansas RH FIP. Our methodology for calculating the revised RPGs is explained in detail in our FIP proposal and associated TSDs.[130] Therefore, comments alleging that we did not explain how we took the factors into consideration in selecting numerical RPGs are incorrect.

We do note that in response to other comments we received stating that our proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo improperly incorporated visibility improvements that would not occur until after 2018, we are providing revised RPGs that reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. We discuss this in greater detail in our final rule and elsewhere in this document.

Comment: [UARG (0176) p. 2] UARG stated that in certain respects, EPA's proposed rule would depart from the requirements of the CAA and EPA's regional haze rules and would disregard EPA's guidance on reasonable progress.[131] UARG urges EPA to withdraw relevant provisions of the proposed FIP.

Response: We acknowledge UARG's comments. UARG's detailed comments on our proposed FIP are included and addressed by us in various sections throughout this RTC document.

Comment: EPA inappropriately declined to consider SCR for Independence Units 1 and 2 under the reasonable progress requirements on the grounds that EPA had found that requiring SCR at White Bluff would lead to insufficient visibility benefits. [Sierra Club et. al. (0171) p. 35-36] Sierra Club et. al. stated that EPA proposed two control options for the

[129] Entergy submitted CAMx source apportionment modeling during the comment period. This modeling shows that Independence has significant visibility impacts in Arkansas Class I areas on the 20% worst days, and further supports our decision to require controls for Independence under reasonable progress. We discuss Entergy's photochemical modeling and the visibility impacts due to SO_2 and NO_X from Independence on the 20% worst days elsewhere in this final rule and in our RTC document.
[130] See 80 FR 18997.
[131] EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) (Reasonable Progress Guidance).

Independence plant: Option 1, which would require scrubbers as well as LNB/SOFA; and Option 2, which would require only scrubbers. 80 Fed. Reg. at 18,997. If EPA were faced with the choice between LNB/SOFA and no NO_X controls at all, LNB/SOFA is the only option consistent with the reasonable progress requirements. However, EPA has set up a false choice by failing to consider more stringent controls such as SCR. LNB/SOFA+SCR is the only option that fully satisfies the NO_X reasonable progress requirements at Independence.

Sierra Club stated that EPA declined to consider SCR for Independence on the grounds that EPA had found that requiring SCR at White Bluff would lead to insufficient visibility benefits. 80 Fed. Reg. at 18,995; *see also id.* at 18,975. There are two primary flaws in this argument. First, even if EPA can consider visibility improvement under reasonable progress, EPA has no rational basis for relying exclusively on the White Bluff analysis given the material differences between White Bluff and Independence. Independence is closer to Hercules-Glades and Mingo than is White Bluff. Reducing a certain amount of NO_X at Independence may yield greater improvements in visibility at Hercules-Glades and Mingo than reducing the same amount of NO_X from White Bluff. It is irrational for EPA to fail to even consider SCR at Independence based on the visibility benefits from SCR at White Bluff without first determining that the visibility improvement from SCR at Independence and White Bluff would be the same or substantially the same. Second, EPA cannot rely on its flawed logic from the White Bluff BART determination to reach an equally flawed outcome for Independence. As explained elsewhere in Sierra Club's comments, the visibility improvement from SCR is significant enough to warrant the reasonable costs of SCR for White Bluff 1 and 2. The same is true at Independence. Therefore, EPA inappropriately declined to consider SCR for Independence Units 1 and 2 in its reasonable progress analysis.

Additionally, EPA claimed that because it rejected SCR at White Bluff, EPA would likely reach the same conclusion at Independence, given the similarities between the plants. For the White Bluff BART determination, EPA rejected SCR because "the incremental visibility benefit over LNB/SOFA+SNCR of up to 0.069 dv at a single Class I area is relatively small considering the incremental cost-effectiveness of $6,717 per ton of NO_X removed for Unit 1 and $5,736 per ton of NO_X removed for Unit 2." 80 Fed. Reg. at 18,975. However, it is unreasonable for EPA to reject SCR based on the incremental costs and benefits relative to SNCR, given that EPA is not proposing to select SNCR as a reasonable progress measure. EPA has provided no rational basis for rejecting SCR because of how it compares to a technology, SNCR, which EPA is not even proposing to require. To the extent that it is rational to examine the incremental costs and benefits of SCR, the proper comparison is between SCR and the technologies that EPA is actually proposing to require: LNB/SOFA.

Response: We disagree that in proposing the two control options for Independence Units 1 and 2 we set up "a false choice" by not evaluating and proposing more stringent NO_X controls, such as SCR. The CAA and the RH regulations give us discretionary authority in conducting the reasonable progress analysis provided that such discretion is exercised in a reasonable manner. We believe that we provided in our proposal a reasonable justification for our decision to focus our reasonable progress analysis of NO_X controls at Independence on LNB/SOFA.

We explained in our proposal that in evaluating NO_X controls under the BART requirements for White Bluff Units 1 and 2, we found that LNB/SOFA is much more cost-effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits that would be obtained with SNCR or SCR were not large enough to justify the additional cost of the more stringent controls for this planning period.[132] Therefore, we proposed to require NO_X controls consistent with LNB/SOFA for White Bluff Units 1 and 2 under the BART requirements. We reasoned that because (1) the Independence and White Bluff facilities are sister facilities and are very similar,[133] and (2) we found that the additional visibility benefits from SNCR and SCR were not large enough to justify the additional cost of these controls at White Bluff for this planning period, we had no reason not to conclude the same for the Independence facility. In considering NO_X controls on Independence under the reasonable progress requirements, we determined that the visibility improvement due to the installation of LNB/SOFA at the Independence facility is of a similar magnitude to the installation of those same controls at the White Bluff facility (see Table below). This indicated that the installation of other NO_X controls on Independence would likely have similar visibility benefits as for White Bluff, and further supported our reasoning that the additional visibility benefits from SNCR and SCR controls on Independence would likely not be large enough to justify the additional cost of these controls for this planning period, just as was the case for White Bluff. Therefore, our reasonable progress evaluation of NO_X controls on Independence Units 1 and 2 focused on LNB/SOFA.[134]

With regard to the comment that Independence is located closer to Hercules-Glades and Mingo (Missouri's Class I areas) than White Bluff, and that SCR controls on Independence may therefore yield greater visibility improvements at these Class I areas than SCR controls on White Bluff, we compare the visibility improvement due to the installation of LNB/SOFA at the Independence facility to the visibility improvement due to those controls at White Bluff in the Table below. We note that while LNB/SOFA controls on Independence are predicted to have greater visibility benefits at Mingo than the same controls on White Bluff, the opposite is true at Hercules-Glades.

Furthermore, we note that the baseline visibility impacts from Independence are greater at Caney Creek and Upper Buffalo than at Missouri's Class I areas.[135] The predicted visibility benefits of LNB/SOFA controls on Independence Units 1 and 2 are also greatest at Caney Creek (approximately three times as much compared to Mingo and over twice as much compared to Hercules-Glades).[136] More importantly, the cumulative visibility benefits across all four Class I areas due to LNB/SOFA controls is similar for the two facilities (see Table below). We had no reason to not expect that the same would be the case for SNCR and SCR controls. Therefore, we

[132] 80 FR at 18995.
[133] To verify that the White Bluff and Independence Plants are sister facilities, we constructed a master spreadsheet that contains information concerning ownership, location, boiler type, environmental controls and other pertinent information on these facilities. We also found that the level of SO_2 and NO_X emissions from the two facilities are of similar magnitude and the facilities are located at comparable distances from the affected Class I areas. See 80 FR at 18992.
[134] 80 FR at 18995.
[135] 80 FR at 24872.
[136] 80 FR at 24872.

disagree with the commenters that our reasoning for focusing our reasonable progress analysis for NO_X controls on Independence was flawed.

Class I Area	Visibility improvement of LNB/SOFA at Independence over baseline (deciviews)	Visibility improvement of LNB/SOFA at White Bluff over baseline (deciviews)
Caney Creek	0.459	0.391
Upper Buffalo	0.198	0.240
Hercules-Glades	0.173	0.366
Mingo	0.148	0.085
Cumulative	0.978	1.082

In any case, even if installation of either SNCR or SCR controls at Independence were to yield greater visibility improvement at the Missouri Class I areas than the same controls at White Bluff, we note that this does not affect our reasonable progress determination. Our rationale for not evaluating the cost and visibility improvement of SNCR and SCR controls for Independence was not because we expected small visibility improvement due to these controls. It was because we didn't anticipate that the level of additional visibility benefit of the installation of these controls on Independence compared to less stringent controls would be large enough to justify the additional costs. We do not expect that the possibility of greater visibility benefits at Missouri's Class I areas from SNCR or SCR controls at Independence compared to SNCR or SCR controls at White Bluff would alter our conclusion on this matter. Further, because NO_X is not a primary driver of regional haze at Arkansas' Class I areas on the 20% worst days, and Arkansas' Class I areas are below the URP glidepath, we find it reasonable to not require more stringent NO_X controls under the reasonable progress requirements for Independence for this planning period.

With regard to White Bluff, the commenter argues that it is unreasonable for us to reject SCR in our BART analysis for White Bluff based on our examination of the incremental costs and visibility benefits relative to SNCR, when we did not even propose to require SNCR. In our examination of the incremental costs and visibility benefits of SCR controls for White Bluff, we compared LNB/SOFA + SCR to LNB/SOFA + SNCR, and we also compared LNB/SOFA + SNCR to LNB/SOFA. We found that the incremental cost effectiveness of LNB/SOFA + SCR compared to LNB/SOFA + SNCR at White Bluff Unit 1 is $6,717/ton removed and the incremental visibility benefit is 0.069 dv at the most impacted Class I area. We also found that

the incremental cost effectiveness of LNB/SOFA + SCR compared to LNB/SOFA + SNCR at White Bluff Unit 2 is $5,736/ton removed and the incremental visibility benefit is 0.069 dv at the most impacted Class I area. As discussed in our proposal, after weighting the five factors, we proposed to determine that the level of additional visibility benefit of SCR controls compared to SNCR is not large enough to justify the incremental cost of the more stringent control. We also proposed to determine that the level of additional visibility benefit of SNCR controls compared to LNB/SOFA is not large enough to justify the incremental cost. Nevertheless, even when we compare LNB/SOFA + SCR to LNB/SOFA in calculating the incremental cost effectiveness and incremental visibility improvements, as the commenters state we should have done, we continue to find that the level of additional visibility benefit of SCR controls is not large enough to justify the incremental cost. Based on our cost estimates of controls, we estimate the incremental cost of SCR over LNB/SOFA for Unit 1 to be $7,338/ton and $6,611/ton for Unit 2. We continue to find that incremental visibility benefits ranging from 0.032 to 0.103 dv on a unit-basis at an individual Class I area and incremental cumulative visibility benefits of 0.216 dv per unit across all 4 impacted Class I areas are not large enough to justify the additional cost of SCR on White Bluff for this planning period. Based on our consideration of the five BART factors, we are finalizing our determination that NO_X BART for White Bluff Units 1 and 2 are controls consistent with LNB/SOFA.

We further address elsewhere in this document comments contending that visibility improvement due to installation of SCR at White Bluff Units 1 and 2, and also at Independence Units 1 and 2, is sufficiently significant to warrant the costs.

Comment: The reasonable progress factors, as well as consideration of visibility improvement, support finding that LNB/SOFA + SCR are reasonable NO_X control measures for Independence Units 1 and 2. [Sierra Club et. al. (0171) p. 35-37] Sierra Club et. al. stated that LNB/SOFA + SCR is the only option that fully satisfies the reasonable progress requirements for NO_X at Independence. Sierra Club et. al. stated that its analysis of SCR controls on Independence Units 1 and 2 indicates that the four reasonable progress factors weigh in favor of SCR.

Using the IPM Cost Modules, the Sierra Club's consultant, Ms. Stamper, calculated that the average cost-effectiveness of SCR would be less than $3000/ton removed using the 2010 Cost Module and between $2700 and $3500/ton removed using the 2013 Cost Module. Stamper Report at 66. Sierra Club argue that these average cost-effectiveness values are well within the range that EPA has found reasonable in other reasonable progress determinations. *See* the Table of cost-effectiveness values below. The incremental cost-effectiveness of SCR is also within the range of incremental cost-effectiveness values that EPA has deemed reasonable when requiring SCR for units in other states. *See* Stamper Report at 25; *see also* Stamper Report, Exs. 101, 104. Thus, even if the incremental cost-effectiveness of SCR is the deciding factor in EPA's decision, there is no basis for rejecting SCR, given that the incremental cost-effectiveness is less than or equal to the incremental cost-effectiveness of controls EPA has approved elsewhere. Moreover, for the reasons discussed elsewhere in Sierra Club et. al.'s comments, EPA should not place undue weight on incremental cost-effectiveness relative to average cost-effectiveness. Entergy could install SCR within 3 years, which is a reasonable period of time (Stamper Report at 67).

Thus, the time necessary for compliance weighs in favor of SCR. The remaining useful life does not weigh against SCR. And in other haze rulemakings, EPA has not indicated that there are energy or non-air environmental quality impacts from SCR significant enough to avoid selecting SCR as a control measure.

Sierra Club stated it retained an air quality expert, Dr. H. Andrew Gray, to model the visibility benefits of operating SCR at Independence Units 1 and 2. In his report, Dr. Gray concludes that the sum of the deciview benefit across the four Class I areas of operating SCR at Independence Units 1 and 2 is 2.099 deciviews. Gray Report at 6-7. Furthermore, had EPA compared the incremental costs and benefits of LNB/SOFA+SCR to LNB/SOFA at Independence, the comparison weighs in favor of requiring SCR. The incremental visibility benefit for SCR at both Independence units relative to LNB/SOFA is 0.303 deciviews at Caney Creek and 0.743 deciviews at the four Class I areas (sum of the deciview benefit across the four Class I areas). Gray Report at 6. The comparable value is 0.43 deciviews for the benefit of the same controls applied at White Bluff. *See* 80 Fed. Reg. at 18,974. Thus, the incremental improvement from SCR relative to the improvement from LNB/SOFA is greater for controls at Independence than for the same controls at White Bluff. This undermines EPA's contention that it can eliminate SCR from consideration at Independence for the same reason that it rejected SCR at White Bluff, namely, that the incremental visibility benefits did not justify the incremental costs. Using the costs calculated by Ms. Stamper, the incremental cost-effectiveness of SCR relative to LNB/SOFA is $6,371 at Unit 1 and $6,311 at Unit 2. *See* Stamper Report at 66. The incremental cost-effectiveness of SCR is within the range of costs that EPA has found reasonable when approving SCR for units in Wyoming, 79 Fed. Reg. at 5,040-41, and is within the range of incremental cost-effectiveness for other controls that EPA has approved, *see* Stamper Report, Exs. 101, 104.

Sierra Club stated that in sum, the reasonable progress factors, as well as visibility improvement, support finding that LNB/SOFA+SCR are reasonable control measures for Independence Units 1 and 2. EPA should require Independence Units 1 and 2 to install and operate LNB/SOFA+SCR under two separate provisions of the regional haze rule. First, the reasonable progress goals for Caney Creek and Upper Buffalo should reflect the visibility improvement from operation of LNB/SOFA+SCR at Independence Units 1 and 2, and therefore the long-term strategy should include SCR in order to meet the goals for Caney Creek and Upper Buffalo. Second, the reasonable progress goals for Hercules-Glades and Mingo should reflect the visibility improvement from operation of LNB/SOFA+SCR at Independence Units 1 and 2, and therefore the long-term strategy should include SCR in order to meet the approvable goals for Hercules-Glades and Mingo.[137]

[137] If EPA does not require SCR, EPA should require SNCR at Independence Units 1 and 2. While SNCR would remove fewer tons of NOx and improve visibility less than SCR, SNCR would be cost-effective, would improve visibility at four Class I areas, and could be installed in a reasonable period of time.

Cost-Effectiveness of Final Reasonable Progress Determinations[138]

Facility	Reasonable Progress Control	Cost, $/ton
Hawaii Electric Co., Kanoelehua Power Plant	SO2 emissions cap[139]	5587
Hawaii Electric Co., Puna Power Plant	SO_2 emissions cap	5583
Hawaii Electric Co., Shipman Power Plant	SO_2 emissions cap	5583
Tri-State Generation, Craig Unit 3	SNCR	4887
Colorado Springs Utilities, Nixon Unit1	Dry FGD	3744
PacifiCorp Jim Bridger Unit 2	SCR	3015
PacifiCorp Jim Bridger Unit 3	SCR	2961
PacifiCorp Jim Bridger, Unit 4	SCR	2492
PacifiCorp Jim Bridger, Unit 1	SCR	2393
Holcim Florence Cement Plant	SNCR	2293
Colorado Springs Utilities, Nixon Unit 1	ULNB/OFA	1372
Phoenix Cement, Clarkdale Kiln 4	SNCR	1142
Rillito Cement Kiln 4	SNCR	1047
Basin Electric, Antelope Valley Unit 2	LNB	661
Montana Dakota Utilities, Heskett Station	Limestone Injection	651
Platte River Power Authority, Rawhide Unit 101	ECC	644
Basin Electric, Antelope Valley Unit 1	LNB	586
Devon Energy Blaine County #1 Compressor	NSCR	282

Response: As discussed in our proposal and in our response to the previous comment, we did not evaluate SNCR or SCR controls for Independence. Our analysis of NO_X controls on Independence instead focused on LNB/SOFA. We have reviewed the analysis of the four reasonable progress factors for SCR controls on Independence submitted by Sierra Club and disagree that it demonstrates that SCR controls are necessary under the reasonable progress requirements for Independence Units 1 and 2 for this planning period.

With regard to Sierra Club's modeling analysis, we disagree with how the commenters assessed and compared the modeled visibility benefits of SCR. The commenters modeled the combined visibility benefit of SCR controls and dry FGD at Independence (on a facility-wide basis), but based on the information provided it does not appear that they modeled or considered the

[138] Sources for the table are as follows: partial FIP for Arizona, 79 Fed. Reg. 9,318, 9,354-56 (Feb. 18, 2104) and 79 Fed. Reg. 52,420 (Sept. 3, 2014); approval of Colorado's SIP, 77 Fed. Reg. 18,052, 18,082, 18,084, 18,087 (Mar. 26, 2012) and 77 Fed. Reg. 76,871 (Dec. 31, 2012); FIP for Hawaii, 77 Fed. Reg. 31,691, 31,711 (May 29, 2012) and 77 Fed. Reg. 61,478, 61,506 (Oct. 9, 2012); FIP for Montana. 77 Fed. Reg. 23,988, 24,069 (Apr. 20, 2012) and 77 Fed. Reg. 57,864 (Sept. 18, 2012); partial SIP approval and partial FIP for North Dakota, 76 Fed. Reg. 58,570, 58,626, 58,630-32 (Sept. 21, 2011) and 77 Fed. Reg. 20,894, 20,897 (Apr. 6, 2012); FIP for Wyoming, 78 Fed. Reg. 34,738, 34,754-56, 34,757-78 (June 10, 2013) and 79 Fed. Reg. 5,032 (Jan. 30, 2014).

[139] "This cap [the SO_2 emissions cap] was derived from EPA's analysis of the costs of switching these units to 1% sulfur fuel." Therefore, the cost-effectiveness for the three Hawaii plants represents the cost to meet the SO_2 cap by switching to low-sulfur fuel.

visibility improvement of SCR controls alone, as was done for White Bluff. Since the visibility benefits due to SCR at White Bluff were modeled using baseline (i.e., uncontrolled) SO_2 emission levels, while the commenters' modeled visibility benefits of SCR at Independence were modeled using controlled SO_2 emission levels, the commenters' comparison of visibility benefits from SCR at White Bluff to visibility benefits from SCR at Independence is incorrect. If the modeling had been performed on a consistent basis allowing for a direct comparison, the visibility benefits from SCR at the two facilities would be similar, as demonstrated by our modeled visibility benefits of LNB/SOFA at the two facilities shown in the table below.[140] Furthermore, the commenter does not provide any modeling for LNB/SOFA and SNCR, so we are unable to assess the incremental visibility benefits of SCR over SNCR as we did for White Bluff. Despite these issues, we have determined that the additional visibility modeling submitted by the commenters does not demonstrate that the visibility benefits due to SCR at Independence are larger than that at White Bluff, or that the incremental visibility benefits due to SCR at Independence (even when compared to LNB/SOFA) are large enough to justify the additional cost of controls.

Class I Area	**Visibility improvement of LNB/SOFA at Independence over baseline (deciviews)**	**Visibility improvement of LNB/SOFA at White Bluff over baseline (deciviews)**
Caney Creek	0.459	0.391
Upper Buffalo	0.198	0.240
Hercules-Glades	0.173	0.366
Mingo	0.148	0.085
Cumulative	0.978	1.082

The commenters' modeling analysis estimates the benefits of SCR at Independence and compares this to the modeled visibility benefits of LNB/SOFA. The commenters state that the incremental visibility benefit of SCR on the two units at Independence relative to LNB/SOFA is 0.303 dv at Caney Creek, but based on the report by Dr. H Andrew Gray (Gray Report) that is referenced in the comment, it appears that the correct number is 0.257 dv. The table below summarizes the results of our modeling of LNB/SOFA controls at Independence and the commenters' modeling of SCR controls at Independence. As we discussed above, the modeling submitted by the commenters for SCR controls at Independence utilized the dry FGD controlled emission rate for SO_2 rather than the baseline SO_2 emission rate, so these numbers are not directly comparable to the visibility benefits of NO_X controls at White Bluff summarized above.

[140] 80 FR at 24872 and 80 FR at 18974.

Class I Area	Independence Modeled visibility benefit over BASE2_DFGD		
	LNB/SOFA	SCR	Incremental benefit of SCR over LNB/SOFA
Caney Creek	0.485	0.742	0.257
Upper Buffalo	0.337	0.557	0.22
Hercules-Glades	0.264	0.388	0.124
Mingo	0.27	0.412	0.142
Sum	1.356	2.099	0.743

As shown in the table above, the largest incremental visibility benefit of SCR on the units at Independence over LNB/SOFA (using the controlled SO_2 emission rate) is 0.257 dv at Caney Creek and 0.22 dv at Upper Buffalo.

With regard to the commenters' analysis of the cost of LNB/SOFA and SCR controls on Independence, we disagree that we erred in the procedure we used in estimating baseline NO_X emissions for our cost analysis of LNB/SOFA controls at Independence. The fact that the commenters can construct an alternative approach to our baseline calculation using 2001-2003 baseline emissions that results in higher cost-effectiveness values (i.e., lower $/ton) does not invalidate our approach. We calculated our baseline NO_X emissions by first acquiring the 2009 to 2013 emissions as reported to us by the facility.[141] We eliminated the high and low values from the 2009-2013 emissions to better address potential yearly variations in coal sulfur data, capacity usage, etc., and make the baseline more representative of plant operations. Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in section 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and the remaining useful life of the unit. We therefore relied on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. One of these areas is in the calculation of the baseline emissions in determining cost effectiveness. We believe the procedure we used is in compliance with the BART Guidelines, and also note that it is consistent with the procedure we used in our cost analysis for controls on White Bluff.

In analyzing the cost of LNB/SOFA + SCR controls on Independence, the commenters assumed a controlled NO_X emission rate of 0.04 lb/MMBtu. However, the Stamper Report referenced in the comment does not provide justification for this assumed controlled emission rate at Independence. To the extent that the commenters intended to rely on the same justification they provided for assuming a controlled NO_X emission rate of 0.04 lb/MMBtu based on LNB/SOFA + SCR controls at White Bluff, we discuss in the section of this document where we discuss cost

[141] http://ampd.epa.gov/ampd/

issues that we disagree that there is information to support a 30 boiler-operating-day rolling average of 0.04 lbs/MMBtu at White Bluff. As with White Bluff, we see no information provided by the commenters to support a controlled NO_X emission rate of 0.04 lb/MMBtu on a 30 boiler-operating-day rolling average. We see no evidence of an SCR operating at that level for extended periods of time, such that we would feel comfortable that a 30 boiler-operating-day rolling average of 0.04 lbs/MMBtu would be sustainable at the Independence facility absent site-specific engineering information. As the commenters' cost analysis is based on an assumed NO_X emission rate of 0.04 lb/MMBtu for LNB/SOFA + SCR, we disagree with the cost analysis.

Due to the issues we discuss above concerning the commenters' revised NO_X baseline and NO_X emission rate, and the significant impact these two inputs have on a cost analysis, we cannot rely on the cost estimate of LNB/SOFA + SCR controls on Independence provided by the commenters.

Nevertheless, even if we were to accept the SCR cost estimate provided by the commenters, we would still disagree that SCR controls must be required for Independence Units 1 and 2 under the reasonable progress requirements for this planning period. We note that the commenters estimate that the cost of LNB/SOFA + SCR controls on Independence is $3,570/ton at Unit 1 and $2,772/ton at Unit 2. The commenters also estimate that the incremental cost effectiveness of SCR compared to LNB/SOFA is $6,371/ton at Unit 1 and $6,311/ton at Unit 2.[142] As we discussed above, the largest incremental visibility benefit of SCR on the two units at Independence (using the controlled SO_2 emission rate) is 0.257 dv at Caney Creek and 0.22 dv at Upper Buffalo. Although, as we discussed above, we cannot rely on the cost estimate of SCR controls on Independence provided by the commenters, even if we were to accept the commenter's cost estimates, we would find that the amount of incremental visibility benefit of SCR controls compared to LNB/SOFA (i.e., 0.257 dv at Caney Creek and 0.22 dv at Upper Buffalo) is not large enough to justify the incremental cost of SCR as calculated by the commenters (i.e., $6,371/ton at Unit 1 and $6,311/ton at Unit 2).

For the reasons discussed above, we disagree with certain aspects of the commenters' reasonable progress analysis and we also disagree that it demonstrates that SCR controls are necessary under the reasonable progress requirements for Independence Units 1 and 2 in this planning period. We continue to believe that we took a reasonable approach in concluding that LNB/SOFA is expected to be more cost-effective than SNCR or SCR, and that the incremental visibility benefit at individual Class I areas as a result of SNCR or SCR controls at each unit of the Independence

[142] With regard to the commenters' reference to the cost effectiveness and incremental cost effectiveness of controls we have required in other regional haze actions, we note that in evaluating different control options for reasonable progress under the long term strategy, even if a particular control option is cost-effective or has a reasonable incremental cost-effectiveness, it may not be the most reasonable and appropriate option when considered alongside the other statutory factors and when visibility improvement is considered. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. As the Eighth Circuit Court acknowledged in *North Dakota v. EPA*, states can take visibility improvement into account when evaluating reasonable progress controls so long as they do so in a reasonable way (North Dakota v. EPA, 730 F.3d 750, 766 (8th Cir. 2013)).

facility is not likely to warrant the incremental cost effectiveness.[143] In light of this, we believe it was reasonable to evaluate only LNB/SOFA in our reasonable progress analysis of NO_X controls for Independence. We believe this is a reasonable approach and that the CAA, RH regulations, and our Reasonable Progress Guidance provide us with discretion to take such an approach in a reasonable progress analysis. As discussed in our final rule and elsewhere in this document, we are finalizing NO_X controls consistent with LNB/SOFA for Independence under the reasonable progress requirements.

With regard to the commenters' statement that it is appropriate to assume that SCR could be installed at Independence within 3 years, we note that the time necessary for compliance was not a determining factor in our decision to not evaluate and not ultimately require SCR for Independence.

With regard to the commenters' contention that we should require Independence Units 1 and 2 to install and operate LNB/SOFA + SCR as part of the long-term strategy requirements under section 51.308(d)(3) to address Arkansas' impacts at Class I areas in Missouri, we disagree. In our proposed partial approval and partial disapproval action on the Arkansas RH SIP, we stated that we agreed that additional emissions reductions in Arkansas, beyond those required under BART, are not necessary to protect visibility at Class I areas outside of the state at this time.[144] This finding remained unchanged in our final action on the Arkansas RH SIP.[145] Therefore, our reasonable progress analysis for Arkansas' Class I areas was conducted to determine if additional controls are necessary in this planning period to make reasonable progress at Arkansas' Class I areas. Although our proposed FIP did evaluate the visibility improvement projected to take place in Missouri's Class I areas (Hercules-Glades and Mingo) due to controls at Independence, this was done solely to be informative. We noted in our proposal that we modeled the visibility improvement projected to result from our proposed controls for Independence in all Class I areas located within 300 km of the Independence Plant. The visibility improvement projected to take place at Hercules-Glades and Mingo due to controls at Independence did not affect our proposed decision for reasonable progress controls. We apologize for any confusion that may have been caused by our modeling of the visibility improvement in Missouri's Class I areas.

Comment: EPA should reject Option 2 under the reasonable progress requirements and, at a minimum, select Option 1, which would require Independence Units 1 and 2 to meet emission limits based on the use of a scrubber and LNB/SOFA. [Sierra Club et. al. (0171) p. 37-39] Sierra Club et. al. stated that EPA has proposed two control options for the Independence plant: Option 1, which would require scrubbers as well as LNB/SOFA; and Option 2, which would require only scrubbers. 80 FR at 18997. EPA should reject Option 2, which would require no NO_X controls, because it is inconsistent with the reasonable progress requirements. In contrast to Option 2, EPA's proposed Option 1, which would require Independence Units 1 and 2 to meet

[143] Thus, we disagree that we "place[d] undue weight on incremental cost-effectiveness relative to average cost-effectiveness." As discussed in our proposal, in our final rule, and in this document, we considered the average cost effectiveness and the incremental cost effectiveness along with the other statutory factors in our cost analysis for NO_X controls on White Bluff and in developing our cost analysis for NO_X controls for Independence.
[144] 76 FR at 64215.
[145] 77 FR 14604.

a NO_X emission limit based on the use of LNB/SOFA, is cost-effective and consistent with each of the four factors for evaluating reasonable progress controls. As a result, in the event that EPA erroneously declines to require LNB/SOFA + SCR at Independence Units 1 and 2, the agency must at least adopt Option 1 in any final haze FIP for Arkansas.

Sierra Club stated that EPA calculated the average cost-effectiveness of LNB/SOFA to be $401 per ton for Unit 1 and $436 for Unit 2. 80 FR at 18996. The Stamper Report used the Sargent & Lundy IPM cost modules to independently calculate the cost of LNB/SOFA for the two Independence units. The report concludes that LNB/SOFA is even more cost-effective than EPA calculated, at $380 per ton for Unit 1 and $287 per ton for Unit 2. Stamper Report at 66. Regardless of whether EPA uses the cost-effectiveness figures from the proposed rule, or Ms. Stamper's calculations, LNB/SOFA at Independence is among the most-cost effective controls that EPA has considered for reasonable progress in any rulemaking, as shown by the table below.

Cost-Effectiveness of Final Reasonable Progress Determinations[146]

Facility	Reasonable Progress Control	Cost, $/ton
Hawaii Electric Co., Kanoelehua Power Plant	SO2 emissions cap[147]	5587
Hawaii Electric Co., Puna Power Plant	SO_2 emissions cap	5583
Hawaii Electric Co., Shipman Power Plant	SO_2 emissions cap	5583
Tri-State Generation, Craig Unit 3	SNCR	4887
Colorado Springs Utilities, Nixon Unit1	Dry FGD	3744
PacifiCorp Jim Bridger Unit 2	SCR	3015
PacifiCorp Jim Bridger Unit 3	SCR	2961
PacifiCorp Jim Bridger, Unit 4	SCR	2492
PacifiCorp Jim Bridger, Unit 1	SCR	2393
Holcim Florence Cement Plant	SNCR	2293
Colorado Springs Utilities, Nixon Unit 1	ULNB/OFA	1372
Phoenix Cement, Clarkdale Kiln 4	SNCR	1142
Rillito Cement Kiln 4	SNCR	1047
Basin Electric, Antelope Valley Unit 2	LNB	661
Montana Dakota Utilities, Heskett Station	Limestone Injection	651
Platte River Power Authority, Rawhide Unit 101	ECC	644
Basin Electric, Antelope Valley Unit 1	LNB	586

[146] Sources for the table are as follows: partial FIP for Arizona, 79 Fed. Reg. 9,318, 9,354-56 (Feb. 18, 2104) and 79 Fed. Reg. 52,420 (Sept. 3, 2014); approval of Colorado's SIP, 77 Fed. Reg. 18,052, 18,082, 18,084, 18,087 (Mar. 26, 2012) and 77 Fed. Reg. 76,871 (Dec. 31, 2012); FIP for Hawaii, 77 Fed. Reg. 31,691, 31,711 (May 29, 2012) and 77 Fed. Reg. 61,478, 61,506 (Oct. 9, 2012); FIP for Montana. 77 Fed. Reg. 23,988, 24,069 (Apr. 20, 2012) and 77 Fed. Reg. 57,864 (Sept. 18, 2012); partial SIP approval and partial FIP for North Dakota, 76 Fed. Reg. 58,570, 58,626, 58,630-32 (Sept. 21, 2011) and 77 Fed. Reg. 20,894, 20,897 (Apr. 6, 2012); FIP for Wyoming, 78 Fed. Reg. 34,738, 34,754-56, 34,757-78 (June 10, 2013) and 79 Fed. Reg. 5,032 (Jan. 30, 2014).

[147] "This cap [the SO_2 emissions cap] was derived from EPA's analysis of the costs of switching these units to 1% sulfur fuel." Therefore, the cost-effectiveness for the three Hawaii plants represents the cost to meet the SO_2 cap by switching to low-sulfur fuel.

Devon Energy Blaine County #1 Compressor	NSCR	282

The three other reasonable progress factors weigh in favor of requiring at least LNB/SOFA for Independence Units 1 and 2. The "time necessary for compliance," 42 U.S.C. §7491(g)(1), is reasonable, since EPA proposed to allow 3 years to install and operate the controls. 80 FR at 18996. Entergy can install LNB/SOFA in less than a year, Stamper Report at 67, so three years is more than reasonable. The "energy and nonair quality environmental impacts" are minimal and the "remaining useful life" does not cut against the controls. *See* 42 U.S.C. § 7491(g)(1).

If EPA considers visibility improvement as part of the reasonable progress analysis, this factor also supports LNB/SOFA as the minimum reasonable progress measure the agency should adopt for controlling NO_X emissions from Independence. LNB/SOFA would improve visibility by 0.461 deciviews at Caney Creek and 0.248 deciviews at Upper Buffalo. 80 FR at 18996.

For all these reasons, EPA should reject Option 2 and, at a minimum, select Option 1, which would require Independence Units 1 and 2 to meet emission limits based on the use of a scrubber and LNB/SOFA. And it is eminently reasonable to require NO_X controls at Independence, given that it currently has no NO_X controls at all, is the second-largest emitter of NO_X in Arkansas, and EPA is proposing NO_X controls for the first- and third-largest NO_X emitters in the state. *See* 80 FR at 18991. EPA has not demonstrated that consideration of the four reasonable progress factors supports requiring no NO_X controls, in light of the record evidence that cost-effective NO_X controls can be installed in a short period of time at Independence Units 1 and 2 with minimal environmental impacts. As EPA has not articulated a rational basis for disregarding the evidence in the record that supports Option 1, it would be arbitrary and capricious for EPA to select Option 2 on this record.

Response: Although we disagree with the commenters' contention that we erroneously declined to require LNB/SOFA + SCR at Independence Units 1 and 2, we appreciate the support the commenters express for our proposed Option 1. We address more detailed comments arguing that we should require LNB/SOFA + SCR at Independence Units 1 and 2 elsewhere in this document. As discussed in our final rulemaking and elsewhere in this document, we are finalizing Option 1 for Independence Units 1 and 2, which consists of requiring SO_2 controls consistent with installation of dry scrubbers and NO_X controls consistent with installation of LNB/SOFA under the reasonable progress requirements.

Although it does not ultimately affect our final decision to require NO_X controls consistent with LNB/SOFA, we disagree with the commenters' contention that we underestimated the cost of LNB/SOFA at Independence and address this issue in the section of this document where we discuss cost issues. Nevertheless, we agree with the commenters that LNB/SOFA controls at Independence are very cost effective, as calculated by us in our cost analysis, and we acknowledge the information presented by the commenters concerning the cost-effectiveness of reasonable progress determinations made in other regional haze actions.

We also agree that single source CALPUFF modeling shows that meaningful reductions to the maximum 98th percentile visibility impact from the Independence facility are expected to be

achieved through NO_X controls. As discussed in our proposal, we conducted CALPUFF modeling of the baseline visibility impacts from Independence and the visibility benefit of LNB/SOFA controls.[148] We found that LNB/SOFA controls on Independence are expected to result in visibility benefits of 0.459 dv at Caney Creek and 0.198 dv at Upper Buffalo (on a facility wide basis), and consider this to be meaningful visibility improvement. We also discuss in detail elsewhere in this document that CAMx source apportionment modeling conducted by Entergy and submitted to us during the comment period for our proposal shows that the contribution to visibility impairment due to baseline emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the average 20% worst days in 2018 at each Arkansas Class I area. We consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources. The results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30 – 40% of the visibility impairment at Arkansas' Class I areas on 2 of the 20% worst days.[149] We expect that installation of cost-effective NO_X controls on Independence would provide visibility improvement on this portion of the 20% worst days, and as such, we are requiring NO_X controls consistent with LNB/SOFA under the reasonable progress requirements.

In response to comments stating that LNB/SOFA controls can be installed in less than a year, we are revising our proposed compliance date for NO_X controls on Independence Units 1 and 2 (as well as White Bluff Units 1 and 2 and Flint Creek Unit 1). As we discuss in the section of this document where we discuss compliance date issues, we are finalizing an 18-month compliance date for NO_X controls for these sources.

3.b. Controls under reasonable progress/Arkansas' Class I areas are below URP glidepath

Comment: EPA did not appropriately analyze which sources, if any, should be controlled under the Reasonable Progress requirements.

[Entergy Arkansas Inc. (0166) p. 18] Entergy stated that EPA's justification for imposing SO_2 and NO_X emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions." 80 FR at 18992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. 80 FR at 18994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NO_X emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress

[148] See our supplemental NO_X modeling results for the Independence facility in 80 FR 24872.
[149] This means 2 out of the 21 days that are the 20% worst of the days with IMPROVE monitoring data.

purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPs. *See* Section III.B of Entergy's comments.

[Entergy Arkansas Inc. (0166) p. 14-17] Entergy stated that for reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NO_X limitations on the two coal-fired units at Independence. EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NO_X within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[150]

Entergy stated that by focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

Entergy stated that EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) (Reasonable Progress Guidance).[151] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

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[150] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[151] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf.

Entergy stated that EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[152] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[153] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[154] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.* at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

Entergy stated that EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF, single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635. EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress.*[155] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

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[152] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").
[153] *Id.* at A-15 – A-26.
[154] *Id.* at A-49.
[155] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

[Entergy Mississippi Inc. (EMI) (0168) p. 4-5) EMI stated that by focusing solely on the Independence Plant, EPA's reasonable progress analysis for the Proposed Rule abandons the analytical approach and criteria that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA utilized and applied in previous decisions to approve/disapprove regional haze SIPs or promulgate regional haze FIPs, EPA made an unsubstantiated decision to evaluate controls for the Independence Plant simply because the agency believes "it would be unreasonable to ignore" the facility. In its four-factor analysis, the agency further abandoned the standards and thresholds that guided previous determinations, choosing instead to propose additional controls for the Independence Plant that exceed the cost estimates and fall short of the visibility improvements documented for other sources under other approved plans. EPA's arbitrary evaluation process for the Arkansas FIP not only distorts the goals and objectives of the regional haze rule but also is contrary to EPA's own requirements for uniformity and regional consistency.

As an initial matter, EPA did not meet the Act's threshold requirement for emission reductions for reasonable progress: that they must be *necessary*. 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). EPA then failed to assess and document the contribution to visibility impairment at any class I Federal area from any Arkansas point source, including the Independence Plant. The failure to determine visibility impact is contrary to typical practice and is completely inconsistent with the detailed approach taken by Region 6 in its promulgation of the regional haze FIP for Texas, in which the agency conducted a refined multi-step process to identify those point sources requiring further evaluation, quantifying visibility impacts from those sources and arriving at a common breakpoint in potential visibility improvement.[156] EPA proceeded to the required four-factor reasonable progress analysis only after narrowing the list of potential point sources.[157] No doubt, this process was utilized because it was the same process utilized by other regions and other states[158] and because, as discussed above, the regional haze rule requires that additional controls for proposed emissions reductions, as stated in an implementation plan, must be *needed* to achieve reasonable progress.[159]

By notable contrast, the same EPA Region did not perform any evaluation to identify any Arkansas point sources contributing to visibility impairment (or measure the scope of any contribution) at the Upper Buffalo or Caney Creek class I Federal areas. Instead, the Agency made the simplistic evaluation that the Independence Plant was a large source of SO_2 and NO_X

[156] *See generally*, Texas Regional Haze FIP (Proposed), 79 Fed. Reg. 74,818 (Dec. 16, 2014); *see also* Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans ("TX FIP TSD"), Appendix A (Nov. 2014).
[157] *See* Texas Regional Haze FIP at 74,872.
[158] *See e.g.*, 79 Fed. Reg. 9,138, 9,352-53 (Arizona Proposed) (Feb. 18, 2014); 77 Fed. Reg. 23,988, 24,058-59 (Montana Proposed) (Apr. 20, 2012); and 76 Fed. Reg. 58,570, 58,624-26 (North Dakota Proposed) (Sept. 21, 2011).
[159] See 42 U.S.C. § 7491(b)(2); Reasonable Progress Guidance at 4-1. *See also* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and 51.308(d)(3). Additionally, logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

emissions and, therefore, "it would be unreasonable to ignore" the facility.[160] This arbitrary approach turns the regional haze rule on its head and marks a drastic departure from past practices.

[Entergy Mississippi Inc. (0168) p. 7-8; Conway Corporation et. al. (0172) p. 7-8; and EEAA (0173) p. 12-14] EMI, Conway Corporation et. al., and EEAA all stated that EPA's entire justification for proposing additional controls at the Independence Plant is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions."[161] However, the fact that a source not otherwise subject to BART may have significant SO_2 or NO_X emissions is irrelevant for reasonable progress purposes. This arbitrary approach to reasonable progress analysis (or lack thereof) is grossly inconsistent with the CAA, Regional Haze regulations and guidance, and EPA's own prior efforts; the latter of which first determined a need for additional controls to achieve reasonable progress and then sought to identify sources and controls that were appropriate and reasonable. EPA's proposal to implement additional controls for the Independence Plant does not further the goal of the regional haze program and, moreover, is unnecessary to achieve reasonable progress during the first planning period.[162]

[Conway Corporation et. al. (0172) p. 4-5, 6-7; and EEAA (0173) p. 8-10, 11-12] Conway Corporation et. al. and EEAA stated that EPA's reasonable progress analysis for the Proposed Rule abandons the analytical approach and determinative criteria that guided previous analyses and determinations. In the place of the criteria and procedures that EPA utilized and applied in previous decisions to approve/disapprove regional haze state implementation plans or promulgate regional haze federal implementation plans, EPA made an unsubstantiated decision to evaluate controls for the Independence Plant simply because the agency believes "it would be unreasonable to ignore" the facility. During its four-factor analysis, the agency further abandoned the standards and thresholds that guided previous determinations, choosing instead to propose additional controls for the Independence Plant that are not cost-effective and fall short of the visibility improvements documented for other sources under other approved plans. EPA's arbitrary evaluation process for the Proposed Rule not only distorts the goals and objectives of the regional haze rule but is also contrary to EPA's own requirements for uniformity and regional consistency.

Conway Corporation et. al. and EEAA stated they provided comments on specific issues relating to the inconsistencies in the EPA's proposed FIP. The commenters stated that reviewed individually, each issue evidences an arbitrary, unjustified and inconsistent application of the regional haze regulations. Collectively, they demonstrate EPA's complete disregard for the consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act.[163] They further oblige the agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency

[160] 80 Fed. Reg. at 18,992.
[161] 80 FR at 18992.
[162] Arkansas Five-Year Progress Report at 39-43 (indicating that all relevant class I Federal areas are ahead of the glide path for the first planning period).
[163] 40 C.F.R. § 56.3(a) and (b).

policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices.[164]

Conway Corporation et. al. and EEAA stated that in the proposed FIP, Region 6 officials abandoned the standardized criteria, procedures and policies previously applied by the agency and, in the process, disregarded all notion of uniformity. Moreover, the EPA's inconsistent treatment is due in large measure to the agency's failure to complete necessary analysis, which is the same justification it provided when it rejected Arkansas' SIP proposal in the first instance.[165]

Conway Corporation et. al. and EEAA stated that as an initial matter, in conducting its reasonable progress analysis, EPA failed to assess and document the contribution to visibility impairment at any class I Federal area from any Arkansas point source, including the Independence Plant. The failure to determine visibility impact is contrary to typical practice and is completely inconsistent with the detailed approach taken by EPA in its promulgation of the regional haze FIP for Texas.[166] There, the agency completed a refined multi-step evaluation that included: Q/D analysis for each Texas point source and relevant Class I Federal area to identify those point sources requiring further evaluation;[167] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis;[168] and, an extinction percentage threshold to arrive at a common breakpoint in potential visibility improvement.[169] EPA proceeded to the required four-factor reasonable progress analysis only after narrowing the list of potential point sources.[170] No doubt, EPA pursued this process because it was the same process utilized previously by EPA and other states[171] and because the regional haze rule requires that any additional emissions reductions must be necessary to achieve reasonable progress.[172]

Conway Corporation et. al. and EEAA stated that by notable contrast, in the proposed FIP, EPA's Region 6 office did not perform any evaluation to identify any Arkansas' point sources contributing to visibility impairment (or measure the scope of any contribution) at the Upper Buffalo or Caney Creek class I Federal areas. Instead, the Agency made the simplistic observation that the Independence Plant was a large source of SO_2 and NO_X emissions and,

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[164] 40 C.F.R. § 56.5(a).
[165] 80 Fed. Reg. at 18991 (noting that EPA's partial disapproval of the Arkansas RH SIP was made, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").
[166] *See generally*, 79 Fed. Reg. at 74818.
[167] *See generally*, Texas Regional Haze FIP (Proposed), 79 Fed. Reg. 74818 (Dec. 16, 2014); *see also* Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD), Appendix A (Nov. 2014).
[168] *Id.* at A-15 thru A-26.
[169] *Id.* at A-49.
[170] *See* 79 Fed. Reg. at 74872.
[171] *See e.g.*, 79 Fed. Reg. 9138, 9352-53 (Arizona Proposed) (Feb. 18, 2014); 77 Fed. Reg. 23988, 24058-59 (Montana
Proposed) (Apr. 20, 2012); and 76 Fed. Reg. 58570, 58624-26 (North Dakota Proposed) (Sept. 21, 2011).
[172] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and 51.308(d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

therefore, "it would be unreasonable to ignore" the facility.[173] This arbitrary approach turns the regional haze rule on its head and marks a drastic departure from past practices.

Response: With regard to the commenters' contention that our primary justification for imposing emission limits under reasonable progress for Independence Units 1 and 2 is that it would be unreasonable to ignore a source representing more than a third of the state's SO_2 emissions and a significant portion of NO_X point source emissions, this is incorrect. While we did state in our FIP proposal that it would be unreasonable to ignore a source representing more than a third of the state's SO_2 emissions and a significant portion of NO_X point source emissions, the commenters took this statement out of context. The full citation from our FIP proposal referenced by the commenters is the following:

> We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period. This is because we believe that in determining whether reasonable progress is being achieved, it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions.[174]

As evidenced by the full citation from our FIP proposal, the fact that we considered it unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions was our primary justification for looking more closely and evaluating the Independence plant in our reasonable progress analysis. It was not, as the commenters contend, our justification for imposing controls on Independence. As we discussed in our FIP proposal, in our final rule, and elsewhere in this document, our decision to require controls on Independence is based on our reasonable progress analysis, as required by the CAA and the Regional Haze Rule under section 51.308(d)(1).

We disagree with commenters contending that the fact that a non-BART source has significant SO_2 or NO_X emissions, or that it would be cost-effective to control such emissions, is irrelevant in determining what sources to take a closer look at and evaluate under reasonable progress. As noted elsewhere in this document, the cost of compliance is one of the four statutory factors under CAA section 169A(g)(1) that EPA is required to consider in a reasonable progress analysis, meaning that consideration of the cost effectiveness of potential controls is not irrelevant for reasonable progress purposes. As SO_2 and NO_X are visibility impairing pollutants, significant SO_2 or NO_X emissions from a source is generally an indication that there may be significant visibility impacts at nearby Class I areas, and that installation of controls may result in substantial emissions reductions and meaningful visibility improvement. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states and EPA have the option of considering the projected visibility benefits of controls in determining if additional controls are necessary to make reasonable progress. Therefore, we find that consideration of a source's emissions and

[173] 80 Fed. Reg. at 18992.
[174] 80 FR at 18992.

whether it would be cost-effective to control such emissions is appropriate and relevant for reasonable progress purposes.

We disagree with commenters contending that we did not appropriately analyze which sources, if any, should be controlled under the reasonable progress requirements. To the extent that the commenters contend that our process for determining which sources should be evaluated under reasonable progress was incorrect because we did not conduct photochemical modeling, such argument is incorrect. As noted above, we are not required to conduct photochemical modeling in a reasonable progress analysis. Our 2007 Reasonable Progress Guidance states that:

> The RHR gives States wide latitude to determine additional control requirements, and there are many ways to approach identifying additional reasonable measures; however, you must at a minimum, consider the four statutory factors.[175]

The states or EPA in the context of a FIP have wide discretion in deciding what approaches, methods, and tools to use in identifying source categories, specific point sources, or pollutants to evaluate for additional controls under the reasonable progress requirements, provided that a reasonable rationale for the approach used is provided. There are a number of different approaches states or EPA in the context of a FIP have used in identifying sources for reasonable progress evaluation, but they usually center around the general premise of evaluating the biggest sources and/or the biggest impactors on visibility. While the states or EPA have the discretion to consider visibility in a reasonable progress analysis, photochemical modeling is not required for purposes of conducting a reasonable progress analysis.

Our FIP proposal provided a detailed explanation of how we determined what sources to evaluate for controls under reasonable progress, and we provided a reasonable rationale for the approach we used. The first step in our analysis involved determining what source categories or specific point sources it would be appropriate to look at more closely and evaluate under the reasonable progress requirements in section 51.308(d)(1) to determine if additional controls are necessary. We explained in our proposal that it was appropriate to focus our analysis on point sources since the other source categories (i.e., natural, on-road, non-road, and area) each contribute a much smaller proportion of the total light extinction at each Class I area in Arkansas based on the CENRAP CAMx modeling.[176] At Caney Creek, point sources contribute 81.04 Mm^{-1} out of a total light extinction of 133.93 Mm^{-1} on the average across the 20% worst days in 2002, or approximately 60.5% of the total light extinction. At Upper Buffalo, point sources contribute 77.80 Mm^{-1} out of a total light extinction of 131.79 Mm^{-1} on the average across the 20% worst days in 2002, or approximately 59% of the total light extinction. In comparison, area sources, which are the source category with the next highest contribution to the total light extinction at each Class I area, contribute approximately 13.3% of the total light extinction at Caney Creek and 15.5% at Upper Buffalo. The remaining source categories each contribute less than 6% of the total light extinction at each Class I area. Therefore, we concluded that it was appropriate to focus our analysis on point sources. To the extent some commenters suggested

[175] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," at 4-2.
[176] See 80 FR at 18989.

that our decision to focus our reasonable progress analysis on point sources was unsubstantiated or arbitrary, this is incorrect and not supported by the record for this action.

The CENRAP CAMx modeling shows that on most of the 20% worst days in 2002, total extinction was dominated by sulfate at both Caney Creek and Upper Buffalo.[177] Additionally, total extinction at Caney Creek was dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002 and a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 was due to nitrate.[178] The CENRAP CAMx modeling also shows that sulfate from point sources was responsible for approximately 54.8% of the total visibility impairment at Upper Buffalo and 56.1% at Caney Creek on the 20% worst days in 2002. Nitrate from point sources was responsible for approximately 3% of the total visibility impairment at each Class I area on the 20% worst days in 2002. As such, although SO_2 emissions are the primary contributor to regional haze in Arkansas' Class I areas on the 20% worst days, NO_X emissions are also a key contributor. Thus, consistent with our 2007 Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,[179] we found it appropriate to evaluate both SO_2 and NO_X controls under reasonable progress.

We explained in our FIP proposal that as a starting point in our analysis to determine whether additional controls on Arkansas point sources are reasonable in the first regional haze planning period, we examined the most recent SO_2 and NO_X emissions inventories for point sources in Arkansas (NEI 2011 v1).[180] We reasoned that examination of the emissions inventories is appropriate because significant SO_2 or NO_X emissions from a source are generally an indication that it may be having significant visibility impacts at nearby Class I areas and that installation of controls may result in substantial emissions reductions and meaningful visibility improvement. We did not conduct photochemical modeling or other more exhaustive analyses to identify potential candidates to evaluate under reasonable progress, and while we recognize that this approach is different from the approaches and methods that we have used or approved in other regional haze actions, we find that the approach we are taking in this action is appropriate given the specific circumstances. In particular, our examination of the SO_2 and NO_X emissions inventories for Arkansas' point sources revealed that the number of point sources that emit SO_2 and NO_X emissions is relatively small. Furthermore, a very small portion of the point sources in the state is responsible for a large portion of the statewide SO_2 and NO_X point source emissions. Specifically, White Bluff, Independence, and Flint Creek are collectively responsible for approximately 84% of the SO_2 point source emissions and 55% of the NO_X point source emissions in the state. Consequently, addressing these sources under the regional haze program will address a large proportion of the visibility impacts due to Arkansas point sources. We are requiring SO_2 and NO_X controls for White Bluff and Flint Creek under the BART requirements in this final action, which will substantially reduce emissions from these two facilities. The Independence Plant, which is not a subject-to-BART source, contributes approximately 36.2% of

[177] See Arkansas Regional Haze SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.
[178] See Arkansas Regional Haze SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.
[179] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," at 2-3 and 3-1.
[180] 80 FR at 18991.

the total SO_2 point source emissions in the state (30,398 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons, based on the 2011 NEI).[181] This source also contributes approximately 21.3% of the total NO_X point source emission in the state (13,411 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons). Based on this examination, we determined that the magnitude of emissions from the Independence Plant warranted further evaluation of the source to determine if it is a significant contributor to regional haze in Arkansas' Class I areas and whether controls at the facility are needed based on an analysis under section 51.308(d)(1).

After White Bluff, Independence, and Flint Creek, the remaining point sources in the State have much lower SO_2 and NO_X emissions than these facilities. In other words, the magnitude of SO_2 and NO_X emissions from point sources in Arkansas drops off considerably after the top 3 emitters. We stated the following in our proposal:

> The fourth largest SO_2 and NO_X point sources in Arkansas are the Future Fuel Chemical Company, with emissions of 3,421 SO_2 tpy, and the Natural Gas Pipeline Company of America #308, with emissions of 3,194 NO_X tpy (2011 NEI). In comparison to the emissions of the top three sources, emissions from these two facilities are relatively small. Therefore, we are not proposing controls in this first planning period for these two facilities because we believe it is appropriate to defer the consideration of any additional sources besides Independence to future regional haze planning periods.[182]

Future Fuel Chemical Company, the point source with the fourth highest SO_2 emissions (after White Buff, Independence, and Flint Creek), contributes approximately 4.1% of the total SO_2 point source emissions in the state (3,420 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons, based on the 2011 NEI). The Natural Gas Pipeline Company of America #308, the point source with the fourth highest NO_X emissions, contributes approximately 5.1% of the total NO_X point source emission in the state 3,194 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons, based on the 2011 NEI). Based on the much smaller magnitude of these sources' emissions, we determined that the remaining point sources in the state are less likely to be significant contributors to regional haze, and thus did not warrant closer evaluation under reasonable progress in this planning period. As such, we found that it is appropriate to evaluate Independence, but not other sources in Arkansas, for controls under reasonable progress in this planning period. The commenters' claims that we were arbitrary and capricious in determining what sources to evaluate under reasonable progress, that we singled out Independence, and that we provided no explanation as to why we did not evaluate other point sources under reasonable progress is not supported by the record in this action.[183]

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[181] See NEI 2011 v1. A spreadsheet containing the emissions inventory is found in the docket for our proposed rulemaking.

[182] 80 FR 18992.

[183] We do note that because of the controls required during this planning period, we expect that the impact from the facilities in Arkansas that were not controlled and not specifically evaluated in the first planning period will become larger on a percentage basis. These sources will become the largest impacting sources and should be considered for analysis under reasonable progress in future planning periods. The methodology we used here thus allows a

Because our examination of the Arkansas emissions inventory revealed that the number of point sources that emit SO_2 and NO_X emissions is relatively small and that a very small portion of the point sources in the state are responsible for a large portion of the statewide SO_2 and NO_X point source emissions, we concluded that other more exhaustive analyses that we have performed in other regional haze actions were unnecessary to identify point sources to evaluate under reasonable progress. In contrast, in states such as Texas, where the universe of point sources is much larger and the distribution of SO_2 and NO_X emissions is very widespread, an evaluation of the state's emissions inventory alone was not sufficient to reveal the best potential candidates for evaluation under reasonable progress. For this reason, we explained in our Texas Regional Haze FIP that due to the challenges presented by the geographic distribution and number of sources in Texas, the CAMx photochemical model was best suited for identifying sources to evaluate for reasonable progress controls.[184] We did not encounter these challenges in the development of our reasonable progress analysis for Arkansas and therefore did not conduct photochemical modeling. We do note that while we did not conduct photochemical modeling to identify Arkansas point sources to evaluate under reasonable progress, Entergy conducted CAMx source-apportionment modeling and submitted it during the comment period. We discuss elsewhere in this document that the results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas.

We also note that the Arkansas RH SIP submitted to us in 2008 did not include a four factor reasonable progress analysis. Therefore, in contrast to our actions in other states where we disapproved the state's reasonable progress analysis but were able to rely on some aspects of the state's analysis in developing our own analysis, for our Arkansas FIP we had to start from square one in developing our analysis and determining what sources to evaluate under reasonable progress.

We disagree with comments arguing that we "failed to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence." To the extent the commenters are claiming that we failed to assess the contribution to visibility impairment from Arkansas point sources because we did not conduct photochemical modeling, we discuss above and elsewhere in this document that we are not required to conduct photochemical modeling in a reasonable progress analysis. For consideration of the visibility impacts at the affected Class I areas and the visibility benefits of potential controls, we relied on the following: CENRAP CAMx source apportionment results, point source emission inventory data that initially identified the Independence facility as having the greatest potential to impact visibility at nearby Class I areas among all Arkansas sources not already controlled under the BART requirements, and the results of our CALPUFF modeling of the maximum or 98th percentile impacts from Independence and the visibility benefits of

consistent procedure to identify facilities for additional control analysis in this and future planning periods and ensures continuing progress towards the goal of natural visibility conditions.

[184] 81 FR 296.

potential controls.[185] Therefore, the claim that we did not assess and document the contribution to visibility impairment from Arkansas point sources is incorrect.

We disagree that the controls we are requiring in our final action for the Independence Plant do not further the goal of the regional haze program and we disagree that they are unnecessary to make reasonable progress during the first planning period. As discussed in our proposal and throughout this final notice, based on our analysis of the four reasonable progress factors and our consideration of the baseline visibility impacts from Independence and the visibility improvement of potential controls, we determined that SO_2 and NO_X controls at Independence would be cost-effective and would result in meaningful visibility benefits at Arkansas' Class I areas, and therefore find that they are reasonable controls and are necessary to make reasonable progress.

We address elsewhere in this document comments claiming that before conducting a reasonable progress analysis we must first determine whether additional controls are necessary to make reasonable progress.

With regard to the comment that our reasonable progress analysis failed to consider any lesser level of controls for Independence, the relative costs of such controls, and the visibility improvement of these controls, we note that for NO_X we evaluated LNB/SOFA, which is a control technology that generally represents one of the lowest levels of NO_X control. For SO_2, we considered both wet and dry FGD. We did not consider lesser technologies for SO_2 since the four factor evaluation demonstrated cost effective controls. We address elsewhere in this document comments contending that we failed to consider the cost per deciview improvement associated with our proposed controls.

We address elsewhere in this document specific comments contending that the controls we proposed for Independence fall short of the visibility improvements documented for other sources under other approved regional haze plans. We also address elsewhere in this document specific comments contending that our proposed controls for Independence provide no perceptible visibility improvement.

We address elsewhere in this document specific comments contending that the SO_2 and NO_X controls we proposed for Independence exceed the cost estimates documented for other sources under other approved regional haze plans where we did not impose reasonable progress controls.

We address elsewhere in this document comments on specific issues relating to what the commenters contend are "inconsistencies in the EPA's proposed FIP."

Comment: EPA's proposed emission limits for Independence are not necessary to achieve reasonable progress since ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018 and will meet the 2018 RPGs established by Arkansas; this trend in visibility improvement is expected to continue beyond 2018.

[185] We address comments contending that we inappropriately used CALPUFF modeling to determine impacts and project visibility benefits from installing controls on Independence elsewhere in this document.

[Entergy Arkansas Inc. (0166) p. 17-23] Entergy stated that Units 1 and 2 at the Independence station are not subject to BART. 80 FR at 18991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective."

Entergy stated that in a reasonable progress analysis, EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review. 64 FR 35714, 35752 (July 1, 1999).

Entergy stated that EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long term goal." Reasonable Progress Guidance at 1-4; *see also id.* at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Entergy asserted that the threshold question is thus whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added).

Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here. Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly that additional emissions reductions are not necessary to achieve reasonable progress. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational"). Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NO_X controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and operation of dry FGD systems, and a rolling 30-day average NO_X emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id.* at 18994, 18997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id.* at 18994.

Entergy asserted that emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress, as ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[186] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current 5-year average shows that, as of 2011, Caney Creek has achieved 73% of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the 5-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id.* at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id.* at 42-43. EPA acknowledges these facts in the FIP proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 FR at 18992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing in its alternative proposal and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[187]

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[186] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

[187] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric

[Entergy Mississippi Inc. (0168) p. 7-8; Conway Corporation et. al. (0172) p. 7-8; and EEAA (0173) p. 12-14] EMI, Conway Corporation et. al., and EEAA all asserted that the goal of the regional haze program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas resulting from manmade air pollution.[188] The goal is not to simply reduce emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The proposal for additional controls on Independence is not necessary to achieve reasonable progress because the Arkansas Department of Environmental Quality (ADEQ) 5-Year Progress Report SIP revision demonstrates that both Caney Creek and Upper Buffalo are and will be below the glide path in 2018.[189] Specifically, monitoring data at Caney Creek and Upper Buffalo show improved visibility for the most impaired and least impaired days since 2001 -- with projections for continued improvement.[190]

The commenters asserted that current 5-year averages show that, as of 2011, Caney Creek achieved 73% of its 2018 visibility impairment reduction goal of 3.88 dv and Upper Buffalo achieved 66% of its 2018 visibility impairment reduction goal of 3.75 dv. Based on the 5-year rolling averages and projected data, both Class I areas are on schedule to achieve the state proposed 2018 RPGs for the 20% worst days ("W20"). Data from Caney Creek and Upper Buffalo also show that the goal of no visibility degradation on the 20% best days ("B20") will be achieved and that visibility has and will continue to improve.[191] EPA acknowledges that Arkansas' Class I Federal areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to exceed the URP for the first planning period.[192]

The commenters argue that in addition to this undisputed evidence, EPA's own analysis further counsels against imposing additional controls on the Independence Plant. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 in 2018 and 43% of the total light extinction at Upper Buffalo.[193] However, the CENRAP modeling also projects that sulfate from *Arkansas* point sources will be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo.[194] The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and

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Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 FR 11958, 11966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 FR 38007 (June 26, 2012).

[188] 42 U.S.C. § 7491(a)(1); 64 FR 35714.

[189] Arkansas Five Year Progress Report at 42-43.

[190] *Id.*

[191] *Id.*

[192] 80 FR at 18992.

[193] *Id.* at 18990.

[194] *Id.*

Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo.[195] The Independence Plant units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even smaller. Despite these very small contributions, the proposed FIP concludes that SO_2 and NO_X controls at the Independence Plant are warranted and reasonable.

The commenters asserted that EPA ultimately lacks evidence of a sufficient need to evaluate additional controls for Arkansas point sources and lacks a sufficient basis (*i.e.* insignificant contribution to visibility impairment) to justify additional controls.

[AECC (0169) p. 2-5] AECC stated that in its reasonable progress analysis, EPA has proposed to require SO_2 and NO_X controls on Independence Units 1 and 2 in its proposed FIP. However, AECC believes that this is completely unfounded. EPA believes it is appropriate to evaluate Independence even though EPA acknowledges that the Arkansas Class I areas as well as the ones outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the uniform rate of progress ("URP" or "glide path") for the first planning period.[196] If Arkansas' Class I areas - the Upper Buffalo Wilderness Area and the Caney Creek Wilderness Area - are expected to meet the URP in the first planning period, then evaluations should be limited to units that are subject to BART. AECC stated that EPA acknowledges that neither of the units at Independence are subject-to-BART sources.[197] These units are not even BART eligible based on the dates they were commissioned. Therefore, the Independence units should not be evaluated during the first planning period.

AECC stated that ADEQ's recently issued five-year regional haze progress report states that both Arkansas Class I areas are expected to meet their respective 2018 RPGs.[198] For both of the Arkansas Class I areas, the most recent data from 2011 and the current five-year rolling average (2007-2011) show that visibility impairment is decreasing more rapidly than the glide path and the RPG.[199] Also, the two Missouri Class I areas that may be impacted by Arkansas' electric generating units (EGUs) - the Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge - have demonstrated visibility improvement between 2000 and 2011.[200]

AECC stated that the emissions trends for Arkansas EGUs are trended downward from 2000-2011[201] and will likely continue to do so with several other federal environmental rules being implemented. The Clean Air Interstate Rule (CAIR) which limited SO_2 and NO_X emissions from EGUs in several states - including Arkansas and most surrounding states - was in effect through the end of 2014. CAIR was replaced by the Cross-State Air Pollution Rule (CSAPR) at the beginning of 2015, which is more stringent than CAIR. CSAPR will become even more stringent in 2017. Indeed CSAPR is already considered "better than BART" for NO_X, but EPA did not

[195] *Id.*
[196] 80 FR at 18992.
[197] *Id.* at 18991.
[198] "State Implementation Plan Review for the Five-Year Regional Haze Progress Report," prepared by the Arkansas Department of Environmental Quality, Air Division, Planning Branch, May 2015, at 56 end 57.
[199] *Id.*
[200] *Id.* at 60.
[201] *Id.* at 36.

even consider the reductions attributable to CSAPR. Compliance with the Mercury and Air Toxics Standard (MATS) is either April 16, 2015 or April 16, 2016 with a one-year extension approval. Owners of coal-fired EGUs across the country are in the process of closing units or installing controls to comply with MATS.[202] The operators of the Flint Creek unit are currently installing controls to comply with MATS which will have co-benefits of reducing particulate matter (PM) and other pollutants which will further improve visibility in nearby Class I areas. EPA proposed a new national ambient air quality standard (NAAQS) for ozone in December 2014. If this rule goes into effect, ozone forming pollutants such as NO_X will be reduced across the nation in order to meet the new standard. A reduction in nationwide NO_X emissions will result in visibility improvements in Class I areas.

AECC asserted that from a technical standpoint, EPA also incorrectly used CALPUFF modeling to determine impacts and project reasonable progress benefits for Independence. CALPUFF is a single-source puff model which will greatly overstate the impacts of emissions and control installation benefits when used for a reasonable progress analysis. When EPA evaluates Independence in future planning periods, EPA should use an appropriate model for reasonable progress analysis. Based on these facts, the Independence units should not be included in the first regional haze planning period. The Arkansas Class I areas are expected to meet their respective 2018 RPGs - even without additional controls. The Class I areas will continue to be below the glide path for years following 2018 due to compliance with the federal rules listed above.

[The Associations (0165) p. 5-9] The Associations stated that they have serious concerns about EPA's overall approach to the regional haze program in Arkansas and the potential impacts to all of the sources identified in EPA's proposal. One example of these concerns is EPA's imposition of expensive and unnecessary BART controls on the Independence plant, which is arbitrary and capricious. In the proposed rulemaking, EPA concedes that the Independence plant is not eligible under the BART program. 80 FR 18944, 18991 (April. 8, 2015). It further admits that Arkansas' two Class I areas, as well as those Class I areas that are "most significantly impacted by Arkansas sources" would meet the Uniform Rate of Progress established for each Class I area. *Id.* at 18992. Indeed, Arkansas' five year review report, using the most recent data, shows that even without additional stationary source emission controls, visibility impairments on the 20% worst days at Arkansas' two Class I areas are decreasing more rapidly than the glidepath and the RPG. Arkansas Department of Environmental Quality, State Implementation Plan Review for the Five-Year Regional Haze Progress Report (Revised May 2015) at 55-58. Nevertheless, EPA discards its key concessions, and ignores Arkansas' data on reasonable progress, in favor of seeking costly controls on the Independence plant without any demonstration that additional emission reductions are necessary to meet the RPGs for these Class I areas.

The Associations stated that under the Regional Haze program, states establish RPGs for reducing visibility impairments by a certain amount of deciviews at Class I areas during each planning period. 40 C.F.R. § 51.308(d)(1). These RPGs are established through an implementation plan. *Id.* § 51.308(d). In determining how to meet these reasonable progress

[202] In spite of the recent Supreme Court decision in *Michigan v. EPA,* (U.S. June 29, 2015), several EGUs have already installed - or are in the process of installing - controls to comply with MATS or have taken other steps to reduce emissions. Even if MATS is stayed or vacated, AECC expects that the rule will go forward before the end of this regional haze planning period along with the associated emission reductions.

goals, the state must consider projected emission reductions anticipated from existing Clean Air Act programs as well as through BART. RPG Guidance at 4-1. BART is a pollution control evaluation scheme that only applies to "BART-eligible" emission sources, meaning those "in existence" on August 7, 1977 and which began operation after August 7, 1962. 42 U.S.C. § 7491(b)(2)(A). Facilities constructed after August 7, 1977 are *not* subject to BART.

The Associations argued that emission reductions through BART and other Clean Air Act programs may be all that is necessary for states to meet their reasonable progress goals and they need do nothing further. RPG Guidance at 4-1. *If*, however, states require additional emission reductions to meet Class I reasonable progress goals, *then* they may implement "additional measures that are reasonable" based on a four-part analysis. *Id.* at 4-2. This may be done where it is *necessary* for Class I areas to achieve their reasonable progress goals. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits … as may be *necessary* to make reasonable progress") (emphasis added); RPG Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

The Associations argued that a key flaw of the proposed rulemaking is EPA's disregard of the *if … then* decision structure established by its own guidance. EPA freely admits that, after considering emission reductions from BART-eligible sources and other Clean Air Act programs, "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the [Uniform Rate of Progress] for the first planning period." 80 Fed. Reg. at 18,992. Under EPA's RPG Guidance, this should mark the end of EPA's RPG analysis. However, despite its own guidance, the proposed rule continued on to impose unnecessary, costly, and unauthorized controls on the Independence plant – a BART-*ineligible* source – on the grounds that it is somehow reasonable to do so.

The Associations asserted that EPA's explanation of "reasonableness," however, has nothing to do with meeting Class I reasonable progress goals, the critical *if-then* scenario that allows for additional emission reduction measures. According to EPA, it has *carte blanche* discretion to impose controls on any facility for any grounds that it considers to be reasonable. Here, the entirety of EPA's "reasonableness" explanation appears to be that the Independence plant is a relatively large source of emissions and that controls at the Independence plant would cost the same as at the White Bluff units. *Id.* at 18991. These considerations of "reasonableness" are completely unmoored from any discussion of achieving reasonable progress goals at either of the Arkansas Class I areas for this planning period. Where Class I areas are projected to meet their reasonable progress goals, nothing in the Clean Air Act authorizes EPA (or a state in the case of a state implementation plan) to impose new control requirements. This prohibits EPA from going further in search of additional emission reductions. *See Motion Picture Ass'n of Amer., Inc. v. FCC*, 309 F.3d 796, 804-805 (D.C. Cir 2002) (federal agency power is limited by statutory authorization); *Ethyl Corp. v. EPA*, 51 F.3d 1053, 1060 (D.C. Cir. 1995) (courts will not presume a delegation of power were statute is silent on the issue); *Aid Ass'n for Lutherans v. U.S. Postal Service*, 321 F.3d 1166, 1175-1178 (D.C. Cir. 2003) (striking down postal regulations related to the mailing of insurance offers because the "Postal Service ha[d] no congressionally delegated authority to exclude" certain types of mailings). The Clean Air Act simply does not give EPA or

states the authority to impose emission reductions without linking those reductions to the necessity of meeting RPGs.

The Associations asserted that allowing EPA to impose tens of millions of dollars of controls on BART-ineligible sources like the Independence plant, based only on what it claims is "reasonable," is not only economically wasteful but effectively re-writes the definition of what sources are BART eligible. Under the Regional Haze program, BART controls may be imposed on (1) major stationary sources in 26 listed categories, (2) that existed on August 7, 1977, (3) but were not in operation prior to August 7, 1962, and (4) emit air pollutants "which may reasonably be anticipated to cause or contribute to any impairment of visibility" at Class I areas. 42 U.S.C. § 7491(b)(2)(A); 40 C.F.R. § 51.301. Under the proposed rule, the first three of these statutory and regulatory criteria would be rendered a nullity. According to EPA, it may impose BART controls on any facility (major or minor), regardless of when it was built or when it began operating, so long as EPA determines it to be "reasonable." *See* 80 FR at 18992 ("it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions."). As implemented in the proposed rule, EPA has effectively adopted a *presumption* that at least some BART-ineligible sources should be subject to BART unless those pollution controls are cost prohibitive.[203] Such a presumption effectively ignores the operative statute and re-writes EPA's own regulations.

The Associations stated that, further, EPA adopts this presumption without first finding it necessary to impose additional emission reductions to meet Class I reasonable progress goals. This necessity determination – finding additional emission reductions to meet reasonable progress goal – anchors the "reasonableness" inquiry in the RPG Guidance. EPA claims that imposing tens of millions of dollars in new controls at the Independence plant is "reasonable," but declines to justify the need to do so. If no further emission reductions are needed to meet Class I reasonable progress goals, then EPA's "reasonableness" inquiry becomes a free-floating vehicle for EPA to issue pollution control edicts without any goal to accomplish. Imposing BART controls on the Independence plant without the need to meet Class I reasonable progress goals contravenes the Clean Air Act, EPA's Regional Haze regulations, EPA's RPG Guidance and is arbitrary and capricious.

[Energy and Environmental Alliance of Arkansas (EEAA) (0173) p. 3] EEAA stated that Section 169A of the Clean Air Act (CAA) establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in the nation's 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[204] In 1999, EPA promulgated the Regional Haze Rule to address regional haze impairment and establish a

[203] The Independence plant was apparently singled out by EPA for additional pollution controls while other BART ineligible emission sources were not. Although the Associations do not believe there were legal or policy justifications for *any* BART-ineligible source to require additional pollution controls, EPA does not provide any explanation for its selective treatment in this case other than the Independence plant being among the top three largest sources in the state. For states attempting to gain EPA's approval of their own implementation plan, EPA provides no criteria as to how it expects them to treat BART-ineligible sources in the future, or what prevents States from imposing new emission controls on *all* BART-ineligible sources. This is the very definition of arbitrary and capricious decision making.

[204] 42 U.S.C. § 7491.

comprehensive visibility protection program for Class I areas.[205] Based on the plain language of the relevant statute and the Regional Haze Rule, two things are immediately obvious. First, the regional haze program is intended to address an aesthetic concern – *i.e.* visibility impairment in distinct areas of the country – not human health concerns. Second, and in part due to the former observation, Congress did not design the program to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost-effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.[206]

EEAA asserted that given the intent of the statute and the goal of the regulations, EPA should have based the determinations in the proposed FIP on whether reductions in emissions and the associated costs thereof are necessary to maintain and achieve reasonable progress towards the national visibility goal. Here, where visibility improvement at relevant Federal Class I areas is well ahead of the EPA-approved Uniform Rate of Progress ("URP" or "glide path") and projected to remain so for more than a decade, many of EPA's proposed determinations are unnecessary and unjustified.

[Edison Electric Institute (0174) p. 4-5, 7] EEI stated that EPA has proposed to require emission controls on Independence Units 1 and 2 to achieve reasonable progress requirements. *See* 80 *FR* at 18991. Neither unit is subject to the BART requirements. *Id.* The installation of controls at Independence 1 and 2 is not necessary to meet the Arkansas Uniform Rate of Progress (URP) visibility goal in the impacted Class I areas because the state already is on track to meet the URP goals for visibility for the first planning period and beyond.[207] Nonetheless, EPA has proposed that it must regulate emissions from Independence 1 and 2 on the basis that, essentially, it is a large source that is not already regulated for visibility purposes—not on any analysis explaining specifically why the emissions from Independence are impairing visibility in a way that does not allow the state to meet URP for the first planning period. *See* 80 *FR* at 18992.

EEI asserted that EPA's disapproval of the 2008 Arkansas Regional Haze SIP was not due to lack of reasonable progress to achieve visibility improvement or for failure to meet the state's URP goals. Rather, EPA primarily disapproved Arkansas' SIP because the underlying emissions reduction requirements were based on presumptive limits instead of on properly conducted unit-specific BART evaluations. Therefore, EPA should not−and, at this time, need not−look beyond BART-eligible units to achieve the state's URP goals during the first planning period, particularly when the state is on track to meet long-term reasonable progress goals for visibility

[205] 64 Fed. Reg. 35714 (July 1, 1999), codified at 40 C.F.R. part 51, subpart P.
[206] *Id.* at 35752.
[207] State Implementation Plan Review for the Five-Year Regional Haze Progress Report, Arkansas Department of Environmental Quality, Revised May 2015.

for the first planning period and beyond. EPA has provided no rationale for regulating the Independence units.

[Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 4] AEEC/AGC stated that although the data contained in the Five-Year Regional Haze Progress Report that ADEQ recently submitted to the EPA reveals that Arkansas is on track to achieve the visibility improvements contemplated by the Regional Haze Rule, EPA proposes to supplant the State of Arkansas's primary authority by imposing a proposed FIP that places unnecessary additional control requirements on a few sources at a significant cost. The CAA requires states to submit SIPs that contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal."[208] The CAA provides states with discretion in establishing reasonable progress goals; it "requires only that a state establish reasonable progress, not the *most* reasonable progress."[209]

[Conway Corporation et. al. (0172) p. 11] Conway Corporation et. al. stated that EPA acknowledges that visibility impairment at Arkansas' Class I areas is decreasing more rapidly than the federally approved URP.[210] This improvement is due, in large measure, to the reduction in visibility related pollutants resulting from already implemented federal and state programs and increased control efficiencies from EGU sources.[211] These results validate Arkansas' original determination that existing state and federal programs were adequate to make reasonable progress toward natural visibility conditions.

[Domtar Supplemental Comments (0170) p. 2-3] Domtar stated that EPA's discussion in the proposed Arkansas Regional Haze FIP addressing reasonable progress prompted their review of the observations at Arkansas' Class I areas and a comparison of the observations to the uniform rate of progress (URP) or "glide path" predicted for each Class I area. This review reveals that Arkansas' Class I areas are well ahead of their URP glidepaths. EPA recognizes this fact in the proposed FIP at 80 FR at 18922. Moreover, if the trend in actual observation data from the 20% worst days over the last 10 years continues, the 2064 goals will be achieved decades in advance. The figure below shows the observations (and trend line) overlaid on the URP glide path for Caney Creek (Upper Buffalo is similar).

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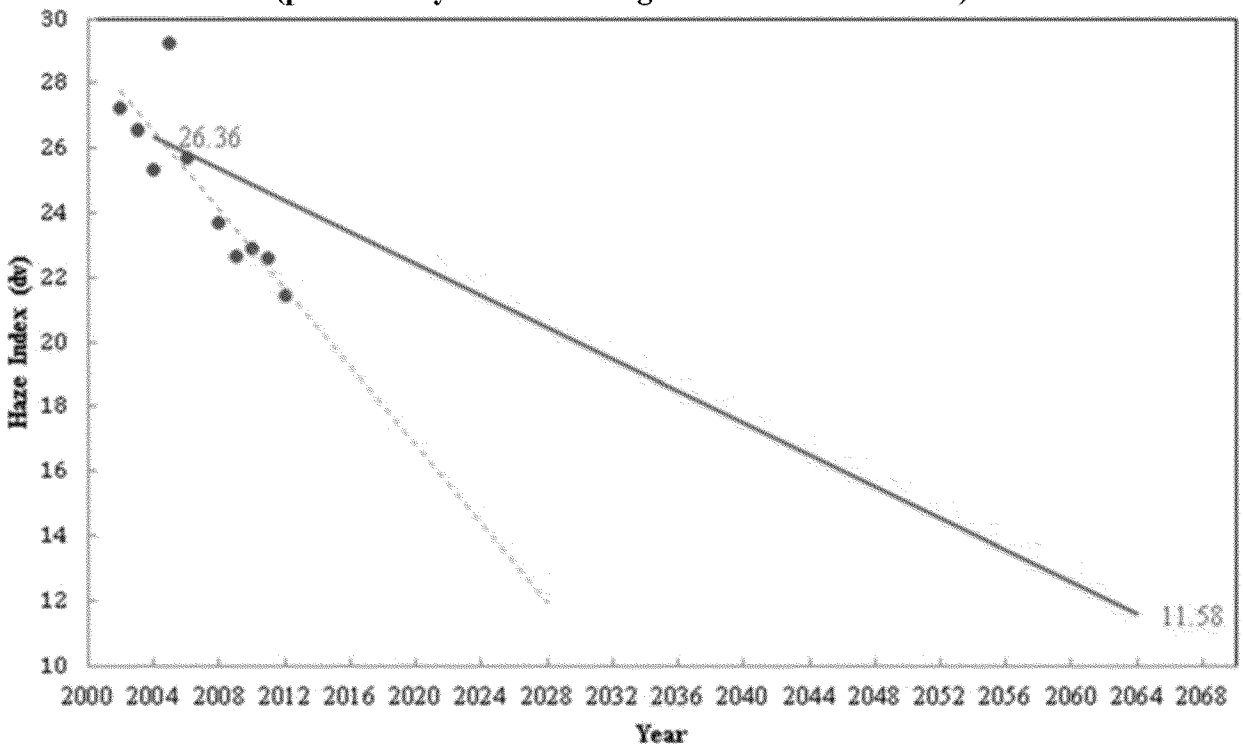
[208] 42 U.S.C. § 7491(b)(2).
[209] *North Dakota v. EPA*, 730 F.3d 750, 768 (8th Cir. 2013) (emphasis added).
[210] *See* 80 FR at 18992.
[211] *See generally,* Arkansas Five-Year Progress Report at 23-37.

Comparison of Caney Creek Glide Path to Actual Observations on 20% Worst Days (provided by Domtar as Figure 7-1 to AR020.0170)



Domtar stated that EPA's reasonable progress assessment results are inappropriate and would set an unlawful precedent. While Domtar is not directly affected by EPA's reasonable progress evaluation proposal, it argues it is indirectly affected through an inevitable increase in electric power prices. As such, Domtar is concerned with EPA's conclusion in the proposed FIP. Despite the fact that visibility improvement in Arkansas' Class I areas is ahead of schedule, EPA proposed emissions controls for SO_2 and possibly NO_X on two non-BART affected units (at Entergy's Independence facility) as part of its reasonable progress evaluation. EPA's reasonable progress analysis is simply not appropriate, especially when the Class I areas of concern are already meeting reasonable progress goals.

[0152-1, 0152-3, 0152-4, 0152-10, 00152-15] Some public hearing commenters stated that ADEQ's Five Year Progress Report SIP revision shows that visibility at Arkansas' Class I areas is better than the URP and that controls for Independence under the reasonable progress requirements are therefore not necessary. The commenters noted that Independence is not a BART source and that this FIP, which is for the first planning period, should only include BART sources. One commenter notes that additional controls for a non-BART source are especially unnecessary given the high cost.

Response: We disagree that we cannot evaluate or require controls under reasonable progress if a Class I area is below the URP glidepath or if subsequent monitoring shows a Class I area meets or is projected to meet its RPG. Some commenters reference the CAA in support of the argument that controls under reasonable progress can only be required by the state or EPA if further action beyond BART is needed to remain on or below the URP glidepath:

> [The RH regulations shall require regional haze SIPs to] contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal…[212]

These commenters interpret the term "reasonable progress" to be defined as being on or below the URP glidepath, and that as long as a Class I area is on or below the URP glidepath, additional controls are not necessary under the reasonable progress requirements. This interpretation is incorrect and does not take into account other, more explicit, statutory and regulatory language. The term "reasonable progress" is defined under CAA section 169A(g)(1) as consideration of (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of any existing source subject to such requirements. The Regional Haze regulations under section 51.308(d)(1)(i)(A) also require consideration of these four statutory factors in establishing the RPGs:

> (i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:
>
> (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

We commonly refer to the evaluation of these four statutory factors as the "four-factor analysis" or "reasonable progress analysis." The statute and regulations are both clear that the states or EPA in a FIP have the authority and obligation to evaluate the four reasonable progress factors and that the decision regarding the controls required to make reasonable progress and the establishment of the RPG must be based on these factors identified in CAA section 169A(g)(1) and the Regional Haze regulations under section 51.308(d)(1)(i)(A).

While the Regional Haze regulations require that a state also consider the URP glidepath in establishing the RPGs, this should not be interpreted to mean that the URP can or should be automatically adopted as the RPG without completing the requisite analysis of the four statutory factors. It also should not be interpreted to mean that a set of controls sufficient to achieve the URP is automatically sufficient for an approvable long-term strategy. Clearly, a state's obligation to set reasonable progress goals based on CAA section 169A(g)(1) and section 51.308(d)(1) applies in all cases, without regard to the Class I area's position relative to the URP. Since an evaluation of the statutory factors is required regardless of the Class I area's position relative to the glidepath, this necessarily means that the CAA and the Regional Haze regulations envisioned that controls could be required under reasonable progress even when a Class I area is on or below the URP glidepath. There is nothing in the CAA or Regional Haze regulations that

[212] CAA section 169A(b)(2).

suggests that a State's obligation, or EPA's in a FIP, to ensure reasonable progress can be met by just meeting the URP.[213]

Some commenters also make the argument that EPA's 2007 Reasonable Progress Guidance suggests that controls under reasonable progress are not necessary if a Class I area is on or below the URP glidepath. The full citation from the 2007 Reasonable Progress Guidance referenced by the commenters is the following:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.[214]

We see nothing in the Reasonable Progress Guidance indicating that additional controls under reasonable progress can only be evaluated or required if further action beyond BART is needed to remain on or below the URP glidepath. Being projected to meet the URP for 2018 does not divest a state or EPA from its authority and obligation to conduct the four factor analysis required under CAA section 169A(g)(1) and section 51.308(d)(1) in determining reasonable progress and establishing the RPGs. We noted in our FIP proposal that the preamble to the Regional Haze Rule states that the URP does not establish a "safe harbor" for the state in setting its progress goals:

> If the State determines that the amount of progress identified through the [URP] analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.[215]

Being projected to meet the URP for 2018 does not automatically mean that no additional controls beyond BART are required under the reasonable progress requirements. The URP is an analytical requirement created by regulation to ensure that states consider the possibility of setting an ambitious reasonable progress goal. Its purpose is to complement, not usurp, the reasonable progress analysis. Based on the analysis of the four statutory factors required under the CAA and Regional Haze regulations, a state or EPA in a FIP may determine that a greater or lesser amount of visibility improvement than what is reflected in the URP is necessary to demonstrate reasonable progress.[216] The state, or EPA in a FIP, has discretionary authority on

[213] See 77 FR 14604, at 14629.
[214] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," at 4-1.
[215] 80 FR at 18992.
[216] 64 FR 35732.

how to weigh the four statutory factors to determine if additional controls are needed to make reasonable progress. Based on our analysis of the four statutory factors under CAA section 169A(g)(1) and under section 51.308(d)(1), along with consideration of the visibility impacts and visibility improvement of controls,[217] we determined that there are reasonable controls available for Independence that would be cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas. Because we have identified that additional progress (beyond the amount reflected in the URP) is reasonable based on our analysis of the four statutory factors and our consideration of the visibility impacts from the facility and the visibility improvement from controls, we are required to adopt that amount of progress as the RPG for each Class I area in Arkansas. It is for this reason that we are requiring controls on Independence under the reasonable progress requirements. It is not, as some commenters contend, "for the sole purpose of achieving emissions reductions."

We note that our conclusion here is consistent with our final action on the Arkansas RH SIP, where we disapproved Arkansas' RPGs precisely because the state established its RPGs without conducting an evaluation of the four statutory factors and did so based on the fact that its Class I areas are below the URP glidepath. In the preamble to our final action on the Arkansas RH SIP, we were clear that an evaluation of the four statutory factors is required regardless of the Class I area's position relative to the URP glidepath:

> [B]eing on the "glidepath" does not mean a state is allowed to forego an evaluation of the four statutory factors when establishing its RPGs. Based on an evaluation of the four statutory factors, states may determine that RPGs that provide for a greater rate of visibility improvement than would be achieved with the URP for the first implementation period are reasonable.[218]

Our final action on the Arkansas RH SIP was published in the Federal Register on March 12, 2012, and became effective on April 11, 2012. We reiterate in this final action that the CAA and Regional Haze regulations require an analysis of the four reasonable progress factors regardless of a Class I area's position relative to the URP and that being below the glide path does not automatically mean that no controls are necessary under reasonable progress.

With regard to comments contending that we are ignoring data from ADEQ's Five Year Progress Report SIP revision, we note that Arkansas submitted the first 5-year Progress Report SIP revision in June 2015 and we are not including our analysis of that SIP revision within this action.[219] The 5-year progress report is a requirement that is separate from the regional haze SIP required for the first planning period as well as the subsequent planning periods, and it has separate content and criteria for us to review. We are therefore not obligated to consider or take action on the 5-year progress report at the same time we promulgate our FIP. Even so, we

[217] Alongside the four statutory factors, we also considered the visibility improvement of controls in our reasonable progress analysis. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.
[218] 77 FR at 14629.
[219] We anticipate taking action on ADEQ's Five Year Progress Report SIP revision in a separate, future action.

acknowledge that recent monitoring data from IMPROVE monitors indicate there has been visibility improvement in Arkansas' Class I areas. The commenters state that ADEQ's Five Year Progress Report SIP revision shows that even without the BART and reasonable progress controls that would be required by our FIP, Caney Creek has achieved 73% and Upper Buffalo has achieved 66% of their respective 2018 RPGs established by Arkansas based on 5-year average data from IMPROVE monitors as of 2011. However, we disagree that this "validate[s] Arkansas' original determination that the existing state and federal programs were adequate to make reasonable progress toward natural visibility conditions." Here, the commenter is referring to the Arkansas Regional Haze SIP submitted to us in 2008, in which the State made the determination that no additional controls were needed under the reasonable progress requirements. First, we note that the determination of whether additional controls are necessary to make reasonable progress toward the national goal of natural visibility conditions must be made based on the four factor analysis required under the CAA and section 51.308(d)(1). However, the State made its determination without conducting the four factor analysis required under the CAA and the Regional Haze regulations, and we partially approved and partially disapproved the SIP in our March 12, 2012 final action on the Arkansas Regional Haze SIP.[220] That action included disapproval of Arkansas' RPGs. As such, the State's RPGs are not a reflection of the controls necessary to make reasonable progress, and any arguments upholding or suggesting that the state's RPGs are appropriate or adequate are not germane to the proposed action we solicited comments on and are outside the scope of this action.

Second, we note that the fact that a Class I area is achieving or is projected to achieve the state's disapproved RPG does not divest us from our authority and obligation to conduct a reasonable progress analysis. The state, or EPA in the case of a FIP, is still required to complete the requisite analyses to determine appropriate controls and emission limits under the BART and reasonable progress requirements, and must adopt and enforce these controls and emission limits. The emission limitations we are requiring in our final action under the BART and reasonable progress requirements, along with other "on the book" reductions, are what we have determined represent reasonable progress at Arkansas' Class I areas, based on our analyses required under the CAA and section 51.308(d)(1). These emission limitations required by our FIP will result in significant visibility improvements at the affected Class I areas beyond what is currently being achieved or observed and will ensure reasonable progress toward the national goal of natural visibility conditions. Third, we note that the Regional Haze Rule provides that these emission limitations and control measures are what is enforceable, not the RPGs themselves.[221] The numeric RPGs are calculated by taking into account the visibility improvement anticipated from these enforceable emission limitations and other control measures (including BART, reasonable progress, and other "on the books" controls). Thus, the RPGs represent the best estimate of the degree of visibility improvement that will result in 2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP or EPA in a regional haze FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[222] But the RPGs themselves are not enforceable. EPA cannot enforce an RPG in the sense of seeking to apply penalties on a state for failing to meet the RPG or obtaining injunctive relief to require a state to

[220] 77 FR 14604.
[221] 64 FR 35733.
[222] 64 FR 35733.

achieve its RPG. However, the long-term strategy can and must contain emission limits and other control measures that apply to specific sources, and that are themselves enforceable. Meeting or being projected to meet the RPG does not necessarily demonstrate that a state has satisfied its requirements under BART and reasonable progress. In sum, the fact that Arkansas' Class I areas are on track to achieve the 2018 RPGs provided by the state in the Arkansas RH SIP does not divest us from our authority and obligation to conduct a reasonable progress analysis, nor does it justify the dismissal of controls for Independence that we have determined, pursuant to that analysis, are cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas.

Additionally, while Arkansas' Class I areas may be below the URP glidepath and be achieving the state's RPGs in 2018, the CENRAP modeling projections for 2018, as well as information presented in ADEQ's Five Year Progress Report SIP revision, suggest that this is due to a large extent to emissions reductions taking place outside of Arkansas. As noted in our proposed partial approval and partial disapproval of the Arkansas RH SIP, the CENRAP 2018 projections indicate that most of the decrease in visibility impairment at Caney Creek and Upper Buffalo in 2018 is expected to be due to SO_2 emissions reductions from point sources in other states:

> Anticipated reductions of SO_4 emissions from point sources in Texas, the eastern United States, Indiana, and Ohio will account for a decrease of 24.41 Mm^{-1} in total light extinction [at Caney Creek in 2018 on the worst 20% days], which is approximately half of the total expected reduction between 2002 and 2018. Even with such large expected reductions in SO_4 emissions from point sources in 2018, extinction due to point sources will still be the highest contributor to visibility impairment on the worst 20% days, accounting for over half of the total extinction. Visibility impairment from all Arkansas sources will decrease by 2.32 Mm^{-1}, almost entirely due to expected reductions from mobile sources.[223]
>
> Anticipated reductions of SO_4 emissions from point sources in the eastern United States, Indiana, Illinois, Kentucky and Ohio will account for a decrease of 28.43 Mm^{-1} in total light extinction [at Upper Buffalo in 2018 on the worst 20% days], more than 60% of the total expected reduction in impairment between 2002 and 2018. Even with such large expected reductions in SO_4 emissions from point sources in 2018, extinction due to point sources will still be the highest contributor to visibility impairment on the worst 20% days, accounting for approximately half of the total extinction. Visibility impairment from all Arkansas sources will decrease by 1.45 Mm^{-1}, due to expected reductions from mobile sources.[224]

We did not conduct photochemical modeling to determine the current contribution from Arkansas and other states to visibility impairment at Caney Creek and Upper Buffalo, but

[223] 76 FR at 64214.
[224] 76 FR at 64215.

emissions data presented in ADEQ's Five Year Progress Report SIP revision[225] suggests that the recent observed improvement in visibility conditions at Arkansas' Class I areas is likely due primarily to emissions reductions outside Arkansas. For example, Table 5.1 from ADEQ's Five Year Progress Report SIP revision shows that 2011 SO_2 emissions from Arkansas EGUs (73,629 tons) were higher than 2002 levels (70,759 tons) and nearly twice as high as the 2018 projected emissions (39,194 tons) that went into the CENRAP modeling projections for 2018.[226] The table also shows that 2011 SO_2 emissions from all Arkansas point sources (EGU and non-EGU combined) were 84,870 tons, which is only slightly lower than 2002 levels (89,786 tons) and significantly higher than the 2018 projected emissions of 46,665 tons that went into the CENRAP modeling projections for 2018.[227] In fact, 2011 SO_2 emissions from all Arkansas source categories combined (95,123 tons) were nearly twice as high as the 2018 projected emissions (49,059 tons) that went into the CENRAP modeling projections for 2018.[228] Similarly, 2011 NO_X emissions from Arkansas point sources, as well as from all Arkansas source categories combined, were over twice as high as the 2018 projected emissions that went into the CENRAP modeling projections for 2018.[229] This suggests that the observed improvement in visibility conditions at Caney Creek, including the fact that the Class I areas are below the URP glidepath and are on track to achieve the state established RPGs, even without the controls required by our FIP, is not due to emissions reductions that have taken place in Arkansas, but rather in other states. To the extent that the commenters are suggesting that Arkansas should be relieved of its regional haze obligations because other states' emission reduction efforts have already resulted in significant visibility improvement at Arkansas' Class I areas, this is incorrect. Rather, Arkansas, or EPA in standing in the state's shoes, must consider the statutory factors in addressing the reasonable progress and long term strategy requirements.

Some commenters point to emissions data between 2000-2011, as presented in ADEQ's Five Year Progress Report, and argue that emissions from Arkansas EGUs trended downward in this period, and that they expect this trend to continue and that our proposed controls on Independence are therefore not necessary. We note that the emissions data presented in ADEQ's Five Year Progress Report SIP revision[230] show that there has been some reduction in NO_X emissions from Arkansas EGUs between 2000 and 2011, but the data show that there has not been very much change in SO_2 emissions during this same time period. According to ADEQ's Five Year Progress Report SIP revision, SO_2 emissions from Arkansas EGUs were 75,057 tpy in 2000 and 73,623 tpy in 2011, with not much variation in the years in between. Therefore, we disagree that SO_2 emissions (which are the primary driver of regional haze in Arkansas' Class I areas on the 20% worst days) from Arkansas EGUs have trended downward between 2000 and 2011.

The relevance of the comment that EPA determined CSAPR to be better than BART but "did not even consider the reductions attributable to CSAPR" is unclear. In determining that CSAPR provides for greater reasonable progress than BART, EPA assessed the visibility benefits across

[225] As noted earlier in our response, we have not taken action on ADEQ's Five Year Progress Report SIP revision. We anticipate taking action on this SIP revision in a separate, future action.
[226] See ADEQ Five Year Progress Report SIP revision, Table 5.1, at 46.
[227] Id.
[228] Id.
[229] Id.
[230] See ADEQ Five Year Progress Report SIP revision, Table 3.1, at 35.

the entire continental United States and found that *on average* across all Class I areas, CSAPR provided for greater visibility improvement than BART. To make this determination, EPA made broad assumptions as to what controls would constitute BART based on the presumptive BART limits in the BART Guidelines. CSAPR requires significant SO_2 and NO_X reductions in many states; in Arkansas, however, the state is subject only to an ozone season NO_X budget requirement. The commenters have presented no evidence that CSAPR will result in any added benefit over and beyond the site-specific BART NO_X controls in our Arkansas FIP at Arkansas' Class I areas, but if the commenters' point is that a program requiring hundreds of thousands of tons of reductions in SO_2 and NO_X across a broad region will achieve greater visibility improvement than the modest BART NO_X controls in the Arkansas FIP, then we would have to agree. To the extent the commenter is arguing that our revised RPGs do not account for the improvement that will result from implementation of CSAPR, we note that the states assumed the implementation of CAIR in setting their goals but that CAIR has now been replaced by CSAPR. Furthermore, with regard to the comment that there is every reason to project continued improvement in visibility at Caney Creek and Upper Buffalo well beyond 2018 as a result of emission reductions achieved through other regional and national programs and that no controls are therefore necessary for the Independence plant in this planning period, we discussed in a separate response to comment that the commenters' suggestions that EPA should further delay the implementation of measures to improve visibility relies on the conclusion that there is a specific pre-determined rate of improvement that constitutes reasonable progress. This is incorrect. As we discussed above, the determination of what constitutes reasonable progress is based on an analysis of the four statutory factors.

With regard to comments arguing that we should not require controls under reasonable progress in this planning period because the regional haze program undertakes a gradual approach toward the national goal of remedying anthropogenic visibility impairment in Federal Class I areas, we note that we agree that the regional haze program contemplates gradual visibility improvements over several planning periods. Those gradual improvements are guided by the principle that controls found to be reasonable in a given planning period should be required now, rather than in some unspecified future planning period. That is the very nature of "reasonable progress." For that reason, we do not consider the controls we are finalizing in this action as being frontloading. As we discuss elsewhere in this document and in our final rule, our cost analysis indicates that the SO_2 and NO_X controls we are requiring for Independence Units 1 and 2 are cost effective and well within the range of cost of controls found to be reasonable by EPA and the states in other regional haze actions for this first planning period. Arkansas did not comply with certain aspects of the Regional Haze Rule and thus portions of its Regional Haze SIP submitted to us in 2008 were not approvable, including the state's reasonable progress determinations and RPGs.[231] We therefore have an obligation to promulgate this FIP to address the disapproved portions of the State's SIP submission. Pursuant to CAA section 169A(g)(1) and our Regional Haze regulations at section 51.308(d)(i)(A), we conducted an evaluation of additional controls under a reasonable progress analysis that considered the four statutory factors. As discussed in our proposal and throughout this final rule, based on the demonstrations we developed pursuant to the CAA and section 51.308(d)(1) and our consideration of the visibility impacts from Independence and the visibility improvement of potential controls, we determined that there are reasonable and cost-effective SO_2 and NO_X controls available for Independence that would result in considerable

[231] 77 FR 14604.

visibility benefit at Arkansas' Class I areas. Under the CAA and the Regional Haze regulations, if we determine that additional controls are reasonable based on the consideration of the four statutory factors, we must require those controls to make reasonable progress toward the national goal of natural visibility conditions. Therefore, we are requiring SO_2 and NO_X controls for Independence Units 1 and 2 under the reasonable progress requirements.

We are requiring controls on Independence under the reasonable progress requirements, not under the BART requirements. CAA section 169A required us to promulgate regulations directing the States to revise their SIPs to include emission limits and other measures as necessary to make "reasonable progress."[232] Congress defined reasonable progress based on the consideration of four statutory factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of any existing source subject to such requirements.[233] We commonly refer to our analysis of these four statutory factors as a reasonable progress analysis. Congress also directed EPA to promulgate regulations requiring BART for a specific universe of older sources, and again provided a set of statutory factors States must consider: (1) the costs of compliance, (2) the energy and nonair quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (3) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[234] We note that many of the factors that must be considered in a BART analysis must also be considered in the reasonable progress analysis. Therefore, some commenters may mistakenly believe that we are somehow stretching the BART analysis to impose BART controls on Independence Units 1 and 2. This is not the case. As discussed in our proposal and in our final rule, in our reasonable progress analysis we considered the reasonable progress statutory factors as well as the visibility improvement of potential controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states and EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.

We disagree that we are treating Independence Units 1 and 2 as if they were subject-to-BART sources by, according to the commenters, "ignoring" whether controls at the units are needed to improve visibility and "looking only at whether controls are 'cost-effective.'" To the extent the commenters are suggesting that we are ignoring whether controls are needed to improve visibility because we conducted a reasonable progress analysis even though Arkansas' Class I areas are below the URP glidepath, we discussed earlier in this response that the analysis of the four statutory factors is a requirement that applies regardless of a Class I area's position on the glidepath. To the extent the commenters are suggesting that we are ignoring whether controls are needed to improve visibility because we did not conduct photochemical modeling in our analysis, we discuss elsewhere in this document that we are not required to conduct photochemical modeling in a reasonable progress analysis. For consideration of the visibility impacts at Arkansas' Class I areas and the visibility benefits of potential controls, we relied on the following: CENRAP CAMx source apportionment results, point source emission inventory

[232] CAA section 169A(b)(2).
[233] CAA section 169A(g)(1).
[234] CAA section 169A(b)(2)(A), (g)(2).

data that initially identified the Independence facility as having the greatest potential to impact visibility at nearby Class I areas among all Arkansas sources not already controlled under the BART requirements, and the results of our CALPUFF modeling of the maximum or 98th percentile impacts from Independence and the visibility benefits of potential controls.[235] Therefore, we disagree with commenters contending that we did not consider whether controls at the units are needed to improve visibility. As we noted above, the "costs of compliance" is a factor explicitly listed under the CAA and section 51.308(d)(1)(i)(A) that must be considered in a reasonable progress analysis. Therefore, we disagree with commenters contending that it was inappropriate for us to consider cost-effectiveness in our decision to require controls at Independence. Based on our consideration of the four reasonable progress factors, as well as the baseline visibility impacts from Independence and the visibility improvement of potential controls, we determined that reasonable controls for SO_2 and NO_X are available for Independence Units 1 and 2 that are cost effective and would result in a large amount of visibility improvement in Arkansas' Class I areas in terms of the 98th percentile impacts from the source, and we are therefore requiring these controls. Therefore, the claim that we ignored whether controls at the units are needed to improve visibility is incorrect.

We disagree with comments arguing that it is inappropriate to require additional controls under reasonable progress for Independence in light of CENRAP modeling that shows Arkansas point sources are responsible for what the commenters contend is only a small portion of the total light extinction at Caney Creek and Upper Buffalo on the 20% worst days in 2018. The commenters state that CENRAP modeling projects that sulfate from Arkansas point sources will be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. As we discuss elsewhere in this document, we disagree that these are small or insignificant visibility impacts. The commenters also contend that the Independence Plant's share of the total contribution from Arkansas point sources is even smaller than this and that controls on Independence are therefore not warranted. We disagree that these visibility impacts are insignificant. As noted above, Entergy submitted CAMx model results as part of their comments. The results of this modeling provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. The modeled contribution to visibility impairment due to baseline emissions from the Independence facility alone were approximately 1.3% of the total visibility impairment at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. Entergy's CAMx modeling also shows that at Upper Buffalo, the Independence facility contributes more to visibility impairment than all the subject-to-BART sources addressed in this action combined. In terms of deciviews, the average impact over the 20% worst days based on Entergy's CAMx modeling (adjusting to natural background conditions) is over 0.5 dv at the Arkansas Class I areas and even larger at the Class I areas in Missouri. These results estimate the visibility impacts from the source on the 20% worst days and confirm and provide additional support to our determination that Independence significantly impacts visibility, both in terms of maximum

[235] We address comments contending that we inappropriately used CALPUFF modeling to determine impacts and project visibility benefits from installing controls on Independence elsewhere in this document.

visibility impairment and visibility impairment on the 20% worst days, and that emissions controls are expected to provide for meaningful visibility benefits towards the goal of natural visibility conditions. We conclude that both approaches, CALPUFF and CAMx, support the determination that the required controls on Independence are reasonable.

While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. The CAMx source apportionment modeling submitted by Entergy showed that NO_X emissions from Independence are responsible for 30-40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days (i.e., 2 out of the 21 days that are the 20% worst of the days with Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data). We expect that installation of NO_X controls on Independence will provide visibility improvement on this portion of the 20% worst days and will also provide meaningful visibility improvement on the 98th percentile day, as shown by the CALPUFF dispersion modeling. After carefully considering all comments submitted to us during the comment period, we are finalizing both SO_2 and NO_X controls for Independence Units 1 and 2 to make reasonable progress at Arkansas' Class I areas (i.e., proposed Option 1), because both SO_2 and NO_X are key pollutants contributing to visibility impairment, and because we have determined that these controls are cost effective and will provide for significant visibility benefits towards the goal of natural visibility conditions at Arkansas' Class I areas.

We disagree with comments contending that we inappropriately used CALPUFF modeling to determine impacts and project visibility benefits from installing controls on Independence. Although the reasonable progress provisions of the Regional Haze Rule place emphasis on the 20% worst days, the CAA goal of remedying visibility impairment due to anthropogenic emissions encompasses all days. Thus, states and EPA have the discretion to consider the visibility impacts of sources and the visibility benefit of controls on days other than the 20% worst days in making their decisions, such as the days on which a given facility has its own largest impacts. Even if the days on which a given facility has its largest impacts are not the same as the 20% of days with the worst visibility overall, the facility's impacts will still need to be addressed for Arkansas' Class I areas to achieve the national goal of natural visibility conditions. The Eighth Circuit previously addressed state and EPA use of CALPUFF for reasonable progress purposes.[236] We address comments contending that CALPUFF modeling overestimates the impacts of emissions and the visibility benefits of controls elsewhere in this document.

One commenter alleges that EPA "proposes to supplant the State of Arkansas' primary authority by imposing a proposed FIP" that requires controls under reasonable progress. In arguing that our FIP should not require controls under reasonable progress, the commenter further states that the CAA provides states with discretion in establishing RPGs and that it requires only that a state establish reasonable progress, not the most reasonable progress. First, we point out that our proposed partial approval and partial disapproval of the Arkansas RH SIP submitted to us in 2008 was published in the Federal Register on October 17, 2011.[237] We held a 66 day public

[236] *North Dakota v. EPA*, 730 F.3d 750, 764-66 (8th Cir. 2013) (discussing reasonable progress determination for the Antelope Valley station).
[237] 76 FR 64186.

comment period and our final action was published on March 12, 2012.[238] In our final action, we determined that the Arkansas RH SIP does not meet certain elements of the CAA and the Federal regional haze requirements and partially approved and partially disapproved the Arkansas RH SIP. The portions that we disapproved included Arkansas RPGs for Caney Creek and Upper Buffalo because the state did not conduct a reasonable progress analysis and also because the RPGs were based on BART determinations that did not meet the requirements of the CAA and the Regional Haze regulations. While we did receive adverse comments on that proposal, no petitions were filed for judicial review of the final rule, and the rule became effective on April 11, 2012. Under section 110(c) of the Act, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within two years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. To date, Arkansas has not submitted a SIP revision following our partial disapproval, and EPA is already past-due on its obligation to promulgate a FIP per the statutory deadlines. Therefore, the comment that we are "supplant[ing] the State of Arkansas' primary authority by imposing a proposed FIP" is not supported by the facts. To the extent the commenter is suggesting that the RPGs provided by Arkansas in its RH SIP are acceptable or appropriate, such comment is not germane to the proposed action we solicited comments on and is outside the scope of this action.

Second, we agree that the CAA provides states with discretion in conducting a reasonable progress analysis and establishing RPGs. However, when standing in the shoes of a state and promulgating a FIP, EPA has the same discretion as the state. Third, we note that the commenter's statement that the CAA "requires only that a state establish reasonable progress, not the most reasonable progress" is taken from a court decision in *North Dakota v. EPA*, 730 F.3d 750, 768 (8th Cir. 2013). We interpret the Court's statement as meaning broadly that just because a more stringent level of control could be technically feasible in a particular instance, it does not mean it necessarily must be required under reasonable progress. We see no conflict with this determination and our proposed Arkansas RH FIP. Extending the Court's reasoning, we too could have proposed additional controls on other sources within Arkansas, or higher levels of control on the source for which we proposed controls. We proposed, however, that neither additional controls nor a higher level of control on the source for which we proposed controls was appropriate, after applying the four reasonable progress factors. In other words, we did not propose the highest level of control (referred to by the Court as "most reasonable"). Based on the analysis that is required under the CAA and section 51.308(d)(1), we have determined that there are cost effective controls available in addition to having significant visibility benefits and we are requiring those controls in this FIP.

Some commenters argue that EPA should not look beyond BART-eligible units to achieve the state's URP goals during the first planning period since "EPA's disapproval of the 2008 Arkansas SIP was not due to lack of reasonable progress to achieve visibility improvement or for failure to meet the state's URP goals." These commenters contend that EPA primarily disapproved Arkansas' SIP because the underlying emissions reduction requirements were based on presumptive limits instead of on properly conducted unit-specific BART evaluations. This statement is incorrect. Our March 12, 2012 partial approval and partial disapproval of the Arkansas RH SIP[239] included disapproval of a large portion of the state's BART determinations,

[238] 77 FR 14604.
[239] 77 FR 14604.

as well as the state established RPGs. We disapproved the state's RPGs both because the RPGs did not reflect appropriate BART determinations and because the state did not conduct the reasonable progress analysis required under the CAA and section 51.308(d)(1) in establishing the RPGs. In foregoing the reasonable progress analysis, the state did not demonstrate that the RPGs it established were a reflection of the control measures and the amount of visibility improvement necessary to make reasonable progress. We discuss elsewhere in this response that the requirements under section 51.308(d)(1) cannot be satisfied by merely being on or below the URP glidepath.

We continue to hold that our reasonable progress analysis, including our approach for determining which sources to look at more closely and evaluate under reasonable progress, is appropriate and in accordance with the CAA, the Regional Haze Rule, and our 2007 Reasonable Progress Guidance. Based on our analysis of the four statutory factors and our consideration of the visibility impacts and visibility benefits of controls, we conclude that the SO_2 and NO_X emission limitations we are establishing for Independence Units 1 and 2 are necessary to make reasonable progress at Arkansas' Class I areas for this planning period.

We disagree with commenters contending that we did not appropriately analyze which sources, if any, should be controlled under the reasonable progress requirements and that we arbitrarily singled out Independence. We address these comments elsewhere in this document.

We discuss elsewhere in this document that the purpose of our reasonable progress analysis for Arkansas' Class I areas is to address visibility impacts at Arkansas' Class I areas and establish RPGs for Arkansas' Class I areas, not to address Arkansas' impacts on Missouri's Class I areas.

We address elsewhere in this document comments stating that our FIP should rely on CSAPR to satisfy the NO_X BART requirement for Arkansas EGUs.

Comment: EPA has not demonstrated that its proposed BART and Reasonable Progress controls are necessary for Arkansas to maintain reasonable progress and achieve the visibility goals of the CAA, especially in view of the uncertainty that those controls will result in actual visibility improvements.

[Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 16-19] Nucor stated that 42 USC §7491 requires that Regional Haze implementation plans contain emission limits, compliance schedules and other measures, including BART, "as may be necessary to make reasonable progress" toward meeting the CAA's visibility goals. Monitoring data shows that Arkansas has made and will continue to make reasonable progress in visibility improvements even without the controls that would be required by EPA's proposed FIP. (Ex. 3, Arkansas Five Year RHR Progress Report, 2015; Ex. 5, ICF International, "Criteria Pollutant Modeling Analysis for Arkansas" July 28, 2014, p. 20 ("The IMPROVE data indicate that the 2018 goals have been met or nearly met in 2012.")).

Nucor stated that the additional emission reductions from coal-fired power plants in the states surrounding Arkansas and the four Class I areas addressed in the proposed FIP will continue Arkansas' visibility improvement trends. As shown by the spreadsheet attached hereto as Ex. 6,

of the 68 fossil-fuel electric generating units closest to Arkansas and the four Class I areas addressed in the proposed FIP, 17 units are scheduled for or have already been retired or converted to natural gas (4.9 GW capacity), and 32 units have had pollution control projects announced or completed since 2010 (13.9 GW capacity). Further reductions in emissions due to the effects of other regulatory programs and developments will further support Arkansas's visibility improvement trends. (See, Ex. 3, Arkansas Five Year RHR Progress Report, 2015, p. 23-34.)

Nucor stated that EPA's maximum modeled visibility improvements for the affected units at White Bluff, Flint Creek and Independence are less than 1dv (the threshold of visibility) for all Class I areas.[240] This does not even take into account the known overestimation of visibility impacts in the CALPUFF model by at least five times, and the fact that these impact levels are well below the CALPUFF model's effective limit of usefulness of 2-3 dv. Given this uncertainty, EPA has not explained how installation of these controls may reasonably be anticipated to result in actual improvement in visibility, which is the purpose of 42 USC §169A and the Regional Haze Rule – not just reduction of emissions for the sake of doing so. National Parks Conservation Association v. EPA, No. 12-73710, 2015 WL 3559149 (9th Cir., June 9, 2015).

As the Supreme Court recently held, federal administrative agencies must engage in "reasoned decision making," the agency's "decreed result must be within the scope of its lawful authority" and "the process by which it reaches the result must be logical and rational." *Michigan v. EPA*, 576 U.S, slip op. at 5 (June 29, 2015). Although it should be apparent, the accepted meaning of the word "necessary" is "indispensable" or "absolutely needed." Webster's New Collegiate Dictionary, (8th Ed.) 1973. Thus, as used in 42 U.S.C. §7491 the term "necessary" means "absolutely needed." In view of the existing and future improvements in air quality in the areas surrounding these four Class I areas, and in view of the uncertainty that EPA's proposed BART and Reasonable Progress controls will result in actual visibility improvements, EPA has not explained nor demonstrated that its BART and Reasonable Progress determinations are "indispensable" or "absolutely needed," *i.e.*, that the only way Arkansas can maintain reasonable progress and achieve the visibility goals of the CAA is to install these controls. See, *North Dakota v. EPA*, 730 F.3d at 768. The meaning of the word "necessary" requires EPA to take these and other relevant factors into consideration in its BART and reasonable progress determinations and to demonstrate that these controls are indispensable. EPA has not explained how it considered these and other relevant factors in reaching its decision that its BART determinations for Flint Creek and White Bluff and its Reasonable Progress determination for Independence is "absolutely necessary" either to meet the reasonable progress goals for the planning period ending on 2018, or the national goal in 2064. *Michigan v. EPA*, 576 U.S, (June 28, 2015).

[Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 8-9] AEEC and AGC stated that 42 U.S.C. § 7491 requires Regional Haze implementation plans to contain emission limits, compliance schedules and other measures, including BART, "as may be *necessary* to make reasonable progress" toward meeting the CAA's visibility goals.[241] Data

[240] See, Exhibit 7 to Nucor's comments, Spreadsheet of Modeled Baseline Visibility Impacts and Visibility Improvements from Proposed FIP.
[241] 42 U.S.C. § 7491 (emphasis added).

contained in the Five-Year Regional Haze Progress Report that ADEQ submitted to the EPA reveals that Arkansas has made and will continue to make reasonable progress in visibility improvements without the controls required by the proposed FIP. Further reductions in emissions due to the effects of other regulatory programs and developments will supplement Arkansas' trend toward visibility improvement. As explained in section five of AEEC and AGC's comments, the EPA's maximum modeled visibility improvements for the affected units at White Bluff, Flint Creek and Independence are less than one deciview for all Class I areas. Further, these projected improvements fail to account for known problems with the models utilized by the EPA. Given these realities, the EPA has utterly failed to demonstrate that installation of the controls required by the proposed FIP may reasonably be anticipated to result in actual improvement in visibility, which is the purpose of the Regional Haze Rule.[242] The accepted meaning of the word "necessary" is "indispensable" or "absolutely needed."[243] In light of the existing and future improvements in visibility surrounding the affected Class I areas, and the uncertainty that the EPA's proposed controls will result in actual visibility improvements, EPA has totally failed to demonstrate that its BART and Reasonable Progress determinations are "indispensable;" EPA has not, and cannot, demonstrate that the proposed controls constitute the only way Arkansas can achieve the visibility goals of the CAA.[244] Since the BART and Reasonable Progress determinations contained in the Proposed FIP are not "necessary," EPA should withdraw the Proposed FIP.

Response: We address in more detail elsewhere in this document comments related to ADEQ's 5-Year Progress Report SIP revision and comments asserting that recent monitoring data demonstrate that Arkansas' Class I areas are on track to meet the RPGs provided by the State in the Arkansas RH SIP even without the controls under BART and reasonable progress that we proposed to require in our FIP. As we discuss in those responses, meeting or being projected to meet the RPG does not necessarily demonstrate that a state has satisfied its requirements under BART and reasonable progress.

Clean Air Act section 169A(b)(2) required us to promulgate regulations directing the States to revise their SIPs to include emission limits and other measures as necessary to make "reasonable progress." Congress defined reasonable progress based on the consideration of four statutory factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, (4) and the remaining useful life of any existing source subject to such requirements.[245] We commonly refer to our analysis of these four statutory factors as a reasonable progress analysis. Congress also directed EPA to promulgate regulations requiring BART for a specific universe of older sources, and again provided a set of five statutory factors States must consider: (1) the costs of compliance, (2) the energy and nonair quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[246]

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[242] National Parks Conservation Association, *supra.*
[243] Webster's New Collegiate Dictionary (8th Ed.), 1973.
[244] North Dakota, *supra*, at 768.
[245] CAA section 169A(g)(1).
[246] CAA section 169A(b)(2)(A), (g)(2).

Thus, the BART determination must be based on an analysis that considers the five statutory factors under CAA section 169A(g)(2) and the Regional Haze regulations under 40 CFR 51.308(e)(1). The determination of what is necessary to make reasonable progress, including whether additional controls beyond BART and other "on the books" controls are necessary to make reasonable progress, must be made based on an analysis of the four statutory factors under CAA section 169A(g)(1) and the Regional Haze regulations under 40 CFR 51.308(d)(1). The Regional Haze regulations under 40 CFR section 51.308(d)(1) also require consideration of these four statutory factors in establishing the RPGs. The Arkansas RH SIP did not meet this statutory and regulatory requirement. In our March 12, 2012, final action on the Arkansas RH SIP, we disapproved several of the State's BART determinations and the State's RPGs. We disapproved the State's RPGs because they were based on BART determinations that did not meet the requirements of the CAA and the Regional Haze regulations, and because the RPGs were determined without conducting the required four factor analysis. That final action became effective on April 11, 2012. Therefore, EPA is required under CAA section 110(c) to promulgate a FIP and/or approve a SIP revision for the portions of the Arkansas Regional Haze SIP that we disapproved on March 12, 2012. This includes conducting BART analyses and making BART determinations for Arkansas' BART sources and conducting a four factor reasonable progress analysis to determine if additional controls (beyond BART and other "on the books" controls) are necessary to make reasonable progress in Arkansas' Class I areas.

The fact that Arkansas' Class I area are achieving or are projected to achieve the State's disapproved RPGs does not divest us from our authority and obligation to conduct BART analyses as well as a four factor analysis to determine appropriate controls and emission limits. As discussed in our proposal and in our final rule, we conducted BART analyses for White Bluff and Flint Creek, as well as other Arkansas BART sources. In our BART analyses, we considered the five statutory factors required under CAA section 169(g)(2) and the Regional Haze Rule at 40 CFR section 51.308(e)(1)(A). We also conducted an analysis of the four reasonable progress factors required under CAA section 169A(g)(1) and 40 CFR 51.308(d)(1), and considered the visibility impacts and visibility improvement of potential controls to determine if additional controls (beyond BART and other "on the books" controls) are necessary to make reasonable progress in Arkansas' Class I areas.[247] We discuss in our final rule and elsewhere in this document that the emission limitations we are requiring under the BART and the reasonable progress requirements in this FIP, along with other "on the book" reductions, are what we have determined are necessary to make reasonable progress at Arkansas' Class I areas, based on our analyses required under the CAA and the Regional Haze regulations. The discussion of how we considered the statutory factors in establishing BART and reasonable progress controls is found in our proposal and in our final rule and further discussed elsewhere in this document.

The Regional Haze Rule provides that these emission limitations and control measures are what is enforceable, not the RPGs themselves.[248] The numeric RPGs are calculated by taking into account the visibility improvement anticipated from these enforceable emission limitations and

[247] As discussed in our proposal and in our final rule, although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states and EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.
[248] 64 FR 35733.

other control measures (including BART, reasonable progress, and other "on the books" controls). Thus, the RPGs represent the best estimate of the degree of visibility improvement that will result in 2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP or EPA in a regional haze FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[249] But the RPGs themselves are not enforceable. As such, meeting or being projected to meet the RPG does not necessarily demonstrate that a state has satisfied its requirements under BART and reasonable progress.

Further, as we discuss elsewhere in this document, we finalized our disapproval of Arkansas' RPGs for Caney Creek and Upper Buffalo in a previous action that became effective on April 11, 2012. Therefore, any comments upholding or suggesting that the State's RPGs are appropriate or adequate are not germane to the proposed action we solicited comments on and are outside the scope of this action.

One commenter states that EPA has not, and cannot, demonstrate that the proposed controls constitute the only way Arkansas can achieve the visibility goals of the CAA. We agree that the controls in our FIP proposal are not the only way Arkansas can fully meet the regional haze requirements in the CAA and our regulations. The CAA and the RH rule gives states and EPA (in the case of a FIP) wide latitude in considering and weighing the statutory factors that must be considered under the requisite analyses under section 51.308(e) in establishing BART and under section 51.308(d)(1) in establishing controls under reasonable progress. Even though we are required to prepare our own analysis to do a FIP, this does not mean our analysis and conclusions are precisely what Arkansas would itself conclude in a SIP revision to meet the CAA requirements. In other words, the state could potentially conduct analyses that fully satisfy the CAA and Regional Haze rule but arrive at a different, but nonetheless approvable, conclusion for BART and reasonable progress controls than we have in this FIP. In our FIP proposal, we stated that we will work with the State of Arkansas if it chooses to develop a SIP revision to replace our FIP.[250] We continue to be committed to work with the state in this process.

While we acknowledge the data provided by one commenter regarding the actual or scheduled retirement or conversion to natural gas, as well as controls on a number of units located close to Arkansas and the Class I areas addressed in our FIP, we do not agree that this justifies withdrawal of our FIP. As discussed in our proposal, in our final action, and elsewhere in this document, the emission limitations we are requiring under the BART and the reasonable progress requirements in this FIP, along with other "on the book" reductions, are what we have determined are necessary to make reasonable progress at Arkansas' Class I areas, based on our analyses required under the CAA and the Regional Haze regulations.

We address elsewhere in this document comments suggesting or contending that we cannot establish controls under BART or reasonable progress that result in visibility improvement less than 1 dv. We also address elsewhere in this document comments contending that there is an overestimation of visibility impacts in the CALPUFF model and that there is uncertainty in the visibility improvement of the controls we are requiring in our FIP.

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[249] 64 FR 35733.
[250] 80 FR at 18945.

Comment: The EPA should not look beyond BART eligible units to achieve greater visibility improvements and should instead defer to ADEQ to reevaluate the RPG and URP before imposing any additional specific emissions reductions. [AEP-SWEPCO July 15, 2015 comments (0164) p. 3-5, and August 7, 2015 comments (0167) p. 4-5] AEP-SWEPCO stated that the Regional Haze Rule and section 169A of the CAA require the states, or EPA in the case of a FIP, to set RPGs by considering four factors: the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. Also, the Regional Haze Rule does not mandate specific milestones or rates of progress towards achieving the national visibility goal, but instead calls for states to establish goals that provide for "reasonable progress" toward achieving natural (*i.e.*, "background") visibility conditions.[251]

In their 5-year Regional Haze Progress Report, ADEQ notes that 40 C.F.R. § 51.308(g)(6) of the RHR requires: "An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals."[252] ADEQ has assessed the current SIP elements and strategies and determined that, based upon relevant data (*i.e.*, projected emissions and modeling results), they are sufficient to enable Arkansas and other states with Class I areas affected by emissions from Arkansas to meet all established reasonable progress goals.[253]

EPA's disapproval of the 2008 SIP was not due to lack of reasonable progress to achieve visibility improvement or for missing the Uniform Rate of Progress (URP). It was disapproved primarily because the underlying emissions were based on presumptive limits and no BART evaluations had been conducted. The RPG and URP in the 2008 SIP, and as supported in the 5-year update, should be accepted as presented by the State. The actions required by EPA in the FIP to conduct BART analyses only serve to achieve greater emission reductions than in that analysis. Therefore, EPA should not look beyond BART eligible units to achieve greater visibility improvements. EPA should not simply use the RH program as leverage to impose emissions reductions that have little benefit to the purpose of the rule to improve visibility. EPA should allow, and defer to, ADEQ to reevaluate the RPG and URP before imposing any additional specific emissions reductions.

EPA determined that it would be appropriate to evaluate the Entergy Independence facility relative to reasonable progress obligations. We, however, disagree with EPA's conclusion that imposing emission controls on the Independence facility is needed to meet the statutory requirements.

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[251] 80 Fed. Reg. at 18989.
[252] STATE OF ARKANSAS, State Implementation Plan Review for the Five-Year Regional Haze Progress Report, Prepared by the Arkansas Department of Environmental Quality Air Division Planning Branch, April2014, Revised November 2014, p. 55 (hereinafter "Five-Year Progress Report).
[253] Five-Year Progress Report, p. 55.

Response: We address elsewhere in this document comments contending that ADEQ's Five Year Progress Report SIP revision shows that Arkansas' Class I areas are projected to meet the State's disapproved RPGs, as well as the URP glidepath in 2018, and that the controls required in our FIP are therefore not necessary.

With regard to the comment that our partial disapproval of the Arkansas RH SIP was not due to lack of reasonable progress, we discuss elsewhere in this document that our March 12, 2012 final action[254] partially approving and partially disapproving the Arkansas RH SIP, included a disapproval of the majority of the state's BART determinations as well as disapproval of the state established RPGs. We disapproved the state's RPGs because the RPGs relied on BART determinations that did not meet the requirements of the CAA and the RH regulations and because Arkansas failed to conduct a four-factor analysis, as required by the CAA and the Regional Haze Rule. Without a four-factor analysis, we were unable to verify whether any additional control measures were necessary to make reasonable progress—the core requirement of the CAA's visibility program.[255] Our final action disapproving the State's RPGs became effective on April 11, 2012. Therefore, any arguments upholding the state's RPGs or stating that we should accept those RPGs are outside the scope of this action.

The commenter contends that the requirements in our FIP only serve to achieve greater emissions reductions than in the Arkansas RH SIP. This is incorrect. Under section 110(c) of the Act, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Therefore, the purpose of our FIP is to correct the deficiencies in the SIP and conduct the required analyses and establish emission limits in accordance with the CAA and the RH rule. We are requiring controls under BART based on our analyses of the five statutory factors required under CAA section 169A(g)(2) and the Regional Haze regulations under 40 CFR 51.308(e)(1). As discussed in our final rule, based on our analysis of the four reasonable progress factors under CAA section 169A(g)(1) and 40 CFR 51.308(d)(1), and our consideration of the visibility improvement of potential controls, we have determined that controls at the Independence plant are cost-effective, reasonable, and would result in meaningful visibility benefits at Arkansas' Class I areas, and are therefore necessary to make reasonable progress. We are therefore requiring these controls.

With regard to the comment that EPA should defer to ADEQ to reevaluate the RPG and URP before imposing any additional specific emissions reductions, we note that Arkansas has not yet submitted a SIP revision following our partial disapproval, and EPA is already past-due on its action per the statutory deadlines. There is no authority in the CAA for EPA to further delay our action for the reasons provided by the commenter. We are operating under a court-ordered deadline to take final action to promulgate a FIP or approve a SIP revision that addresses the deficiencies in the Arkansas RH SIP by August 31, 2016.[256]

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[254] 77 FR 14604.
[255] CAA section 169A(b)(1) and (g)(1).
[256] *Sierra Club v. Gina McCarthy*, No. 4.14CV00643JLH (ED Ark. Western Div. Nov. 3, 2015).

Comment: Even if EPA were to decide, as it should, not to establish NO_X BART emission limits for White Bluff, Flint Creek, and Independence, Arkansas would still meet or exceed the emissions reductions necessary to meet the URP and satisfy the reasonable progress requirements. [UARG (0176) p. 14-15] UARG stated that EPA proposes reasonable progress emission limits as part of the FIP. The proposed reasonable progress emission limits are not justified under EPA's visibility rules and the Reasonable Progress Guidance and rest on an incorrect legal premise. EPA therefore should not promulgate the proposed reasonable progress emission limits.

Even if a reasonable progress assessment were warranted here, the information in the record establishes that no additional emission reduction requirements are necessary or justified to achieve reasonable progress during the regional haze program's first planning period with respect to the units that EPA analyzes. In the proposed rule, EPA evaluates three facilities under the reasonable progress provisions: the White Bluff Plant, the Flint Creek Power Plant, and the Independence Power Plant.

As for White Bluff and Flint Creek, EPA properly proposes to find that the SO_2 and NO_X BART requirements that EPA proposes for those units are "adequate for this first planning period to eliminate these sources from further consideration of controls under the reasonable progress requirements for this first regional haze planning period." 80 Fed. Reg. at 18,991. The proposed rule states that the proposed BART FIP requirements for these units are "anticipated to result in a substantial reduction in SO_2 and NO_X emissions from these two facilities." *Id.* Relying on BART to satisfy reasonable progress is consistent with the Reasonable Progress Guidance. *See* Reasonable Progress Guidance at 4-2 to 4-3, 5-1. It is appropriate, therefore, for EPA to determine that no additional emission reduction requirements are needed for these facilities in response to the reasonable progress provisions.

Further, even if EPA were, in effect, to revise its proposed BART determinations for White Bluff Units 1 and 2 and Flint Creek Unit 1 by not promulgating the proposed NO_X BART limits for those units, as recommended in Section II of UARG's comments, both facilities would still satisfy all reasonable progress requirements for the first planning period. As stated above, Arkansas's Regional Haze SIP, as submitted to EPA, required emission reductions that were more than adequate to meet the URPs during the first planning period, and those emission reductions would have been sufficient to satisfy reasonable progress requirements for that period. EPA proposes SO_2 and NO_X BART emission limits for White Bluff and Flint Creek that – in conjunction with other proposed control requirements – are significantly more stringent than necessary to meet the URPs, and, as discussed in Section II of UARG's comments, the proposed FIP's NO_X BART limits for these plants would produce negligible visibility improvement, according to EPA's projections. If EPA were to decide – as it should – not to promulgate the proposed FIP's NO_X BART requirements for these three units, Arkansas would nevertheless meet or exceed the rate of emission reductions necessary to meet the relevant URPs and to satisfy reasonable progress requirements.

Response: We address elsewhere in this document comments contending that an evaluation under reasonable progress and that controls under reasonable progress are not necessary because

Arkansas' Class I areas are projected to meet the state's RPGs and are projected to be below the URP glidepath in 2018.

As we discuss in more detail elsewhere in this document, meeting or being projected to meet the RPG and/or being below the URP glidepath in 2018 does not necessarily demonstrate that a state has satisfied its requirements under BART and reasonable progress for the first planning period. Further, the fact that Arkansas' Class I areas are projected to meet the State's RPG and are below the 2018 URP glidepath, does not divest us from our authority and obligation to conduct NO_X BART analyses for White Bluff and Flint Creek and determine appropriate controls under the BART requirements. Nor does it divest us from our authority and obligation to conduct a reasonable progress analysis to determine if there are controls in addition to BART that are necessary to make reasonable progress for the first planning period. We discuss in our final rule and elsewhere in this document that we have determined, based on our analysis of the five statutory factors, that NO_X emission limits consistent with LNB/SOFA controls are BART for White Bluff Units 1 and 2 and that NO_X emission limits consistent with LNB/OFA controls are BART for Flint Creek Unit 1. We also discuss in our final rule and elsewhere in this document that based on our analysis of the four statutory reasonable progress factors and our consideration of the visibility improvement of potential controls, we have determined that SO_2 and NO_X controls for Independence would be cost-effective and would result in meaningful visibility benefits at Arkansas' Class I areas, and therefore find that these are reasonable controls and are necessary to make reasonable progress. As such, we are requiring SO_2 and NO_X controls for Independence Units 1 and 2 under the reasonable progress requirements.

We discuss elsewhere in this document that in our March 12, 2012 final action[257] on the Arkansas RH SIP, we disapproved the State's RPGs because the RPGs relied on BART determinations that did not meet the requirements of the CAA and the RH regulations and because Arkansas failed to conduct the four-factor analysis required by the CAA and the Regional Haze Rule. Without a four-factor analysis, we were unable to verify whether any additional control measures were necessary to make reasonable progress—the core requirement of the CAA's visibility program.[258] Our final action partially disapproving the Arkansas RH SIP became effective on April 11, 2012. Therefore, to the extent the comment contends that the Arkansas Regional Haze SIP satisfied the reasonable progress requirements for the first planning period, such argument is not germane to the proposed action we solicited comments on and is outside the scope of this action.

We appreciate the commenter's support of our decision not to require additional controls beyond BART for White Bluff and Caney Creek to satisfy the reasonable progress requirements.

We address elsewhere in this document specific comments contending that our NO_X BART limits for White Bluff, Flint Creek, and Independence would produce negligible visibility improvement.

[257] 77 FR 14604.
[258] CAA section 169A(b)(1) and (g)(1).

Comment: [UARG (0176) p. 18-19] UARG stated that EPA proposes, as Option 1, SO_2 and NO_X emission limits to satisfy reasonable progress requirements for the Independence Power Plant. *Id.* In the alternative, EPA proposes, as Option 2, only the SO_2 emission limits due to the vanishingly small extent of the putative "visibility improvements" – amounting to "less than 0.003 dv" – that the proposed NO_X emission limits for Independence would produce. *Id.* If EPA proceeds with these unjustified reasonable progress limits at all, it plainly must reject Option 1 and instead adopt Option 2, as imposition of the proposed NO_X emission limits would not be remotely defensible.

In any event, however, neither Option 1 nor Option 2 recognizes that, for SO_2 as well as for NO_X, these proposed reasonable progress emission limits are not compelled by the CAA or EPA's rules and are unwarranted and improper under the circumstances. Because the URPs for the relevant Class I areas are projected to be met and even exceeded in the absence of any of these proposed emission limits, and because the projected visibility improvements these limits would produce are very small and cannot justify the very large costs that would be incurred to implement them, EPA should withdraw this part of its proposed rule.

Response: We disagree that our proposed SO_2 and NO_X controls for Independence are inappropriate and not compelled by the CAA or Regional Haze rule. We disagree that our proposed SO_2 and NO_X controls on Independence are expected to produce "very small" visibility benefits and that the costs are therefore not justified. We address specific comments concerning these issues elsewhere in this document. As discussed in greater detail in our final rule and elsewhere in this document, we are finalizing both SO_2 and NO_X controls for Independence (i.e., proposed Option 1).

We also discuss elsewhere in this document that the fact that a Class I area is below the URP glidepath does not automatically mean that no controls or evaluation under reasonable progress is necessary.

Comment: EPA should not require front-loading of extensive control requirements in the first regional haze planning period, and should instead delay consideration of controls on Independence until the next planning period to allow regulated entities the opportunity to conduct integrated compliance planning in ways that are consistent with provision of reliable and affordable electric power.

[Edison Electric Institute (0174) p. 2-4, 7] EEI stated that the Clean Air Act (CAA) regional haze program tasks states with determining what is reasonable progress toward elimination of man-made visibility impairment, for which EPA has set a goal of 2064 with required progress milestones (i.e., 10-year planning and SIP revisions, with program reviews in the middle of each 10-year planning period).[259] Accordingly, the CAA's regional haze program contemplates gradual visibility improvements along a "glide path" toward the 2064 goal. This program does not require immediate and costly reductions in the first planning period or any subsequent planning period that go beyond what is needed to make "reasonable progress," as determined by

[259] The first 10-year planning period began in 2009 and ends in 2018. The next runs from 2019-2028, with SIPs due in 2018.

a state based on its assessment of the four statutory factors.[260] Thus, it neither requires nor authorizes the front-loading of extensive control requirements. *See* RHR, 64 *Fed. Reg.* 35,721, 35,732 (July 1, 1999)(describing the analytical requirements for setting reasonable progress goals in terms of achieving a "uniform rate of progress" toward the 2064 goal).

Delaying consideration of controls on Independence until the next planning period is a more reasonable approach that would allow for the consideration of updated information, such as control equipment characteristics and costs, emissions reductions attributable to other regulatory and market drivers, and contemporaneous monitoring and meteorological conditions, which would allow the coordination of these important investment and regulatory decisions with the implementation of other pending regulations. Finally, this approach would give states and regulated entities the opportunity to conduct integrated compliance planning in ways that are consistent with provision of reliable and affordable electric power. EPA should withdraw its proposed controls for Independence 1 and 2.

As EPA and the states begin to implement the next rounds of the regional haze program to continue to make reasonable progress, EPA should allow states—through state environmental and electric utility regulators and in conjunction with power companies—to consider the timing and scope of additional control activities, consistent with effective long-term utility planning. This planning process is vital to minimize impacts on the cost and reliable provision of electricity to customers and to allow investment decisions to be made over suitable planning horizons. EPA also must take into consideration progress already made through the installation of controls to satisfy BART requirements and other CAA regulations that can result in reduced emissions that may lessen visibility impairment.

Response: We agree that the regional haze program contemplates gradual visibility improvements over several planning periods. Those gradual improvements are guided by the principle that controls found to be reasonable in a given planning period should be required now, rather than in some unspecified future planning period. That is the very nature of "reasonable progress." For that reason, we do not consider the controls we proposed and those we are finalizing in our FIP as being frontloading. As we discuss in our final rule and throughout this document, our cost analysis indicates that the SO_2 and NO_X controls we are requiring for Independence Units 1 and 2 are cost effective and well within the range of cost of controls found to be reasonable by EPA and the states in other regional haze actions for this first planning period. Arkansas did not comply with certain aspects of the Regional Haze Rule and thus portions of its Regional Haze SIP submitted to us in 2008 were not approvable, including the state's reasonable progress determinations and RPGs.[261] We therefore have an obligation to promulgate this FIP to address the disapproved portions of the State's SIP submission. Pursuant to CAA section 169A(g)(1) and our Regional Haze regulations at 40 CFR section 51.308(d)(1), we conducted an evaluation of additional controls under a reasonable progress analysis that considered the four statutory factors. As discussed in our proposal and throughout this final rule, based on the demonstrations we developed pursuant to the CAA and section 51.308(d)(1) and our consideration of the visibility impacts from Independence and the visibility improvement of

[260] Cost of compliance, time necessary for compliance, energy and non-air quality impacts of compliance and remaining useful life of any existing source subject to such requirements.
[261] 77 FR 14604.

potential controls, we determined that there are reasonable and cost-effective SO_2 and NO_X controls available for Independence that would result in considerable visibility benefit at Arkansas' Class I areas. Under the CAA and the Regional Haze regulations, if we determine that additional controls are reasonable based on the consideration of the four statutory factors, we must require those controls. Therefore, we are requiring SO_2 and NO_X controls for Independence Units 1 and 2 under reasonable progress in this planning period.

The commenter has not presented any information that justifies the dismissal of controls for Independence that we have determined, pursuant to the analysis required under CAA section 169A(g)(1) and 40 CFR section 51.308(d)(1), are reasonable controls that are cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas.

The comments regarding implementation of the next rounds of the regional haze program are outside the scope of this action. However, we note that, as we have done in the first round of regional haze SIPs, we will allow states to consider the timing and scope of additional control activities, consistent with effective long-term utility planning, as the states begin to develop future SIPs.

Comment: EPA improperly relied on CALPUFF modeling in its reasonable progress analysis, and Entergy has conducted photochemical modeling to demonstrate that imposing controls on Independence will not result in any meaningful visibility improvement at Arkansas' Class I areas. [Entergy Arkansas Inc. (0149) p. 18, 20-23] Entergy stated that EPA improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[262] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols- biogenic (SOAB), mobile sources, and Arkansas area sources,[263] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost Entergy's customers and co-owners over $1 billion.

Entergy stated that it has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[264] Recent IMPROVE monitoring data show that

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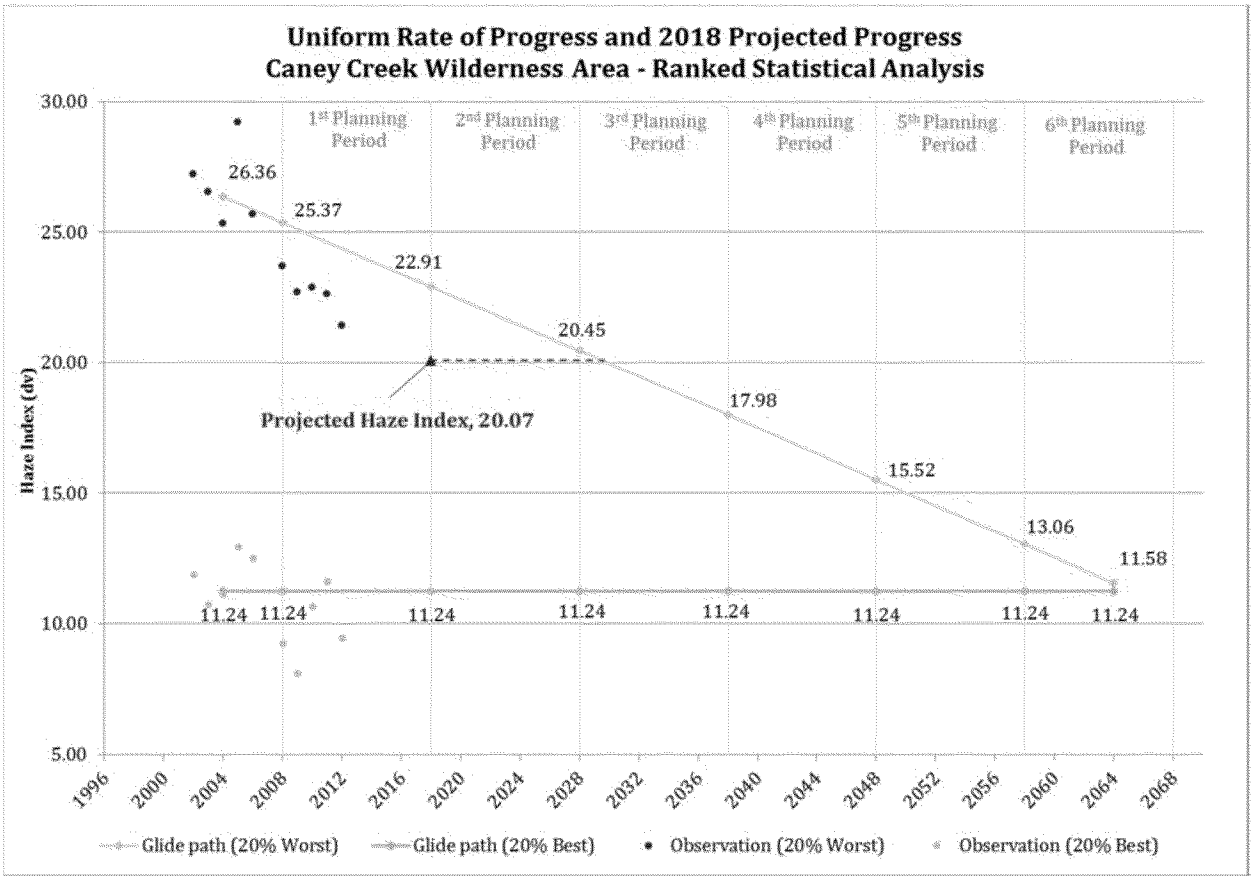
[262] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[263] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id.*

[264] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment*

the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[265] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo,[266] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

"Uniform Rate of Progress and 2018 Projected Progress Caney Creek Wilderness Area-Ranked Statistical Analysis"
(provided by Entergy as Figure 1 to AR020.0166)

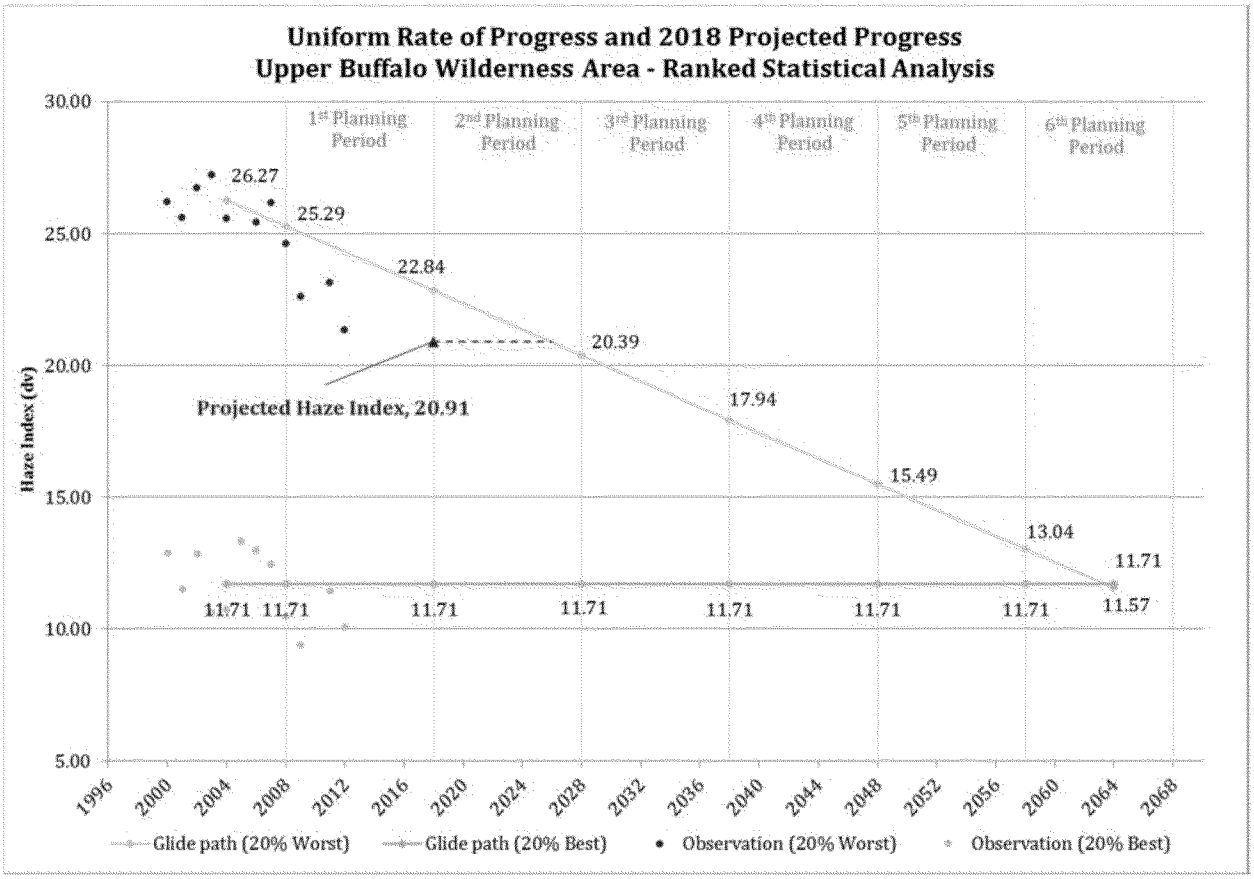


Report, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[265] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

[266] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

"Uniform Rate of Progress and 2018 Projected Progress Upper Buffalo Wilderness Area-Ranked Statistical Analysis (provided by Entergy as Figure 2 to AR020.0166)



Entergy stated that Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NO_X emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[267] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[268] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NO_X reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

Response: We acknowledge the data plots provided by the commenter. However, we discuss elsewhere in this document that being below the URP glidepath does not automatically mean that no controls or evaluation under reasonable progress is necessary in this planning period. Additionally, we discuss elsewhere in this document that the improvement in visibility conditions in Arkansas' Class I areas (including the fact that Arkansas' Class I areas are below the URP glidepath), as observed from IMPROVE monitor data, appears to be in large part due to emissions reductions outside Arkansas. While we agree that point sources outside Arkansas have a significant visibility impact at Arkansas' Class I areas, we discuss elsewhere in this document that most of the visibility improvement currently observed in Arkansas' Class I areas appears to be due to emissions reductions that have taken place outside the state. To the extent that the commenter is suggesting that Arkansas should be relieved of its regional haze obligations because other states' emission reduction efforts have already resulted in significant visibility improvement at Arkansas' Class I areas, this is incorrect. Rather, Arkansas or EPA in standing in the state's shoes, must consider the statutory factors in addressing the reasonable progress and long term strategy requirements.

While we agree that Arkansas mobile and area sources have visibility impacts in Arkansas' Class I areas, we disagree that Arkansas point sources do not. Our analysis of the CENRAP 2018 CAMx photochemical modeling showed that on the 20% worst days, Arkansas point sources contribute significantly to visibility impairment at Arkansas' Class I areas (greater than 4% of total visibility impairment at each Arkansas Class I area). We consider this to be a significant contribution considering that this percentage is out of the entire universe of sources (spanning all source categories both within and outside of the state) that contribute to visibility impairment in Arkansas' Class I areas. As we discussed in our proposal and elsewhere in this document, White Bluff, Independence, and Flint Creek are the three largest emitters of SO_2 and NO_X point source emissions in the state, and are responsible for approximately 84% of the SO_2 point source emissions and 55% of the NO_X point source emissions in the state. Independence alone is responsible for approximately 36% of the SO_2 point source emissions and 21% of the NO_X point source emissions in the state. Therefore, we expect that addressing these sources under regional haze will address a large proportion of the visibility impacts due to Arkansas point sources. We also note that the CAMx source-apportionment modeling submitted to us by the commenter also

[267] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.
[268] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions.

shows that the Independence Plant has significant visibility impacts in Arkansas' Class I areas on the 20% worst days.

Entergy's CAMx modeling shows that the contribution to visibility impairment due to emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the 20% worst days in 2018 at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. The CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined. In terms of deciviews, the average impact from Independence over the 20% worst days, based on Entergy's CAMx modeling and adjusted to natural background conditions, is over 0.5 dv at each of the Arkansas Class I areas. The results of Entergy's CAMx modeling provide additional support to our determination that Independence significantly impacts visibility, both in terms of maximum visibility impacts from the source and visibility impairment on the 20% worst days.

While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. The CAMx source apportionment modeling submitted by Entergy showed that NO_X emissions from Independence are responsible for 30-40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days (i.e., 2 out of the 21 days that are the 20% worst of the days with IMPROVE monitoring data). We expect that installation of NO_X controls on Independence will provide visibility improvement on this portion of the 20% worst days and will also provide meaningful visibility improvement on the 98th percentile day, as shown by the CALPUFF dispersion modeling. After carefully considering all comments submitted to us during the comment period, we are finalizing both SO_2 and NO_X controls for Independence Units 1 and 2 because both SO_2 and NO_X are key pollutants contributing to visibility impairment, and because we have determined that these controls are cost effective and will provide for significant visibility benefits towards the goal of natural visibility conditions at Arkansas' Class I areas.

We discuss Entergy's CAMx modeling and ranked statistical analysis in greater detail elsewhere in this document. We address elsewhere in this document comments contending that we improperly relied on CALPUFF modeling in our reasonable progress analysis and that such modeling overestimated the visibility impacts from Independence.

We address specific comments related to the cost of controls for Independence in the section of this document where we discuss cost issues.

Comment: EPA's proposed BART and reasonable progress determinations are necessary to make reasonable progress. [Sierra Club et. al. (0171) p. 46-47] Sierra Club et. al. stated that other commenters argue that the regulations require BART only as necessary to make reasonable

progress, and that EPA has not demonstrated that BART is necessary in order to make reasonable progress. This argument ignores that the BART factors overlap with the reasonable progress factors; both BART and reasonable progress are defined to include consideration of cost, energy and non-air environmental impacts, and the remaining useful life of the source. *Compare* 42 U.S.C. § 7491(g)(1) *with id.* § 7491(g)(2). In practice, however, both analyses often involve the same factors, since states and EPA frequently consider visibility improvement and existing controls when conducting reasonable progress analyses (which are required for BART), and in practice EPA considers the time necessary for compliance when setting BART compliance deadlines (this is required for reasonable progress).

Here, after considering the five BART factors, EPA has proposed controls for various Arkansas sources. EPA has conducted a source-specific BART analysis for Arkansas sources that considers all of the elements EPA would be required to consider in a reasonable progress analysis.[269] Thus, EPA's BART analysis shows that the controls satisfy the statutory factors for reasonable progress.

For Independence Units 1 and 2, EPA is proposing controls as reasonable progress measures, not as BART, and thus commenters' argument does not apply to the Independence controls.

Response: We appreciate the commenter's support of our proposed FIP.

3.c. Consistency

Comment: The cost-effectiveness of the SO_2 controls EPA proposed for the Independence Plant far exceeds the cost-effectiveness standards reviewed and approved by EPA in other regional haze actions, and the controls also have lower projected visibility improvement than controls rejected by EPA in other Regional Haze actions.

[Entergy Mississippi Inc. (EMI) (0168) p. 5-6] EMI stated that EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After failing to make the threshold determination of whether any emission reductions are necessary for the state to make reasonable progress at its Class I areas and then making the unsubstantiated and unsupportable determination to target only the Independence Plant, EPA applied dollar per ton cost-effectiveness estimates and visibility improvement rates for the proposed controls that are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's proposal attempts to justify a cost-effectiveness of dry FGD at Independence Plant totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2.[270] This far exceeds

[269] In situations where a state or EPA does not conduct a source-specific BART analysis that considers the five statutory factors, the BART analysis provides no meaningful information as to the conclusions that would be reached in a reasonable progress analysis. For example, where states or EPA rely on a trading program, such as CSAPR, to satisfy the BART requirements, the BART analysis says nothing about whether additional controls are needed to make reasonable progress—since the reasonable progress factors have not been analyzed for each source as part of the BART determination.
[270] *Id.* at 18,933.

the cost-effectiveness standards reviewed and approved by EPA for the Kentucky[271] and North Carolina state implementation plans.[272]

Further, relying on the multisource CENRAP model, EPA projected that the proposed visibility benefits from all proposed FIP controls (*i.e.* BART and Reasonable Progress Determinations) would be 0.19 dv at Upper Buffalo and 0.21 dv at Caney Creek over 2018 projections.[273] These purported results represent the same type of negligible improvement in visibility that was specifically avoided in previous EPA actions.[274] Proposing such controls with such a low amount of visibility benefit also ignores EPA's previous statement that improvements of less than 0.5 dv are "relatively small" and are not reasonable justification for additional controls -- even though the controls may be cost-effective.[275]

[Entergy Arkansas Inc. (0166) p. 16] EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost-effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling $2,477/SO2 ton removed for Unit 1 and $2,686/SO2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states.

Response: As we discuss in our final rule and elsewhere in this document, in response to comments we received on our initial cost analysis presented in our proposal, we have revised our cost estimate for dry FGD for Independence Units 1 and 2. Based on this revision to our cost analysis, we find that dry FGD is estimated to cost $2,853/$SO_2$ ton removed at Unit 1 and $2,634/$SO_2$ ton removed. Although these cost estimates are slightly higher than we estimated in our proposal, we continue to find these controls to be cost effective and well within the range of cost of controls found to be reasonable by EPA and the States in other regional haze actions.

We disagree with the statement that our proposal to require SO_2 controls for Independence is inconsistent with our approvals of the Kentucky and North Carolina Regional Haze SIPs. Additionally, the factual contexts of both of these actions are easily distinguished from context in which we assessed potential reasonable progress controls for Independence.

The commenter contends that in our proposed approval of the Kentucky Regional Haze SIP, we approved the state's use of a $2,000/$SO_2$ ton threshold. This is incorrect. In the preamble of our proposed approval of the Kentucky Regional Haze SIP, we discussed that the state identified 10 units for evaluation under reasonable progress, and that 9 of these were EGUs subject to CAIR.

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[271] 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011) (approving the use of a $2,000 per ton SO_2 screening threshold).
[272] 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012) (approving state's decision not to implement additional controls for reasonable progress despite cost-effectiveness determinations ranging from $912 to $1,922 per ton of SO_2 removed).
[273] 80 Fed. Reg. at 19,998, (Table 67).
[274] *See e.g.,* 77 Fed. Reg. at 24,012 (Montana Proposed) (EPA determined that 0.18 dv improvement was too low to justify additional SO_2 controls on one facility); 76 Fed. Reg. 12,651, 12,661 (Oregon Proposed) (Mar. 8, 2011) (EPA rejected relatively low-cost per ton controls that yielded only 0.18 dv improvement).
[275] 77 Fed. Reg. 30,454, 30,464 (Oregon Final). (May 23, 2012).

The remaining facility, Century Aluminum, is not an EGU. We further discussed that for the limited purpose of evaluating the cost of compliance for the reasonable progress assessment in this first regional haze SIP for the non-EGU Century Aluminum, Kentucky concluded that it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy. As a result, Kentucky decided to use CAIR as a guide, using a cost of \$2,000/ton of SO_2 reduced as a threshold for cost-effectiveness for that particular non-EGU source. Kentucky found that the cost effectiveness of the SO_2 control as suggested by the VISTAS control cost spreadsheet for potlines 1–4 at Century Aluminum is \$14,207/ton of SO_2 removed. The State thus concluded that, based on the high cost on a \$/ton basis, there are no cost-effective SO_2 reasonable progress controls available for the Century Aluminum units for the first implementation period. We proposed to approve Kentucky's determination, but we also stated the following concerning our position on Kentucky's use of a \$2,000/SO_2 ton threshold:

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the Kentucky SIP still ensures reasonable progress. In proposing to approve Kentucky's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP submittal that Kentucky, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I area.[276]

It is clear in our proposed approval that we were not approving or otherwise advocating Kentucky's use of a \$2,000/SO_2 ton threshold in the reasonable progress analysis. On the contrary, we expressed concern that the use of a specific threshold for assessing cost may result in a state not fully considering potential reasonable control measures above that threshold that would have meaningful visibility improvement on its Class I areas. Furthermore, our statements in the proposal indicate that had there been evidence of more affordable controls available above the \$2,000/SO_2 ton threshold used by the state that provide meaningful visibility improvement at the Class I areas, we might have arrived at a different decision concerning the approvability of Kentucky's reasonable progress analysis for SO_2.

North Carolina took a similar approach to that of Kentucky in its SO_2 reasonable progress analysis by relying on a cost threshold when deciding on measures for its non-EGUs. North Carolina set this threshold based on the estimated cost of compliance with its Clean Smokestacks Act, a law establishing a state-wide cap on SO_2 and NO_X emissions from the State's two major utilities. In our proposed approval of the North Carolina Regional Haze SIP, we discussed that the state identified 11 units (non-EGU) for evaluation. We noted that North Carolina decided that for the limited purpose of evaluating the cost of compliance for non-EGUs in the SO_2 reasonable progress assessment for the first implementation period, it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy and therefore also used a cost-effectiveness threshold for its non-EGUs. North Carolina's threshold was based

[276] 76 FR at 78206.

on "[t]he facility-by-facility cost for EGUs under [the Clean Smokestacks Act which] ranged from 912 to 1,922 dollars per ton of SO_2 removed," a statement which the commenters appear to have misinterpreted to mean that North Carolina rejected potential reasonable progress measures with costs falling within this range.[277] Rather, upon conducting cost evaluations for the non-EGUs and determining that the costs of controls exceeded its threshold, North Carolina concluded that there were no cost-effective reasonable progress SO_2 controls available for the first implementation period. We proposed to approve North Carolina's determination, but we also stated the following concerning our position on North Carolina's use of a specific cost-effectiveness threshold:

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the North Carolina SIP still ensures reasonable progress. In proposing to approve North Carolina's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP submittal that North Carolina, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I areas.[278]

As in the case of Kentucky, it is clear that in our proposed approval of North Carolina's reasonable progress determination, we were not approving or otherwise advocating North Carolina's use of that specific cost-effectiveness threshold in the reasonable progress analysis. Therefore, we disagree that our requirement of SO_2 controls for Independence Units 1 and 2 under reasonable progress is inconsistent with our actions on the Kentucky and North Carolina Regional Haze SIPs.

The commenter contends that the level of visibility improvement projected to result from our proposed SO_2 controls on Independence is the same level of visibility improvement that we have specifically avoided in other EPA actions. This is incorrect. The commenter appears to be confusing the results of two different types of modeling assessments: (1) the estimated improvement in the 2018 RPG for the average across the 20% worst days at Caney Creek and Upper Buffalo that we calculated would result from all the controls in our Arkansas FIP proposal in the context of light extinction due to all sources in that time period and (2) the CALPUFF modeled visibility improvement due to controls on Independence Units 1 and 2 based on the maximum (98th percentile) facility impacts using CALPUFF dispersion modeling and natural visibility conditions as background. The commenter references our proposed actions on the Montana RH FIP and the Oregon RH SIP. The commenter is specifically referring to our statement that 0.18 dv is a relatively small visibility improvement for each of the SO_2 controls considered for the Ash Grove facility in our Montana RH FIP proposal.[279] We were clear in our Montana RH FIP proposal that 0.18 dv and the other visibility impacts presented in Table 37 of

[277] 77 FR at 11870.
[278] 77 FR 11858, 11872.
[279] 77 FR 24012.

that Federal Register notice represent the change in the maximum 98th percentile impact over the modeled 3-year meteorological period using CALPUFF dispersion modeling (at the Class I area that showed the greatest improvement) for the SO_2 controls evaluated.[280] The commenter also refers to Oregon's rejection in the Oregon RH SIP of new low-NO_X burners with modified overfire air (NLNB/MOFA) plus SNCR for the PGE Boardman facility "because adding SNCR only provided an additional 0.18 dv of visibility improvement over NLNB/MOFA at the Mt. Hood Wilderness Area, and because of concerns about excess ammonia emissions (commonly referred to as ammonia slip) which may result in increased rates of secondary particulate matter in the form of ammonium sulfate."[281] In our proposed action on the Oregon RH SIP, we proposed to approve Oregon's determination that SNCR is not required under BART for that facility. The 0.18 dv visibility improvement the commenter refers to represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period using CALPUFF dispersion modeling at the Mt. Hood Wilderness Area.[282]

In contrast, the visibility improvement projected to result from our proposed SO_2 controls for Independence, similarly based on the change in the maximum 98th percentile impact over the modeled 3-year meteorological period using CALPUFF dispersion modeling (at the Arkansas Class I area that showed the greatest improvement), is 1.178 dv facility wide (i.e., Units 1 and 2 combined).[283] Assuming that the visibility improvement is distributed more or less evenly between the two units,[284] the amount of visibility improvement expected from our proposed SO_2 controls on a per unit basis is significantly higher than the visibility improvement that was projected to result from the SO_2 and NO_X controls that were dismissed in the proposed actions for Montana and Oregon referenced by the commenter. The 0.19 dv and 0.21 dv improvement at Upper Buffalo and Caney Creek the commenter refers to is not the CALPUFF modeled visibility improvement of the maximum 98th percentile impacts from the facility. Instead, it represents the estimated improvement in the projected 2018 visibility conditions for the average across the 20% worst days for Caney Creek and Upper Buffalo that we calculated based on adjustments to the 2018 CENRAP photochemical modeling that would result from all the controls in our FIP proposal. As we discuss in depth elsewhere in this document, the RPGs are values that will be compared in a progress report to actual visibility conditions, and accordingly should represent the expected actual overall visibility conditions. CALPUFF modeled estimates of source impacts and benefits of controls as discussed above, have a different purpose, which is to help guide decisions on the control of individual sources.

The commenter also claims that our proposed controls for Independence Units 1 and 2 "ignores EPA's previous statement that improvements of less than 0.5 dv are 'relatively small' and are not reasonable justification for additional controls—even though the controls may be cost-effective." The commenter is referring to a statement we made in our proposed action on the Oregon RH SIP with regard to the state's determination on reasonable progress for Oregon point sources. However, the commenter is mischaracterizing our statement. The full citation is the following:

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[280] 77 FR 24012.
[281] 76 FR 12661.
[282] 76 FR 12661.
[283] 80 FR at 24873.
[284] We believe this is a reasonable assumption since the two units are nearly identical, have emissions stacks located adjacent to each other, and the two units have comparable SO_2 emissions.

> Since all of these sources have Q/d values below 20, EPA believes that their impacts on nearby Class I areas are expected to be less than 0.5 dv. Thus, EPA agrees with Oregon's conclusion that additional controls of non-BART point sources for reasonable progress purposes are not reasonable in the first planning period, because even though there are cost effective controls identified, visibility improvement is anticipated to be relatively small.[285]

It is clear that the "0.5 dv" we mention in our proposed action on the Oregon RH SIP refers not to the visibility improvement that would result from installation of controls, but rather to the *baseline visibility impacts* of the point sources at the nearby Class I areas. In comparison, we found that the baseline impacts from Independence (Units 1 and 2 combined) are 2.512 dv at Caney Creek and 2.264 dv at Upper Buffalo, which we consider to be significant impacts.[286] Therefore, the claim that our proposed controls on Independence Units 1 and 2 are in contradiction with the statement we made in our proposed action on the Oregon RH SIP, is incorrect.

Based on our analysis of the four reasonable progress factors and our consideration of the baseline visibility impacts from Independence and the visibility improvement of potential controls, we have determined that SO_2 and NO_X controls at Independence would be cost-effective and would result in meaningful visibility benefits at Arkansas' Class I areas, and therefore find that they are reasonable controls and are necessary to make reasonable progress.

We address elsewhere in this document other specific comments contending that our proposed controls on Independence would produce negligible visibility improvement.

We address elsewhere in this document comments contending that EPA "fail[ed] to make the threshold determination of whether any emission reductions are necessary for the state to make reasonable progress at its Class I areas."

We also address elsewhere in this document comments contending that we were arbitrary and capricious in determining what sources to evaluate under reasonable progress, that we "targeted" the Independence Plant, and that our decision to evaluate the Independence Plant was unsubstantiated and unsupported.

Comment: EPA's evaluation and application of NO_X control requirements for the Independence Plant is inconsistent with EPA's actions in the Texas Regional Haze FIP.

[Entergy Mississippi Inc. (EMI) (0168) p. 6-7) EMI stated that EPA's decision to evaluate *and propose* NO_X controls at the Independence Plant also stands completely opposite its decision not to even evaluate similar controls for Texas' point sources despite similar visibility conditions.

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[285] 77 FR 30464.

[286] See 80 FR 24872. See also the document titled "Summary of Additional Modeling for Entergy Independence," which is found in the docket for our proposed rulemaking.

EPA elected not to evaluate Texas point sources for NO_X controls because modeling suggested that impacts from the sources were "primarily due to sulfate emissions" -- *i.e.* NO_X emissions from those sources were not significantly impacting class I Federal Areas.[287] In Arkansas, EPA was even more explicit, stating that "visibility impairment is not projected to be significantly impacted by nitrate on the 20% worst days at Caney Creek or Upper Buffalo."[288] Incredibly, however, the agency evaluated and proposed NO_X controls for the Independence Plant Units 1 and 2.[289] Concern with this point is heightened by the low projection for anticipated visibility improvement due to the NO_X controls[290] and because such controls are completely unnecessary to achieve reasonable progress and stay ahead of the uniform rate of progress.[291]

EMI stated that reviewed individually, each issue evidences an arbitrary, unjustified and inconsistent application of the regional haze regulations. Collectively, they demonstrate EPA's complete disregard for the consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act.[292] They further oblige the agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices."[293] In EPA's Arkansas FIP proposal, Region 6 abandoned the standardized criteria, procedures and policies previously applied by the agency and, in the process, disregarded all notion of uniformity. Even worse, the EPA's inconsistent treatment is due in large measure to the Agency's failure to complete necessary analysis, which is the same justification it provided when it rejected Arkansas' SIP proposal in the first instance.[294]

[Entergy Arkansas Inc. (0166) p. 16, 17] Entergy stated that EPA's decision to evaluate *and propose* NO_X controls at Independence stands completely opposite its decision not to even evaluate NO_X controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NO_X limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for

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[287] Texas Regional Haze FIP at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions.").
[288] 80 Fed. Reg. at 18,994.
[289] *Id.* at 18,996.
[290] *Compare* 79 Fed. Reg. at 9360 (Arizona Proposed) (rejecting installation of selective catalytic reduction technology for reasonable progress where it was projected to result in 0.41 dv improvement at affected class I Federal areas) *with* 80 Fed. Reg. at 18,966 (projecting a 0.461 dv improvement over baseline).
[291] *See* State of Arkansas, State Implementation Plan Review for the Five-Year Regional Haze Progress Report, at 42-43 (May 2015) (hereinafter "Arkansas Five-Year Progress Report") available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.
[292] 40 C.F.R. § 56.3(a) and (b).
[293] 40 C.F.R. § 56.5(a).
[294] 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas RH SIP was made, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NO_X, and almost not at all by Independence. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP.

Entergy stated that reviewed individually, the inconsistencies identified between EPA's proposed FIP for Arkansas and other Regional Haze actions is evidence of an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

[Conway Corporation et. al. (0172) p. 6; and EEAA (0173) p. 11] Conway Corporation et. al. and EEAA stated that EPA's decision to evaluate *and propose* NO_X controls at the Independence Plant also stands completely opposite its decision not to even evaluate similar controls for Texas' point sources despite similar visibility conditions. EPA elected not to evaluate Texas point sources for NO_X controls because modeling suggested that impacts from the sources were "primarily due to sulfate emissions" -- *i.e.* NO_X emissions from those sources were not significantly impacting Federal Class I areas.[295] In Arkansas, EPA was even more explicit in stating that "visibility impairment is not projected to be significantly impacted by nitrate on the 20% worst days at Caney Creek or Upper Buffalo."[296] Incredibly, however, the agency evaluated and proposed NO_X controls for the Independence Plant Units 1 and 2.[297] The arbitrary nature of this aspect of the Proposed Rule is further evidenced by the low projection for anticipated

[295] 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions.").
[296] 80 Fed. Reg. at 18994.
[297] *Id.* at 18966.

visibility improvement due to the NO_X controls[298] and because additional controls are completely unnecessary to achieve the RPGs and stay ahead of the uniform rate of progress.[299]

Response: This comment, and our response to it, illustrate the very fact-specific nature of individual evaluations and decisions under the regional haze program. It is critical to understand the full context of each decision. In each one, the EPA applies the requirements of the statute and regulations in a consistent manner, but the different facts—unique to each state and facility—inevitably lead to different outcomes. We agree that in our Texas FIP action we noted that on the 20% worst days, the impacts from the EGUs we evaluated under reasonable progress were primarily due to sulfate emissions. We also agree that in our Arkansas FIP proposal we acknowledged that the CENRAP modeling demonstrates that sulfate is the primary driver of regional haze in Arkansas' Class I areas on the 20% worst days. This does not mean that NO_X is not a key pollutant contributing to regional haze impairment in both states. For instance, the CENRAP CAMx modeling shows that total extinction at Caney Creek is dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, and a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 is due to nitrate.[300]

As a key pollutant, we considered NO_X controls under reasonable progress in both Texas and Arkansas. In our Texas FIP, we considered NO_X controls under reasonable progress for the Works No. 4 Glass Plant but ultimately did not require those controls based on the emission reductions already occurring at the facility, the anticipated lifetime of the furnaces, and the fact that Furnace No. 2 had undergone rebricking within the past few years. Although we determined it was reasonable to not require additional controls for Works No. 4 Glass Plant at this time, we encouraged Texas to consider additional controls when Furnace No. 2 is scheduled for its next rebricking. We also found that in Texas all the EGUs that we evaluated for controls under reasonable progress had existing LNB for control of NO_X emissions. This is in contrast to Independence, which is the second largest source of NO_X point source emissions in Arkansas and is not currently equipped with any NO_X controls. As such, Independence was a more compelling candidate for evaluation of NO_X controls in the first planning period than were the EGUs in Texas that we evaluated for controls under reasonable progress.

As NO_X is a visibility impairing pollutant and Independence is responsible for a very large portion of the point source NO_X emissions in the state (approximately 21.3%),[301] we determined that it was reasonable to evaluate NO_X controls under reasonable progress in our Arkansas FIP proposal. We conducted CALPUFF modeling and found that the Independence Plant has

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[298] *Compare* 79 Fed. Reg. at 9,360 (Arizona Proposed) (rejecting installation of selective catalytic reduction technology for reasonable progress where it was projected to result in 0.41 dv improvement at affected class I Federal areas) *with* 80 Fed. Reg. at 18,966 (projecting an 0.461 dv improvement over baseline)

[299] *See* State of Arkansas, State Implementation Plan Review for the Five-Year Regional Haze Progress Report 42-43 and 55-56 (May 2015) (hereinafter "Arkansas Five-Year Progress Report") *available at* http:www.adeq.state.ar.us/air/planning/odfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

[300] See Arkansas Regional Haze SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[301] See NEI 2011 v1. A spreadsheet containing the emissions inventory is found in the docket for our proposed rulemaking.

significant visibility impacts in Arkansas' Class I areas due to NO_X emissions based on the 98th percentile visibility impacts from the facility, and also found that LNB/SOFA would improve these visibility impacts.[302] We also found that LNB/SOFA is very cost effective ($401/ton removed for Unit 1 and $436/ton removed for Unit 2). For these reasons, we proposed LNB/SOFA for Independence Units 1 and 2 under Option 1. In addition, we discuss in more detail elsewhere in this document that Entergy submitted CAMx photochemical modeling during the public comment period showing that nitrate from Independence is responsible for 30-40% of the visibility impairment in Arkansas' Class I areas on 2 out of the 20% worst days in 2018. We expect that the installation of NO_X controls at Independence, which we found to be very cost effective, would provide visibility improvement on this portion of the 20% worst days, thereby assuring reasonable progress toward the goal of natural visibility conditions. Based on our consideration of the four statutory factors and the visibility improvement available from controls, we have determined that there are reasonable NO_X controls available for Independence that are cost effective and would result in considerable visibility improvement. Therefore, we are requiring these controls.

We disagree that our decision to require NO_X controls for Independence is inconsistent with our Arizona FIP proposal. In that action, we proposed that neither SCR nor SNCR was required to achieve reasonable progress for Springerville Units 1 and 2 in this regional haze planning period because:

> [w]hile the cost per ton for SNCR may be reasonable, the projected visibility benefits are relatively small (0.18 dv at the most affected area). The projected visibility benefits of SCR are larger (0.41 dv at the most affected area), but we do not consider them sufficient to warrant the relatively high cost of controls for purposes of RP in this planning period. However, these units should be considered for additional NO_X controls in future planning periods.[303]

The "relatively high cost" of SCR controls we refer to in that statement is $6,829/ton NO_X removed for Springerville Unit 1 and $6,085/ton NO_X removed for Springerville Units 2.[304] Thus, our decision to not propose SCR at Springerville Units 1 and 2 was not because we considered the visibility benefits to be too small, as the commenter appears to believe. Instead, it was because we determined that, under these circumstances, this level of visibility improvement was not sufficient to warrant the cost per ton of emissions reduced. In contrast, we found that the cost of LNB/SOFA at Independence Units 1 and 2 is significantly lower ($401/ton removed for Unit 1 and $436/ton removed for Unit 2), and we determined that 0.459 dv visibility

[302] Although the reasonable progress provisions of the Regional Haze Rule place emphasis on the 20% worst days, the CAA goal of remedying visibility impairment due to anthropogenic emissions encompasses all days. Thus, states and EPA have the discretion to consider the visibility impacts of sources and the visibility benefit of controls on days other than the 20% worst days in making their decisions, such as the days on which a given facility has its own largest (98th percentile) impacts. Because Independence has significant 98th percentile visibility impacts, these impacts will need to be addressed to achieve the CAA goal of remedying visibility impairment due to anthropogenic emissions.

[303] 79 FR 9318, 9360 (February 18, 2014).

[304] 79 FR 9318, 9359.

improvement at the most impacted Class I area due to installation of these controls (on a facility-wide basis) warranted the cost of these controls. Therefore, we disagree that the NO_X controls we proposed and are finalizing in this action for Independence Units 1 and 2 in any way contradict our action on the Arizona Regional Haze FIP.

We disagree that our proposed reasonable progress controls are arbitrary, unjustified, inconsistent with the CAA and regional haze regulations, and address specific comments concerning this issue elsewhere in this document.

We address elsewhere in this document other specific comments contending that our FIP proposal abandoned the standardized criteria, procedures, and policies applied by EPA in other regional haze actions with respect to the reasonable progress analysis.

We also address elsewhere in this document comments contending that controls under reasonable progress are not required when a Class I area is projected to achieve the RPGs established by the state or when the Class I area is below the glidepath.

Comment: The RPGs proposed by EPA reflect an arbitrary and disparate treatment of Arkansas in comparison to surrounding states where EPA has proposed or accepted RPGs that would allow the states to achieve natural visibility conditions until well beyond the national goal of 2064.

[ADEQ (0160) p. 17-21] ADEQ stated that as pointed out in the Five-Year Progress Report State SIP revision, Arkansas is making substantial progress in addressing regional haze in its Class I areas and is on schedule to meet its own proposed RPGs and the URP for the first planning period.[305] This means that Arkansas is well on track to reaching background visibility conditions by 2064. Despite this progress, EPA proposed RPGs that are more aggressive than that necessary to achieve the program's goal, which is inconsistent with surrounding states that have wide-ranging RPGs placing them on a path to achieve background visibility conditions well beyond 2064.

Arkansas is making considerable progress in reducing regional haze based on its own RPGs. The most recent data from 2011 and the current five-year rolling average shows that visibility impairment is decreasing more rapidly than the URP and Arkansas's proposed 2018 RPGs.[306] In fact, CENRAP modeling indicates that Arkansas may reach its own 2018 RPGs without additional control measures beyond those described in Arkansas's now-disapproved SIP.[307] The Upper Buffalo Wilderness area is expected to achieve its 2018 RPG of an improvement of 3.75 deciviews for the 20% worst days without any additional controls on sources.[308] Similarly, the Caney Creek Wilderness area is on track to achieve its 2018 RPG of 3.88 deciviews of visibility improvement for the 20% worst days.[309] Based on Arkansas' proposed RPGs, Arkansas may

[305] Exhibit 1 to ADEQ's comments, at 56.
[306] Exhibit 1 to ADEQ's comments, at 56.
[307] *Id.*
[308] *Id.* at 55.
[309] *Id.*

reach background conditions in Caney Creek by 2062 and in the Upper Buffalo by 2063.[310] Any further controls or more stringent RPGs are simply unnecessary to achieve the goal of reaching background visibility conditions by 2064.

Despite Arkansas being on schedule to meet or beat the trajectory needed to achieve background visibility conditions by 2064, EPA is proposing more stringent RPGs that would require unnecessary additional controls. Specifically, EPA is requiring additional controls on Entergy Independence Units 1 and 2.[311] EPA's proposed RPGs are more aggressive, which is inconsistent with EPA's approach in certain other states that allow RPGs that would improve visibility over a much longer timeframe.[312]

EPA has proposed or accepted RPGs for other states that would allow those states to meet background visibility conditions well into the next century. In Texas, EPA proposed RPGs that would allow that state to achieve natural visibility conditions for the 20% worst days in Big Bend Wilderness Area in 194 years and in the Guadalupe Mountains in 159 years.[313] In Oklahoma, EPA proposed a 2018 RPG for the 20% worst days that put that state on track to attain natural visibility in the Wichita Mountains in 92 years.[314] For Arkansas, EPA has required RPGs that would be even more stringent than those needed to reach background visibility conditions in 49 years, which is the program's target.

In states farther geographically removed from Arkansas, EPA's treatment disparity becomes even more profound. In California, EPA approved that state's RPGs even though many of its Class I areas would not reach natural background conditions until well into the 2100's and beyond. For example, California's RPGs will not achieve background conditions in Desolation Wilderness Area until 2307, in Yosemite National Park until 2160, and in Ansel Adams Wilderness Area until 2200.[315]

There is no justification for EPA arbitrarily setting RPGs that are stricter than those proposed by Arkansas and include controls on Entergy's Independence Plant. EPA's dramatically disparate approach to Arkansas's RPGs in comparison to other states is unreasonable and unnecessary to achieve "reasonable progress" towards reaching background conditions. EPA should withdraw the Proposed FIP and any subsequent plan should contain goals that are reasonable in light of EPA's treatment of other states.

[Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 12-13]
AEEC and AGC stated that the Five-Year Regional Haze Progress Report that ADEQ submitted to the EPA reveals that Arkansas is on track to meet the visibility improvements contemplated by the Regional Haze Rule, meaning that Arkansas is actually on track to reach background

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[310] *Id.*
[311] 80 FR 18944 at 18992.
[312] 80 FR 18944 at 18997. ("These RPG's reflect rates of progress that are faster than the rates projected by Arkansas.").
[313] 79 FR 74853 at 74887.
[314] Id.
[315] Approval and Promulgation of Air Quality Implementation Plans; State of California; Regional Haze State Implementation Plan and Interstate Transport Plan; Interference With Visibility Requirement, 76 FR 13944, at 13951

visibility conditions by 2064. Notwithstanding this progress, the Proposed FIP arbitrarily contains RPGs more aggressive than necessary to achieve the program's goal, despite the fact that the EPA has approved RPGs for surrounding states that will not attain background visibility conditions until well after 2064.

Despite Arkansas being on track to achieve background visibility conditions by 2064, the Proposed FIP contains RPGs more stringent than those contained in the Arkansas SIP. These RPGs require unnecessary and costly controls.[316] These stringent RPGs simply do not align with EPA's approach in other states, where it has approved RPGs that improve visibility over a much longer timeframe.[317]

The Proposed FIP contains no justification for EPA's inconsistent approach, whereby it sets strict RPGs for Arkansas and includes unnecessary controls on Entergy's Independence Plant while allowing other states to utilize RPGs that will not attain background visibility conditions until hundreds of years after Arkansas will actually achieve background visibility without installing the controls required by the Proposed FIP. Since the Proposed FIP contains arbitrary and capricious revisions to Arkansas's RPGs, despite the fact that Arkansas is already well on its way to compliance with the Regional Haze Rule and other states have received more generous treatment, the EPA should withdraw the Proposed FIP.

Response: As discussed extensively throughout this document, the CAA and the Regional Haze regulations are clear that in establishing the RPGs, states (or EPA in standing in the state's shoes in a FIP) must conduct an analysis of the four statutory factors under CAA section 169A(g)(1) section 40 CFR section 51.308(d)(1) to determine whether additional controls (i.e., beyond those required under BART and other "on the books" controls) are necessary to make reasonable progress. Thus, being projected to meet the state's 2018 RPGs and/or being below the URP glidepath does not automatically mean that a Class I area is making reasonable progress and that the requirements under the CAA and section 51.308(d)(1) are fully satisfied without the need for analysis of additional controls. The fact that Arkansas' Class I areas are on track to achieve the 2018 RPGs provided by the state in the Arkansas RH SIP and are below the URP glidepath does not divest us from our authority and obligation to conduct a reasonable progress analysis, nor does it justify the dismissal of controls for Independence that we have determined, pursuant to that analysis, are cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas.

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[316] 80 Fed. Reg. 18944 at 18992.

[317] EPA has proposed or accepted RPGs for other states that allow those states to meet background visibility conditions well into the next century. In Texas, EPA proposed RPGs that allow Texas to achieve natural visibility conditions for the 20% worst days in Big Bend Wilderness Area in 194 years and in the Guadalupe Mountains in 159 years. 79 Fed. Reg. 74853 at 74887. In Oklahoma, EPA proposed a 2018 RPG for the 20% worst days that put Oklahoma on track to attain natural visibility in the Wichita Mountains in 92 years. Id. EPA approved California's RPGs even though many of its Class I areas will not reach natural background conditions until well into the next century and beyond. California's RPGs, which EPA approved, will not achieve background conditions in Desolation Wilderness Area until 2307, in Yosemite National Park until 2160, and in Ansel Adams Wilderness Area until 2200. 76 Fed.

The preamble to the Regional Haze Rule[318] states the following with regard to consideration of the URP glidepath:

> If the State determines that the amount of progress identified through the [URP] analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.

This means that in some cases, the state or EPA may find, based on the required analysis of the four statutory factors alongside consideration of the visibility improvement of controls, that there are additional reasonable controls available that are cost effective and have meaningful visibility improvement, and are therefore necessary for reasonable progress, even if the applicable Class I area is below the URP glidepath. On the other hand, there may be cases where the state or EPA find, based on the required analysis of the four statutory factors alongside consideration of the visibility improvement of controls, that there are no available reasonable progress controls for the first implementation period and that a lesser amount of progress than reflected in the URP is reasonable.

Based on our analyses under section 51.308(d)(1) alongside consideration of the visibility improvement of controls, we determined that there are reasonable controls available for Independence Units 1 and 2 that are cost-effective and would provide for meaningful visibility improvement at Arkansas' Class I areas. Therefore, we must require these controls under reasonable progress and provide RPGs that represent our best estimate of the degree of visibility improvement that will result in 2018 from the set of control measures in our FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[319] Thus, this comment, and our response to it, illustrate the very fact-specific nature of individual evaluations and decisions under the regional haze program. It is critical to understand the full context of each decision. In each one, the EPA applies the requirements of the statute and regulations in a consistent manner, but the different facts—unique to each state and facility—inevitably lead to different outcomes. Thus, we disagree that our proposed Arkansas FIP and the RPGs we are finalizing are inconsistent with the RPGs we have established or approved in other regional haze actions where natural visibility conditions at the applicable Class I areas are projected to be achieved beyond 2064.

We address in greater detail comments related to ADEQ's Five Year Progress Report SIP revision and recent IMPROVE monitor data elsewhere in this document.

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[318] 64 FR 35732

[319] 64 FR 35733.

Comment: EPA's proposed requirement of additional emissions reductions under reasonable progress is inconsistent with its action on regional haze in Nevada. [The Associations (0165) p. 7-8] The Associations stated that even if EPA had some free-floating authority to dictate new controls, it has previously determined that, where mandatory programs (including BART) allow a state to meet reasonable progress goals during the first planning period, it is "reasonable" to determine that no further emission reductions are required. In rebuffing comments by environmental groups demanding that the State of Nevada impose additional emission reductions even though the Jarbidge Wilderness Area was slated to meet its reasonable progress goals, EPA stated:

> The [Regional Haze Rules] and EPA's guidance affords the State considerable flexibility in determining whether additional emission reduction measures are needed to achieve the [Reasonable Progress Goal] in the first planning period. [Nevada] reasonably concluded that the cost of additional controls was not warranted given projected emissions reductions from anthropogenic sources and the fact that the majority of haze at Jarbidge is from natural and out of state sources. 77 Fed. Reg. 17,334, 17337 (Mar. 26, 2012).

This approach, whereby a state or EPA only imposes reasonable additional controls when "needed" to meet reasonable progress goals, is amply supported by the Clean Air Act and EPA's Regional Haze guidance. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits … as may be *necessary* to make reasonable progress") (emphasis added); RPG Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

For Nevada, EPA found that it was imminently reasonable to forego additional, expensive pollution controls when the reasonable progress goals for a Class I area were already being met. For Arkansas, however, EPA has completely reversed its prior position without any coherent explanation. EPA may not reverse its prior policy positions without providing some reasoned explanation for that reversal. *See*, *e.g.*, *Dillman v. NTSB*, 588 F.3d 1085, 1089-90 (D.C. Cir. 2009); *California ex rel. Lockyer v. U.S. Dep't of Agric.*, 459 F. Supp. 874, 904 (N.D. Cal. 2006), *aff'd*, 575 F.3d 999 (9th Cir. 2009) (requiring "new evidence that would lead to a different conclusion"). Instead of adhering to its rationale in Nevada, or explaining why it is changing its position, EPA "focuses on the" non-BART eligible Independence plant for no reason other than it is a relatively large source of emissions. *Id.* at 18,991-992. It does so "even though Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the [Uniform Rate of Progress] for the first planning period." *Id.* at 18,992. Given EPA's prior position in Nevada, its concession that the Arkansas Class I areas will meet their reasonable progress goals should end the inquiry absent some significant concerns about the state being able to meet the Uniform Rate of Progress in future planning periods. With respect to the first planning period, imposing new pollution controls on the Independence plant serves no purpose whatsoever.

Response: We agree that in some cases it may be appropriate to determine that no additional controls beyond BART and "on the books controls" are necessary in the first implementation period to make reasonable progress. However, as discussed extensively in our proposal and throughout this document, the determination of what is necessary to make reasonable progress, including whether additional controls are necessary, must be made based on the required analyses under CAA section 169A(g)(1) and section 51.308(d)(1). We discuss extensively throughout this document that the fact that Arkansas' Class I areas are on track to achieve the 2018 RPGs provided by the state in the Arkansas RH SIP and are below the URP glidepath does not divest us from our authority and obligation to conduct a reasonable progress analysis.

We disagree with the commenter's contention that our proposed requirement of additional controls under reasonable progress for Independence Units 1 and 2 is inconsistent with our approval of Nevada's reasonable progress determination. The commenter's contention that "For Nevada, EPA found that it was imminently reasonable to forego additional, expensive pollution controls when the reasonable progress goals for a Class I area were already being met," mischaracterizes our rationale for agreeing with Nevada's decision not to require additional controls under reasonable progress. In our proposed approval of the Nevada RH SIP, we stated the following:

> EPA finds that the State's decision not to seek additional control measures is supported by the attributes of regional haze at Jarbidge as well as the expected reductions in statewide emissions of SO_X and NO_X and BART controls on three facilities. The WRAP's regional analysis indicates that haze at Jarbidge is mostly from natural sources like wildfires, and most of the anthropogenic sources contributing to that haze are outside the State. Based upon everything NDEP considered in its SIP, EPA is proposing to approve Nevada's demonstration that its RPG provides for reasonable progress in the first planning period as required in CFR 51.308(d)(1)(i), (ii) and (vi).[320]

Additionally, the commenter references only part of the citation from our final action on the Nevada RH SIP. The full citation is the following:

> As explained in the proposed rule, in promulgating the SIP NDEP considered the four factors in setting the reasonable progress goal for the Jarbidge Wilderness Area, the only Class I area in Nevada. The RHR and EPA's guidance affords the State considerable flexibility in determining whether additional emission reduction measures are needed to achieve the RPG in the first planning period. The NDEP reasonably concluded that the cost of additional controls was not warranted given projected emissions reductions from anthropogenic sources and the fact that the majority of haze at Jarbidge is from natural and out-of-state sources. Moreover,

[320] 76 FR at 36465.

> NDEP noted in its comments that "of the five proposed electrical generating units (EGUs) included in the State's 2018 emissions inventory, only two have moved forward and are now operational," which would further lower emissions projections for both NO_X and SO_2 by 2018. The comments do not demonstrate that the State failed to consider reasonably the four factors, but the comments question whether the State should have done a more robust analysis. EPA has considered the comments and the comments have not provided any further specific facts that should have been considered in the State's analysis beyond conclusory criticisms. Therefore, given the broad discretion the RHR affords the State, and the lack of specificity in the comments on this issue, EPA reaffirms its proposed decision to approve the State's reasonable progress goal for Jarbidge.[321]

There is nothing in these citations indicating that the reason we approved Nevada's determination that no additional controls were necessary under reasonable progress was because "the reasonable progress goals for [the] Class I area were already being met." On the contrary, our statement indicates that Nevada had reasonably considered the four statutory factors and that it had reasonably concluded that the cost of additional controls was not warranted given projected emissions reductions from anthropogenic sources and the fact that the majority of haze at Jarbidge is from natural and out-of-state sources. And it was for these reasons that we finalized our approval of Nevada's reasonable progress determination.

Furthermore, we note that certain distinctions can be made between Arkansas' Class I areas and that of Nevada (i.e., Jarbidge Wilderness Area). In contrast to Nevada's Class I area, where it was found that the driver of haze is emissions from natural sources, the CENRAP photochemical modeling indicated that sulfate from point sources is the primary driver of regional haze in Arkansas' Class I areas, accounting for approximately 56% of the total visibility impairment at Caney Creek and approximately 59% of the total visibility impairment at Upper Buffalo on the 20% worst days in 2002. We do note that the CENRAP modeling for 2002 does indicate that for Caney Creek, the largest contributions of visibility impairment due to sulfate emissions come from Texas and the eastern United States. For Upper Buffalo, the largest contributions of visibility impairment due to sulfate emissions come from the eastern United States, Indiana, Illinois, and Kentucky. This bears similarity to our finding in Nevada that most of the anthropogenic sources contributing to haze are outside the State. However, we also make the important observation that the CENRAP 2018 modeling projections indicate that reductions of sulfate from point sources outside Arkansas are expected to account for a large percentage of the total expected reduction in impairment between 2002 and 2018. For example, anticipated reductions of sulfate from point sources in Texas, the eastern United States, Indiana, and Ohio will account for a decrease of 24.41 Mm^{-1} in total light extinction, which is approximately 50% of the total expected reduction in Caney Creek between 2002 and 2018.[322] Similarly, anticipated reductions of sulfate from point sources in the eastern United States, Indiana, Illinois, Kentucky, and Ohio will account for a decrease of 28.43 Mm^{-1} in total light extinction, which is more than

[321] 77 FR at 17337.
[322] 76 FR at 64214.

60% of the total expected reduction in impairment in Upper Buffalo between 2002 and 2018.[323] While it is anticipated that there will be large reductions in impairment due to reductions of sulfate from point sources in these other states, sulfate from Arkansas point sources is actually expected to increase between 2002 and 2018. This distinguishes Arkansas from Nevada, where the expected reductions in Nevada's statewide emissions of SO_X and NO_X, including BART controls on three facilities, was part of our justification for agreeing with Nevada that controls under reasonable progress are not necessary. In the Nevada situation, the relevance of the observation that significant reductions in statewide emissions were expected was that this suggested that opportunities for even further emission reductions within Nevada were limited. This is not the case for Arkansas. We believe that these technical facts distinguish Arkansas' Class I areas from the Jarbidge Wilderness Area.

We also make the observation that the citation from our final action on the Nevada RH SIP explains that the RHR and EPA's guidance affords the State considerable flexibility in determining whether additional emission reduction measures are needed to achieve the RPG in the first planning period. In a FIP, EPA must step into the shoes of the state and this flexibility and discretion shifts to us. For Arkansas, in 2012, we disapproved Arkansas' reasonable progress goals because Arkansas did not conduct a four factor analysis as required by section 51.308(d)(1) and because the state's reasonable progress goals relied on the state's BART determinations, a large portion of which we disapproved because they did not meet the requirements of the CAA and RH regulations.[324] We have reasonably exercised our discretion to conduct a four-factor analysis of the largest contributors to visibility impairment, which is the same approach we have used in multiple FIPs (i.e., Texas, Arizona, North Dakota). Our proposed FIP, which we took comment on, conducted a four factor analysis for Arkansas' Class I areas. Based on our consideration of the four statutory factors alongside consideration of the visibility improvement of controls, we determined that there are reasonable controls available for Independence Units 1 and 2 that are cost-effective and would provide for meaningful visibility improvement at Arkansas' Class I areas. Therefore, we must require these controls under reasonable progress and establish RPGs that reflect these additional controls as well as the BART controls that are part of our FIP. This comment, and our response to it, illustrate the very fact-specific nature of individual evaluations and decisions under the regional haze program. It is critical to understand the full context of each decision. In each one, the EPA applies the requirements of the statute and regulations in a consistent manner, but the different facts—unique to each state and facility—inevitably lead to different outcomes. Thus, we disagree that our Arkansas RH FIP is inconsistent with our action on the Nevada RH SIP.

The commenter states that EPA made a "concession that the Arkansas Class I areas will meet their reasonable progress goals." This is incorrect. On the contrary, we disapproved the RPGs established by Arkansas in our final action on the Arkansas RH SIP, published on March 12, 2012.[325] Therefore, the state established RPGs are not a reflection of the control measures necessary to make reasonable progress. We also discuss elsewhere in this document that the RPGs are an analytical tool we use to evaluate whether the measures in the implementation plan

[323] 76 FR at 64215.
[324] 77 FR 14604.
[325] 77 FR 14604.

are sufficient to make reasonable progress, but they are not enforceable.[326] The RH rule provides that what is enforceable are the emission limitations and other control measures that apply to specific sources (including both BART and sources controlled under reasonable progress).[327] Achieving or being projected to achieve the RPG does not necessarily demonstrate that a state has satisfied the reasonable progress requirement. The state or EPA must complete the required four factor analysis to determine appropriate controls and emission limits under reasonable progress, and must adopt and enforce these controls and emission limits.

We address elsewhere in this document comments contending that our approach for determining what sources to analyze under reasonable progress is inappropriate, inconsistent and arbitrary, and that we inappropriately focused on Independence in our reasonable progress analysis.

Comment: EPA must consider the four reasonable progress factors for Arkansas' Class I areas, even if the areas are below the glidepath. [Sierra Club et. al. (0171) p. 29-30] Sierra Club et. al. stated that the overarching requirement of the Clean Air Act's haze provisions is for each state's plan to include "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress." 42 U.S.C. § 7491(b)(2). The statute defines reasonable progress to account for four factors: the cost of controls, the time needed to install controls, energy and non-air quality environmental impacts of controls, and the remaining useful life of the source. *Id.* § 7491(g)(1); *see also* 40 C.F.R. § 51.308(d)(1)(i)(A).

EPA's implementing regulations require each state with a Class I area to set a reasonable progress goal for each area within its borders, 40 C.F.R. § 51.308(d)(1), based on considering the four statutory factors for reasonable progress, *id.* § 51.308(d)(3). Each state must also determine the uniform rate of progress. *Id.* § 51.308(d)(1)(i)(B). If a state set a reasonable progress goal that provides for less progress than the URP, the state must demonstrate that achieving the URP is unreasonable and that the alternative goal is reasonable. *Id.* § 51.308(d)(1)(ii). Moreover, each state must consult with other states that contribute to haze in the host state's Class I areas. *Id.* § 51.308(d)(1)(iv), (d)(3)(i)-(iii).

Neither the statute nor the regulations exempts states from the required reasonable progress analysis merely because a Class I area is on the glidepath to achieving the URP. To the contrary, EPA's long-standing interpretation of the regional haze rule is that "the URP does not establish a 'safe harbor' for the state in setting its progress goals." 79 Fed. Reg. 74,818, 74,834 (Dec. 16, 2014). If it is reasonable to make more progress than the URP, a state must do so, as EPA explained in the 1999 regional haze rule:

> If the State determines that the amount of progress identified through the [URP] analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State

[326] See 51.308(d)(1)(v).
[327] 64 FR 35733.

> should adopt that amount of progress as its goal for the first long-term strategy. 64 Fed. Reg. at 35,732.

Having disapproved Arkansas's regional haze plan, EPA has an obligation to conduct a reasonable progress analysis for Caney Creek and Upper Buffalo based on a consideration of the four statutory factors for reasonable progress. 40 C.F.R. § 51.308(d)(1). EPA must also ensure that the plan contains all measures necessary to meet Arkansas's share of the reductions needed to meet the reasonable progress goals for Class I areas affected by Arkansas's emissions. 40 C.F.R. § 51.308(d)(3). In developing the reasonable progress goals and long-term strategy for Arkansas, "EPA 'stands in the shoes of the defaulting State, and all of the rights and duties that would otherwise fall to the State accrue instead to EPA.'" *Cent. Arizona Water Conservation Dist. v. EPA*, 990 F.2d 1531, 1541 (9th Cir. 1993); *see also North Dakota*, 730 F.3d at 757 ("[I]f a state fails to submit a SIP, submits an incomplete SIP, or submits a SIP that does not meet the statutory requirements, EPA is obligated to implement its own FIP to correct the deficiency in the SIP").

Response: We generally agree with this comment with regard to our decision to evaluate Independence Units 1 and 2 under reasonable progress. We address elsewhere in this document more specific comments stating that we must address in this FIP the requirements under section 51.308(d)(3) with regard to Class I areas outside the state affected by Arkansas' emissions.

Comment: EPA appropriately prioritized the Independence Power Plant in its Reasonable Progress Analysis, and EPA should require installation of scrubbers and SCR at the plant. [The Sierra Club et. al. (0171) p. 30-31] Sierra Club et. al. stated that the Entergy Independence plant has two coal-fired units, rated at 900 MW each. 80 Fed. Reg. at 18,992. It is the second-largest point source of SO_2 and NO_X emissions in Arkansas. *Id.* The plant is responsible for 36% of SO_2 and 21% of NO_X emissions from all the point sources in Arkansas. *Id.* at 18,991. These huge quantities of pollution degrade air quality in large swaths of Arkansas, including at the Caney Creek and Upper Buffalo Class I areas. *Id.* at 18,994, 18,996. Additionally, air pollution from the Independence plant winds up in neighboring states, such as Missouri, where it impairs visibility at the Hercules-Glades and Mingo Class I areas. *Id.*

The Independence plant lacks modern air pollution controls, despite the availability of cost-effective technologies that are widely used at other electric generating units. The plant has no scrubbers, and indeed has no post-combustion controls for SO_2 emissions. *Id.* at 18,992. Similarly, the plant has no post-combustion controls for NO_X emissions. *Id.* EPA's analysis indicates that installing scrubbers and SCR at Independence Units 1 and 2 would be cost-effective and would significantly improve visibility. In the reasonable progress analysis for other FIPs, EPA has prioritized point sources that are "upwind" of Class I areas, "have high SO_2 emissions and lack modern pollution controls." 77 Fed. Reg. 61,478, 61,711 (Oct. 9, 2012). Given that the Independence plant meets all three of these criteria—it is upwind of Class I areas, has very high SO_2 emissions (and high NO_X emissions), and lacks modern pollution controls—EPA properly prioritized the Independence plant for review during the reasonable progress analysis.

In addition, the regional haze screening analysis used by federal land managers (FLMs)—who are responsible for protecting visibility in Class I areas—provides further support for EPA's decision to prioritize Independence. As discussed in more detail in the Gray Report,[328] FLMs rely on a screening methodology based on the potential emissions of certain pollutants as well as the distance to the Class I area of interest— referred to as "Q/D", *i.e.*, emissions rate (Q) divided by distance (D)—to make preliminary determinations regarding which emitting facilities will have an adverse impact on visibility. Gray Report at 12-16. The FLMs consider a source located more than 50 km from a Class I area to have a negligible visibility impact with respect to a Class I area if the Q/D value is 10 or less. *Id.* at 12. The Q/D value for the top three EGU emitters in Arkansas (Independence, White Bluff, and Flint Creek) are more than 10 times the threshold, which strongly indicates that emissions from these sources have a significant visibility impact at the four Class I areas considered by EPA. *Id.* at 14. The largest Q/D value for any Arkansas source is at Independence, for which the computed Q/D value (269) strongly supports the need for emission reductions at that facility. *Id.* The SO2 and NOX emission rates at Independence are similar to White Bluff, with distances to the four Class I areas that are generally closer. *Id.* Dr. Gray's Q/D analysis strongly supports EPA's recommendation to require emission reductions from Independence as the Q/D figures for all four Class I areas far exceed the screening threshold. In fact, based on this Q/D analysis, Independence's impact on visibility appears to far exceed that of any other source in Arkansas with the exception of White Bluff, which also significantly impacts visibility at all four Class I areas.

Given the reasonable cost of controls for Independence and the significant visibility improvement from their use, the reasonable progress goals for Caney, Upper Buffalo, Mingo, and Hercules Glades should reflect installation and operation of a scrubber and SCR controls at the Independence plant. Arkansas's long-term strategy should require Independence Units 1 and 2 to operate a scrubber and SCR to meet these reasonable progress goals.

Response: We acknowledge the Q/D analysis provided by the commenter in the Gray Report, and agree that it shows that the Independence Plant exceeds the screening threshold that has been used in other reasonable progress analyses. The Q/D analysis provided by the commenter supports our decision to evaluate controls for Independence under reasonable progress. While we generally agree with the necessity to evaluate Independence Units 1 and 2 under reasonable progress, and the need for SO_2 and NO_X control on these units to make reasonable progress, we disagree that SCR or SNCR controls are necessary. We address comments arguing that we should require SCR or SNCR controls for Independence under reasonable progress elsewhere in this document. We also discuss elsewhere in this document that the purpose of our reasonable progress analysis is to address the requirements under section 51.308(d)(1) and (d)(3) related to visibility impacts in Class I areas within the state. The purpose of the analysis is not to address the requirement under section 51.308(d)(3) related to visibility impacts in Class I areas outside the state. Although we do recognize that controls on Independence are expected to result in visibility improvements in Missouri's Class I areas.

[328] "Visibility Modeling: Technical Support Document to Comments of Conservation Organizations," EPA's Proposed Federal Implementation Plan for Arkansas for the First Planning Period of 2008 to 2018, Prepared by Dr. H. Andrew Gray, August 7, 2015.

Comment: Along with the consideration of costs of compliance, the remaining three reasonable progress factors all weigh in favor of requiring a scrubber at Independence Units 1 and 2. [Sierra Club et. al. (0171) p. 32-33] Sierra Club et. al. stated that along with consideration of the costs of compliance, the remaining three reasonable progress factors all weigh in favor of requiring a scrubber at Independence Units 1 and 2. There are no energy or non-air quality environmental impacts from a scrubber that are significant enough to warrant rejecting a scrubber, particularly given that EPA has required a scrubber as BART for many plants. *See, e.g.*, 76 Fed. Reg. 81,728 (Dec. 28, 2011) (requiring six units in Oklahoma to meet a SO2 limit of 0.06 lb/MMBtu based on the use of a scrubber), upheld by *Oklahoma*, 723 F.3d at 1206, 1224. Moreover, BART requires the same consideration of non-air quality environmental impacts of controls as does the reasonable progress analysis, so EPA's conclusion in BART determinations that scrubbers do not create environmental impacts sufficient to negate their benefits should apply with equal force in reasonable progress analyses. *Compare* 42 U.S.C. 7491(g)(1) (reasonable progress analyses shall consider "non-air quality environmental impacts of compliance") *with* 42 U.S.C. § 7491(g)(2) (BART determinations shall consider "non-air quality environmental impacts of compliance"). The "time necessary for compliance" factor likewise favors requiring a scrubber, given that a scrubber can be installed within 3 years, which is a reasonable period of time. *See* Stamper Report at 32-35. Consideration of the final factor, "the remaining useful life" of the Independence plant, does not negate the case for requiring a scrubber, given that there is no information in the record regarding the remaining useful life of the Independence plant that weighs in favor of any particular control.

If EPA were to consider visibility improvement, which is not a statutory factor for reasonable progress, *see* 42 U.S.C. § 7491(g)(1), such consideration would support requiring a scrubber. Operating a dry scrubber at the Independence plant would improve visibility by 0.938 deciviews at Caney Creek and 0.888 deciviews at Upper Buffalo. 80 Fed. Reg. at 18,994. A wet scrubber would improve visibility by 0.97 deciviews at Caney Creek and 0.904 deciviews at Upper Buffalo. *Id.*

In sum, all four statutory factors support finding that a scrubber is necessary to make reasonable progress: the cost is reasonable; the time to comply is more than reasonable, since EPA is allowing 5 years to install and operate the controls, and controls can and should be installed earlier; the energy and non-air impacts are minimal; and the remaining useful life does not cut against the controls. Moreover, the visibility improvement from a dry or wet scrubber would be significant. Taken together, the reasonable progress factors weigh in favor of requiring Independence Units 1 and 2 to install and operate a scrubber in order to make reasonable progress at Caney Creek and Upper Buffalo. The visibility improvement from operating a scrubber at these two units should be reflected in the reasonable progress goals for Caney Creek and Upper Buffalo.

Response: While we generally agree that the FIP emission limits for Independence Units 1 and 2 can be achieved by SO_2 scrubber controls, we take no position as to specific statements made in this comment. We do note that based on additional visibility modeling we conducted for Independence Units 1 and 2 following the publication of our April 8, 2015 proposal, we found that dry scrubbers on the Independence units would improve visibility by 1.096 dv at Caney

Creek and 1.178 dv at Upper Buffalo.[329] Wet scrubbers on the Independence units would improve visibility by 1.113 dv at Caney Creek and 1.196 dv at Upper Buffalo.

We address elsewhere in this document specific comments regarding the cost of scrubber controls and the time necessary for compliance with SO_2 controls for Independence Units 1 and 2.

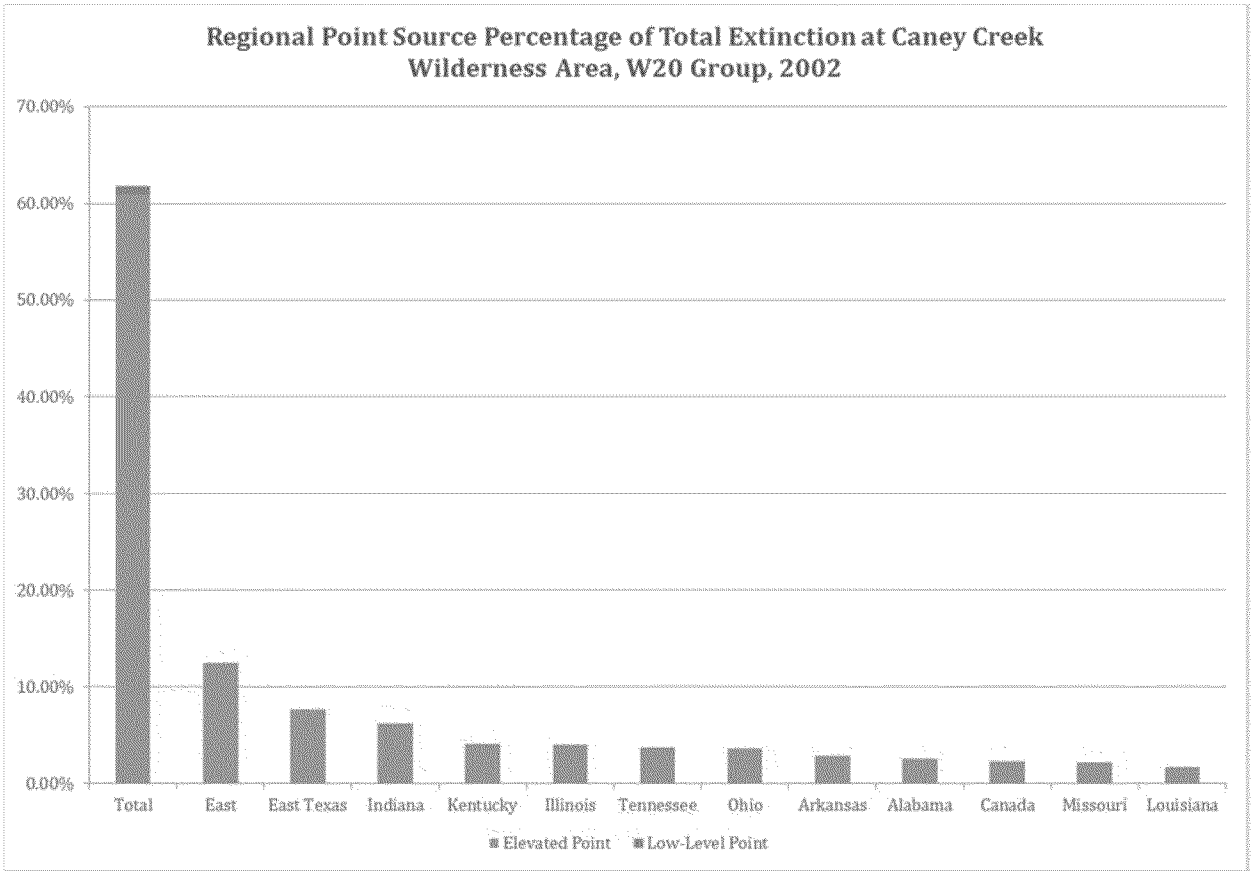
3.d. Impacts from other source categories

Comment: Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas than do Arkansas point sources. [Entergy Arkansas Inc. (0166) p. 23-29] Entergy stated that in the proposed FIP, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[330]

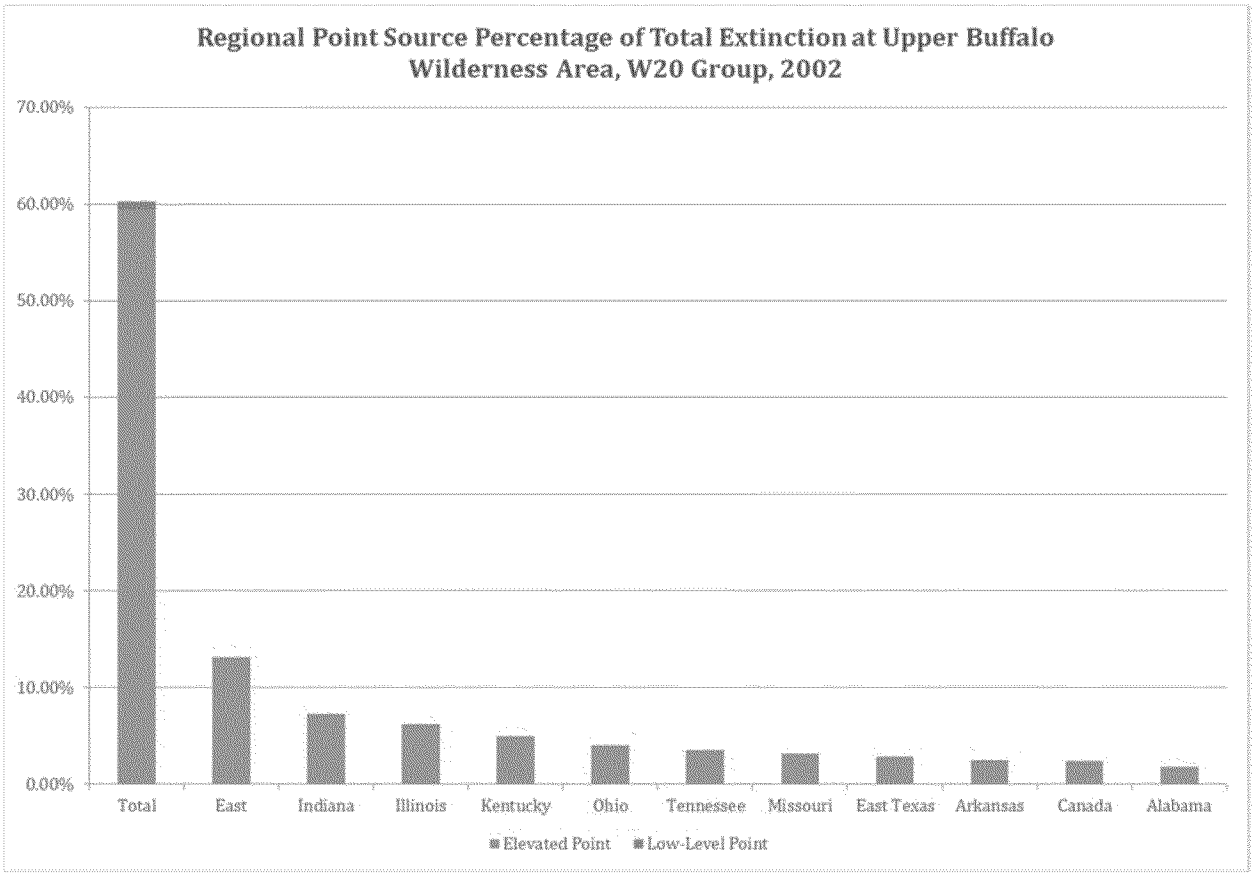
[329] See 80 FR 24872. See also the document titled "Summary of Additional Modeling for Entergy Independence," which is found in the docket for our rulemaking.

[330] Figures 3 and 4, as well as Figures 5 and 6 of Entergy's comments, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

"Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002"
(provided by Entergy as Figure 3 to AR020.0166)



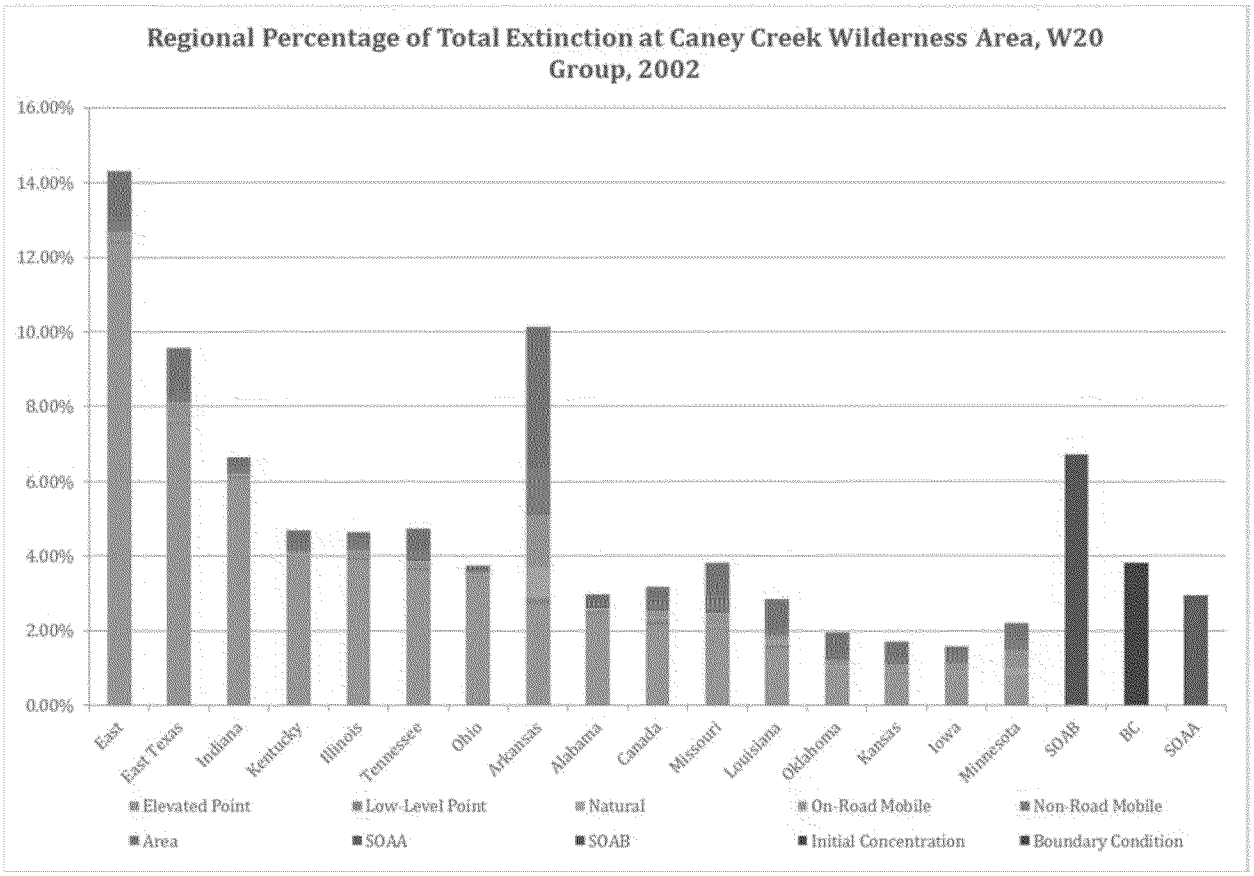
"Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002"
(provided by Entergy as Figure 4 to AR020.0166)



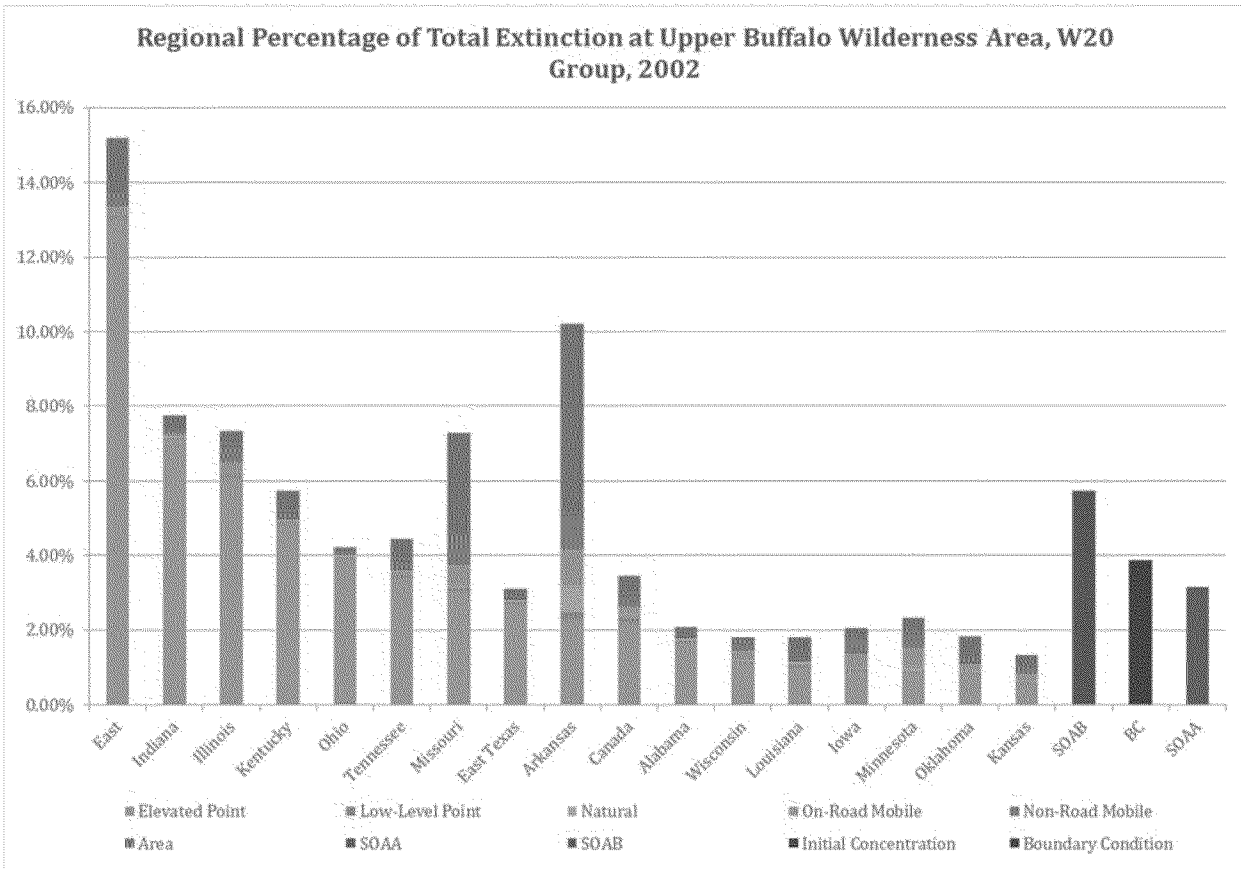
Entergy asserted that Figures 3 and 4, which it provided, display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only 2.87%, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a 2.47% contribution.

Entergy stated that in addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 of Entergy's comments.

"Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002"
(provided by Entergy as Figure 5 to AR020.0166)



"Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002"
(provided by Entergy as Figure 6 to AR020.0166)



At Caney Creek, Arkansas area sources contribute 3.75% of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only 2.87%. Even more significantly, Arkansas area sources contributed 5.09% towards extinction at Upper Buffalo compared to 2.47% from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

Response: We acknowledge the graphs and data presented by the commenter. We agree that point sources outside Arkansas have a larger contribution to visibility extinction at Caney Creek and Upper Buffalo. The commenter's analysis of contributions to visibility impairment above focuses on visibility impairment in 2002. However, the projected 2018 contributions to visibility impairment show large anticipated reductions in contributions from many areas outside of Arkansas. Arkansas point sources are projected to contribute more than 4% towards total

visibility impairment at both Caney Creek and Upper Buffalo in 2018. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area.

The commenter also contends that most of Arkansas' share of the contribution to visibility impairment at Caney Creek and Upper Buffalo comes from Arkansas area and mobile sources, not point sources. While we agree that Arkansas area sources do have a slightly greater percentage contribution than do Arkansas point sources, we do not agree that Arkansas mobile sources have a greater percentage contribution than Arkansas point sources. The fact that Arkansas area sources have a slightly greater percentage contribution than Arkansas point sources does not justify not evaluating Arkansas point sources in our reasonable progress analysis. Additionally, we discuss in detail in our proposal and elsewhere in this document that sulfate is the primary driver of regional haze in Arkansas' Class I areas and sulfate emissions are primarily due to point sources. Therefore, it is reasonable and appropriate to focus our analysis on Arkansas point sources. We disagree that Arkansas' point source contribution of 2.87% at Caney Creek and 2.47% at Upper Buffalo in 2002 is small or insignificant, and as we noted above, projected 2018 point source contributions are even larger, at greater than 4% at each Class I area.

We also disagree that the visibility impacts from the Independence Plant on Arkansas' Class I areas are small or insignificant. As discussed elsewhere in this document, Entergy submitted CAMx model results as part of their comments. The results of this modeling provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. The modeled contribution to visibility impairment due to baseline emissions from the Independence facility alone were approximately 1.3% of the total visibility impairment at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. Entergy's CAMx modeling also shows that at Upper Buffalo, the Independence facility contributes more to visibility impairment than all the subject-to-BART sources addressed in this action combined. In terms of deciviews, the average impact over the 20% worst days based on Entergy's CAMx modeling (adjusting to natural background conditions) is over 0.5 dv at the Arkansas Class I areas and even larger at the Class I areas in Missouri. These results estimate the visibility impacts from the source on the 20% worst days and confirm and provide additional support to our determination that the Independence facility significantly impacts visibility, both in terms of maximum visibility impairment and visibility impairment on the 20% worst days, and that emissions controls are expected to provide for meaningful visibility benefits towards the goal of natural visibility conditions.

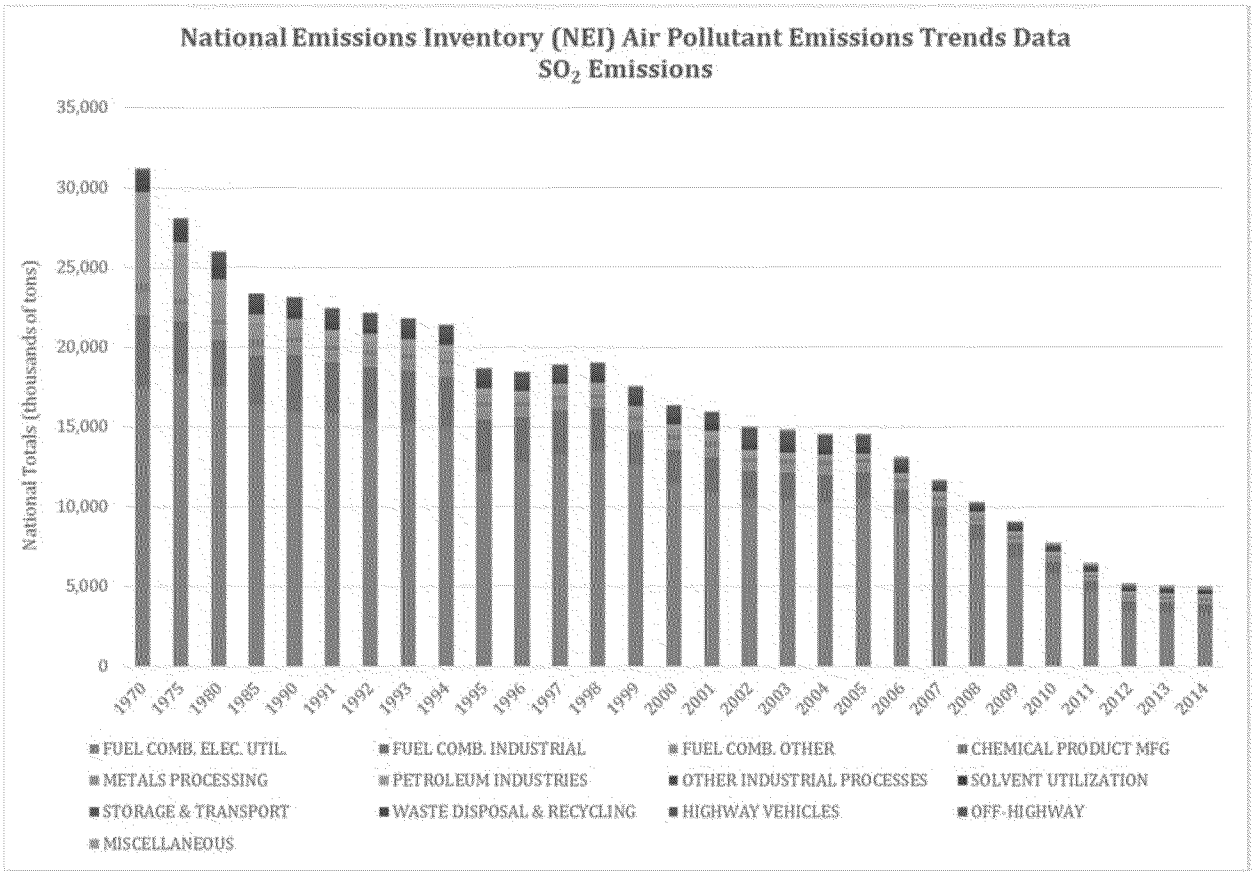
We also make the observation that because of the controls required during this planning period, we expect that the impact from the point sources and other source types in Arkansas that were not controlled and not specifically evaluated in the first planning period will become larger on a percentage basis. These sources will become the largest impacting sources and should be

considered for analysis under reasonable progress in future planning periods. The methodology we used here thus allows a consistent procedure to identify sources for additional control analysis in this and future planning periods and ensures continuing progress towards the goal of natural visibility conditions.

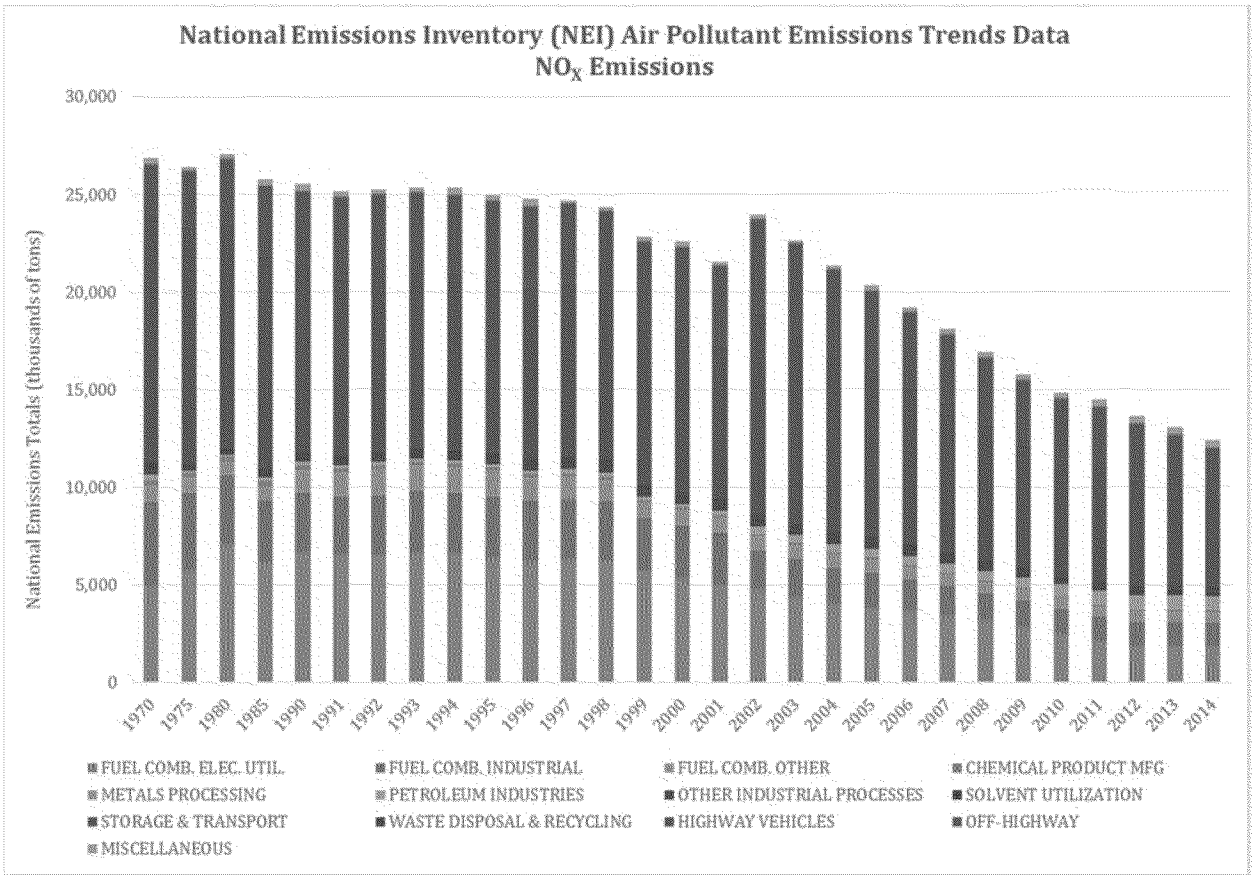
Comment: Continued emissions reductions from out-of-state sources included in the CENRAP modeling will further Arkansas' progress towards background visibility without the need for controls on Independence. [Entergy Arkansas Inc. (0166) p. 29-32] Entergy stated that its analysis demonstrates that Arkansas' Class I areas will remain below the glidepath in the first planning period and well into the second based on actual data; however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[331] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO2 and NO_X emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 of Entergy's comments (demonstrating declining emissions trends and the contributions of EGUs).

[331] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

"National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data SO_2 Emissions"
(provided by Entergy as Figure 7 to AR020.0166)



National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data NO_X Emissions (provided by Entergy as Figure 8 to AR020.0166)



Entergy stated that according to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States. (Reasonable Progress Guidance at 4-1.)

Entergy stated that EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

Response: We address elsewhere in this document comments contending that controls on Independence are not necessary because Arkansas' Class I areas are below the URP glidepath. We acknowledge the information presented by the commenter regarding emissions reductions

from sources outside of Arkansas that impact visibility at Arkansas' Class I areas. The commenter contends that this trend in emissions reductions from sources outside Arkansas will continue into the future and will further Arkansas' progress towards natural visibility conditions, even without controls on Independence. The commenter also points to our Reasonable Progress Guidance as stating that it is important to account for the emissions reductions anticipated from CSAPR and other CAA programs in setting RPGs, and alleges that we failed to take these anticipated emissions reductions from sources outside Arkansas into account in revising the RPGs for Arkansas' Class I areas. To the extent the commenter is suggesting that Arkansas should be relieved of its obligations to address visibility impairment caused by sources within the state because emissions reductions from other states are already resulting in significant visibility improvement in Arkansas' Class I areas, this is incorrect. Rather, Arkansas or EPA in standing in the state's shoes, must consider the statutory factors in addressing the reasonable progress and long term strategy requirements. We discuss this issue and also provide a discussion of Arkansas' emissions trends from 2002 to 2011 elsewhere in this document.

Further, the commenters' suggestions that EPA should delay the implementation of control measures for Independence that we have determined are cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas, relies on the conclusion that there is a specific pre-determined rate of improvement that constitutes reasonable progress. This is incorrect. As we discuss elsewhere in this document, the determination of what constitutes reasonable progress is based on the required analysis under CAA section 169A(g)(1) and 40 CFR section 51.308(d)(1).

To the extent that the commenter is concerned about whether our proposed RPGs reflect the effects of the emission reductions from other regulatory requirements and sources in other states, we believe this step of accounting for emissions reductions anticipated from other CAA programs has already been addressed through the regional planning organization (RPO) process and the 2018 CENRAP modeling projections that included projected reductions due to implementation of CAIR that states relied on in setting their RPGs. Under CAIR, point source emissions of SO_2 were projected to increase in Arkansas. We recognize that in calculating proposed revised numeric RPGs for Arkansas' Class I areas, we did not update the projections to take into account any changes in emissions reductions anticipated to take place due to implementation of CSAPR and other CAA programs that were not already included in the 2018 CENRAP modeling projections. But the commenter has not provided any additional information to support any anticipated SO_2 reductions from Arkansas point sources in the near future to address any existing regulatory requirements. In our proposed action in Arkansas,[332] as well as our actions in Texas and Oklahoma,[333] Arizona,[334] and Hawaii,[335] the 2018 modeled RPGs previously developed by the RPO were adjusted based on a methodology of scaling of visibility extinction components in proportion to emission changes. We noted that although we recognize that this method is not refined, it allows us to translate the emission reductions achieved through the FIP into quantitative RPGs, based on modeling previously performed by the RPOs. This provides an estimate of the visibility benefit due to the required controls in the context of the

[332] 80 FR 18944, 18997
[333] 81 FR 296
[334] 79 FR 52420, 52468
[335] 77 FR 31692, 31708

projected 2018 visibility conditions and RPGs established by Arkansas in its 2008 RH SIP. While there is limited precedent for adjusting the RPO calculated RPGs to account for emissions reductions achieved in a FIP or revised SIP, we took a reasonable approach based on the information available. Specifically, we adjusted the 2018 RPGs provided by Arkansas by the amount of visibility benefit anticipated from the difference in emissions reductions between the estimates that went into the CENRAP modeling and those from our Arkansas FIP that are expected to take place by 2018.[336] We believe that this is a reliable estimate of the amount of visibility benefit anticipated from controls beyond the projected 2018 CENRAP RPGs. We also note that we do not believe that our methodology for estimating the revised RPGs is problematic because the RPGs are not directly enforceable, unlike the emission limits that apply to specific sources under the regional haze requirements.

Comment: EPA's Proposed FIP does not include consideration of the substantial impacts of the actions of FLMs to haze conditions. [ADEQ (0160) p. 23-24] ADEQ stated that as set forth in 40 C.F.R. § 51.308(i), the Regional Haze Rule requires states such as Arkansas to coordinate in various ways with Federal Land Managers. For example, states are required to provide Federal Land Managers with notice of the identified visibility impairment and an opportunity for consultation.[337] However, despite EPA requiring this coordination, the actions of the Land Managers themselves are responsible for a disproportionate and unmeasured impact on the visibility of Arkansas's Class I areas. States such as Arkansas are required to identify the impairment and elements for inclusion in the visibility monitoring strategy.

In 2007, the Arkansas Forestry Commission approved a Smoke Management Program that was developed, among other reasons, as a means of assuring that land managers throughout the State use specific techniques designed to ensure that burns conducted for the purpose of forest management (prescribed burns) do not interfere with air quality management goals. Prescribed burning is widely recognized as a wildfire prevention technique and is also used to revitalize forest ecosystems. When properly conducted, prescribed burning is a useful technique for various forest management purposes.

A Federal Land Manager is "the Secretary of the department with authority over the Class I areas."[338] While several state agencies and private-sector entities practice prescribed burning, the United States Forest Service ("USFS") is the largest practitioner. The USFS uses prescribed burns from within the very Class I areas that are meant to be protected by the Regional Haze Rule. For example, in 2006 the USFS was responsible for as much as 60% of the 30,000 acres of prescribed burns that were reported in the State.[339] In 2011, federal agencies were responsible for most of the burns that were conducted in violation of the procedures described in the State's

[336] In response to other comments we received stating that our proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo improperly incorporated visibility improvements that would not occur until after 2018, we are providing revised RPGs that reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. We discuss this in greater detail in our final rule and elsewhere in this document.
[337] 40 C.F.R. § 51.308 (i).
[338] 40 C.F.R. § 51.301
[339] Dr. Lynne C. Thompson, Presentation to the Arkansas Prescribed Fire Council (May 18, 2015) attached as Exhibit 3 to ADEQ's comments.

Smoke Management Plan in which voluntary participants including the USFS agree to meet certain air-quality related criteria before initiating prescribes burns.[340] Most of burns conducted by federal agencies such as the USFS in Arkansas were conducted within the boundaries of designated National Forests.[341]

There is currently no accepted regulatory procedure for isolating the visibility impacts of prescribed burning from other anthropogenic sources of haze. However, prescribed burns continue to be a significant source of the haze in the Class I areas that are meant to be protected by the Regional Haze program. As a result, the actions of Federal Land Managers practicing prescribed burning should be given due consideration. Therefore, EPA should withdraw the Proposed FIP, and any subsequent plan should include consideration of the substantial impacts of Federal Land Managers to haze conditions.

Response: We acknowledge the information provided by the commenter. We take no position with respect to specific comments made regarding prescribed burning conducted by FLMs. We agree that section 51.308(d)(3)(v) requires that in establishing its long-term strategy, a state must consider at a minimum several factors, including smoke management techniques for agricultural and forestry management purposes. Section 51.308(d)(3)(v) states the following:

> (v) The State must consider, at a minimum, the following factors in developing its long-term strategy:
>
> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
>
> (B) Measures to mitigate the impacts of construction activities;
>
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
>
> (D) Source retirement and replacement schedules;
>
> (E) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the State for these purposes;
>
> (F) Enforceability of emissions limitations and control measures; and
>
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

[340] Exhibit 3 to ADEQ's comments.
[341] Id.

In our final action on the Arkansas RH SIP, we partially approved and partially disapproved the long term strategy for each Arkansas Class I area contained in the Arkansas RH SIP.[342] We found that Arkansas did not appropriately consider emission limitations and schedules for compliance in developing its long-term strategy, which corresponds to the requirement under section 51.308(d)(3)(v)(C). Specifically, we found that Arkansas did not follow the CAA and the Regional Haze Rule in establishing certain BART emission limits and did not complete a reasonable progress analysis to determine if additional controls were necessary in the first planning period. We also found that aside from this element of the long-term strategy, remaining elements of the long term strategy in the Arkansas RH SIP satisfied the requirements under section 51.308(d)(3)(v) for the first planning period. This includes Arkansas' consideration of agricultural and forestry smoke management techniques under section 51.308(d)(3)(v)(E). The purpose of our FIP is to address the disapproved portions of the Arkansas RH SIP for the first implementation period.[343] Since we found in a previous final action that Arkansas adequately considered agricultural and forestry smoke management techniques under section 51.308(d)(3)(v)(E), we do not have the authority to address section 51.308(d)(3)(v)(E) in this FIP. Therefore, we believe that this comment contending that our FIP is required to include consideration of the impacts of prescribed burning conducted by the FLMs or other parties is outside the scope of this action. However, if the state believes that the approved portion of the Arkansas RH SIP no longer adequately addresses the requirements under 51.308(d)(3)(v)(E), the State may submit a SIP revision that re-evaluates this element of the long term strategy and includes any necessary control measures to address impacts from prescribed burning.

Comment: EPA's Proposed FIP is improper because it adopts an individual source-based approach to setting RPGs. [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 19-20; and Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 10-11] Nucor and AEEC/AGC both stated that EPA's Proposed FIP also is improper as to Independence because it adopts an individual source-based approach to setting reasonable progress goals inconsistent with the Clean Air Act. Reasonable Progress provisions are intended to address contributions from a wide range of sources that can be best addressed on a source-category basis. They are fundamentally different from other provisions such as those for BART and reasonably attributable visibility impairment (RAVI), which are specifically designed to address individual sources. As the Tenth Circuit recently explained, "[n]either the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in the determination of reasonable progress." WildEarth Guardians v. EPA, 770 F.3d 919, 944 (10th Cir. 2014). Instead, the Clean Air Act discusses "classes or categories of sources" that "may reasonably be anticipated to cause or contribute significantly to impairment of visibility" and directs EPA to promulgate rules to address them. 42 U.S.C. §7491(a)(3), (b)(1).

Nucor and AEEC/AGC stated that in contrast, under the Clean Air Act, BART and Reasonably Attributable Visibility Impairment (RAVI) provisions are applied individually to "each major stationary source" meeting certain threshold criteria. *Id.* §7491(b)(2)(A)(c). This distinction is carried over into EPA's regulations. For example, under the Regional Haze Rule, SIPs that incorporate reasonable progress goals are intended to address "regional haze." 40 .F.R.

[342] 76 FR at 64218 and 77 FR 14604
[343] 80 FR at 18946-18947.

§51.308(d). Regional haze is defined by EPA as "visibility impairment that is caused by the emission of air pollutants from numerous sources over a wide geographic area." *Id.* § 51.301 [emphasis added]. In contrast, EPA defines BART as an "emission limitation [that] must be applied on a case-by-case basis ...." *Id.* Likewise, EPA explains that its RAVI provisions are designed to address "visibility impairment that is caused by the emission of air pollutants from one or a small number of sources." *Id.* Thus, EPA's regulations treat reasonable progress goals, which address emissions from a broad range of sources, differently than the BART and RAVI provisions, which address individual sources. Consequently, EPA does not have the authority and should not have established a separate Reasonable Progress control just for Independence.

AEEC/AGC stated that in the Proposed FIP, the EPA fails to explain how one could somehow use factors required to be considered in setting specific numerical targets, which are not enforceable,[344] to require specific enforceable limits for a single plant. The proposed FIP contains no legal justification for the analysis EPA has performed using the reasonable progress factors enumerated in 40 C.F.R. § 51.308(d)(1)(A), nor does the EPA cite legal authority for identifying and requiring emissions controls for "reasonable progress sources;" indeed, the term "reasonable progress source" does not appear in the Regional Haze Rule. Since the reasonable progress provisions of the CAA do not permit a source-specific analysis in the determination of reasonable progress, the EPA lacks authority to establish separate Reasonable Progress controls for the Independence plant; therefore, the EPA should withdraw the Proposed FIP.

Response: In our Arkansas FIP, we have conducted the requisite analyses to determine what controls are necessary to make reasonable progress by considering those sources and source categories with the most significant impact on visibility impairment. We explained in our FIP proposal that our reasonable progress analysis focused on the point source category since the other source categories each contribute a much smaller proportion of the total light extinction at each Class I area in Arkansas based on the CENRPAP modeling.[345] We then examined Arkansas point source emission inventory data that initially identified White Bluff, Flint Creek, and the Independence facility as having the greatest potential to impact visibility at nearby Class I areas out of all Arkansas point sources. Since we are requiring SO_2 and NO_X controls for White Bluff and Flint Creek under the BART requirements in this final action, which will substantially reduce emissions from these two facilities, we determined that it was appropriate to eliminate these sources from further consideration of controls under the reasonable progress requirements for this planning period. As such, our evaluation of controls under reasonable progress focused on the Independence Plant. We discuss our approach to determine what sources to evaluate under reasonable progress in greater detail in our proposal, in our final rule, and elsewhere in this document. Thus, we did consider those sources and source categories with the most significant impact on visibility impairment.

While our FIP does consider and ultimately apply controls on an individual source basis to assure reasonable progress, this is consistent with the CAA, our regulations, and past EPA guidance. The four statutory factors under CAA Section 169A(g) and 40 CFR 51.308(d)(1)(i)(A) are directed to the listed possible features or consequences of potential emission control

[344] The Regional Haze Rule states that "[t]he reasonable progress goals established by the State are not directly enforceable." 40 C.F.R. § 51.308(d)(1)(v).
[345] See 80 FR at 18989.

measures for sources, including individual stationary sources. The CAA and the Regional Haze regulations expressly set forth that the reasonable progress analysis must consider the "compliance" time and costs for "potentially affected sources." A state determines the rate of progress that is reasonable for a Class I area after taking into account the four statutory factors--as applied to specific sources or groups of sources – to determine what additional controls should be required in its regional haze SIP. Thus, individual stationary sources may be subject to emission limits and source specific analysis when determining whether additional controls are necessary to make reasonable progress.

The comment misinterprets the cited 10th Circuit case. In that case, that court found that reasonable progress is not required to be demonstrated on a source-by-source basis (or via "source-specific analysis"), but this emphatically does not mean that individual sources are free from any possibility of required new or stricter controls as part of establishing reasonable progress goals or what is necessary as part of a long-term strategy. Nothing in that decision states that individual source controls cannot be required when establishing reasonable progress goals. When a State or EPA in a FIP conducts the requisite analysis—whether it begins it by analyzing sources individually or by analyzing source categories—it should encompass the possibility of applying individual source controls, when they are warranted and reasonable. If, for example, a source category analysis were supplemented with information showing that one particular point source presented the most compelling set of facts in terms of the four factors weighing in the direction of an additional emission control measure being necessary for reasonable progress, based on that source being responsible for a majority of the emissions from the category and there being a feasible and highly cost effective control, then it would be proper for the State (or EPA in a FIP) to focus its analysis on that source, including with a source-specific assessment. To conclude otherwise vitiates the statutory purpose and asks for an entirely ineffectual analysis which could not result in possible emission limitations as expressly envisioned in the statute. If the CAA's requirements were such that the only individual stationary sources that could be looked to for emission reductions to promote reasonable progress were sources subject to controls for BART, then States, or EPA acting as necessary in the place of a State, would have little to no room for additional progress and even less need for sequential planning periods to build on past progress. Source-specific emission limitations, as promulgated in our FIP, are manifestly envisioned by the statute. See CAA Section 169A(b)(2); 40 CFR 51.308(d)(1) and (3). Incidentally, the cited 10th Circuit case had considered the claim that the State of New Mexico failed to conduct source-specific analyses for its non-BART sources with specific attention to the Escalante plant. However, there was no record evidence that this plant, remote from any relevant Class I areas, had notable impacts for regional haze purposes for this initial planning period. In future regional haze planning periods, depending on technical evidence, that plant (and others in New Mexico) may very well be subject to controls as may be required to meet reasonable progress.

The commenter's suggestion that because the RPGs are not themselves enforceable we cannot require specific enforceable limits for a single plant is not consistent with the requirement that each regional haze SIP or FIP include enforceable emissions limitations as necessary to ensure that the SIP or FIP will provide reasonable progress toward the national goal of natural visibility conditions. We discuss elsewhere in this document that the numeric RPGs provided by the state or EPA represent the best estimate of the degree of visibility improvement that will result in

2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP or EPA in a regional haze FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[346] Thus, the RPGs are intended to provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP. But, as noted by the commenter, the RPGs themselves are not enforceable.[347] EPA cannot enforce an RPG in the sense of seeking to apply penalties on a state for failing to meet the RPG or obtaining injunctive relief to require a state to achieve its RPG. However, the long-term strategy can and must contain emission limits and other control measures that apply to specific sources under the reasonable progress requirements, and that are themselves enforceable. The fact that the RPGs are not enforceable does not mean that we cannot conduct a source-specific evaluation of the reasonable progress factors or require source-specific emission limits under the reasonable progress requirements.

The commenter states that we make reference to "reasonable progress sources" in our FIP proposal, and states that this term does not appear in the Regional Haze Rule or related guidance. The commenter contends that we cite no legal authority for identifying and requiring emissions controls for "reasonable progress sources." Where we used the term "reasonable progress sources" in our FIP proposal, we used it as shorthand to refer to sources that we are controlling or evaluating for controls under the reasonable progress requirements. We explained above why individual stationary sources may be subject to controls and source-specific analysis when establishing reasonable progress goals.

3.e. Other

Comment: It would be premature for EPA to finalize its proposed RPGs when the Agency intends to revise the Regional Haze Rule. [ADEQ (0160) p. 16-17] ADEQ stated that for some time now, EPA has been considering changes to the Regional Haze program's metrics for tracking progress as well as a possible three-year extension of the schedule for submitting updated SIPs currently due in 2018. In the July 2015 timeframe, the Air Quality Policy Division of the EPA Office of Air Quality Planning and Standards announced a series of conference calls with representatives of the U.S. Department of Agriculture, the Department of the Interior, and regional, state, local and tribal governments with the following items on the agenda:

- Rulemaking activities including the proposal to delay of the State Implementation Plan ("SIP") submission deadline to 2021 from 2018, options for the process and schedule for submitting progress reports, and options for revising Reasonably Attributable Visibility Impairment rule provisions;
- Guidance to refocus the visibility tracking metric and framework on the controllable fraction of visibility impairment;
- Guidance to determine what constitutes a long-term strategy providing for reasonable progress.

[346] 64 FR 35733.
[347] See 51.308(d)(1)(v).

As indicated by the items on this agenda, it is apparent that EPA intends to reconsider the manner in which rates of progress toward the visibility goals of the Regional Haze Rule are determined and calculated. These changes would likely be made through a combination of guidance documents and rulemaking. Due to the EPA's intent to significantly revise the manner in which these metrics are considered, it is premature and unnecessary to revise the RPGs that Arkansas has determined to be appropriate. Accordingly, EPA should withdraw the proposed FIP.

Response: The commenter is correct that EPA has been considering delaying until 2021 the deadline for the SIP submittals currently due in 2018 to address regional haze in the second planning period. This proposal was published in the Federal Register on May 4, 2016. (81 FR 26943) The EPA has also been considering issuing guidance to refocus the visibility tracking metric and framework on the controllable fraction of visibility improvement and guidance to determine what constitutes a long-term strategy providing for reasonable progress in the second planning period and beyond. The notice of availability of this draft guidance for public comment was published in the Federal Register on July 8, 2016. However, we disagree that the possibility of future rulemaking revisions and guidance to address reasonable progress for the second regional haze period and beyond means that it is premature or unnecessary for EPA to conduct the reasonable progress analysis required under CAA section 169A(g)(1) and 40 CFR 51.308(d)(1) to determine if additional controls are necessary to make reasonable progress and to establish RPGs for the first planning period. The proposed rulemaking and draft guidance address the second and future implementation periods only, while this action on Arkansas concerns the first implementation period. Further, we discuss elsewhere in this document why we do not have the authority to further delay promulgation of our FIP to address the disapproved portions of the Arkansas RH SIP.

To the extent the commenter contends that the RGPs in the Arkansas RH SIP are appropriate, we discuss elsewhere it this document why such comments are outside the scope of this rulemaking.

4. Specific BART Issues

4.a. Control Levels and Emission limits

Comment: EPA's proposed SO_2 BART limit of 0.11 lb/MMBtu for Power Boiler 2 is too stringent, and its selection of emission baseline information for the purpose of establishing the SO_2 BART limit for Power Boiler No. 2 is inappropriate. [Domtar (0161) p. 6, 10-13] Domtar stated that table 43 on page 18979 of the FIP proposal identifies the baseline maximum 24-hour emission rates for the Ashdown Mill. Assuming EPA proceeds with BART for the Ashdown Mill, Domtar agrees with EPA that the following are the appropriate 24-hour maximum emission rates and baseline periods to be used for purposes of BART.

BART Unit	Baseline Period	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PM_F (lb/hr)
Power Boiler 1	2009-2011	207.4	21.0	30.4
Power Boiler 2	2001-2003	526.8	788.2	81.6

Domtar stated that, however, it disagrees with EPA's selection of emission baseline information for the purpose of establishing the SO_2 BART limit for Power Boiler 2. Instead of using data from the BART baseline period of 2001-2003 for calculating the BART SO_2 limit, EPA arbitrarily selected to use data from the 2011-2013 time period. No changes occurred with respect to Power Boiler 2 that would warrant resetting the baseline period for Power Boiler 2 or otherwise justify the use of 2011-2013 data as a baseline. In the approved portions of the Arkansas SIP, EPA agreed (with respect to the cost of controls) that baseline emissions may reflect past practices. Similarly, in EPA's BART guidelines, reference is made to calculating baseline emissions using on a continuation of past practices (Guidelines, at 39167). By analogy, in determining the BART limit for SO_2, the percent reduction also should be applied to the past practice of Power Boiler 2 as reflected in the 2001-2003 timeframe. This approach is consistent with prior EPA BART determinations for pulp and paper facilities. 77 Fed. Reg. 46955 (Aug. 7, 2012) (Response to Comments on BART Baseline).

Domtar stated that assuming EPA proceeds with BART for the Ashdown Mill, the Mill believes an SO_2 limit of 155 lb/hr for Power Boiler 2 is appropriate under the BART five factor analysis. EPA's proposed limit of 0.11 lb/MMBTU is too stringent, is based on the use of an inappropriate baseline and assumes the existing control equipment can continuously operate at the upper range of its capability (90% efficiency) over long periods of time, without supporting data or other documentation.

Domtar stated that in the methodology to calculate the proposed BART limit, EPA used data from recent years for determining the proposed BART limit, ignoring the more appropriate BART baseline information. No justification is given for not using the baseline, or why the particular years selected by EPA are better than the BART baseline years or legally appropriate. The variety of data sets EPA used is summarized below:

- Baseline SO_2 emissions of 2,078 TPY determined using 2001-2003 data for determining tons of SO_2 removal for purposes of calculating cost effectiveness
- Scrubber efficiency of 69% determined from 2011-2013 data
- Annual emission rate of 280.9 lb/hr from years 2011-2013 to determine the BART limit

Domtar stated that EPA's selection of actual SO_2 emission data from 2011-2013 is inconsistent with the method used by EPA to set other BART limits where EPA relied on the BART baseline information. For example, in a BART matter involving a Georgia-Pacific pulp and paper mill in Wisconsin, the State with EPA concurrence used baseline years of 2002-2004 to establish the BART emission limitations. 77 Fed. Reg. 46955 (Aug. 7, 2012). In the approved portions of the Arkansas SIP, U.S. EPA agreed (with respect to the cost of controls) baseline emissions may

reflect past practices (Guidelines, at 39167.). By analogy, the percent reduction in SO2 for the Ashdown Mill also should be applied to past practice as reflected in the 2001-2003 timeline.

Domtar stated that deviating from the BART baseline information is appropriate if significant changes were made to the emission units or permit conditions were imposed that prevent a unit from operating at the BART baseline emission value. However, this is not the case for Power Boiler 2. The BART baseline information is representative of Power Boiler 2's potential operations. The fact that the Ashdown Mill voluntarily elects to operate at a lower SO_2 level is not relevant. Moreover, by not utilizing the BART baseline actual emission in establishing the proposed BART SO_2 limit, EPA penalizes the Ashdown Mill for its voluntary SO_2 emission reductions undertaken on its own initiative since the BART baseline period.

Domtar stated that here, the Mill voluntarily reduced SO_2 emissions by over 40% since the BART baseline years. The Ashdown Mill was an early actor and voluntarily reduced SO_2 emissions prior to the proposed BART requirements. Using the actual emission data from the BART baseline period of 2001-2003, gives the Mill credit for its early voluntary action. Also, using the earlier baseline appropriately recognizes that the state and federal governments' delay in imposing BART years after it was required to be completed. The Ashdown Mill should not be required to use a later baseline because government agencies were dilatory in implementing the BART program. If the BART program was implemented as contemplated under the EPA's BART rules, the 2001-2003 baseline information would have been used in setting the BART limit.

Domtar stated that in addition to the use of an inappropriate baseline year, EPA wrongly applied the maximum rated heat input capacity of 820 MMBTU/hr when it converted from a lb/hr limit to a lb/MMBTU limit. This inaccurate methodology of using emission data and maximum rated heat input to calculate the proposed SO_2 BART limit is a significant concern.

Domtar stated that based on monthly SO_2 information for the 2011-2013 period, EPA estimated that the SO_2 control efficiency for the scrubber on Power Boiler 2 to be approximately 69%. The scrubber is currently operated based on a pH set point and the use of pH controllers to adjust the amount of caustic scrubbing solution needed to maintain continuous compliance with the permitted SO_2 emission limit of 1.2 lb/MMBTU. Information the Ashdown Mill provided to EPA indicated the existing scrubber may achieve on a short-term basis an SO_2 control efficiency of 90%. However, there is no documentation showing that the scrubber can sustain this maximum performance level on a long term basis.

The Ashdown Mill requests that EPA revise the methodology for calculating the SO_2 BART emission rate to use average SO_2 emissions from the 2001-2003 baseline period as follows:

- Use the average SO_2 emissions in lb/hr from the 2001-2003 BART baseline period
- Assume the existing scrubbers operated at a 69% control efficiency during the baseline period
- Calculate an SO_2 emission limit in lb/hr based on baseline actual emissions and a 90% control efficiency (although the Mill believes it is not appropriate to use a short-term very

high control efficiency for a long-term limit; for purposes of this calculation, the Mill will use EPA's assumed long-term control efficiency of 90%)

Based on this approach, the revised SO_2 limit for Power Boiler 2 is:

- **No. 2 Power Boiler Average SO_2 Emissions**

Baseline Year	Average SO_2 (lb/hr)
2001	557.0
2002	475.0
2003	394.0
Average SO_2 Emission Rate (lb/hr)	475.3

- **Calculating No. 2 Power Boiler BART SO_2 Emission Rate at 90% Control Efficiency**

475.3 lb/hr at about 69% control efficiency or at 30.7% uncontrolled efficiency

$$\frac{475.3 \text{ lb/hr}}{(0.307)} = 1{,}548.21 \text{ lb/hr uncontrolled SO2 emissions}$$

- **SO2 Emission Rate at 90% Control Efficiency**

$$1548.21 \text{ lb/hr} * (1 - 0.9) = 154.8 \text{ lb/hr or } 155 \text{ lb/hr}$$

Domtar stated that in summary, the actual average SO_2 emission rate in lb/hr for the 2001-2003 period is 475.3 lb SO_2/hr. Using EPA's assumption that the SO_2 control efficiency for the scrubber during the baseline period is approximately 69% and using the EPA assumed long-term scrubber removal efficiency of 90% equates to an SO_2 limit of 155 lb /hr. Thus, The Ashdown Mill requests EPA revise the proposed SO_2 limit for Power Boiler 2 from 0.11 lb/MMBTU to 155 lb/hr on a 30-day boiler operating day. As noted above, the Ashdown Mill is requesting a boiler operating day be defined as *a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler*.

Domtar stated that it requests any SO_2 emission limit for No. 2 Power Boiler be expressed on a lb/hr basis. For EPA's proposed limit, the boiler's maximum heat input rating of 820 MMBTU/hr was used to determine the lb/MMBTU limit. The use of the maximum heat input rating is not representative of average (typical) boiler operating conditions, which are lower than the maximum heat input capability. In this situation, the use of actual emission data and maximum rated heat input to calculate the proposed SO_2 BART limit is inappropriate and an inaccurate methodology which creates significant concerns. The actual average heat input during the 2001-2003 baseline period is 586 MMBtu/hr. It is this value that should have been used to calculate a lb/MMBTU limit. However, if EPA expresses the limit on a lb/hr basis as requested, the Mill's concern becomes moot.

With the SO2 limit being expressed on a lb/hr basis, section 52.173(19)(i) needs to be deleted and 52.173(19)(ii) renumbered to 52.173(19)(i) and revised to read as follows:

> NO_X and SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of NO_X or pounds of SO_2. Each boiler operating day of the 30-day rolling average for the power boiler shall be determined by adding together the pounds of NO_X or SO_2 from that day and the preceding 29 boiler operating days and dividing the total pounds of NO_X or SO_2 by the sum of the total number of hours during the same 30 boiler operating day period. The result shall be the 30 boiler operating day rolling average in terms of lb/hr emissions of NO_X or SO_2. If a valid NO_X pounds per hour or SO_2 pounds per hour is not available for any hour for the power boiler, that NO_X pounds per hour or SO_2 pounds per hour shall not be used in the calculation of the 30 boiler operating day rolling average for NO_X or SO_2.

[0152-6] One public hearing commenter also stated that since the regional haze baseline period, the Domtar Ashdown Mill has voluntarily reduced SO2 emissions by more than 40%. The commenter stated that any decisions on emissions reductions should account for the voluntary actions undertaken by Domtar.

Response: We appreciate the commenter's support of our use of 2009-2011 as the baseline period in our BART analysis for Power Boiler No. 1.

With regard to Power Boiler No. 2, we discussed in our proposal that we requested information from the facility to determine if upgrades to the existing scrubbers are technically feasible and if they would be cost effective and provide meaningful visibility benefit. This assessment first required us to determine the current control efficiency of the scrubbers. Because our BART analysis involved determining the current control efficiency of the existing scrubbers, we found that the most reasonable approach was to use data that reflect the current control efficiency of the existing scrubbers, as opposed to 2001-2003 data. In order to conduct our BART analysis, we requested monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur content of each fuel type burned.[348] These were the three most recent full calendar years of data available at the time we conducted our BART analysis. For these reasons, our use of 2011-2013 as the baseline for calculating the current control efficiency of the existing scrubbers and our proposed SO_2 BART limit for Power Boiler No. 2 was appropriate and justified.[349]

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[348] See 80 FR at 18984. See also August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

[349] The commenter notes that the baseline SO_2 emission of 2,078 tpy we used to determine the tons of SO_2 removed for purposes of calculating the cost effectiveness of controls was based on 2001-2003 emissions data. It is unclear if the commenter is suggesting that we should use 2011-2013 data for purposes of calculating the cost effectiveness of our proposed control. We note that we are not revising the cost estimate and calculation of the cost effectiveness of

As discussed in detail in our proposal, based on the emissions data and fuel usage data Domtar provided to us, we estimated that the current control efficiency of the existing scrubbers is approximately 69% based on 2011-2013 data.[350] The data also indicated that the existing scrubbers could achieve up to 90% removal efficiency. As discussed in our proposal, Domtar indicated that the scrubbers are currently operated in a manner that allows for compliance with permitted emission limits.[351] In other words, the facility generally uses only the amount of scrubbing solution needed to comply with permitted emission limits. The information the facility provided indicated that it would be possible to add more scrubbing solution to achieve greater SO_2 removal than required to meet the boiler's existing SO_2 permit limit; specifically, the information indicated that additional scrubbing reagent can be added to increase the control efficiency of the existing scrubbers to 90%.[352]

We agree that we applied the boiler's maximum heat input rating of 820 MMBtu/hr when we calculated our proposed limit of 0.11 lb/MMBtu, and based on information provided by the commenter, we acknowledge that use of the maximum heat input rating is not representative of average (typical) boiler operating conditions. To address the commenter's concern, we are finalizing an SO_2 BART limit for Power Boiler No. 2 in terms of lb/hr. As we discussed in our proposal, based on the emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2011-2013 was 280.9 lb/hr.[353] This annual average SO_2 emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control to this emission rate results in a controlled emission rate of 91.5 lb/hr.[354]

We recognize that the boiler's SO_2 emissions are currently lower than they were in the 2001-2003 period, and that had we used 2001-2003 data to calculate the current control efficiency and SO_2 BART emission limit, as the commenter requests, this would have resulted in a less stringent emission limit. However, as discussed above, the most reasonable approach is to use

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SO_2 controls on Power Boiler No.2 that we presented in our proposal. However, we have examined the effect of using emissions data from 2011-2013 to calculate the cost effectiveness of using additional scrubbing reagent. Based on 2011-2013 emissions data previously provided by Domtar, we estimate that 2011-2013 annual average emissions from Power Boiler No. 2 were 1,228 tpy and that additional scrubbing reagent would cost approximately $2,387/ton removed. Had we used 2011-2013 emissions data to calculate the cost effectiveness, we would still find this control to be cost effective. This exercise appears in the file titled "Domtar PB2_Cost2011-2013."

[350] See 80 FR at 18984. See also the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2—Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[351] 80 FR at 18983 and 18984.

[352] 80 FR 18984.

[353] See 80 FR at 18984. See also the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." Copies of these documents can be found in the docket for our rulemaking.

[354] See 80 FR at 18984. See also the spreadsheet titled "No2 Boiler Monthly Avg SO2 emission rate and calculations." A copy of this spreadsheet can be found in the docket for our rulemaking.

recent data in our calculation of an appropriate SO_2 BART emission limit. As Domtar is requesting an emission limit in terms of lb/hr, we are finalizing for SO_2 BART for Power Boiler No. 2 an emission limit of 91.5 lb/hr on a 30 boiler-operating-day rolling average. We believe this emission limit reflects operation of the scrubbers at 90% control efficiency and addresses the SO_2 BART requirement for Power Boiler No. 2.

We believe it reasonable to set the emission limit using baseline emissions resulting from recent/current fuels. Given that we don't find it appropriate to use emissions from the 2001-2003 period to calculate the SO_2 emission limit, the control efficiency from that period is irrelevant. What is relevant are the current uncontrolled SO_2 emissions and the possible control efficiency of the existing scrubbers, which is what we considered in our BART analysis. We found in our analysis that during the 2011-2013 period, the company was able to achieve an average monthly control efficiency of 90% and find that this level of control is reasonable, and can be achieved by the use of sufficient reagent and scrubber pump upgrades to achieve the lower level. We also note that the commenter did not provide additional information to support the claim that the existing scrubbers cannot consistently achieve the level of control efficiency necessary to meet an emission limit of 91.5 lb/hr on a 30 boiler-operating-day rolling average.

In sum, we disagree that an emission limit of 155 lb/hr on a 30 boiler-operating-day satisfies the SO_2 BART requirement for Power Boiler No. 2. We are finalizing an SO_2 emission limit of 91.5 lb/hr on a 30 boiler-operating-day rolling average.

As requested by the commenter, we are revising the regulatory language at section 52.173 to reflect that we are finalizing an SO_2 emission limit in lb/hr. We also discuss elsewhere in this document that, as requested by Domtar, we are revising the definition in our FIP of "boiler operating day" for the Domtar Ashdown Mill Power Boilers No. 1 and 2.

Comment: EPA's proposed NO_X limits for White Bluff and Independence cannot be achieved based on the plants' current operating conditions. [Entergy Arkansas Inc. (0149) p. 49-52] Entergy stated that the NO_X emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[355] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and

[355] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

Entergy stated that the impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 *(YTD)	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

Entergy stated that this change in dispatch coincided with a sharp drop in natural gas prices (see Entergy's August 7, 2015 comments to EPA, Figure 15, p. 50). This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Entergy stated that this change in dispatch for the units at both White Bluff and Independence is significant with regard to NO_X emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[356] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NO_X emission rates. This memorandum is attached as Exhibit G to Entergy's comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating

[356] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NO_X emissions from the units. Controlled NO_X emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NO_X concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

Entergy stated that this was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

Entergy stated that the concern arises from low-load operation during which periods of higher NO_X emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

Entergy stated that to address the potential for a higher NO_X emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NO_X/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NO_X emission limit for each unit at both White Bluff and Independence as follows:

- For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NO_X/hr, based on a rolling 30-boiler operating day average; and
- For unit operation at 50-100% of capacity, a limit of 0.15 lb NO_X/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

Entergy stated that this alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NO_X emission reductions.

Response: We acknowledge the information provided in the comment and in the attachments referenced by the commenter. We understand Entergy's concerns that because of recent changes in dispatch of the units, White Bluff Units 1 and 2 and Independence Units 1 and 2 are no longer expected to be able to consistently meet our proposed NO_X emission limit of 0.15 lb/MMBtu over a 30-boiler-operating-day period based on LNB/SOFA controls. We believe the commenter has provided sufficient information to substantiate that the units are not expected to be able to meet our proposed NO_X emission limit of 0.15 lb/MMBtu when the units are primarily operated at less than 50% of their operating capacity. In particular, the information provided by the commenter indicates that LNB/SOFA achieves optimal NO_X control when the boiler is operated

from 50 to 100% steam flow because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers.[357] This allows the combustion zone airflow to be sub-stoichiometric and oxygen to be reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing (i.e., converting to NO_X). When a boiler is operated below the 50 to 100% capacity range, NO_X concentrations on a lb/MMBtu basis can be elevated due to the lower heat input rating, even though the pounds of NO_X emitted (i.e., on a mass basis) is less due to the reduced amount of fuel and air. In light of the information provided by the commenter, we believe it is appropriate to promulgate a bifurcated NO_X emission limit for each unit, as suggested by the commenter.

Therefore, in this FIP we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity, as requested by the commenter. Specifically, the 30 boiler-operating-day rolling average is to be calculated for each unit by the following procedure: (1) summing the total pounds of NO_X emitted during the current boiler-operating-day and the preceding 29 boiler-operating-days, including only emissions during hours when the unit was dispatched at 50% or greater of maximum capacity; (2) summing the total heat input in MMBtu to the unit during the current boiler-operating-day and the preceding 29 boiler-operating-days, including only the heat input during hours when the unit was dispatched at 50% or greater of maximum capacity; and (3) dividing the total pounds of NO_X emitted as calculated in step 1 by the total heat input to the unit as calculated in step 2.

In addition to this limit that is intended to control NO_X emissions when the units are operated at 50% or greater of maximum capacity, we are also establishing a limit in lb/hr to control NO_X emissions when the units are operated at less than 50% of maximum capacity. However, the 1,342.5 lb/hr emission limit suggested by the commenter is too high to appropriately control NO_X emissions when the units are operated at low capacities. There is no indication in the comments and attachments submitted by the commenter that the 1,342.5 lb/hr emission limit suggested by the commenter was based on a vendor guarantee. The commenter did not explain how the 1,342.5 lb/hr limit was calculated, but it appears that it was calculated by multiplying the 0.15 lb/MMBtu limit by the maximum heat input rating for each unit (8,950 MMBtu/hr), which yielded 1,342.5 lb/hr. We believe that an emission limit of 1,342.5 lb/hr would be appropriate when the unit is operated at high capacities, considering that the limit was calculated based on the unit's maximum heat input rating. However, such an emission limit would not be sufficiently protective or appropriate when the unit is operated at lower capacities when it is expected that NO_X emissions on a mass basis would be lower compared to operation at high capacity. To address this concern, we have calculated a new emission limit of 671 lb/hr that is based on 50% of the unit's maximum heat input rating, and is applicable only when the unit is being operated at less than 50% of the unit's maximum heat input rating. We calculated this limit by multiplying 0.15 lb/MMBtu by 50% of the maximum heat input rating for each unit (i.e., 50% of 8,950 MMBtu/hr, or 4,475 MMBtu/hr). This limit is on a rolling 3-hour average, where the average is to be calculated by including emissions only from the hours during which the unit was operated at less than 50% of the unit's maximum heat input rating (i.e., hours when the heat

[357] See Exhibit G to Entergy Arkansas Inc.'s comments.

input to the unit is less than 4,475 MMBtu). We are not establishing a lb/hr emission limit that applies when the units are operated at 50% or greater of the unit's maximum heat input rating because there is no need for it since the 0.15 lb/MMBtu limit will address NO_X emission during those operating conditions.

As such, we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity, as requested by the commenter. In addition, we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 671 lb/hr on a rolling 3-hour average that applies only to the hours when the unit is operated at less than 50% of the unit's maximum heat input rating. We believe that these limits address the commenter's concern of not being able to meet the lb/MMBtu emission limit when the unit is being operated at lower capacities, and will also ensure that NO_X emissions are appropriately controlled when the units are operated at higher capacities, as well as when they are operated at lower capacities.

Comment: EPA failed to consider all available control technologies and failed to properly evaluate visibility impacts. [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 28-32] Nucor stated that according to EPA's BART Guidelines, the determination of BART should proceed according to the following five steps:

1. Identify all available retrofit technologies.
2. Eliminate technically infeasible options.
3. Evaluate control effectiveness of remaining control technologies.
4. Evaluate impacts and document the results.
5. Evaluate visibility impacts.

80 Fed.Reg. 18944, 18949 (April 8, 2015). After this analysis is complete, the regulatory agency still must evaluate the factors and select the best alternative. 70 Fed.Reg. 39104, 39170 (July 6, 2005). EPA did not identify or evaluate all available retrofit technologies for White Bluff and Flint Creek. In addition, while EPA may have modeled visibility impacts from the technologies that it did consider, EPA did not adequately evaluate those visibility impacts; for example, EPA did not evaluate the cost of the technology compared to the improvement in visibility as expressed in deciviews (i.e. $/dv).[358]

Nucor state that low sulfur coal has been used as the fuel source for White Bluff, Flint Creek and Independence for many years. When construction of White Bluff was approved by the Arkansas Public Service Commission, it required White Bluff to use low-sulfur coal instead of high sulfur coal.[359] Entergy's five-factor analysis points out that the amount of sulfur in coal is the most

[358] The $/dv calculation is expressly approved in the BART guidelines. 70 Fed.Reg. 39104, 39170 (July 6, 2005).
[359] See Arkansas Public Service Commission Order No. 14, Docket 73-048 U(U- 2488), October 11, 1974, attached hereto as Exhibit 11 to Nucor's comments.

important factor in controlling SO_2 emissions.[360] EPA's own documents in support of the national Regional Haze Rule indicate that use of 0.7% low-sulfur coal reduces SO_2 emissions by over 70%.[361] The U.S. Energy Information Administration states that low-sulfur coal may reduce SO_2 emissions by up to 85%.[362] EPA has approved the use of low-sulfur coal as Best Available Control Technology for purposes of its PSD regulations. In fact EPA has approved the use of low-sulfur coal as BART for a coal-fired power plant even though it determined that Dry Sorbent Injection ("DSI") at a cost of only $991/ton S02 was "cost-effective" for that plant.[363]

Nucor stated that as indicated, White Bluff, Flint Creek and Independence have been using low-sulfur coal for many years. The charts attached as Exhibits 15A and 15B show that White Bluff's average coal sulfur content since 2009 has been in the range of 0.25 – 0.30%; but the BART analyses relied on by EPA did not identify, much less evaluate the use of low-sulfur coal as BART.[364] In addition, although Entergy identified DSI as an available control technology in its BART Five-Factor analysis, that control technology was never evaluated by Entergy nor by EPA, and no explanation was given as to why DSI was not evaluated.[365] DSI also was identified in the Flint Creek BART Five-Factor Analysis as an available control technology, but also was not evaluated.[366] Because low-sulfur coal, DSI and other potential available systems of control were not evaluated, EPA's BART analyses did not satisfy the requirements of the BART guidelines, and thus EPA's Proposed FIP should be withdrawn. North Dakota v. EPA, 730 F.3d 750, 764 (8th Cir. 2013) (EPA BART determination vacated where EPA did not consider all available control technologies).

Nucor stated that EPA also failed to adequately evaluate the visibility impacts of the available retrofit technologies that were identified and evaluated. Although EPA modeled numeric visibility improvements from the control technologies that were evaluated using the CALPUFF model, EPA did not explain how it weighed those visibility impacts. At most, EPA stated for a particular numerical dv improvement that it was "considerable" or "significant," however, EPA did not explain how it balanced those visibility improvements against the other BART factors to determine BART.[367] EPA should explain how it weighed the five BART factors and why it made the BART determinations that it did - as well as its Reasonable Progress determinations - and

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[360] See Exhibit 12 to Nucor's comments, Entergy Revised BART Five-Factor Analysis for White Bluff, dated October 14, 2013, included in this Docket as document 0045, p. 5-1.
[361] See Exhibit 13 to Nucor's comments, Hawes, T., Worksheet from EPA's docket EPA-HQ-OAR-2002-0076, document number 145.
[362] See EIA December 21, 2001 forecast, attached as Exhibit 14 to Nucor's comments.
[363] See EPA's Final BART determination for PPL Corrette, 77 Fed.Reg. 23988, 24031 (April 29, 12012) which approved the use of coal with a 0.3% sulfur content as BART.
[364] EPA admittedly relied on the BART five-factor analyses submitted by Entergy and AEP, rather than performing its own five-factor analysis. See, Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan, p. 13, footnote 13, Docket document No. 0002. Neither the White Bluff nor the Flint Creek five-factor analyses identified or considered low-sulfur coal as an available technology. Even if EPA had already decided to reject low-sulfur coal as BART, that technology should have been identified and evaluated so that the public would be able to provide meaningful comments on EPA's Proposed FIP.
[365] See Exhibit 12 to Nucor's comments, p. 5-2.
[366] See Exhibit 16 to Nucor's comments, AEP BART Five-Factor Analysis for Flint Creek, September 2013, p. 5-1.
[367] EPA failed to evaluate the cost/dv of the various control technologies. Instead EPA appeared to simply determine whether a particular control technology was "cost-effective," and then to choose a particular control technology based only on the incremental cost difference between the control technology choices, irrespective of whether any of the evaluated control technologies was reasonably certain to result in an actual improvement in visibility.

why those costs are reasonable in light any "reasonably certain" visibility benefits, especially given the known shortcomings of the CALPUFF model as discussed elsewhere in Nucor's comments.

Response: We disagree that the CAA or the RH regulations require EPA to consider and evaluate every available retrofit technology in evaluating BART. The CAA requires the following in evaluating BART:

> [I]n determining best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[368]

Section 51.308(e)(1)(ii)(A) requires the following:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Neither the CAA nor the RH regulations require that every single technology available must be considered in the BART analysis. We recognize that the BART Guidelines provide that a BART analysis involves the five basic steps listed by the commenter. The BART Guidelines also provide further clarification as to what is involved in the step of identifying all available retrofit technologies:

> In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology— the list is complete if it includes the maximum level of control each technology is capable of achieving. 40 C.F.R. Part 51, App. Y § (IV)(D).

In addition, the BART Guidelines provide the following:

> If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible

[368] CAA section 169A(g)(2).

> improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. *Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section* (emphasis added).[369]

As noted by the commenter, our FIP proposal did rely on the BART analyses provided by White Bluff and Flint Creek. The BART analyses provided by White Bluff[370] and AEP Flint Creek[371] did identify DSI as an available control option. However, the remainder of each company's analysis focused only on wet FGD and dry FGD. In accordance with the BART Guidelines, Entergy assessed the control effectiveness of each of the technically feasible control options and ranked them according to their effectiveness. DSI was found to be the least effective. Likewise, AEP conducted a similar analysis. DSI, again, was found to be the least effective control option. The companies themselves chose to eliminate DSI as a control option, thus voluntarily committing to "a BART determination that consists of the most stringent controls available," and relieving us of the duty to consider this less stringent control option in our analysis. We noted in our proposal that we concurred with the approach taken by each company as it involved evaluating the most stringent option as well as one other option.[372] Because each company found in their respective BART analysis that SO_2 BART is an emission limit of 0.06 lb/MMBtu consistent with the installation of dry scrubbing technology, there was no need to evaluate DSI, which is a less stringent control option. This is consistent with the CAA, the Regional Haze Rule, and the BART Guidelines.

Additionally, the BART analysis provided by AEP Flint Creek stated that the retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as Flint Creek Unit 1 currently uses a low sulfur fuel and would not achieve significant additional reductions through alternative coal supplies.[373] Similarly, the BART analysis provided by Entergy White Bluff stated that the SO_2 controls evaluated are limited to add-on controls that eliminate SO_2 after it is formed, as Units 1 and 2 currently use a low sulfur fuel and thus would not achieve significant additional reductions through alternative fuel supplies comparable to the most efficient add-on

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[369] 40 C.F.R. Part 51, App. Y, section (IV)(D)(1)(9).
[370] See "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110)," dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this document is found in the docket for our proposed rulemaking.
[371] See "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107)," dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. A copy of this document is found in the docket for our proposed rulemaking.
[372] 80 FR at 18965 and 18970.
[373] See "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107)," at 5-1, dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. A copy of this document is found in the docket for our rulemaking.

controls.[374] Thus, the use of low sulfur coal is reflected in the baseline scenario for these units. Furthermore, while a facility can voluntarily agree to switch to a different type of coal to comply with BART requirements, we cannot dictate to facilities which coal they should burn as a control measure.[375] Therefore, we disagree with the claim that our BART analysis is flawed because it did not evaluate DSI or other less stringent controls such as lower sulfur coal.

We also disagree with the commenter's application of *North Dakota v. EPA,* 730 F.3d 750 to our proposal. The court in that case found that EPA's refusal to consider the *existing pollution control technology* in use at the Coal Creek Station because it had been voluntarily installed, was arbitrary and capricious and our FIP promulgating SNCR as BART for the Coal Creek Station was therefore vacated. The vacatur of our BART determination was not, as the commenter contends, because we did not consider every retrofit control technology available in the BART analysis.

To the extent the commenter suggests that our Arkansas FIP proposal is inconsistent with our Montana FIP action because we did not evaluate low sulfur coal for White Bluff and Flint Creek in the Arkansas FIP proposal, we disagree. The commenter makes the allegation that in our Regional Haze FIP for Montana, we approved the use of low sulfur coal as SO_2 BART for PPL Corette even though DSI was determined to cost \$991/ton SO_2 and found to be cost-effective. This is incorrect. In that action, we stated the following:

> We identified that three flue gas desulfurization (FGD or "scrubbing ') technologies as available control technologies for consideration at Corette. Two of these options, dry sorbent injection (DSI) and semi-dry scrubbing (sometimes referred to as LSD), are dry scrubbing technologies. The third option is a wet scrubbing technology known as limestone forced oxidation (LSFO). We did not consider fuel-switching options as Corette already burns very low-sulfur coal. 77 FR at 24043.

In our Montana RH FIP action we did not evaluate the use of low sulfur coal in the SO_2 BART evaluation for Corette. We evaluated two types of dry scrubbing technologies and a wet scrubbing technology. In that action, we found the average cost-effectiveness of DSI at PPL Corette to be \$3,940/SO_2 ton removed and not, as the commenter contends, \$991/SO_2 ton removed.[376] We also found LSD to have an average cost-effectiveness of \$5,442/SO_2 ton removed and LSFO to have an average cost-effectiveness of \$6,365/SO_2 ton removed.[377] We found that the visibility improvement at the Class I area with the greatest improvement is

[374] See "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110)," at 5-1, dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this document is found in the docket for our rulemaking.

[375] We do note that in this FIP we are making the determination that SO_2 and PM BART for AECC Bailey Unit 1 and AECC McClellan Unit 1 is a limit on the sulfur content of the fuel burned. As the sources currently burn fuel oil with a sulfur content greater than 0.5%, compliance with the BART requirement will likely necessitate switching to fuel oil with lower sulfur content. However, as discussed in our proposal, our SO_2 and PM BART determinations are based on a BART analysis provided by AECC Bailey and McClellan in which the sources voluntarily accepted a limit on the sulfur content of the fuel burned (see 80 FR at 18950).

[376] 77 FR at 24044.

[377] 77 FR at 24045.

expected to be 0.176 dv for DSI, 0.253 dv for LSD, and 0.256 dv for LSFO.[378] We stated in that action that we weighed costs against the anticipated visibility impacts at Corette, but found that the cost of SO_2 controls is not justified by the visibility improvement, and determined that BART for SO_2 is the existing operation at PPL Corette with an emission limit of 0.70 lb/MMBtu.[379] Our BART determination was an emission limit of 0.70 lb/MMBtu, which reflects existing operations. Our BART determination for Corette was not, as the commenter contends, use of low sulfur coal.

In our Arkansas FIP proposal, for both Flint Creek Unit 1 and White Bluff Units 1 and 2 we evaluated a wet scrubbing technology and one type of dry scrubbing technology. We did not evaluate DSI for these units, but as discussed above, we believe that our analyses are still in accordance with the CAA, the RH rule, and our BART Guidelines. We also note that the SO_2 controls we evaluated for Flint Creek Unit 1 and White Bluff Units 1 and 2 were more cost-effective (i.e., lower $/ton removed) and are expected to have greater visibility improvement compared to the SO_2 controls we evaluated for Corette in the Montana FIP proposal, which we ultimately determined were not BART. For example, in our Arkansas FIP proposal we found that the average cost-effectiveness of NID at Flint Creek Unit 1 was $3,845/$SO_2$ ton removed, and that the visibility improvement at the Class I area with the greatest improvement is expected to be 0.615 dv.[380] As discussed in our final rule and elsewhere in this document, in light of comments we received during the comment period, we have revised our initial cost estimate for dry scrubbers on White Bluff Units 1 and 2. Based on these revisions, we determined that dry scrubbers are estimated to cost $2,565/$SO_2$ ton removed at Unit 1 and that the visibility improvement at the Class I area with the greatest improvement expected to be 0.813 dv.[381] We also determined that dry scrubbers are estimated to cost $2,421/$SO_2$ ton removed at Unit 2 and the visibility improvement at the Class I area with the greatest improvement is expected to be 0.767 dv.[382]The costs on a dollar per ton removed basis are lower and the projected visibility improvement is higher for the controls we evaluated in our Arkansas FIP compared to the SO_2 controls we evaluated and determined were not BART for Corette in our Montana FIP action. Therefore, we see nothing in our Montana RH FIP that is in contradiction with our Arkansas FIP.

We disagree that we did not explain how we considered the statutory factors in our BART analyses and our reasonable progress analysis. Specifically, the commenter contends that we did not explain how we weighed the visibility improvement of controls versus the cost and the other statutory factors. This is not true. Our FIP proposal discussed in detail how we considered and weighed the statutory factors, and our rationale for determining what control option is BART. In particular, we carefully considered whether the visibility improvement expected from controls warranted the costs in terms of cost-effectiveness. When considering one control option versus the next most stringent option (i.e., wet scrubbers vs. dry scrubbers), we also carefully considered whether the additional visibility improvement of the more stringent option warranted the additional cost. To the extent the commenter is alleging that we did not explain how we weighed the visibility improvement versus the cost because we did not calculate and consider the

[378] 77 FR at 24046.
[379] 77 FR at 24047.
[380] 80 FR at 18966.
[381] 80 FR 18972.
[382] 80 FR 18972.

cost in dollars per deciview improvement ($/dv) in our FIP proposal, we disagree that we are required to do this and address this comment elsewhere in this document.

With regard to the comment claiming that there is uncertainty in the CALPUFF model and therefore no reasonable certainty in the visibility improvement of controls, we address this issue elsewhere in this document.

Comment: EPA's proposed FIP did not evaluate the maximum degree of SO_2 emissions reduction achievable with a NID scrubber. [Sierra Club et. al. (0171) p. 13-14] Sierra Club et. al. stated that while they support EPA's proposed SO_2 BART determination for Flint Creek Unit 1 as the minimum that BART requires for this plant, a NID scrubber can easily achieve an emission rate of 0.04 lbs/MMBtu. We urge EPA to conclude that SO_2 BART at Flint Creek requires an emission limit of 0.04 lb/MMBtu based on the use of a scrubber.

Sierra Club et. al stated that under the CAA and applicable regulations, to determine BART, EPA must evaluate the highest control efficiency achievable by a particular technology. 42 U.S.C. § 7491(b)(2)(A) (requiring "*best* available retrofit technology") (emphasis added); 40 C.F.R. Part 51, Appendix Y ("in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving"); *see* 76 Fed. Reg. 64,186, 64,202 (Oct. 17, 2011) ("in identifying all options, you must identify the most stringent option (*i.e.*, maximum level of control each technology is capable of achieving) as well a reasonable set of options for analysis."); *see also* 64 Fed. Reg. 35,714, 35,740 (July 1, 1999) ("In establishing source specific BART emission limits, the State should identify the maximum level of emission reduction that has been achieved in other recent retrofits at existing sources in the source category."). As demonstrated in the attached Stamper Report, AEP's analysis (relied on by EPA) fails to consider the highest control efficiency of a NID scrubber. Several sources of information demonstrate that EPA has not based its BART determination on the highest control efficiency for this technology, including: industry experience and vendor guarantees that indicate that NID scrubbers can achieve lower emission limits than .06 lb/MMBtu; AEP's own discussions with vendors and its representations to the Arkansas Public Service Commission ("APSC"); and flaws in AEP's calculations of baseline SO_2 emissions that distort the achievable emission limit of this technology.

First, actual performance and vendor guarantees indicated that a NID scrubber can achieve a control efficiency of greater than 95%. Stamper Report at 8-9. Flint Creek could achieve a 0.04 lb/MMBtu limit, which reflects 91% control from recent 30-day average SO2 emission rates at Flint Creek and 94.8% SO2 removal from the maximum annual average SO2 rate that occurred during 2001. *Id.* at 13. According to EPA, AEP's "discussions with vendors" indicated an outlet achievable SO_2 emission rate of 0.06 lb/MMBtu with NID technology, which reflects 92% SO_2 removal from 0.75 lb/MMBtu, the baseline emission rate assumed by AEP. *See* 80 Fed. Reg. at 18,965. This statement is belied by data from other EGUs. For example, Sargent & Lundy reports that vendors have guaranteed an emission limit of 0.04 lb/MMBtu limit for circulating dry scrubbers, such as a NID scrubber. *Id.* at 9. Thus, a circulating dry scrubber such as a NID system at Flint Creek could readily achieve a 0.04 lb/MMBtu SO2 limit. *Id.* at 6-9.

Second, a lower limit is supported by the fact that AEP represented to the APSC that NID technology can attain 98% removal:

> [NID technology] can attain higher levels of SO_2 reduction, with vendor guarantee removal rates of 98% compared to maximum removal rates of 95% for [spray dryer absorbers] and other [dry FGD] technologies....The [dry FGD] system that is proposed for installation at Flint Creek will remove 95% of the SO_2 in the flue gas to meet anticipated emission limits for the design basis fuel.[383]

Moreover, AEP's assumed SO_2 emission limit is inconsistent with its vendor's guarantee that the NID scrubber would meet a limit of 0.055 lb/MMBtu. Stamper Report at 8. Since such a guarantee is likely based on a short-term stack test, rather than a 30-day rolling average, the technology could likely achieve a lower limit over a longer-term period. *Id.*

Finally, flaws in calculating baseline SO_2 emissions distort the achievable emission limit of this technology. AEP assumed an uncontrolled emission rate of 0.75 lb/MMBtu using data likely from 2001 to 2003. *See* Stamper Report at 8 (noting that AEP likely used 2001-2003 as the baseline period). But the maximum 30-day average SO_2 limit from January 2012 to December 2014 has been much lower: 0.48 lb/MMBtu. *Id.* EPA should use this more-recent data, presumably reflective of the use of a lower sulfur coal, in assessing the control efficiency of this technology as the more-recent data better reflects anticipated Flint Creek SO_2 emissions. *See* 40 C.F.R. Part 51, App. Y, § IV.D.4.c. Using this revised baseline, a NID scrubber at Flint Creek would have to achieve a 91% removal efficiency to meet an emission limit of 0.04 lb/MMBtu. Stamper Report at 9. Installation of NID technology at Flint Creek could easily achieve such removal efficiency. Accordingly, EPA should revise its Flint Creek BART analysis to include an emission limit of 0.04 lb/MMBtu based on installation of a NID scrubber.

Response: We agree with the commenter that the Regional Haze rule requires that in establishing source specific BART emission limits, the State (or EPA in a FIP) should identify the maximum level of emission reduction that has been achieved in other recent retrofits at existing sources in the source category.[384] The BART Guidelines also provide that in analyzing the control technology available, the most stringent control level that the technology is capable of achieving should be considered.[385]

We acknowledge the information provided in the comment as well as in the referenced attachments regarding the level of control efficiency that has been demonstrated and guaranteed by vendors for NID installation at other EGUs. We acknowledge that the lowest SO_2 emission guarantees for a NID system are 0.04 lb/MMBtu. The comment cites to proposed NIDs at Homer City 1 & 2 (2016), Indian River Unit 4 (2011), Brayton Point Unit 3 (2013), and (Clay) Boswell

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[383] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Service Commission, Docket 12-008-U, at 22 (Ex. 11 to Stamper Report).
[384] 64 FR at 35740.
[385] 40 C.F.R. Part 51, App. Y § (IV)(D)(3)(3).

Unit 4 (2016). We researched each one of these facilities and learned that only Indian River Unit 4 and Brayton Point Unit 3 are currently operating. We downloaded the SO_2 CEMS data for these two facilities from CAMD, computed 30-day BOD averages, achieved SO_2 control efficiencies, and determined the maximum 30-day BODs. This analysis is present in our final docket.[386] Neither of these units is performing at a level of 98% SO_2 control or 0.04 lb/MMBtu.

Indian River Unit 4 has achieved only 86% SO_2 removal based on a design level of 96%, rather than 98%.[387] The maximum 30-day BOD is 0.94 lb/MMBtu and the lowest 30-day BOD, representing its best performance, is 0.07 lb/MMBtu. Brayton Point Unit 3 has achieved 94% SO_2 removal and the maximum 30-day BOD is 0.16 lb/MMBtu. Brayton Point Unit 3 is scheduled for shutdown in 2017.[388] Thus, the limited available SO_2 CEMs data for these two NIDs indicate that they are not yet achieving the theoretical 98% level of control.

The other NIDs cited in this comment are "polishing" scrubbers on circulating fluidized bed boilers, which are not similar boiler types. As explained by the Guidance, *similar* sources with the control technology already in place should be used to evaluate what level of control can be achieved at the source. Further, Flint Creek Unit 1 burns low sulfur western coal, and none of the units cited by the commenter burn this type of coal. Seward burns high sulfur waste coal; Gilbert Unit 3 burns high sulfur bituminous coal; and Spurlock Unit 4 burns high sulfur bituminous coal and switchgrass.[389] The Guidance provides us with the discretion to consider "special circumstances pertinent to the specific source under review." In this case, we must consider the different coals being utilized by each respective unit in determining what emission limit is achievable. As the coal used in the units mentioned by the commenter differs from the coal used in the unit at Flint Creek, it would be inequitable to compare these units.

We agree that, in some cases, NID systems may be capable of achieving a lower emission rate than that assumed in the AEP Flint Creek analysis. However, when the sulfur content of the coal is low, a lower control efficiency is anticipated. Due to the low sulfur content of the coal burned at Flint Creek Unit 1, it is uncertain whether the high control efficiencies cited by the commenter could be achieved. There is no information available to us demonstrating that NID installation at Flint Creek Unit 1 can consistently achieve an emission level of 0.04 lb/MMBtu. As noted by the commenter, the vendor's performance guarantee for NID installation at Flint Creek Unit 1 is an average emission rate of less than or equal to 0.055 lb/MMBtu. The commenter is correct that only one page from the Alstom proposal that includes the vendor's performance guarantee was included in the docket because this is what was provided to us by AEP. However, based on discussions with AEP, the vendor's performance guarantee was based on a 30-day rolling average. As such, the BART analysis provided by AEP Flint Creek states that discussions with vendors have indicated that an outlet emission rate of 0.06 lb/MMBtu at Flint Creek will be

[386] See "Selected NID BOD SO_2 Averages.xlsx," found in the docket for our rulemaking.
[387] Burns & McDonnell, Indian River Unit 4, http://www.burnsmcd.com/Resource_/Project/1302/ProjectPdf/Indian-River-Unit-4.pdf.
[388] Dorothy Davis Ballard, Brayton Point Coal-Fired Power Plant Confirmed for Shut Dow by 2017, Power, January 29, 2014, http://www.pennenergy.com/articles/pennenergy/2014/01/brayton-point-coal-fired-power-plant-confirmed-for-shut-down-by-2017.html.
[389] http://www.ekpc.coop/pressreleases/2009%20press%20releases/2009-04-01_Spurlock4_commercial_start.pdf

achievable with the NID technology evaluated,[390] and the company's BART analysis assumed this emission rate. Since BART emission limits, which apply at all times (including during startup and shutdown), must allow an adequate margin for compliance, we believe that it is appropriate for the BART analysis to assume an SO_2 emission rate of 0.06 lb/MMBtu for NID. There is no information available to us to substantiate that an emission rate of 0.04 lb/MMBtu can be consistently achieved at Flint Creek Unit 1. Therefore, we continue to believe that an emission limit of 0.06 lb/MMBtu on a 30-boiler operating-day rolling average is reasonable for NID at Flint Creek Unit 1.

Regarding the testimony presented by AEP to the Arkansas Public Service Commission indicating that NID can attain 98% removal of SO_2 emissions, AEP communicated to us that the testimony before the Arkansas Public Service Commission discusses the maximum design capability based on the "design basis fuel" (i.e., potential emissions) whereas the BART analysis is based on the actual average baseline emission rate and projected unit performance.[391] AEP also explained that the outlet emission rate evaluated in the BART analysis was based on the vendor's performance guarantee, which was quoted as an outlet rate (i.e., 0.06 lb/MMBtu) rather than a percent control efficiency.[392] For all the reasons discussed above, even if we were to revise the baseline to be 2012-2014 instead of 2001-2003, as the commenter suggests, we still do not know with certainty whether NID installation on Flint Creek Unit 1 would be able to consistently achieve an emission level of 0.04 lb/MMBtu. We continue to believe that an emission limit of 0.06 lb/MMBtu on a 30-boiler operating-day rolling average is reasonable and appropriate for NID at Flint Creek Unit 1.

Comment: EPA's proposal did not evaluate the maximum degree of emissions reductions achievable with NO_X controls at AEP Flint Creek Unit 1. [Sierra Club et. al. (0171) p. 15-16] Sierra Club et. al. stated that EPA proposes that NO_X BART for Flint Creek Unit 1 is an emission limitation based on the installation of LNB/OFA. Such controls would cost-effectively achieve some emissions reductions and, as such, represent the minimum that EPA must require, as shown by EPA and confirmed by the Stamper Report. LNB/OFA does not, however, represent "the application of the *best* system of continuous emission reduction" as required by BART. Instead, as Ms. Stamper's report shows, SCR is a cost-effective control that fully satisfies all of the BART requirements. The Stamper Report discusses several ways in which EPA and AEP underestimated the removal efficiency of SNCRs and SCRs and thus underestimated the cost effectiveness of these technologies. Stamper Report at 15-27. Ms. Stamper's analysis shows that these controls are even more efficient at NO_X removal than EPA assumed because: EPA failed to appropriately consider a control scenario that included SCR or SNCR with LNB/OFA; SCR can achieve a greater than 90% control efficiency; SCR can achieve much higher removal efficiency in practice; and AEP's vendor guarantees are inconsistent with EPA's assumed removal rates.

[390] "BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107)," dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. A copy of the BART analysis is found in the docket for our proposed rulemaking.
[391] See document titled "March 4, 2013 email from AEP," found in the docket for our proposed rulemaking.
[392] Id.

AEP underestimated the cost-effectiveness of LNB/OFA plus SCR because AEP underestimated the NO_X reductions achievable by these technologies. AEP analyzed SCR control efficiency alone (without LNB/OFA) to meet a NO_X limit of 0.07 lb/MMBtu. This reflects 77% NO_X removal efficiency from AEP's assumed 0.31 lb/MMBtu baseline NO_X emission rate. The assumed 0.07 lb/MMBtu NO_X emission limit does not reflect the maximum degree of NO_X reduction achievable with this technology. Stamper Report at 16.

First, EPA's analysis for both SCR and SNCR should have begun with the assumed NO_X control rate achieved by LNB/OFA of .23 lb/MMBtu. Stamper Report at 15, 23. AEP could install SCR or SNCR concurrently with LNB/OFA and the combination of these controls improves their cost effectiveness. AEP's analysis of SNCR and SCR must be revised to account for the control rate achieved by LNB/OFA.

Second, AEP's analysis, which EPA relied on, fails to account for the maximum control efficiency achievable by SCR. SCR is routinely designed to achieve greater than 90% control and all major SCR catalyst vendors can guarantee at least 90% efficiency for SCRs burning coals with a wide range of properties, including from low sulfur Powder River Basin ("PRB") subbituminous coal. Stamper Report at 16-19. Further, permitting agencies have required lower NO_X limits than the 0.07 lb/MMBtu based on operation of SCR. For example, the Plant Washington PSD permit requires a 0.05 lb/MMBtu on a 30-day rolling average basis, while the PSD permit for the Desert Rock power plant requires a 0.05 lb/MMBtu limit over a rolling 365-day period during a 60-month "Optimization Period." *Id.* at 19. In the New Mexico regional haze FIP, EPA determined that SCR was the "most cost-effective pollution control" and imposed a NO_X BART emission limit of 0.05 lb/MMBtu on a 30 boiler-operating-day average basis for the San Juan Generating Station. *Id.* at 19.

Third, in practice, many other EGUs with SCRs have achieved emission rates of 0.05 lb/MMBtu or lower. In its response to comments document for its NO_X BART finding for the San Juan Generating Station, EPA found significant support in actual emissions data to support its finding that a 0.05 lb/MMBtu NO_X limit was achievable on a 30-boiler operating day average basis, including a study that identified 25 units that are achieving NO_X emission rates lower than 0.05 lb/MMBtu on an hourly basis. *Id.* Ms. Stamper's report cites several plants that have achieved rate lower than 0.05 lb/MMBtu: Seminole Units 1 and 2 (achieving 0.04 lb/MMBtu), Morgantown Units 1 and 2 (achieving 0.043 to 0.054 lb/MMBtu), Trimble Unit 1 (achieving 0.032 lb/MMBtu), Cope Generating Station (achieving 0.032 lb/MMBtu), as well as the Mountaineer plant, Cliffside Unit 5, Havana Unit 9, Parish Unit 7, and Parish Unit 8. *Id.* at 20-21.

Thus, AEP's evaluation of SCR to meet an emission rate of 0.07 lb/MMBtu at Flint Creek, which reflects only 77% NO_X removal across the SCR system, is inconsistent with the higher levels of NO_X removal guaranteed by vendors, required by permits, and achieved in practice in the industry. SCR plus LNB/OFA should be able to readily achieve a 0.04 lb/MMBtu emission limit on a 30-day average basis at Flint Creek. This reflects an 87% removal efficiency from 2001-2003 maximum 30-day average rates, and it represents 83% NO_X control from the 0.23 lb/MMBtu emission rate expected with the LNB/OFA. *Id.* at 23.

Response: We disagree with Sierra Club's position that BART controls must be selected solely based on which are the "best system of control." This viewpoint disregards the fact that the regulations require that the State, and the EPA in the case of a FIP, consider the following five factors in determining what controls are appropriate: cost, energy and nonair quality environmental impacts, pollution controls in use at the source, remaining useful life, and visibility improvement.[393] The "*best* system of continuous emission reduction" can only be determined once these factors are considered.

Sierra Club and Ms. Stamper also state that AEP overestimated the cost of SNCR and SCR because the analysis should have begun with the assumed NO_X control rate of 0.23 lb/MMBtu, achieved by the first-in-line LNB/OFA controls, which would result in a lesser loading to the SNCR and SCR systems and reduce their operating costs. Instead, the analysis for SNCR was based on a reduction from 0.31 lb/MMBtu to 0.2 lb/MMBtu and the analysis for SCR was based on a reduction from 0.31 lb/MMBtu to 0.07 lb/MMBtu. We agree with the Sierra Club and Ms. Stamper on this point. For SNCR controls on Flint Creek, we have corrected this error. As discussed in the section of this document where we discuss cost issues, we have also corrected the error in AEP SWEPCO's assumed 20 year equipment life for SNCR. The following table provides AEP SWEPCO's SNCR cost analysis with another column added to include these corrections:

Parameters/Costs	**Equation**	**AEP SWEPCO**	**EPA**
Boiler design capacity, mmBtu/hr (Q_B)	Q_B	6324	6324
Total operating time (t_{op}, hrs/yr)	$t_{op} = CF_{total} \times 8760$ hrs/yr	7752	7752
Total Capacity Factor (CF_{total})	$CF_{total} = CF_{plant} \times CF_{SNCR}$	0.92	0.92
Plant Capacity Factor (CF_{plant})[2]		0.92	0.92
SNCR Capacity Factor (CF_{SCNR})[3]	$CF_{SNCR} = t_{SNCR}/365$	1	1
Assumed NOx removal efficiency (η_{NOx})[4]		35%	**13.04%**
Uncontrolled NOx rate (NOx_{in}, lb/MMBtu)[5]		0.33	**0.23**
Electricity Cost ($Cost_{elect}$, \$/kwh)[6]		\$0.05	\$0.05
Water Cost ($Cost_{water}$, \$/gal)[7]		\$0.00362	\$0.00362
Coal Cost ($Cost_{coal}$, \$/MMBtu)[8]		\$2.50	\$2.50
Coal HHV (Btu/lb)[9]		9,000	9,000
Cost of Ash Disposal (C_{ash}, \$/ton)[10]		\$9.0	\$9.0
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	0.0944	**0.0806**
	a. Equipment CRF, 20-yr life, 7% interest		
Cost Index[11]			
a. 2011 Cost Index	585		
b. 1998 Cost Index	389.5		

[393] Summarized from Section 51.308(e)(1)(ii)(A).

Capital Costs			
Direct Capital Cost (A)	DC ($) = ($950/MMBtu) × Q_B × ((2375 MMBtu/hr/Q_B)^0.577) × (0.66 + 0.85η_{NOx}) × (CI_{2011}/CI_{1998})	$5,007,199	$4,031,069
Indirect Installation Costs ($)			
General Facilities	0.05 × A	$250,360	$201,553
Engineering and Home Office Fees	0.10 × A	$500,720	$403,107
Process Contingency	0.05 × A	$250,360	$201,553
Total Indirect Installation Costs (B)	= General Facilities Cost + Engineering and Home Office Fees + Process Contingency	$1,001,440	$806,214
Other Installation Costs ($)			
Project Contingency (C)	C = 0.15 × (A + B)	$901,296	$725,592.50
Total Plant Cost (D)	D = A + B + C	$6,909,934	$5,562,876
Allowance for Funds During Construction (E)	E = 0 (Assumed for SNCR)	$0	$0
Royalty Allowance (F)	F = 0 (Assumed for SNCR)	$0	$0
Preproduction Cost (G)	G = 0.02 × (D + E)	$138,199	$111,258
Inventory Capital (H)[12]	H = $Vol_{reagent}$ (gal) × $Cost_{reagent}$ ($/gal)	$76,102	$8,957
$Cost_{reag}$, 50% Urea solution ($/gal)[13]		1.54	1.54
Volume of Reagent Tank ($Vol_{reagent}$ (gal))	$Vol_{reagent}$ (gal) = q_{sol} x days of reagent supply × 24 hr/day	49,417	5,817
Urea solution volumetric flow rate (q_{sol}, gal/hr)[14]	q_{sol} = (m_{sol} x 7.481 gal/ft^3)/$\rho_{reagent}$	147.07	17.31
Mass flow rate of urea solution (m_{sol}, lb/hr)[15]	m_{sol} = $m_{reagent}/C_{ureasol}$	1,395.84	164.30
Mass flow rate of reagent ($m_{reagent}$, lb/hr)[16]	$m_{reagent}$ = (NOx_{in} x Q_B x η_{NOx} × NSR x $M_{reagent}$)/(M_{NOx} x SR_T)	697.92	82.15
Normalized Stoichiometric Ratio (NSR)	NSR = ([2 × NOx_{in} + 0.7] × η_{NOx})/NOx_{in}	1.43	0.66
Initial Catalyst and Chemicals (I)	I = 0 (Assumed for SNCR due to no catalyst)	$0	$0
Total Capital Investment (TCI) (Capital Cost)	**TCI = D + E + F + G + H + I**	**$7,124,235**	**$5,683,091**
Annual Costs ($)			
Annual Maintenance Cost (J)	J = 0.015 × TCI	$106,864	$85,246
Annual Reagent Cost (K)	K = q_{sol} × $Cost_{reag}$ × t_{op}	$1,755,781	$206,662
Annual Electricity Cost (L)	L = P × $Cost_{elect}$ × t_{op}	$58,064	$18,344
Power (P, kW)	P = (0.47 × NOx_{in} × NSR × Q_B)/9.5	149.80	47.33
Annual Water Cost (M)	M = q_{water} × $Cost_{water}$ × t_{op}	$18,775	$2,210
Water flowrate for SNCR system (q_{water}, gal/hr)[17]	q_{water} = (m_{sol}/ρ_{water}) × [($C_{ureasolstored}/C_{ureasolinj}$) - 1]	669.06	78.75
Annual ΔCoal Cost (N)	N = ΔCoal × $Cost_{coal}$ × t_{op}	$109,558	$12,895
Additional coal required (ΔCoal, MMBtu/hr)[18]	ΔCoal = (Hv × $m_{reagent}$ × [(1/$C_{ureasolinj}$) - 1])/10^6 Btu/MMBtu	5.65	0.67
Annual ΔAsh Cost (O)	O = (ΔAsh × $Cost_{ash}$ × t_{op})/2000 lb/ton	$1,643	$193
Additional ash generated (ΔAsh , lb/hr)[19]	ΔAsh = (ΔCoal × ashproduct × 10^6 Btu/MMBtu)/HHV	47.11	5.54
Direct Annual Costs (DAC)/Variable O&M	**DAC = J + K + L + M + N + O**	**$2,050,684**	**$325,551**

Indirect Annual Costs (IDAC)/Annualized Capital Cost	**IDAC = CFR × TCI**	**$672,477**	**$457,980**
Total Annualized Costs (TAC)	**TAC = DAC + IDAC**	**$2,723,162**	**$783,531**

TAC = DAC + IDAC **$2,723,162**

Note in the above table, we have added another column with our corrections to (1) the assumed NO_X removal efficiency (ηNO_X), (2) the uncontrolled NO_X rate (NOxin, lb/MMBtu), and (3) a recalculation of the capital recovery factor (CRF), corresponding to a 30 year life. The resulting annualized cost drops from $2,723,162 to $783,531.

We have also recalculated AEP SWEPCO's cost-effectiveness calculation.[394] Below is AEP SWEPCO's cost-effectiveness calculation as presented in its BART analysis,[395] along with our corrections. The first table is AEP SWEPCO's cost-effectiveness calculation. In the second table, we make corrections to errors in both AEP SWEPCO's summing of the total annual costs, and in the tons reduced calculations. In the third table, we carry those corrections forward, and incorporate the corrections to the SNCR cost analysis we discuss above.

[394] See the file, AR020-0037-02_Consolidated_Spreadsheet_2013-09-09-EPA.xlsx.
[395] Bart Five Factor Analysis, Flint Creek Power Plant, September 2013, Version 4. Table 6-3.

AEP SWEPCO

Control Technology	Baseline NOX Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOX tpy)	Annual Emissions Reductions (NOX tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	4,294.65	825.62	$16,000,000	$1,289,382	$240,000	$132,364	$1,454,621	$1,762	-
LNB/OFA/SNCR	5,120.27	0.20	3,771.82	1,348.45	$16,000,147	$1,398,940	$240,000	$133,033	$4,177,782	$3,098	$5,209

AEP SWEPCO (tons reduced and total annl cost corrected)

Control Technology	Baseline NOX Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOX tpy)	Annual Emissions Reductions (NOX tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	3,798.91	1,321.36	$16,000,000	$1,289,382	$240,000	$132,364	$1,661,746	$437	-
LNB/OFA/SNCR	5,120.27	0.20	3,303.40	1,816.87	$23,124,235	$1,961,859	$240,000	$2,183,048	$4,384,908	$2,413	$5,496

EPA (tons reduced, total annl costs, control level and control efficiency corrected)

Control Technology	Baseline NOX Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOX tpy)	Annual Emissions Reductions (NOX tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	3,798.91	1,321.36	$16,000,000	$1,289,382	$240,000	$132,364	$1,661,746	$1,258	-
LNB/OFA/SNCR	5,120.27	0.20	3,303.40	1,816.87	$21,683,091	$1,747,362	$240,000	$457,915	$2,445,277	$1,346	$1,581

As can be seen from the third table above, we calculate that SNCR + LNB/OFA has a revised cost-effectiveness of $1,346/ton, as opposed to cost effectiveness of $1,258/ton for LNB/OFA alone. Also, we calculated that the incremental cost effectiveness of SNCR + LNB/OFA over LNB/OFA alone is $1,581/ton. We re-apply the BART five factors, with emphasis on cost and visibility improvement. We conclude that despite the improvement in the cost-effectiveness of SNCR + LNB/OFA over LNB/OFA alone, the resulting relatively small visibility improvement is not worth the cost.

As for SCR, we note Ms. Stamper's separate SCR cost analysis, which we address in the cost section of this document. In Ms. Stamper's SCR cost analysis, she assumes a NO_X control level of 0.04 lbs/MMBtu, using the IPM SCR cost algorithms. Ms. Stamper makes a case that because her resulting $/ton figures are in line with other required SCR installations, the Flint Creek facility should similarly be required to install SCR. First, as we discuss in our response to another comment concerning the White Bluff facility, we do not believe that Ms. Stamper has demonstrated that her assumed level of control has been maintained on a 30 day BOD average at other similar facilities, such that it can be applied to the Flint Creek facility. However, we have reviewed the information Ms. Stamper presents and conclude, as we did in our New Mexico FIP, that it supports a 30 Boiler Operating Day (BOD) NO_X average of 0.05 lbs/MMBtu for a SCR installation at the Flint Creek facility.

Second, as we indicate in Table 44 of our TSD and Ms. Stamper notes in her report, the maximum visibility improvement due to SCR at Flint Creek was 0.245 dv, which occurred at Caney Creek. We further note that AEP SWEPCO's SCR cost analysis is almost completely undocumented. However, due to the relatively low visibility incremental improvement expected from SCR compared to SNCR, cost was not the only factor in our decision making. For instance, if we make reasonable, conservative adjustments to the anticipated visibility benefit, based on a control level of 0.055 lbs/MMBtu rather than the modeled rate of 0.067 lbs/MMBtu[396], we estimate that the resulting visibility improvement at Caney Creek would be no higher than 0.26 dv.[397] Even accepting Ms. Stamper's SCR cost analysis of $3,511/ton (which would be higher were it revised using a controlled NO_X rate of 0.05 lbs/MMBtu), we do not consider the relatively small visibility improvement to be worth the cost of the SCR installation.

Therefore, we are requiring Flint Creek Unit 1 to meet an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average based on LNB/OFA to comply with the NO_X BART requirement.

Comment: EPA's proposal did not evaluate the maximum control level achievable with dry scrubbers at White Bluff Units 1 and 2. [Sierra Club et. al. (0171) p. 21] Sierra Club et. al. stated that EPA proposed that SO_2 BART for White Bluff Units 1 and 2 is an emission limitation

[396] Modeled emission rates were based on a maximum heat input of 6324 MMBtu/hr multiplied by the anticipated control rate (e.g. 0.067 lb/MMBtu) Baseline emissions determined from 2001-2003 CAMD data were 1945 lb/hr, approximately 0.308 lb/MMbtu.

[397] Modeled visibility benefit at CACR over baseline from SCR at 0.067 lb/MMbtu was 0.245 dv. SCR at 0.055 lb/MMBtu would result in an additional reduction in emissions from baseline of only 4%. Assuming a linear relationship between emission and visibility impacts, this would also result in an increase in visibility benefit of only 4%.

of 0.06 lb/MMBtu on a 30-day rolling average based on the operation of a dry scrubber or another technology. 80 Fed. Reg. at 18,972-73. Entergy's SO_2 BART analysis for White Bluff evaluated the control efficiencies of wet and dry scrubbers. Entergy did not consider a NID technology dry scrubber. As demonstrated in Section I.A.1.b of the Sierra Club's comments, both wet and dry scrubbers (including circulating dry scrubbers such as NID technology) can achieve SO_2 removal levels in the 95-99% range. Entergy should have evaluated a dry scrubber, such as NID scrubber, as an SO2 BART option at White Bluff with an emission limit of 0.04 lb/MMBtu. Such an emission limit is readily achievable with this technology. Ms. Stamper's cost analysis assumes a more-appropriate .04 lb/MMBtu limit for dry scrubbers, including a NID scrubber.

Response: We agree that the Alstom NID circulating dry scrubber is a promising SO_2 control option. However, as we discuss elsewhere in this document, the limited available SO_2 CEMs data for NID system installations indicate that they are not yet achieving the same performance as a conventional wet scrubber (i.e., 0.04 lb/MMBtu) that was evaluated for White Bluff Units 1 and 2. Therefore, we believe it would be reasonable to assume that NID can consistently achieve an SO_2 emission limit of 0.06 lb/MMBtu, but not 0.04 lb/MMBtu. We also believe it was appropriate to evaluate in the BART analysis an emission limit of 0.04 lb/MMBtu for wet FGD and 0.06 lb/MMBtu for semi-dry scrubbers. The BART Guidelines provide the following:

> A possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not our intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, you should use judgment in deciding on those alternatives for which you will conduct the detailed impacts analysis (Step 4 below). For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, you may evaluate only the less costly of these options. You should narrow the scope of the BART analysis in this way only if there is a negligible difference in emissions and energy and non-air quality environmental impacts between control alternatives.[398]

As the BART analysis for White Bluff Units 1 and 2 evaluates semi-dry scrubbers and assumes a control efficiency of 0.06 lb/MMBtu, which is the same level of control we expect can be consistently achieved with NID, we disagree that it is necessary to also evaluate NID for White Bluff Units 1 and 2.

We also note that as NID technology is theoretically capable of achieving the same or better SO_2 control efficiency as the SO_2 controls that we evaluated, White Bluff is free to choose NID or any other technology to satisfy its emission limits. Thus, if the NID is as claimed in this comment — low capital investment and maintenance costs, low power consumption, and high removal of hazardous pollutants for about the same cost— the plant owner may choose to select

[398] 40 C.F.R. Part 51, App. Y § (IV)(D)(2).

the NID to satisfy its emission limits. Thus, including NID in our evaluation would not have changed our proposed SO_2 emission limits. We further address the emissions limit achievable through the use of NID scrubbers elsewhere in this document.

Comment: EPA's proposal did not evaluate the maximum degree of NO_X emissions reductions achievable with LNB/SOFA plus SCR at White Bluff Units 1 and 2. [Sierra Club et. al. (0171) p. 23, 25] Sierra Club et. al. stated that EPA proposed that NO_X BART for White Bluffs Units 1 and 2 is an emission limitation of 0.15 lb/MMBtu based on the installation of LNB and separated overfire air ("SOFA"). 80 Fed. Reg. at 18974. Ms. Stamper's Report shows that when the appropriate degree of emission reductions is evaluated, SCR is BART for White Bluff. Entergy assumed that installation of SCR along with LNB/SOFA at White Bluff Units 1 and 2 could achieve an emission rate of 0.055 lb/MMBtu. Stamper Report at 35. A NO_X limit of 0.055 lb/MMBtu reflects a 63% NO_X removal with SCR, with the LNB/SOFA alone achieving a NO_X limit of 0.15 lb/MMBtu. *Id.* at 40. This assumption (which EPA relied on) unlawfully fails to reflect the maximum degree of NO_X emissions reductions achievable with this control scenario. *See* 42 U.S.C. § 7491(b)(2)(A) (requiring "*best* available retrofit technology") (emphasis added).

As demonstrated in Section I.A.2.a of the Sierra Club et. al.'s comments, SCR systems are routinely designed, with vendor guarantees, to achieve greater than 90% NO_X removal. An emission limit of 0.04 lb/MMBtu at the White Bluff units, which reflects 73% removal from the 0.15 lb/MMBtu NO_X rate achieved with the LNB/SOFA alone, is easily achievable by pairing an SCR with LNB and SOFA. Stamper Report at 39-40.

Entergy's air dispersion modeling (which EPA relied on) underestimated the visibility benefits from LNB/SOFA plus SCR at White Bluff for two reasons. First, Entergy modeled the visibility benefits of LNB/SOFA at an emission limit of 0.15 lb/MMBtu and of LNB/SOFA plus SCR at an emission limit of 0.055 lb/MMBtu. These modeled visibility benefits underestimate the true benefits to visibility because, as noted elsewhere in the Sierra Club et. al.'s comments, Entergy relied on the 2009-2011 NO_X baseline which reflected the period of lowest NO_X emission rates at White Bluff Units 1 and 2. Second, Entergy failed to evaluate LNB/SOFA plus SCR at an emission limit of 0.04 lb/MMBtu, which is readily achievable with these controls. Accordingly, EPA should re-model the visibility benefits of these controls using more appropriate emissions reflective of baseline and post-control emissions.

Response: As we discuss in the section of this document where we discuss cost issues, we have reviewed the information Ms. Stamper presents regarding the level of control that can be achieved with LNB/SOFA + SCR and conclude that it supports a 30 Boiler Operating Day (BOD) NO_X average of 0.05 lbs/MMBtu for a SCR installation at the White Bluff facility. We disagree with Ms. Stamper that it supports a 30 BOD average of 0.04 lbs/MMBtu, as she contends. We see no evidence of an SCR operating at that level for extended periods of time, such that we would feel comfortable that a 30 BOD average of 0.04 lbs/MMBtu would be sustainable at the White Bluff facility absent site-specific engineering information. Although in our proposal we made corrections to Entergy's NO_X BART cost analyses, we did not criticize its choice of a SCR NO_X emission limit of 0.055 lbs/MMBtu. Entergy's SCR NO_X emission rate of

0.055 lbs/MMBtu was based on "permitted emission compliance"[399] which for this type of rate is generally based on 30 day calendar compliance period. Entergy confirms this on page 6-3 of its BART analysis.[400] Our New Mexico FIP decision to which Ms. Stamper cites, is based on a 30 BOD compliance period. As we discuss in our New Mexico FIP, "[Use of a] BOD would ensure that, when an outage occurs, the emissions following startup will be averaged with the emissions data from before the outage, rather than with the period of time during which the unit did not have any emissions at all because it was offline."[401] In other words, a 30 BOD averaging period is in effect less stringent that a straight 30 calendar averaging period because it doesn't overweigh emissions spikes as a 30 calendar day average can do during an extended outage. As a consequence, we considered Entergy's 0.055 lb/MMBtu average to be essentially equivalent to, or potentially more stringent than the 0.05 lb/MMBtu 30 BOD average we required in our New Mexico FIP, which forms the bulk of Ms. Stamper's support. Thus we (1) disagree with Ms. Stamper that SCR for White Bluff should be evaluated on the basis of a NO_X rate of 0.04 lbs/MMBtu, and (2) we believe Entergy's use of a 30 day calendar NO_X rate of 0.055 lb/MMBtu in its evaluation of SCR was reasonable (although as discussed elsewhere, we had other issues with Entergy's White Bluff BART analyses). This renders moot Ms. Stamper's contention that Entergy's air dispersion modeling (which we relied on) underestimated the visibility benefits from LNB/SOFA plus SCR at White Bluff because the analysis is based on an emission limit of 0.055 lb/MMBtu and did not evaluate an emission limit of 0.04 lb/MMBtu.

In critiquing our NO_X BART evaluation, Ms. Stamper also argues that Entergy's 2009-2011 baseline maximum 24-hour NO_X emission rates of 3,001.4 lb/hr for Unit 1 and 3,527.4 lb/hr for Unit 2 were not appropriate for use in the BART analysis because they reflected the period of lowest NO_X emission rates for the units and therefore "underestimate the true benefits to visibility." However, the BART Guidelines do not require that the baseline used in the BART analysis be constructed from the highest emissions from any given year or years, only that, as Ms. Stamper acknowledges, the "baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[402] We believe it was reasonable to select baseline maximum 24-hour NO_X emission rates that reflected the installation of controls and a change in operations after the neural network was installed in 2006, which eliminates from consideration the highest NO_X annual emission average for Unit 1 from the 2001-2003 period. Any additional controls would be implemented in combination with the existing neural network. Therefore one method to consider the existing controls is to consider the use of the neural network as the baseline for visibility assessments for additional NO_X controls

Comment: EPA was not required to consider DSI and low-sulfur coal as control options for White Bluff and Flint Creek because EPA proposed to require the most stringent control and the BART Guidelines do not require analysis of less stringent controls. [Sierra Club et. al. (0171) p. 45-46] Sierra Club et. al. stated that Nucor argues in its comments that EPA erred by failing to evaluate low-sulfur coal and dry sorbent injection ("DSI") as control options in the

[399] See page 8 of Appendix E (the Sargent & Lundy NO_X control cost study for Entergy) to the White Bluff Plant Revised BART Five-Factor Analysis, dated 10/14/13.
[400] Id. "this rate includes consideration of normal fluctuations which may occur over a 30-day compliance period."
[401] 76 FR 52402.
[402] 70 FR 39167.

BART analyses. But where a source proposes the most stringent control as BART, and EPA proposes to require the most stringent control, the BART Guidelines do not require analysis of less stringent controls. Specifically, the BART Guidelines state:

> If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. *Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section.* 40 C.F.R. Part 51, App. Y § (IV)(D)(1)(9) (emphasis added).

Sierra Club stated that here, Entergy submitted a BART analysis for White Bluff Units 1 and 2 that proposes the most stringent SO2 control—a scrubber. *See* Entergy, Revised BART Five Factor Analysis, White Bluff Steam Electric Station at 5-6 (Oct. 2013), EPA Docket ID No. EPA-R06-OAR-2015-0189-0045. EPA has agreed with Entergy and proposed a BART limit for SO2 emissions based on the use of a scrubber. Because the source here, Entergy, proposed, and EPA accepted, "a BART determination that consists of the most stringent controls available," "there is no need to complete the remaining analyses in this section." 40 C.F.R. Part 51, App. Y § (IV)(D)(1)(9). Thus, neither Entergy nor EPA was required to analyze less stringent control options such as low-sulfur coal or DSI.

Sierra Club stated that similarly, AEP has not only committed to installing the most stringent control for SO2 emissions, AEP is already constructing a scrubber at Flint Creek. *See* Stamper Report at 14; *see also* AEP, BART Five Factor Analysis Flint Creek Power Plant at 5-6 (Sept. 2013), EPA Docket ID No. EPA-R06-OAR-2015-0189-0037 (proposing that BART be based on the installation and operation of a NID scrubber). Even if the scrubber is not "already in place," AEP has "commit[ted] to a BART determination that consists of the most stringent controls available," and thus "there is no need to complete the remaining analyses in this section." 40 C.F.R. Part 51, App. Y § (IV)(D)(1)(9). Under the BART Guidelines, EPA was not required to analyze SO2 controls, such as low-sulfur coal and DSI, which are less effective than a scrubber.

Response: We appreciate the commenter's support of our FIP proposal.

4.b. Technical Feasibility of Controls

Comment: Domtar believes that SNCR is a technically infeasible technology for Power Boiler No. 1. [Domtar (0161) p. 8-9] Domtar stated that assuming EPA proceeds with BART for the Ashdown Mill, the Mill conceptually agrees with the proposed NO_X BART limit for Power Boiler 1 of 207.4 lb/hr on a 30-day averaging basis with no add-on control.

The Ashdown Mill agrees with EPA's determination that for Power Boiler 1 the installation of FGR, LNB, Ultra Low NO_X Burners (ULNB), OFA, Methane-de- NO_X and SCR are technically infeasible. EPA's review of SNCR concludes that the technology is feasible but the high costs on a dollar per ton of NO_X removal basis[403] does not justify the purported small visibility improvement ranging from 0.061 dv to 0.136 dv at any single Class 1 area. This level of "improvement," if it even exists, would be imperceptible to the human eye, which cannot detect a change of less than 1.0 dv. Moreover, as discussed in other comments, the purportedly visibility increase is within the margin of error of the CALPUFF mode, and any visibility improvements cannot be reasonably anticipated to occur.

The Ashdown Mill disagrees with EPA's determination that SNCR is a feasible technology for Power Boiler 1. We base our conclusion on a study[404] that was performed for Power Boiler 2 but the results are also applicable to Power Boiler 1. *See* Appendix A to Domtar's comments. Both Power Boiler 1 and Power Boiler 2 provide steam for the pulp and papermaking processes at the Mill. Due to large fluctuations in steam demand inherent in the pulp and paper making operations, the boilers require continuous adjustment of fuel firing rates and excess air levels. These boilers are operated to track steam loads required for the pulp and papermaking processes and are not operated under base load conditions as occurs with utility boilers. The study shows furnace temperature tracking steam demand. Due to the combustion on mainly biomass fuels, the furnace temperature in the area where SNCR nozzles would be installed is usually below the temperature needed for the SNCR reaction to take place. Since optimal furnace temperatures cannot be consistently maintained, the urea injection needed for reducing NO_X emissions will result in excess ammonia being present. This ammonia will combine with chlorides and sulfides in the combustion gas producing increased corrosion on downstream metal and heat surfaces. In addition, it is known that chlorides in the gas stream will combine with excess ammonia to create condensable PM2.5 particles in the flue gas, thereby increasing PM2.5 emissions. With respect to Power Boiler 1, SNCR is not a technically feasible control technology, and its use potentially will result in increased PM2.5 emissions which can further affect visibility.

Response: We appreciate the commenter's support of our proposed NO_X BART emission limit of 207.4 lb/hr for Power Boiler No. 1.

We do not believe the commenter has provided sufficient information to demonstrate that SNCR is a technically infeasible control technology for Power Boiler No. 1. The BART Guidelines provide the following regarding the determination of technical feasibility:

> "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail

[403] SNCR removal costs estimated to be $12,700 per ton of NO_X removed at 20% removal efficiency and $7,640 per ton of NO_X removed at 45% removal efficiency and $7,640 per ton of NO_X removed at 32.5% removal efficiency.
[404] International Applied Engineering, Inc. Observations of Chartered Steam Rates and Furnace Exit Gas Temperature.

> below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.[405]

The NSR permit for the Temple-Inland Kraft Linerboard Mill, located in Orange County Texas, requires that the bark boiler install and operate SNCR to achieve a NO_X emission limit of 0.166 lb/MMBtu based on a 30 day rolling average. Like the Domtar Power Boilers No. 1 and 2, the Temple Inland Kraft boiler exhibits load swing. We also note there are other similarities in the operating parameters of the bark boiler at Temple Inland Kraft and Power Boiler No. 1 at the Domtar Ashdown Mill. For example, similar to Domtar's Power Boiler No. 1, the bark boiler at Temple Inland Kraft is permitted to burn, among other fuel types, bark/wood biomass, natural gas, and tire-derived fuel. The Temple Inland Kraft bark boiler has a maximum heat input rating of 656 MMBtu/hr, which is comparable to the maximum heat input rating of 580 MMBtu/hr for Domtar's Power Boiler No. 1. Therefore, we believe that this type of technology meets the technical feasibility definition under the BART Guidelines for power boilers of this type. But we acknowledge Domtar's concerns that because Power Boiler No. 1 is a high load swing boiler, there is uncertainty as to the level of NO_X control that SNCR can achieve at this boiler on a long-term basis, including whether optimal furnace temperature can be consistently maintained to achieve appreciable NO_X control. Additional information specific to Power Boiler No. 1 would be necessary to support the claim that SNCR operation at this power boiler would not achieve appreciable NO_X emissions reductions on a long-term basis. However, we are finalizing our determination that NO_X BART for Power Boiler No. 1 is an emission limit of 207.4 lb/hr, which is a reflection of the boiler's operation at the baseline emission rate and does not require SNCR installation. Therefore, the uncertainty related to the technical feasibility of SNCR raised by the commenter does not affect our final BART decision.

We address comments related to the CALPUFF margin of error in the modeling section of this document.

Comment: Domtar believes that MdN and SNCR for NO_X control on Power Boiler 2 are not technically feasible. [Domtar (0155) p. 14-15] Domtar stated that it agrees with EPA's determination that MdN for NO_X control is not technically feasible. The Ashdown Mill also agrees with EPA's assessment the installation of SNCR on Power Boiler 2 is not appropriate. EPA concludes it is not appropriate due to the NO_X control efficiency of SNCR. The Ashdown Mill believes the installation and operation of SNCR on Power Boiler 2 is not technically feasible based on the observations in a study conducted on Power Boiler 2 by International Applied Engineering[406] (see Appendix A to Domtar's comments). The study concludes that with the large fluctuations in steam demand inherent in the pulp and paper making operations the boilers require continuous adjustment of fuel firing rates and excess air levels.

[405] 40 C.F.R. Part 51, App. Y § (IV)(D)(2).
[406] International Applied Engineering, Inc. Observations of Chartered Steam Rates and Furnace Exit Temperature.

These boilers are operated to track steam loads required for the pulp and papermaking processes and are not operated under base load conditions. The study shows that Power Boiler 2's furnace temperature tracks steam demand. Due to the combustion of biomass fuels, the furnace temperature in the area where SNCR nozzles would be installed is usually below the temperature needed for the SNCR reaction to take place. Since optimal furnace temperatures cannot be consistently maintained, the urea injection needed for reducing NO_X emissions will either be too much or too little. When too little, NO_X removal will be less than projected; when too much, excess ammonia slip will occur. The excess ammonia will combine with chlorides and sulfides in the combustion gas producing increased corrosion on downstream metal and heat surfaces. In addition, it is known that chlorides in the gas stream will combine with excess ammonia to create condensable PM2.5 particles in the flue gas, thereby increasing PM2.5 emissions. The Ashdown Mill believes the technical studies show that SNCR is not a technically feasible control technology for Power Boiler 2 and potentially will increase PM2.5 emissions.

Response: We appreciate the commenter's support of our position that MdN is a technically infeasible control option for Power Boiler No. 2. While we believe that SNCR may be a technically feasible control technology for similar power boilers, as discussed in our proposal, we believe Domtar provided sufficient information to demonstrate that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis.[407] There is uncertainty as to the actual level of NO_X control that SNCR would be able to achieve on a long term basis at Power Boiler No. 2, but we agree that the information provided by Domtar indicates it is likely to be well below optimal control levels. We are finalizing a BART emission limit consistent with LNB controls.

4.c. Domtar Ashdown Mill Repurposing Project

Comment: [Domtar (0155) p. 3-5] Domtar stated that in late 2014 significant changes to the Domtar Ashdown Mill were announced. The Ashdown Mill is undergoing a major re-purposing project to realign the Mill's manufacturing processes with the changing pulp and paper market. This project takes the Mill in a new direction by converting an existing paper machine that manufactures high quality, value-added paper to a fluff pulp line. The fluff pulp will be used in absorbent personal care products. While the fluff pulp to be produced will be high quality, the profit margin is substantially less than with the production of paper. As such, the economic profile of the re-purposed Mill is important to continued operations.

The re-purposing project will require reconfiguration of the Mill and will affect or require major changes to many of the Mill's systems including the power boilers used to produce steam for the paper machines, the converted fluff pulp equipment and other Mill process systems. Most significantly for purposes of BART involving Power Boiler 1 and Power Boiler 2, this reconfiguring of the Mill and the ultimate product mix is expected to substantially alter steam demand from No. 1 and No. 2 Power Boilers. Once the re-purposing and re-configuration of the Mill systems is complete and fully operational, the final state of Mill operations is anticipated to require changes in steam production from Power Boiler 1 and Power Boiler 2. In addition, the

[407] 80 FR 18986.

Mill is also initiating other projects that will improve process efficiencies and may also affect steam production needs. The machine conversion portion of the re-purposing project is scheduled to start up in the third quarter of 2016. The next phase will be a shakedown period in 2017 where the Mill will obtain a greater understanding of the fluff pulp production process and the Mill's steam needs. Following this shakedown, 2018 will be the first year of full production.

Key to understanding steam demand needs and correspondingly the changes in the use of Power Boilers 1 and 2 is running the boilers through both the shakedown period and first full production year. This schedule allows the Mill to determine the effects of seasonal weather changes (winter conditions) and the inherent variability that occurs when operating (and learning) a new production process. The Mill needs to have sufficient time to re-balance the Mill operations in its newly reconfigured state. For that reason, data from 2017 and 2018, including the winter seasons, is essential for the Mill in making the decision as to whether to continue full or intermittent operation of Power Boilers 1 and 2 and, if so, using what fuels, at what cost, or to retire or mothball one of these units.

Related to the re-purposing of the Mill and future post-project operations are the non-condensable gas ("NCG") and bark feed systems. Currently, NCG gases are incinerated in Power Boiler 2 (as required by other Clean Air Act rules). In addition, both Power Boilers 1 and 2 share a common bark feed system. Changes in steam needs, changes in utilization or retirement of Power Boilers 1 or 2 will affect these interrelated systems. Assuming EPA proceeds in finalizing BART for the Ashdown Mill, a 5-year compliance schedule for achieving the SO2 and NO_X BART requirements for Power Boiler 2 is essential, given the integrated nature of the Mill and the complexities resulting from the re-purposing project.

For BART compliance plan purposes, the first unknown that needs to be resolved (once the project is fully completed and operating during 2017 and 2018) is the Mill's steam needs. Understanding whether Power Boilers 1 and 2 will be required to operate and, if so, whether one or both will fully operate, only need to operate intermittently or not at all is essential. In addition, to determining which boilers will operate and how they will be operated, a decision on fuel mix also will need to be made. The project schedule sets these key decision(s) to be made in late 2018. Once the decision on Mill steam needs and boiler utilization occurs, the BART compliance schedule needs to allow additional time for implementation of the boiler scenario option selected by the Mill. These scenarios could range from the mothballing or retiring Power Boilers 1 or 2 to shifting fuels. In addition, changes involving the NCG gases, an integral part of the kraft pulping process, and the shared biomass feed system also need to be determined, new systems engineered and environmental permits obtained as required.

The Ashdown Mill takes its environmental compliance obligations very seriously. At the same time, the need to expend funds wisely and to structure flexibility into regulatory compliance programs so that the Mill remains a viable entity in the global market is also essential. Both of these elements need to be incorporated into BART requirements and BART compliance schedule for Power Boilers 1 and 2 to balance environmental obligations with the practical management, engineering and financial issues associated with this and the Mill's re-purposing project.

It is against this backdrop that the Domtar Ashdown Mill is offering specific comments regarding the EPA's proposed BART Requirements for Power Boiler 1 and Power Boiler 2 at the Ashdown Mill.

Summary of Key Mill Specific BART Issues:

- 5-year compliance period is essential for Power Boiler 2 SO_2 and NO_X
- Include alternate compliance options that remove BART limits when no longer applicable (*e.g.*, units are fuel switched, retired, etc.)
- Boiler operating day for Power Boiler 1 and Power Boiler 2 should be defined as a Mill operating day
- Express the SO_2 BART limit for Power Boiler 1 in an alternate form of lb/day instead of lb/hr
- Modify the stack testing frequency for demonstrating compliance with the NO_X BART limit for Power Boiler 1 to 5 years
- Adjust the SO_2 BART limit for Power Boiler 2 and express in an alternate form of lb/hr instead of lb/MMBTU
- Adjust the timeline for adopting a FIP to allow ADEQ to develop and obtain approval of a BART SIP for the Mill.

[0152-6] One public hearing commenter noted that in late 2004, Domtar announced a major project that will convert a paper machine at the Ashdown Mill to produce high quality fluff pulp. The project will repurpose some of the mill's assets.

Response: We acknowledge the information presented by the commenter regarding the repurposing project the Domtar Ashdown Mill is currently undergoing and how this may result in changes in steam needs, changes in utilization, or retirement of Power Boilers 1 and 2. We address elsewhere in this document the commenter's detailed comments on each of the key issues listed.

Comment: [Domtar (0161) p. 3-5] Domtar stated that it understands EPA is proposing BART for the Ashdown Mill as part of the FIP process. However, other major aspects of the Mill, including Power Boilers 1 and 2, are regulated by the Arkansas Department of Environmental Quality (ADEQ) under the Arkansas State Implementation Plan (SIP). Dual regulation over Power Boilers 1 and 2 (key components of the Mill) creates a significant regulatory burden. The dynamic, changing nature of the global pulp and paper market requires flexibility in implementing changes at the Ashdown Mill in order to remain competitive. Being required not only to change permit requirements with ADEQ but also potentially modify the Mill-specific FIP rule likely will delay the ability to react quickly to changing market conditions and customer demands and can seriously affect future Mill operations.

Assuming EPA proceeds with BART for the Ashdown Mill, we believe EPA should work with ADEQ to convert EPA's current FIP approval process into an approved ADEQ SIP. Doing so is consistent with cooperative federalism built into the Clean Air Act and will avoid the delays, costs and likely inconsistencies that will result from regulating Power Boilers 1 and 2 by both

Arkansas under the SIP and EPA under the FIP. Also, given the requested compliance schedule and the ongoing conversion project, allowing ADEQ the time to develop a SIP will not adversely affect the Agency's BART timetable for the Ashdown Mill. Finally, information in Arkansas DEQ recently released 5 year Regional Haze Progress Report[408] shows Arkansas as meeting or exceeding its glide path so additional time to develop a SIP will not affect Arkansas' ability to meet its 2018 reasonable progress goals.

Response: As we note in our final rule, the State retains its authority to submit a revised state plan consistent with CAA and Regional Haze Rule requirements. EPA stands ready to work with the State on a SIP revision that would replace some or all elements of the FIP.

To the extent the commenter is requesting that we delay finalizing our FIP such as to allow time for Arkansas to submit a SIP revision before a FIP is promulgated, we do not have the authority to delay finalizing our FIP. The CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator disapproves a state implementation plan submission "unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan." Our partial approval and partial disapproval of the Arkansas RH SIP was published in the Federal Register on March 12, 2012 and the rule became effective on April 11, 2012.[409] Arkansas has not yet submitted a SIP revision following our partial disapproval, and EPA is already past-due on its action per the statutory deadlines. There is no authority in the CAA for EPA to further delay our action for the reasons provided by the commenter. We are operating under a court-ordered deadline to take final action to promulgate a FIP or approve a SIP revision that addresses the deficiencies in the Arkansas RH SIP by August 31, 2016.[410]

We address elsewhere in this document comments related to ADEQ's Five Year Progress Report SIP revision.

We address comments on Domtar's request to extend the compliance date for BART for its affected boilers elsewhere in this document.

Comment: Domtar requests that the final FIP include an alternate compliance option for SO_2 BART for Power Boiler 1 in the event the boiler is converted to natural gas or retired as part of the Domtar Ashdown Mill's re-purposing project. [Domtar (0161) p. 8] Domtar stated that the Ashdown Mill is in the process of re-purposing and is in a state of transition. Once the re-purposing and re-configuration is complete and the Mill is fully operational, the Mill will need to decide if Power Boiler 1 will continue with full or intermittent operation, if so, what fuels will be used or will be retired. If the boiler is fuel switched to natural gas or the boiler retired, the SO_2 BART limit will be unnecessary along with the associated monitoring, recordkeeping and reporting requirements for the SO_2 BART limit. The Ashdown Mill is

[408] State of Arkansas State Implementation Plan Review for the Five-Year Regional Haze Progress Report, Arkansas
Department of Environmental Quality, Air Division Planning Branch, Revised May 2015.
[409] 77 FR 14604.
[410] Sierra Club v. Gina McCarthy, No. 4.14CV00643JLH (ED Ark. Western Div. Nov. 3, 2015).

requesting EPA include in the BART FIP final rule an alternate compliance option that removes all of SO_2 BART related requirements for Power Boiler 1 if this boiler is fuel switched to natural gas or permanently retired.

Domtar stated that if Power Boiler 1 is fuel switched to burn only natural gas, an alternate compliance option needs to be developed to allow compliance to be based on the use of AP-42 emission factors and fuel use records. Requirements for NO_X testing need to be removed. If Power Boiler 1 is retired, there is no need to retain the NO_X BART limit and the associated monitoring, recordkeeping and reporting requirements for the NO_X BART limit. An alternate compliance option should address this retirement scenario as well.

Response: We proposed an SO_2 BART emission limit of 21.0 lb/hr for Power Boiler No. 1. As discussed in our final rule and elsewhere in this document, we are finalizing an emission limit in terms of lb/day, as requested by Domtar in a separate comment. We proposed to find that to demonstrate compliance with its SO_2 BART emission limit, the facility was required to use a site-specific curve equation (provided to us by the facility) to calculate the SO_2 emissions from Power Boiler No. 1 when combusting bark, and to confirm the curve equation using stack testing.[411] We also proposed to find that to calculate the SO_2 emissions from Power Boiler No. 1 when combusting fuel oil, the facility must assume that the SO_2 inlet is equal to the SO_2 being emitted at the stack.[412] In our proposal we invited public comment specifically on the issue of whether our proposed method of demonstrating compliance is appropriate.

We note that we became aware that Power Boiler No. 1 wished to burn only natural gas after the end of the comment period for our proposal, and that the facility has submitted a permit renewal application to ADEQ that will reflect this enforceable change.[413] We do not agree that the SO_2 BART emission limit becomes "unnecessary" when a unit is switched to burn only natural gas. The Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.[414] Therefore, a BART emission limit is still applicable and is required regardless if the unit switches to natural gas.

However, the repurposing project the mill is currently undergoing and the fact that the facility's air permit will be revised such that Power Boiler No. 1 will be permitted to burn only natural gas, which generally results in negligible SO_2 emissions, render it appropriate to provide the facility with flexibility in demonstrating compliance with the SO_2 emission limit. Therefore, in addition to the method we proposed for demonstrating compliance with the SO_2 BART emission limit for Power Boiler No. 1, we are also finalizing one alternative method for demonstrating compliance: the owner or operator may demonstrate compliance with the SO_2 emission limit by switching Power Boiler No. 1 to burn only pipeline quality natural gas. Therefore, if the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, this would satisfy the requirement for demonstrating compliance with the boiler's SO_2 BART emission limit, and the reporting and recordkeeping requirements would be waived.

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[411] 80 FR 18980.
[412] 80 FR 18980.
[413] See file "Record of Meeting_March 10 2016," which can be found in the docket for this rulemaking.
[414] 40 CFR 51.301.

We are revising proposed section 52.173 to reflect this alternative method for demonstrating compliance.

We are finalizing our determination that NO_X BART for Power Boiler No. 1 is an emission limit of 207.4 lb/hr. We proposed that to demonstrate compliance with this NO_X BART emission limit, the facility was required to conduct annual stack testing. In response to a separate comment provided by Domtar, in our final FIP we are requiring stack testing every five years instead of annually to demonstrate compliance with the NO_X BART emission limit. The repurposing project the mill is currently undergoing and the fact that the facility's air permit will be revised such that Power Boiler No. 1 will be permitted to burn only natural gas render it appropriate to provide the facility with flexibility in demonstrating compliance with the NO_X emission limit. Therefore, we are also providing one alternative method for demonstrating compliance with the NO_X emission limit: if the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP-42 emission factors and fuel usage records. Under these circumstances, the facility would not be required to demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 through stack testing. We are revising proposed section 52.173 to reflect this alternative method for demonstrating compliance.

With regard to the request that we include a provision in our FIP that removes all SO_2 and NO_X BART related requirements for Power Boiler 1 if this boiler is permanently retired in the future, we noted above that the Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The BART emission limits and applicable requirements continue to apply regardless if a BART source is mothballed or retired/shut down without being dismantled, decommissioned, and having the air permit revoked. In the event that the BART source is permanently shut down, dismantled, decommissioned, and the permit revoked in the future, the process for removing the BART emission limits and applicable requirements would necessarily involve a request by the company for partial FIP withdrawal or a SIP revision from the State in the event that we have approved a SIP revision that replaces our FIP. We are committed to work with ADEQ and the facility to partially withdraw our FIP with respect to the emission limits for the BART unit or revise the SIP if at some point in the future the company decides to permanently shut down, dismantle, and decommission the boiler and surrender the air permit.

Further, we consider the conditions under which a unit is permanently retired and the mechanism by which this is made enforceable to be critical. Because the company has not decided if and when Power Boiler No. 1 will be permanently retired or decided what the conditions of the retirement will be, we believe that it is reasonable and appropriate to wait until the company makes these decisions instead of including a provision in our FIP that waives the BART recordkeeping requirements in anticipation that the unit's permanent retirement will take place under certain conditions and made enforceable through a particular mechanism that may be different from what ultimately takes place.

Comment: Domtar requests that the final FIP include an alternative compliance option for the SO_2, NO_X, and PM BART limits for Power Boiler 2 in light of the Mill's repurposing project. [Domtar (0155) p. 14, 15, and 17] Domtar stated that if Power Boiler 2 is fuel switched to natural gas or retired as part of the Domtar Ashdown Mill's repurposing project, there is no need to retain the SO_2 and PM BART limits and the associated monitoring, recordkeeping and reporting requirements for the SO_2 and PM BART limits. The Ashdown Mill requests that EPA include in the BART FIP final rule an alternative compliance option which removes the SO_2 and PM BART limits and the associated monitoring, recordkeeping and reporting requirements if the boiler is fuel switched to natural gas or permanently retired.

Additionally, if Power Boiler 2 is fuel switched to natural gas as part of the Domtar Ashdown Mill's repurposing project, the NO_X BART requirements need to be modified to require compliance based on the use of AP42 emission factors and fuel use records. The requirement to operate and maintain a NO_X CEM needs to be removed. If Power Boiler 2 is retired, the NO_X BART requirements are unnecessary. The Ashdown Mill requests EPA include alternate compliance options in the BART FIP final rule provisions to address these potential scenarios.

Response: As discussed in our final rule and elsewhere in this document, we are finalizing an SO_2 BART emission limit of 91.5 lb/hr and we are finalizing our determination that compliance with the Boiler MACT PM standard as revised satisfies the PM BART requirement for Power Boiler No. 2. We proposed to require the facility to demonstrate compliance with the SO_2 emission limit for Power Boiler No. 2 using the existing CEMS, and to demonstrate compliance with the PM emission limit using the same method that is used for demonstrating compliance with the Boiler MACT PM standard. We are finalizing these methods for demonstrating compliance with the SO_2 and PM emission limits for Power Boiler No. 2.

With regard to the commenter's request that we include an alternate compliance option in our FIP that removes the SO_2 and PM BART limits if the boiler is switched to natural gas, we do not have the authority to do this. The Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.[415] The BART emission limits are still applicable and are required regardless if the unit is switched to natural gas. However, the repurposing project the mill is currently undergoing and the possibility of Power Boiler No. 2 being converted to burn only natural gas render it appropriate to provide the facility with flexibility in demonstrating compliance with the SO_2 and PM emission limits for Power Boiler No. 2. Therefore, we are providing one alternative method for demonstrating compliance with the SO_2 and PM emission limits: the owner or operator may demonstrate compliance with these emission limits by switching Power Boiler No. 2 to burn only pipeline quality natural gas. Therefore, if Power Boiler No. 2 is switched to burn only pipeline quality natural gas, and the air permit is revised to reflect this change, this would satisfy the requirement for demonstrating compliance with the boiler's SO_2 and PM BART emission limits, and the related reporting and recordkeeping requirements would be waived. Under these circumstances, the SO_2 and PM BART determinations for Power Boiler No. 2 would continue to apply but the facility would be able to demonstrate compliance with these emission limits by virtue of switching to natural gas and it would not be required to use the existing CEMS to

[415] 40 CFR 51.301.

demonstrate compliance with the SO_2 BART emission limit. We are revising proposed section 52.173 to reflect this.

We are requiring Power Boiler No. 2 to meet an emission limit of 345 lb/hr to satisfy the NO_X BART requirement. We proposed to require the facility to demonstrate compliance with this NO_X emission limit using the existing CEMS, and we are finalizing this method for demonstrating compliance. However, the repurposing project the mill is currently undergoing and the possibility of Power Boiler No. 2 being converted to burn natural gas only render it appropriate to provide the facility with flexibility in demonstrating compliance with the NO_X emission limit. Therefore, we are providing one alternative method for demonstrating compliance with the NO_X emission limit: if Power Boiler No. 2 is switched to burn only pipeline quality natural gas, and the air permit is revised to reflect this and the operation of the CEMS is not required under other applicable regulatory requirements,[416] the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP-42 emission factors and fuel usage records. Under these circumstances, the facility would not be required to use the existing CEMS to demonstrate compliance with the NO_X BART emission limit. We are revising proposed section 52.173 to reflect this.

We do not have the authority to include in our FIP a provision that removes all SO_2, NO_X, and PM BART requirements for Power Boiler No. 2 if it is permanently retired in the future. As noted above, the Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The BART emission limits and applicable requirements continue to apply regardless if a BART source is mothballed or retired/shut down without being dismantled, decommissioned, and having the air permit revoked. In the event that the BART source is permanently shut down, dismantled, decommissioned, and the permit revoked in the future, the process for removing the BART emission limits and applicable requirements would necessarily involve a request for a partial FIP withdrawal or a SIP revision in the event that we have approved a SIP revision that replaces our FIP. We are committed to work with ADEQ and the facility to partially withdraw our FIP with respect to the emission limits for the BART unit or revise the SIP if at some point in the future the company decides to permanently shut down, dismantle, and decommission the boiler and surrender the air permit.

Further, we consider the conditions under which a unit is permanently retired and the mechanism by which this is made enforceable to be critical. Because the company has not decided if and when Power Boiler No. 2 will be permanently retired or decided what the conditions of the retirement will be, we believe that it is reasonable and appropriate to wait until the company makes these decisions instead of including a provision in our FIP that waives the BART recordkeeping requirements in anticipation that the unit's permanent retirement will take place under certain conditions and made enforceable through a particular mechanism that may be different from what ultimately takes place.

[416] We find that as long as the operation of the existing CEMS is required under other applicable regulatory requirements, the most reasonable approach is to continue demonstrating compliance with the NO_X BART emission limit using data from the CEMS.

Comment: Domtar requests that the final FIP include a five year schedule for complying with the SO_2 and NO_X BART emission limits for Power Boiler 2 in light of the Mill's repurposing project. [Domtar (0155) p. 13-14, 15] Domtar stated that EPA proposes to require compliance with the SO_2 BART emission limit for Power Boiler 2 within 3 years of the effective date of the final rule. EPA also proposes compliance with the NO_X BART emission limit within 3 years of the effective date of the final rule. With the Mill transformation and re-purposing project and all of the work associated with this huge undertaking, the Ashdown Mill needs a 5-year compliance window from the effective date of the final rule for the SO_2 and NO_X BART requirements for Power Boiler 2 (assuming EPA decides to proceed with BART for the Mill). It is anticipated that this Mill transformation project may significantly affect Mill steam demands reducing the amount of steam needed from Power Boiler 1 and 2. Ultimately, this transformation project may determine future use of Power Boiler 2. Once the re-purposing and re-configuration of the Mill systems is complete and fully operational, the Mill will decide whether Power Boiler 2 will continue with full or intermittent operation, if so, using what fuels, or will it be permanently retired. A 5-year schedule recognizes the interconnected operations of the Mill, in which changes to one system or component requires changes to other interconnected components. Given the Mill's interconnected nature as well as the complex aspects of the re-purposing project, a 5-year compliance schedule for achieving the SO_2 BART and NO_X BART requirements for Power Boiler 2 is essential.

As announced late last year, the Mill is converting a paper machine to produce fluff pulp. This transformation project is being driven by the continued decline in the demand for paper products. Power 1 and Power Boiler 2 are part of the Mill's steam generating components. The steam generating units are operated to produce steam that is needed for the manufacturing of pulp and paper products. Once the re-purposing and re-configuration of the Mill systems is complete and fully operational, the Mill will decide whether Power Boiler 2 will continue with full or intermittent operation, if so, using what fuels, or will it be permanently retired.

In order to make this decision, the Mill will need to go through the startup, initial operation and a shakedown period with the new fluff pulp process. Since this is a significant change for the Mill it is uncertain how long it will take to learn how to operate and to optimize in this newly configured state. The Mill will then need at least 2 winter cycles to understand what the maximum steam demand requirements will be for the newly configured Mill.

In addition, related to the re-purposing of the Mill and future post-project operations is the non-condensable gas (NCG) and bark feed systems. Currently, NCG gases are incinerated in Power Boiler 2 (as required by other Clean Air Act rules) and both Power Boilers 1 and 2 share a common bark feed system. Changes in the utilization or retirement of Power Boilers 1 or 2 will affect these interrelated systems. Significant time will be required to engineer new or modified systems, obtain environmental permits and implement the changes.

The re-purposing project is scheduled to be completed and the newly configured Mill is anticipated to start-up in late 2016. A current unknown associated with the project is the Mill's steam needs. The Mill will operate through the winter of 2016-2017 and will be learning how to operate and optimize the new process. The winter of 2017-2018 will be the first real indicator of

what winter steam demands will be in the re-purposed state. For the purposes of selecting an appropriate BART compliance schedule and future Mill operations, the understanding of how Power Boiler 2 will operate and on what fuels is essential. The project schedule will set these key decision points in late 2018. Once the decision on Mill steam needs and boiler utilization is made, additional time is required to implement the boiler scenario selected by the Mill. These scenarios could range from the mothballing or retiring Power Boilers 1 or 2 to shifting fuels. In addition, changes involving the combustion of the NCG gases and the shared biomass feed system also need to be determined and new systems engineered and permitted, as needed. Another factor to be considered is determining the ability of the existing SO_2 scrubber to continuously operate at 90% removal on a long term basis. If Power Boiler 2 continues to use solid fuels, additional time is needed to optimize the existing scrubber to consistently perform at this higher level of control efficiency on a long-term basis.

Response: We have reconsidered the SO_2 and NO_X BART compliance dates for Power Boiler No. 2 in response to this comment. We understand the commenter's concerns with respect to how the transformation and repurposing project the mill is currently undertaking may significantly affect mill steam demands and may ultimately determine future use of Power Boiler No. 2. We understand that the mill will decide the future use of Power Boiler No. 2, including whether it will be converted to other fuels or permanently retired, after the repurposing and reconfiguration of the mill systems is complete and fully operational and after the mill has learned how to operate and to optimize in its newly configured state. Our understanding from the comments is that Ashdown Mill expects to make this decision in late 2018, but that additional time will be needed to implement the boiler scenario selected by the mill, which could include switching fuels, mothballing or retiring the boilers, or continued operation and combustion of solid fuels and installation of air pollution controls to meet the BART emission limits. It is not EPA's intention to place an undue burden on the Domtar Ashdown Mill by requiring a compliance date that may not provide sufficient time for the mill to install controls or otherwise make the necessary operating changes to meet the boiler's BART emission limits. While we believe that a 3-year compliance date is generally sufficient for installation of the controls on which the BART emission limits are based, due to the special circumstances in this case we believe that it is reasonable and appropriate to establish a longer compliance date particularly since it could avoid unnecessary investment in controls that may be no longer needed due shutdown or fuel switch. Therefore, we are requiring that the mill comply with the SO_2 and NO_X BART emission limits no later than 5 years from the effective date of this final rule and have amended the proposed regulatory text to reflect this change. We believe that this adequately addresses the commenter's concerns while in keeping with the CAA mandate that compliance with BART requirements must be as expeditiously as practicable but no later than 5 years after promulgation of this FIP.

4.d. Other Compliance Dates

Comment: Domtar requests that the compliance date for SO_2 and NO_X BART for Power Boiler 1 and PM BART for Power Boiler No. 2 be changed to 30 calendar days. [Domtar (155) p. 7-8, 9, 17] Domtar stated that EPA is proposing compliance with the NO_X BART limit for Power Boiler 1 to be on the effective date of the final rule. Should EPA proceed with

imposing BART limits on Power Boiler 1, the Ashdown Mill requests the compliance date be changed to 30 calendar days after effective date of the final rule. That will give the Mill additional time to prepare the compliance records if there is a short period (*e.g.*, 30 days) between when the rule is promulgated and the effective date, especially if the effective date of the final rule falls on a weekend or a holiday. In addition, if any confusion exists regarding exactly when the effective date is, the cushion of 30 days helps to provide more certainty. This extra time will be needed if EPA finalizes any changes to definitions or other requirements that require the Ashdown to adjust recordkeeping systems.

Domtar stated that EPA is proposing compliance with the SO_2 BART limit for Power Boiler 1 to be effective on the date of the final rule. The Ashdown Mill is requesting the compliance date be changed to 30 calendar days after effective date of the final rule. The 30 days will give the Mill time to prepare the compliance records if there is a short period (*e.g.*, 30 days) between when the rule is promulgated and the effective date, especially if the effective date of the final rule falls on a weekend or a holiday. In addition, if for some reason there is confusion regarding exactly when the effective date is, the cushion of 30 days helps to provide certainty. This extra time will also be needed if EPA finalizes any changes to definitions or requirements and the Ashdown Mill will need the additional time to adjust recordkeeping systems.

Domtar stated that EPA is proposing compliance with the PM BART limit for Power Boiler 2 to be on the effective date of the final rule. The Ashdown Mill is requesting the compliance date be changed to 30 calendar days after the effective date of the final rule. The additional 30 days will provide additional time to prepare the necessary compliance records especially if there is a short period between when the rule is promulgated and the effective date or if the effective date of the final rule falls on a weekend or a holiday. In addition, if confusion exists regarding the effective date of the final rule, deferring the effective date helps provide more certainty. This extra time will also be needed by the Ashdown Mill if EPA adopts changes to definitions or requirements, which mandate adjustments to recordkeeping systems.

Response: We are finalizing a NO_X BART emission limit of 207.4 lb/hr for Power Boiler No. 1, which is what we proposed. We proposed an SO_2 BART emission limit of 21.0 lb/hr for Power Boiler No. 1, and as discussed in our final rule and elsewhere in this document, we are finalizing an emission limit of 504 lb/day in response to a separate comment provided by Domtar. We are finalizing our determination that compliance with the Boiler MACT PM standard satisfies the PM BART requirement for Power Boiler No. 2. As discussed elsewhere in this section of the final rule, we are finalizing some changes to the definitions and BART requirements for Power Boiler No. 1. After carefully considering this comment, we have determined that extending the compliance dates associated with the aforementioned BART emission limits for Power Boiler No. 1 is appropriate because it is a reasonable request that will allow the owner or operator of the affected facility to prepare applicable compliance records and adjust recordkeeping systems without unduly delaying compliance with the BART requirements. Therefore, we are revising the compliance dates we proposed for the SO_2 and NO_X BART emission limits for Power Boiler No. 1 and the PM BART requirement for Power Boiler No. 2 such that the owner or operator must comply with these emission limits no later than 30 calendar days from the effective date of the final rule.

Comment: EPA should use its discretion under the Regional Haze Rule and delay the Arkansas BART requirements for all sources for five years to avoid a piecemeal approach and align compliance timelines so that the full effects of other regulatory changes will be known. [Domtar Supplemental Comments (0170) p. 3] Domtar stated that EPA's proposed BART requirements will require installation of new emission controls on utility electric generation resources at a significant cost. The utilities will pass these costs on to Arkansas ratepayers. The Ashdown Mill, like other energy intense manufacturers, will be affected by the increasing cost of electric power needed to operate our processes. With other emerging regulatory initiatives targeting coal burning utilities, EPA should also consider these other factors which will be driving substantial changes to major coal burning facilities.

Not only are manufacturing facilities, such as the Ashdown Mill, undertaking major transformation projects that potentially may result in a move away from coal. Other emerging regulations targeting major utility units, such as the recently released final Clean Power Plan rule and the upcoming final rule on ozone standards, are likely to further reduce coal burning and further remove visibility concerns.

Domtar stated that while the Ashdown Mill's technical analysis on the CALPUFF margin of error shows no BART controls are warranted, it understands EPA may disagree. A practical alternative is for EPA to use its discretion under the Regional Haze Rule and delay the Arkansas BART requirements for all sources for five years. This will align compliance timelines so that the full effects of all of these regulatory changes will be known. Facilities affected by these other requirements can plan holistic compliance strategies rather than being compelled to follow an expensive and potentially wasteful piecemeal approach. Using the maximum five-year window allowed under BART will provide the Ashdown Mill the time to determine if coal will continue as a fuel for the facility. It will also provide the other affected sources in Arkansas with time to address the Clean Power Plan strategies and other significant regulatory programs that may also remove coal as a fuel. The effect of allowing a full five-year compliance program will thereby minimize the potential for stranded assets and minimize the cost increases on companies and on ratepayers. This approach is further compelled by the fact that Arkansas is more than meeting its "glide path" as discussed above.

Response: We acknowledge the commenter's concerns related to the potential increase in utility rates for Arkansas ratepayers as well as to potential requirements related to other CAA and EPA regulatory actions. We agree that multiple regulatory actions are pending that will affect the power sector and that regulatory development should be coordinated when possible while still meeting the statutory and regulatory requirements for compliance. We also recognize the importance of long-term and coordinated planning on the parts of owners of industrial sources that are subject to BART. However, we disagree that our FIP presents a tight or unreasonable regulatory timeline. It is an appropriate timeline for cost-effective control measures needed to meet the regional haze requirements.

The CAA and Regional Haze Rule require the installation and operation of BART, in particular, to be carried out expeditiously. The CAA defines the term "as expeditiously as practicable" to mean "as expeditiously as practicable but in no event later than five years after the date of

approval of a [Regional Haze] plan revision . . . ."[417] Therefore, we do not have the authority to delay compliance dates across the board for all subject-to-BART sources in Arkansas to allow time for greater certainty regarding requirements associated with other CAA and regulatory requirements. We also disagree that ADEQ's finding that Arkansas Class I areas are projected to be below the URP glidepath in 2018 is sufficient justification for delaying the compliance dates for all subject-to-BART sources in Arkansas. We address other more specific comments related to this issue in a separate response.

In determining what is "as expeditiously as practicable" for installation and operation of a particular control technology, the states and EPA usually consider the amount of time it generally takes to install and operate that type of technology at similar sources and the compliance dates that have been required for the installation and operation of the same type of control technology at similar sources in other regional haze actions, especially if there are no source-specific considerations or other special circumstances that would prevent the source from installing and operating the control technology within the same amount of time. For example, where a particular control technology can generally be installed and operated in 3 years, and where there are no source-specific considerations or other special circumstances that would affect the facility's ability to install and operate the control technology within that time frame, it would not be in accordance with the CAA and the Regional Haze Rule to allow a 5-year compliance period because that would not be as expeditiously as practicable. Additionally, considering that most other states already have plans in place that fully address the regional haze requirements, it would be inequitable and contrary to the intent of the CAA and the Regional Haze Rule to further delay implementation of regional haze requirements in Arkansas by allowing a 5-year compliance date across the board for all of Arkansas' subject-to-BART sources. Therefore, we disagree that it is appropriate for us to allow a 5-year compliance date for all subject-to-BART sources in Arkansas, rather than establishing deadlines consistent with the facts and regulatory requirements in each instance.

We do note that we are revising some of the compliance dates we proposed in response to source-specific considerations raised in other comments. We address these comments in separate responses.

We disagree that the BART controls we proposed are unwarranted because of the "CALPUFF margin of error." We address specific comments related to the CALPUFF margin of error elsewhere in this document.

Comment: EPA should impose a shorter SO_2 BART compliance deadline for Flint Creek Unit 1 considering AEP is currently in the process of installing the NID scrubber with a planned operation date of May 2016. [Sierra Club et. al. (0171) p. 14-15] Sierra Club et. al. stated that if EPA's final SO_2 BART determination is based on installation of a NID dry scrubber, EPA should impose a shorter compliance deadline, as required by the Act. EPA's proposed FIP requires Flint Creek Unit 1 to comply with the SO_2 BART determination within five years from the effective date of the final rule. 80 Fed. Reg. at 18,967. Yet the statute requires a source to comply with BART as expeditiously as possible, but no later than five years

[417] CAA section 169A(b)(2)(A) and (g)(4).

from the effective date of EPA's action on the regional haze plan. 40 C.F.R. §51.308(e)(1)(iv). AEP could install a NID scrubber at Flint Creek much more expeditiously than five years from the effective date of the rule. The utility has already obtained an APSC order finding that NID dry scrubber installation is in the public interest.[418] ADEQ has already issued a Title V air permit for scrubber construction and operation at Flint Creek.[419] Further, it appears that on-site construction of the NID scrubber has begun, and that the Flint Creek owners intend to operate it by May 29, 2016, in order to comply with EPA's MATS rule.[420] Thus, given that AEP is currently installing the NID scrubber with a May 2016 planned operation date, EPA's five-year SO_2 BART compliance deadline does not comply with the statutory requirement that BART controls be installed "as expeditiously as practicable," 42 U.S.C. § 7491(b)(2)(A). Since AEP is installing the NID scrubber for MATS as well as BART compliance, EPA should require SO_2 BART compliance at Flint Creek by no later than May 29, 2016.

Response: We acknowledge the information provided by the commenter regarding AEP Flint Creek's plans to complete installation of the NID system in 2016 in order to comply with 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, otherwise known as the Utility MATS Rule. MATS establishes emission limits for three categories of pollutants: mercury, acid gases (HCl and SO_2), and non-mercury hazardous air pollutant (HAP) metals. To address acid gases, an EGU must comply with an HCl emission limit unless it is equipped with a wet or dry FGD or DSI and an SO_2 CEMS, in which case it has the option of complying with an alternative SO_2 emission limit. The applicable alternative SO_2 emission limit is 0.2 lb/MMBtu.

The commenter has made us aware that the Arkansas PSC has determined that dry scrubber installation at Flint Creek is in the public interest and that the installation of those controls is already underway and anticipated by the company to be complete by May 29, 2016. The commenter also points to the air permit issued to Flint Creek by ADEQ on October 25, 2013, which allows for the installation and operation of new control equipment and associated material handling systems to comply with the requirements of the Utility MATS Rule. These controls include a NID system on Unit 1. The AEP-SWEPCO website also indicates that the installation of these scrubber controls is driven by MATS and future Regional Haze rules.[421] A timeline provided on the website states that construction of these controls began in October 2013 and that installation will be complete and the facility will be operating with these controls by the end of May 2016. In addition, the commenter has made us aware that the Arkansas PSC requires Flint Creek to provide quarterly reports on the progress of the installation of these controls. The first report the company submitted to the Arkansas PSC is dated March 26, 2014, and stated that the FGD project includes the installation of an Alstom NID system to comply with MATS and in anticipation of the BART requirements. The report also stated that the NID system and associated equipment are to be constructed at Flint Creek Unit 1, and that the company

[418] *See* 7/10/2013 SWEPCO News Release, SWEPCO Receives Arkansas Commission Approval for Flint Creek Plant Project, at https://www.swepco.com/info/news/viewRelease.aspx?releaseID=1424.
[419] *See* Stamper Report at 14 (citing October 25, 2013 Permit No. 0276-AOP-R6 at 5 (Ex. 29 to Stamper Report)).
[420] Stamper Report at 14 (citing Flint Creek Retrofit Project, SWEPCO News & Info Site at https://swepco.com/info/projects/FlintCreek/; March 26, 2014 Independent Monitor Report for AEP Flint Creek Plant Unit 1, submitted to the Arkansas Public Service Commission under Docket No. 12-008-U, at (Ex. 30 to Stamper Report)).
[421] https://www.swepco.com/info/projects/FlintCreek/

established design, procurement, and construction schedules to bring the upgraded plant fully on line by May 29, 2016. The commenter provided the report as an attachment to the comments submitted, but this and all other quarterly reports the company submitted to the Arkansas PSC are available online.[422] The most recent quarterly report available on the Arkansas PSC website is dated March 10, 2016, and covers the fourth quarter in 2015. This report indicated that the company still expected the upgraded plant to be fully on line by May 29, 2016. We verified the status of the installation of the controls with the company, who confirmed that installation of the NID controls was completed in June 2016, and that the plant is now operating with those controls.[423]

After carefully considering the information the commenter has brought to our attention, we no longer believe that a 5-year compliance date is appropriate for the SO_2 BART controls we are requiring for Flint Creek. We agree with the commenter that BART controls must be installed as expeditiously as practicable.[424] Therefore, we are finalizing a shorter compliance date. The information made available to us during the comment period, as discussed above, indicates that Flint Creek intends to operate the NID system to comply with the alternative SO_2 emission limit under the Utility MATS rule. The applicable SO_2 emission limit is 0.2 lb/MMBtu. The SO_2 emission limit we are requiring in our FIP to satisfy the BART requirement is 0.06 lb/MMBtu. As indicated in the information and other documentation the commenter provided, the company plans to use the same NID system to comply with MATS and to comply with the facility's SO_2 BART requirement. We expect that to achieve an emission rate of 0.06 lb/MMBtu, additional scrubbing reagent would be needed beyond that required to meet the 0.2 lb/MMBtu emission limit the company is required to meet by April 2016 under MATS. We also recognize that it is possible that the reagent handling system installed to meet the 0.2 lb/MMBtu emission limit would need some upgrades in order to accommodate the additional scrubbing reagent that would be needed to achieve the more stringent 0.06 lb/MMBtu emission limit we are requiring in this FIP. Therefore, to allow the facility sufficient time to secure the additional scrubbing reagent that would be needed to comply with the SO_2 BART emission limit and to make any necessary upgrades to the reagent handling system, we are finalizing an 18-month compliance date for Flint Creek Unit 1 to comply with the SO_2 BART requirement. We believe this is will provide sufficient time for the facility to be able to achieve the SO_2 BART requirement while still meeting the statutory mandate that BART controls be installed as expeditiously as practicable.

Comment: EPA should impose a shorter NO_X BART compliance deadline for Flint Creek Unit 1. [Sierra Club et. al. (0155) p. 19] Sierra Club et. al. stated that if EPA's final NO_X BART determination for Flint Creek is based on installation of LNB/OFA, in order to comply with its statutory mandate, EPA should establish a shorter compliance deadline. EPA's proposed FIP requires Flint Creek Unit 1 to comply with the NO_X BART determination within three years from the effective date of the rule. 80 Fed. Reg. at 18,969. As noted above, compliance with BART is required as expeditiously as practicable. 40 C.F.R. §51.308(e)(1)(iv). AEP has been planning for the installation of LNB/OFA and construction has already begun. Stamper Report at

[422] See the Arkansas PSC website at http://www.apscservices.info/efilings/docket_search.asp. The quarterly reports the company is required to submit to the Arkansas PSC are available by searching for docket No. 12-008-U.
[423] See file titled "Record of Call- Flint Creek_August 10 2016," which is found in the docket for this rulemaking.
[424] CAA section 169A(b)(2)(A).

27. Given that the utility is currently installing LNB/OFA with a May 2016 planned operation date, EPA's three-year NO_X BART compliance deadline does not represent the expeditious implementation required by law. If EPA selects LNB/OFA only as BART NO_X for Flint Creek, it should require a NO_X BART compliance date of no later than May 2016. *Id.*

If EPA selects SCR plus LNB/OFA as NO_X BART for Flint Creek, EPA should establish a compliance date of May 2016 for LNB/OFA and within three years of the final rule's effective date for SCR. As demonstrated in Ms. Stamper's report, three years is more than sufficient for installation of SCR and would represent expeditious implementation. *Id.*

Response: We are finalizing our determination that NO_X BART for AEP Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of LNB/OFA. The commenter has not provided sufficient information to corroborate the claim that installation of LNB/OFA at Flint Creek Unit 1 is expected to be completed by May 2016. We acknowledge that on July 10, 2013, the Arkansas PSC filed an order agreeing that the installation of additional environmental controls at Flint Creek Unit 1, including LNB/OFA to meet the NO_X BART requirement, is in the public interest.[425] In the attachments to the comment, the commenter points to a news article that references a January 21, 2014 report submitted by AEP/SWEPCO to the Arkansas PSC.[426] In that January 21, 2014 report, AEP/SWEPCO announces that construction of environmental controls at Flint Creek commenced on January 20, 2014.[427] However, the January 21, 2014 report does not specify if this includes construction of LNB/OFA. While we acknowledge that there is publicly available information indicating that the company planned to complete installation of a NID system and activated carbon injection by May 2016 to comply with the Utility MATS rule, there is no information available to us corroborating that the expected date of LNB/OFA installation was also May 2016.

In fact, the comments submitted by the company itself indicate that the company has not begun installation of these controls.[428] The company submitted comments requesting a 5 year compliance date (instead of the 3 year compliance date we proposed) for LNB/OFA installation to allow time for planning, selection of engineering and design professionals, vendors, contractors, permitting, start up and commissioning, and coordinating and scheduling unit outages. The comments submitted by AEP/SWEPCO are in contradiction to the commenter's allegations that LNB/OFA installation is already underway and expected to be complete by May 2016. We address the company's comments regarding this issue in a separate response to comment.

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[425] See Arkansas Public Service Commission, Docket No. 12-008-U, Order No. 14, dated July 10, 2013. A copy of the order can be found at http://www.apscservices.info/pdf/12/12-008-u_227_1.pdf

[426] See the document titled "Technical Support Document to Comments of Conservation Organizations," which is an attachment to the comments submitted by Earthjustice, the National Parks Conservation Association, and Sierra Club. These and all other comments submitted during the public comment period are found in the docket associated with this rulemaking.

[427] http://www.apscservices.info/pdf/12/12-008-u_238_1.pdf

[428] See the comments submitted by AEP-SWEPCO, dated July 15, 2015 and August 7, 2015. These and all other comments submitted during the public comment period are found in the docket associated with this rulemaking.

Nonetheless, we agree with the commenter that LNB/OFA can typically be installed within a 6-8 month timeframe. However, in determining the appropriate compliance date for these NO_X controls, we have also taken into consideration that we are finalizing NO_X emission limits consistent with the installation of LNB/OFA or LNB/SOFA controls for a total of 5 EGUs in this FIP and that the installation of these controls will require outage time. These 5 EGUs are Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, and combined they accounted for approximately 45% of the state's 2015 heat input.[429] Because of the heavy reliance on these EGUs for electricity generation in the state, we recognize that it may be difficult to schedule outage time to install LNB/OFA or LNB/SOFA on all 5 of these Arkansas units within the typical installation timeframe of 6 – 8 months and at the same time supply adequate electricity to meet demand in the state. In light of these unique circumstances, we find that it is appropriate to finalize an 18-month compliance date for Flint Creek Unit 1, White Bluff Units 1 and 2, Independence Units 1 and 2, to comply with the NO_X emission limits required by this FIP. This compliance date provides the affected utilities sufficient time beyond typical LNB/OFA installation timeframes to install these controls and comply with their NO_X emission limits, while safeguarding the continuity of Arkansas' electricity supply.

As discussed elsewhere in this document, we are not requiring SCR controls on Flint Creek Unit 1. Therefore, the comment related to the compliance date of SCR controls is moot.

Comment: EPA should impose a shorter NO_X BART compliance deadline for White Bluff Units 1 and 2. [Sierra Club et. al. (0171) p.25] Sierra Club et. al. stated that if EPA's final NO_X BART determination for White Bluff is based on installation of a SCR with LNB/SOFA, EPA should establish a deadline that requires compliance as expeditiously as possible. *See* 40 C.F.R. §51.308(e)(1)(iv). As noted in Section I.A.2.c of the Sierra Club's comments, SCRs can be installed in three years. If EPA's final BART determination requires SCR, EPA should require a NO_X BART compliance date for SCR at White Bluff of no later than within three years of the final rule's effective date, which would represent the expeditious implementation required by 42 U.S.C. § 7491(b)(2)(A). The NO_X BART compliance date for LNB/SOFA should be eight month's from the final rule's effective date. Stamper Report at 46.

Alternatively, if EPA finalizes its proposal to require LNB/SOFA only as NO_X BART for White Bluff, EPA should require compliance within eight months of the final rule's effective date. Eight months is sufficient time for installation of these controls. *Id.*

These comments also apply and are extended to Independence Units 1 and 2.

Response: We are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity. In addition, we are requiring each unit to meet a NO_X emission limit of 671 lb/hr on a rolling 3-hour average that is applicable only when the unit is being operated at less than 50% of the unit's maximum heat input rating. These emission limits are consistent with the installation and operation of LNB/SOFA controls. In light

[429] Based on data reported to us by these facilities. See http://ampd.epa.gov/ampd/.

of the comment, we have reconsidered the compliance date for the NO_X BART requirements for White Bluff Units 1 and 2 and for the NO_X controls under reasonable progress for Independence Units 1 and 2. Based on the supporting information provided by the commenter, we agree with the commenter that 6 – 8 months is the typical installation timeframe for LNB/OFA controls. However, in determining the appropriate compliance date for these NO_X controls, we have also taken into consideration that we are finalizing NO_X emission limits that are consistent with the installation of LNB/OFA or LNB/SOFA controls for a total of five EGUs in this FIP and that the installation of these controls will require outage time. These 5 EGUs are White Bluff Units 1 and 2, Independence Units 1 and 2, and Flint Creek Unit 1. These 5 units combined accounted for approximately 45% of the state's 2015 heat input.[430] Because of the heavy reliance on these EGUs for electricity generation in the state, we recognize that it may be difficult to schedule outage time to install LNB/OFA or LNB/SOFA on all 5 of these Arkansas units within the typical installation timeframe of 6 – 8 months and at the same time supply adequate electricity to meet demand in the state. In light of these unique circumstances, we find that it is appropriate to finalize an 18-month compliance date for White Bluff Units 1 and 2, Independence Units 1 and 2, and Flint Creek Unit 1 to comply with the NO_X emission limits required by this FIP. This compliance date provides the affected utilities sufficient time beyond typical LNB/OFA installation timeframes to install these controls and comply with their NO_X emission limits, while safeguarding the continuity of Arkansas' electricity supply.

We address elsewhere in this document specific comments contending that we should require installation of SCR with LNB/SOFA at White Bluff Units 1 and 2 to address the BART requirements and at Independence Units 1 and 2 to address the reasonable progress requirements.

Comment: If EPA's FIP does not rely on CSAPR to meet the NO_X BART requirement for Arkansas EGU's and the requirement to install LNB/OFA at Flint Creek Unit 1 is finalized, the EPA should extend the compliance date to allow 5 years for installation of controls. [AEP-SWEPCO July 15, 2015 comments (0164) p. 1-3, and August 7, 2015 comments (0170) p. 2-4] AEP-SWEPCO stated that if CSAPR=BART is not established in Arkansas for compliance with the NO_X regional haze requirements, AEP-SWEPCO does support EPA's determination of accepting the LNB/OFA controls as BART and the associated limits included in our submittal. However, if this requirement to install LNB/OFA remains in the final FIP, the proposed 3 year compliance timeframe is unreasonable. The regional haze rule provides for compliance with BART as soon as practicable, but no later than 5 years. The time frame must allow for planning, selection of engineering and design professionals, vendors, contractors, permitting, start up and commissioning, and coordinating and scheduling unit outages. Further, EPA has allowed installation schedules up to 5 years in other states and EPA should allow such a time frame here.

Response: We are finalizing our determination that NO_X BART for AEP Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of LNB/OFA. In response to a separate comment, we agree that LNB/OFA can typically be installed within a 6-8 month timeframe. We have also determined that the company has not provided any information regarding any special

[430] Based on data reported to us by these facilities. See http://ampd.epa.gov/ampd/.

circumstances specific to the facility that sets it apart from other facilities and that would prevent it from completing installation of controls within typical 3-year LNB/OFA installation timeframes. Although, as discussed elsewhere in this document, we agree that LNB/OFA can typically be installed within a 6-8 month timeframe, in determining the appropriate compliance date for these NO_X controls, we have also taken into consideration that we are finalizing NO_X emission limits consistent with the installation of LNB/OFA or LNB/SOFA controls for a total of 5 EGUs in this FIP and that the installation of these controls will require outage time. These 5 EGUs are Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, and combined they accounted for approximately 45% of the state's 2015 heat input.[431] Because of the heavy reliance on these EGUs for electricity generation in the state, we recognize that it may be difficult to schedule outage time to install LNB/OFA or LNB/SOFA on all 5 of these Arkansas units within the typical installation timeframe of 6 – 8 months and at the same time supply adequate electricity to meet demand in the state. In light of these unique circumstances, we find that it is appropriate to finalize an 18-month compliance date for Flint Creek Unit 1, White Bluff Units 1 and 2, Independence Units 1 and 2, to comply with the NO_X emission limits required by this FIP. This compliance date provides the affected utilities sufficient time beyond typical LNB/OFA installation timeframes to install these controls and comply with their NO_X emission limits, while safeguarding the continuity of Arkansas' electricity supply.

4.e. Compliance Demonstration Requirements

Comment: EPA's definition of Boiler Operating Day in the proposed FIP. [Domtar (0161) p. 6-7] Domtar stated that the July 6, 2005 BART Guidelines final rule states the following:

> For EGU's, specify an averaging time of a 30-day rolling average, and contain a definition of "boiler operating day" that is consistent with the definition in the proposed revisions to the NSPS for utility boilers in 40 C.F.R. Part 60, subpart Da.22 You should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. This would allow 30 day rolling average emission rates to be calculated consistently across sources.

Domtar stated that for purposes of BART for Ashdown's Power Boiler 1 and Power Boiler 2, EPA is defining boiler operating day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the power boiler, consistent with the guidelines for utility boilers. However, the Ashdown Mill boilers are not utility boilers; they are industrial boilers. The Ashdown Mill defines a Mill operating day to be a 24-hour period between 6 a.m. and 6 a.m. the following day. All of the Mill's systems for Power Boiler 1 and Power Boiler 2 are programmed around this definition of a Mill operating day and to modify these systems requires a significant amount of effort and requires the gathering and maintaining of multiple sets of records. Assuming EPA proceeds with BART for the Ashdown Mill, the Mill requests that for Power Boiler 1 and Power Boiler 2 a boiler operating day be

[431] Based on data reported to us by these facilities. See http://ampd.epa.gov/ampd/.

defined as *a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.*

Domtar stated that harmonizing the definitions of a boiler operating day and a Mill operating day helps address the inherent management issues that occur with dual EPA and ADEQ regulation of Power Boilers 1 and 2. In addition, harmonizing the definitions does not increase costs for the Mill, reduces confusion for the Mill operators, multiple sets of records will not be required and unnecessary changes to existing monitoring systems will not be necessary. We believe EPA is authorized or can use its discretion to define a boiler operating day for the Ashdown Mill to be consistent with the Mill's boiler operating day definition.

Response: After carefully considering the comment, we agree that Domtar's request is reasonable and that it is appropriate to harmonize the definitions of a boiler operating day and a Mill operating day to avoid any unnecessary modification or reprogramming of Power Boilers 1 and 2. To accommodate Domtar's request, for purposes of Power Boiler 1 and Power Boiler 2, we are defining a boiler operating day as "a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler." We are revising our final action to reflect this change.

Comment: Domtar requests changes to the requirements for demonstrating compliance with the NO_X BART limit for Power Boiler 1. [Domtar (0161) p. 9-10] Domtar stated that proposed Section 52.173(19)(ii) requires compliance with the BART NO_X limit for Power Boiler 1 be demonstrated with an annual stack test. We agree, in general, stack testing is an appropriate method for demonstrating compliance. However, the proposed frequency of an annual stack test is not appropriate. Historical NO_X stack test data from 2001, 2002, 2003, 2004, 2005 and 2010 for Power Boiler 1 show the NO_X emissions to be fairly consistent.

Domtar stated that based on the numerous previous stack tests, conducting stack tests annually is not warranted. Should EPA proceed with BART for the Ashdown Mill, the Mill is requesting the stack testing requirement be modified to require NO_X stack testing every 5 years to demonstrate compliance with the BART NO_X limit, which is consistent with the Ashdown Mill's Title V permit requirements.

Domtar stated that in addition, proposed section 52.173(16)(iii) requires for both SO_2 and NO_X, that for each boiler operating day a 30-day rolling average determined by (i) adding together the pounds from that day of SO_2 and NO_X and the preceding 29 boiler operating days and (ii) dividing the total pounds of SO_2 or NO_X by the sum of the total number of hours during the same 30 boiler operating day period. The reference to NO_X in this section needs to be removed as compliance with the NO_X limit is determined with stack testing. In addition, the discussion regarding SO_2 in this section can be moved to proposed Section 52.173(16)(i) and proposed Section 52.173(16)(iii) can be eliminated altogether.

Response: After carefully considering the comment, we have reconsidered our proposed requirement of annual stack testing. We agree that the results of the NO_X stack testing conducted by Domtar for Power Boiler No. 1 demonstrate that NO_X emissions have historically remained

well below the NO_X emission limit we are finalizing for the boiler.[432] Therefore, we agree with the company that it is appropriate to require stack testing every 5 years instead of annually. In our final action we are requiring that the facility demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 by conducting stack testing every five years, beginning no later than 1 year from the effective date of our final action. As discussed in a separate response, we are also providing one alternative method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Specifically, if the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP-42 emission factors and fuel usage records. Under these circumstances, the facility would not be required to demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 through stack testing.

As compliance with the NO_X BART emission limit is to be determined through stack testing, we agree with the commenter that the reference to NO_X in our proposed section 52.173(16)(iii) should be removed. We acknowledge this error and are correcting this in our final action.

Comment: Domtar requests that EPA's proposed BART SO_2 limit for Power Boiler 1 of 21 lb/hr be expressed as 504 lb/day. [Domtar (0161) p. 7-8] Domtar stated that assuming EPA proceeds with BART for the Ashdown Mill, the Mill conceptually agrees with the proposed BART SO_2 limit for Power Boiler 1 of 21.0 lb/hr on a 30-day averaging basis with no add-on control. However, based on the methodology the Mill uses to determine fuel usage, the limit needs to be expressed in an alternative form to better match with the compliance averaging time of 30 days. The Mill uses monthly fuel usage records and reconciles the monthly usage records based on fuel inventory records at the end of each month. Records of daily fuel usage may be adjusted at the end of the month as part of the reconciliation process. Domtar requests the BART limit of 21.0 lb/hr be expressed as 504 lb/day.

Domtar stated that section 52.173(19)(iii) of the proposed rule requires SO_2 emissions for each day are determined by summing the hourly emissions measured in pounds of SO_2. Calculating hourly SO_2 emissions using hourly fuel throughput information is not a workable approach for Power Boiler 1 where the practice is to use monthly fuel throughput information that is reconciled at the end of each month. The Ashdown Mill requests the requirement referencing summing of hourly SO_2 emission be removed. The Mill will track daily SO_2 emissions and requests the 30-day rolling averages for compliance purposes be determined within 15 days of the end of each month to allow time for the monthly fuel reconciliation processes to be completed and the daily fuel throughput values adjusted accordingly. After the fuel reconciliation is completed, the 30-day rolling averages for compliance purposes will be determined and the "official" compliance records maintained.

[432] See Excel file titled "Email from Domtar Regarding NOx Stack Test for PB1," found in the docket for this final rule. The data provided by Domtar indicate that out of the stack testing conducted in 2001, 2002, 2003, 2004, 2005, and 2010, the highest NO_X emission rate from Power Boiler No. 1 was 171.3 lb/hr, compared to the 207.4 lb/hr NO_X emission limit we are finalizing.

Response: After carefully considering this comment we have determined that Domtar's request for an SO_2 BART emission limit in terms of lb/day is reasonable. An emission limit in terms of lb/day will be better suited for the mill's methodology of using monthly fuel throughput information. Therefore, as requested by the facility, we are finalizing an SO_2 BART emission limit of 504 lb/day for Power Boiler No. 1.

In addition, as the Mill reconciles the monthly fuel usage records based on fuel inventory records at the end of each month and may have to adjust records of daily fuel usage as part of the reconciliation process, we believe it is reasonable and appropriate for the Mill to determine 30-day rolling averages within 15 days of the end of each month to allow time for the monthly fuel reconciliation process to be completed.

Comment: EPA should revise the requirements for demonstrating compliance with the SO_2 and NO_X BART limits for Domtar Power Boiler 2. [Domtar (0161) p. 13, 15] Domtar stated that EPA is proposing compliance with the proposed SO_2 and NO_X BART limits for Power Boiler 2 be determined by using the existing CEM system. In Section 52.173(19)(iii), EPA requires the owner/operator to comply with the CEMs quality assurance procedures in 40 C.F.R. Part 75. Since the Ashdown Mill is an industrial facility, the Mill is complying with the CEM requirements including the quality assurance requirements contained in 40 C.F.R. Part 60. EPA needs to correct this language to reference 40 C.F.R. Part 60 and not 40 C.F.R. Part 75. In addition, any existing CEM systems and associated methods and procedures (*e.g.*, QA/QC, etc.) approved by the State should be adequate and appropriate for use in SO_2 and NO_X BART monitoring. No need exists for EPA to review and approve these existing systems when they were previously reviewed and approved by the State.

Response: We agree with the commenter that since the Domtar Ashdown Mill is an industrial facility, it is complying with the CEM requirements including the quality assurance requirements contained in 40 C.F.R. Part 60 instead of those contained in 40 C.F.R. Part 75. We acknowledge this error and are correcting section 52.173 to reflect this.

Comment: EPA must clarify the PM BART requirements for Domtar Power Boiler 2 so these requirements are consistent with definitions and requirements of Boiler MACT. [Domtar (0161) p. 16-17] Domtar stated that assuming EPA proceeds with BART for the Ashdown Mill, the Mill agrees with the proposed BART PM limit of 0.44 lb/MMBTU based on the MACT standard for the "biomass hybrid suspension grate" sub-category contained in the 2013 Boiler MACT final rule. The Ashdown Mill also agrees with EPA's approach of relying on the Boiler MACT standards for PM to satisfy the PM BART requirement. However, for this streamlined BART approach, EPA must also ensure that the monitoring, recordkeeping, reporting requirements for PM BART are consistent with the monitoring, recordkeeping and reporting requirements under Boiler MACT. Deviating from the MACT requirements will result in additional administrative burden for the facility in maintaining "multiple sets of compliance books." It also will create confusion for external stakeholders if different values and information are being reported.

Domtar stated that EPA is proposing compliance with the PM emission limit be determined by maintaining the 30-day rolling average wet scrubber pressure drop and the 30-day rolling average wet scrubber liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM limit according to 40 C.F.R. Part 63 § 7530(b) and Table 7 to subpart DDDDD of Part 63.

Domtar stated that EPA is essentially proposing the same methods for demonstrating compliance with the Boiler MACT PM standard be used for demonstrating compliance with the PM BART emission limit. However, several of the definitions in Boiler MACT are different than in the existing BART rules and in this BART proposal. For example, under Boiler MACT the 30-day rolling average is defined to be the arithmetic mean of the previous 720 hours of valid operating data. In contrast, for purposes of BART, EPA defines a 30-day rolling average to consist of 30 consecutive boiler operating days.

Examples of other inconsistencies between BART definitions/requirements and Boiler MACT follow:

- During periods of startup and shutdown, Boiler MACT uses work practices and does not require data collected during startup and shutdown periods to be used in calculating averages. In Boiler MACT Section 63.7500(f) states standards apply at all times the affected units is operating, except during periods of startup and shutdown during which time comply only with the Table 3 work practices. Section 63.7505(a) further states: These emission limits and operating limits apply at all times the affected unit is operating except for periods noted in §63.7500(f). The proposed BART requirements require continuous emissions monitoring during all periods of operation including periods of startup, shutdown, and malfunction. In addition proposed BART requirements in Section 52.173(27) states: At all times, including periods of startup, shutdown and malfunction, the owner or operator to the extent practical, maintain and operate the unit including air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. In contrast, Boiler MACT requirements allow certain air pollution control equipment to startup up as expeditiously as possible.
- Boiler MACT is Section 63.7540((a)(1) states: Operating limits must be confirmed or reestablished during performance tests. Unlike the BART proposed language in § 52.173(22) that requires the one-hour pressure drop and the one-hour average liquid flow rate measured during each performance test, Boiler MACT only requires confirmation and not re-establishing the pressure drop and flow rate operating limits during performance tests subsequent to the initial performance test.
- Section 63.7540((a)(1) states: "operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operation limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with emission limits or to establish new operating limits." Under Boiler MACT, a deviation of an operating limit does not mean a violation of the emission standard.

For the final rule, assuming EPA proceeds with BART for the Ashdown Mill, EPA must clarify the PM requirements for BART so these requirements are consistent with the definitions and requirements of Boiler MACT.

Response: We generally agree with the comment. We proposed to find that the Domtar Ashdown Mill may rely on compliance with the Boiler MACT PM standard to satisfy the PM BART requirement for Power Boiler No. 2, and we did not intend for our FIP to establish requirements for compliance demonstration, monitoring, recordkeeping, and reporting different from those the mill is already required to comply with under the Boiler MACT PM standard. In our proposal, our intent was to propose requirements for compliance demonstration, monitoring, recordkeeping, and reporting for the PM BART limit for Power Boiler No. 2 that are consistent with those under the Boiler MACT PM standard. However, the commenter has brought to our attention that only some of the compliance demonstration, monitoring, recordkeeping, and reporting requirements associated with the Boiler MACT PM standard were included under our proposed section 52.173(c)(21) and (22) and that it appeared that we were proposing a separate and distinct set of requirements associated with our PM BART determination for Power Boiler No.2. Therefore, to ensure clarity and consistency, we are revising the regulatory text found under 40 CFR section 52.173(c) that applies to Power Boiler No. 2 for PM BART to state that the mill shall rely on compliance with the Boiler MACT PM standard under 40 CFR Part 63 Subpart DDDDD as revised to satisfy the PM BART requirement for Power Boiler No. 2. We interpret this to mean that compliance with the applicable Boiler MACT PM standard as revised is sufficient to demonstrate compliance with the PM BART requirement. We are not establishing a separate set of requirements for compliance demonstration, monitoring, recordkeeping, and reporting (i.e., in addition to those already required under the Boiler MACT PM standard, as revised), that Power Boiler No. 2 is required to comply with to satisfy the PM BART requirement.

4.f. Agreement with EPA's Proposed BART decisions

Comment: AECC agrees with EPA's proposed BART determinations for AECC Bailey Generating Station Unit 1 and AECC McClellan Generating Station Unit 1. [AECC (0169) p. 1-2] AECC stated that the EPA's BART determination for SO_2 and particulate matter (PM) emissions for these two units is to switch to a lower sulfur fuel oil. EPA's BART determination for NO_X emissions is to maintain the existing NO_X emission limit in the respective unit's air permit with no additional controls. AECC agrees with these determinations.

Response: We appreciate AECC's support of our proposed SO_2 and PM BART determinations for these two units. In our final action, we are finalizing these BART determinations.

Comment: AECC agrees that wet scrubbers are not BART at the Flint Creek Power Plant Unit 1 and the White Bluff Steam Electric Station Units 1 and 2. [AECC (0169) p. 2] AECC stated that for the Flint Creek Unit 1, EPA states that a wet scrubber is projected to result in "minimal incremental visibility improvement" over a dry scrubber, and, therefore, EPA did not

consider a wet scrubber to be BART.[433] For the White Bluff units, EPA states that dry scrubbers are more cost-effective than wet scrubbers and the additional visibility benefits obtained as a result of the greater level of control wet scrubbers offer over dry scrubbers are not worth the additional cost of wet scrubbers.[434] AECC agrees with these assessments.

Response: We appreciate AECC's support of our proposed SO_2 BART determinations for Flint Creek Unit 1 and White Bluff Units 1 and 2. In our final action, we are finalizing these BART determinations.

Comment: AECC agrees that both SNCR and SCR are not justified at Flint Creek Unit 1 and White Bluff Units 1 and 2. [AECC (0169) p. 2] AECC stated that EPA believes that adding SNCR at Flint Creek is not justified due to the minimal incremental visibility improvement over use of low- NO_X burners (LNB) with over-fire air (OFA).[435] Also, EPA believes that the addition of SCR cannot be justified due to a small visibility improvement relative to the high costs associated with SCR.[436] The results of EPA's SNCR and SCR analyses for White Bluff are similar. AECC agrees with these assessments.

Response: We appreciate AECC's support of our proposed NO_X BART determinations for Flint Creek Unit 1 and White Bluff Units 1 and 2. In our final action, we are finalizing these BART determinations.

Comment: EPA's proposed FIP properly uses a streamlined approach to assess BART where circumstances make a full BART analysis unnecessary. [UARG (0176) p. 9-10] UARG stated that in certain BART analyses presented in the proposed rule, EPA uses "a more streamlined approach to making BART determinations" where baseline visibility impacts are small. 80 Fed. Reg. at 18,975 (quoting 70 Fed. Reg. at 39,116); *see also id.* at 18,980, 18,988. For example, in light of the 0.01-dv baseline impact of the White Bluff Auxiliary Boiler at the most-affected Class I area, "the visibility improvement that could be achieved through the installation and operation of controls would be negligible, such that the cost of those controls could not be justified." *Id.* at 18,975; *see id.* at 18,970 Table 31 (showing the magnitude of estimated baseline visibility impacts from White Bluff Auxiliary Boiler). EPA likewise explains that small baseline visibility impacts from SO_2 emissions from the Domtar Ashdown Mill Power Boiler No. 1 (ranging from 0.014 dv to 0.335) cannot be addressed in a way that would produce meaningful visibility improvement at reasonable cost and, therefore, that unit warrants streamlined BART analysis with respect to its SO_2 emissions. *Id.* at 18,979-80 & Tables 44 & 45; *see id.* at 18,980 (observing that "any visibility improvement that could be achieved as a result of emissions reductions associated with the installation and operation of SO_2 controls [at that unit] would be negligible, and … the cost of those controls could not be justified"). As EPA explains in the proposed rule, the BART Guidelines allow and contemplate such streamlined assessments in these circumstances:

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[433] 80 Fed. Reg. al 18966 (April 8, 2015).
[434] *Id.* at 18993.
[435] *Id.* at 18968.
[436] *Id.*

> Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible. 70 Fed. Reg. at 39,116, *quoted in* 80 Fed. Reg. at 18,975; *see also id.* at 18,980 & n.81.

UARG stated that EPA presents a similar, albeit augmented, rationale for its streamlined BART assessment for particulate matter ("PM") emissions from the Domtar Ashdown Mill Power Boiler No. 2.EPA refers to "the very low baseline visibility impacts" from that boiler's PM emissions and the "potential for a very small amount of visibility improvement" from installation of emission controls for BART. *Id.* at 18,988. EPA further notes that the unit is subject to a "maximum achievable control technology," or "MACT," standard for its PM emissions under section 112 of the CAA and that the BART Guidelines provide that PM emission sources regulated by MACT standards generally may rely on compliance with those standards to satisfy BART requirements for their PM emissions. *Id.*

UARG stated that in sum, it is appropriate and consistent with the BART Guidelines for EPA to make a streamlined BART assessment where, as in the circumstances discussed above, no reasonable possibility exists that installation and operation of BART emission controls could feasibly and cost-effectively produce appreciable visibility improvement in relevant Class I areas.

Response: We appreciate UARG's support of the streamlined approach we took for making BART determinations for these sources.

Comment: The statutory factors support EPA's determination that a scrubber is SO_2 BART for Flint Creek Unit 1. [Sierra Club et. al. (0171) p. 12-13] Sierra Club et. al. stated that the statutory BART factors—in addition to cost effectiveness—support EPA's determination that BART limits for SO2 emissions from Flint Creek should be based on the use of a scrubber. *See* 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). First, EPA has reasonably considered the degree of visibility improvement that is expected to result from the use of a scrubber at Flint Creek. AEP's modeling, on which EPA relies, indicates that the installation of a NID scrubber at Flint Creek would result in significant visibility improvements at all four Class I areas that were considered (relying on 98th percentile impacts): .615 dv (Caney Creek); 0.464 dv (Upper Buffalo); 0.414 (Mingo); and 0.345 dv (Hercules-Glades). 80 Fed. Reg. at 18,966. These visibility improvements are significant and securing them is essential to achieving the national

visibility goal. Second, EPA appropriately considered the existing SO_2 controls for Flint Creek (*i.e.*, there are none), and recognized also that Flint Creek primarily burns low-sulfur coal. 80 Fed. Reg. at 18,964; Stamper Report at 3. Third, EPA appropriately evaluated the energy and non-air quality environmental impacts of compliance and reasonably determined that no such impacts argued against selection of a scrubber as SO2 BART for Flint Creek. *See* 80 Fed. Reg. at 18,966. EPA noted that some energy impacts (*i.e.*, the potential increased power requirements of wet scrubbers) were included in the cost-effectiveness calculations. *Id.* Finally, EPA reasonably considered the remaining useful life of the source, as it noted that AEP has not established any shutdown date and thus the anticipated useful life of the boiler should be as long as the capital cost recovery period of controls. *See id.* at 18,967. As Ms. Stamper notes, an equipment life of 30 years is an appropriate assumption for determining cost effectiveness of wet and dry scrubbers as many such control systems have been operated for longer than 30 years. Stamper Report at 9.

Response: We appreciate the commenter's support of our determination that SO_2 BART for Flint Creek Unit 1 is an emission limit that is based on the use of a scrubber.

Comment: The statutory factors support EPA's determination that scrubbers are SO_2 BART for White Bluff Units 1 and 2. [Sierra Club et. al. (0171) p. 22] Sierra Club et. al. stated that the other BART statutory factors—in addition to cost effectiveness—also support EPA's determination that a scrubber is SO_2 BART for White Bluff. *See* 42 U.S.C. § 7491(g)(2) 40 C.F.R. § 51.308(e)(1)(ii)(A). First, EPA has reasonably considered the degree of visibility improvement that is expected to result from the use of a scrubber at White Bluff. Entergy's modeling, on which EPA relies, indicates that the installation of a dry scrubber at White Bluff Unit 1 would result in significant visibility improvements at all four Class I areas that were considered (relying on 98th percentile impacts): 0.813 dv (Caney Creek); 0.762 dv (Upper Buffalo); 0.683 dv (Hercules-Glades); and 0.620 (Mingo). 80 Fed. Reg. at 18,972. The modeled visibility improvements resulting from operation of a dry scrubber at White Bluff Unit 2 are similarly significant though, with the exception of Upper Buffalo, slightly less than the visibility improvement predicted for Unit 1. *See id.* Entergy's modeling for a wet scrubber at White Bluff Units 1 and 2 shows similar visibility improvements as compared to dry scrubbers, with slightly larger improvements predicted for the Arkansas Class I areas and slightly smaller improvements for the Missouri Class I areas. *See id.* These visibility improvements are significant and securing them is essential to achieving the national visibility goal. Second, EPA appropriately considered the existing SO2 controls for White Bluff (*i.e.*, there are none.). 80 Fed. Reg. 18,969; Stamper Report at 28. Third, EPA appropriately evaluated the energy and non-air quality environmental impacts of compliance and reasonably determined that no such impacts argued against selection of a scrubber as SO_2 BART for White Bluff. *See* 80 Fed. Reg. 18,971-72. EPA noted that some energy impacts (*i.e.*, the potential increased power requirements of wet scrubbers) were included in the cost-effectiveness calculations. *Id.* at 18,972. Finally, EPA reasonably considered the remaining useful life of the source, as there is no indication in the record that Entergy has established any shutdown date for the White Bluff units and thus the anticipated useful life of these boilers should be as long as the capital cost recovery period of controls. As Ms. Stamper notes, an equipment life of 30 years is an appropriate assumption for determining cost-

effectiveness of wet and dry scrubbers as many such control systems have been operated for longer than 30 years. *See* Stamper Report at 9, 41.

Response: We appreciate the commenter's support of our determination that SO_2 BART for White Bluff Units 1 and 2 is an emission limit that is based on the use of a scrubber.

4.g. Other

Comment: [Domtar (0161) p. 5] Domtar stated that a description of the Power Boiler 1 and Power Boiler 2 begins on page 18978 of the proposal. With respect to the description of heat input ratings, the word "maximum" should be used. For Power Boiler 1, the average steaming rate is approximately 130,000 lb/hr and for Power Boiler 2, the average steaming rate is approximately 340,000 lb/hr.

Response: We acknowledge the comment and agree that the description of heat input ratings in our proposed FIP at 80 FR at 18978-79 refers to maximum heat input rating. We also appreciate the correction provided by the commenter for the average steaming rate for Power Boiler 1 and Power Boiler 2. These errors did not affect our proposed BART determinations.

Comment: [Domtar (0161) p. 14] Domtar stated that assuming EPA proceeds with BART for the Ashdown Mill, the Mill agrees with the proposed BART NO_X limit for Power Boiler 2 of 345 lb/hr on a 30 boiler operating day averaging basis. However, the preamble discussion on pages 18987-18988 discusses the installation of LNB and further comments that the emission limit of 345 lb/hr (on a 30 boiler operating day rolling average basis) is based on the installation and operation of LNB. As noted in the proposed rule text and in the associated table on page 19003, the limit is not tied to the installation of LNB. EPA needs to correct the preamble discussion to remove the references to installing and operating LNB.

Response: We appreciate the commenter's support of our proposed NO_X BART emission limit for Power Boiler 2 of 345 lb/hr on a 30 boiler operating day averaging basis. We are finalizing this emission limit. While this limit was determined based on the NO_X emission rate expected from the installation and operation of LNB at Power Boiler No. 2, we agree with the commenter that Domtar is not required to install LNB to comply with this emission limit. Domtar is free to choose any technology that meets the NO_X limit we are establishing.

Comment: EPA should withdraw the BART emission limits for Bailey Unit 1 if the State submits to EPA a revised Regional Haze SIP contains a demonstration that the unit is not subject to BART. [UARG (0176) p. 7] UARG stated that in light of revised modeling concerning the visibility impacts of emissions from Bailey Unit 1, as described by EPA in the proposed rule, *see* 80 Fed. Reg. at 18,949, EPA should withdraw the proposed BART emission limits (or, if the Agency promulgates those limits at the conclusion of this rulemaking, should subsequently rescind those limits) if the state submits to EPA a revised regional haze SIP that contains or reflects the demonstration that EPA acknowledges has already been made that that

unit is not properly deemed subject to BART. EPA notes that revised modeling conducted after EPA promulgated its 2012 final rule on the Arkansas SIP "shows visibility impacts from Bailey Unit 1 below 0.5 dv, which is the threshold used by Arkansas to determine if a source is subject to BART." *Id.* EPA thus does not dispute that the newer modeling shows that Bailey Unit 1 has only a below-threshold impact, *see id.*, but assert that at this time it lacks "discretion to reopen the issue of whether the source is subject to BART because we [*i.e.*, EPA] already approved the portion of the 2008 Arkansas [regional haze] SIP in which Arkansas determined AECC Bailey Unit 1 is subject to BART and Arkansas has not provided us a SIP revision to replace the previous determination." *Id.* (footnote omitted). EPA should commit to promptly withdraw the proposed FIP BART emission limits for Bailey Unit 1, or to rescind any final FIP BART emission limits that EPA may hereafter promulgate for this unit, if Arkansas submits a SIP revision containing a determination that the unit is not subject to BART.

Response: We disagree with the commenter that in our proposed FIP we made the admission that ADEQ has made a demonstration that AECC Bailey Unit 1 "is not properly deemed subject to BART." In our proposal we merely made the observation that the revised modeling provided to us shows visibility impacts from Bailey Unit 1 below 0.5 dv, which is the threshold used by Arkansas to determine is a source is subject to BART.[437] We also specifically stated that our proposal is not reconsidering or reopening the issue of whether the source is subject to BART because we do not have the discretion to do this.[438]

We are willing to work with ADEQ and the facility to develop a SIP that could replace our FIP. Such a SIP will need to meet the CAA and the Regional Haze regulations. We will take action on such SIP revision according to the statutory timeframes allowed under the CAA. Additionally, if such a SIP includes a determination made by the State that AECC Unit 1 is not subject to BART, ADEQ must include the appropriate supporting documentation to substantiate this. We will work with ADEQ during the SIP revision process to ensure the necessary supporting documentation is part of the SIP submittal.

Comment: EPA's NO_X BART analysis for Lake Catherine Unit 4 did not adequately consider non-environmental impacts of BOOS, along with other statutory BART factors, and is therefore legally flawed. [Sierra Club et. al. (0171) p. 26-27] Sierra Club et. al. stated that EPA must base BART determinations on an analysis of the five statutory BART factors: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) existing pollution controls in use at the source, (4) the remaining useful life of the source, and (5) the degree of visibility improvement. 42 U.S.C. §7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). The Lake Catherine Unit 4 BART analysis fails to accurately consider non-environmental impacts, along with compliance costs and the degree of visibility improvement. EPA incorrectly found that "there are not any energy or non-air quality environmental impacts associated with the operation of NO_X controls at Entergy Lake Catherine Unit 4 that would affect our proposed BART determination." 80 Fed. Reg. at 18,977. EPA and Entergy relied on a Sargent & Lundy May 2013 report to support their Lake Catherine Unit 4 NO_X BART determination. Stamper Report at 53. Sargent & Lundy found, based on its BOOS testing, that Entergy would need to

[437] 80 FR 18949.
[438] 80 FR 18949.

increase the firing rate of natural gas by approximately 25% to operate the unit at the same capacity factor. *Id* at 54. Neither EPA nor Entergy recognized the increased use of natural gas required for operation of BOOS in their Lake Catherine Unit 4 NO_X BART analyses or analyzed the additional environmental impacts associated with increased fossil fuel use, such as increased greenhouse gas and toxic air emissions. *Id.* Sargent and Lundy found no need for increased natural gas usage with the other control scenarios. *Id.*

Response: We acknowledge the information provided in the comment and in the attachments referenced in the comment. However, we disagree with the commenter that we made an incorrect finding that there are no energy or non-air quality environmental impacts associated with the operation of NO_X controls at Entergy Lake Catherine Unit 4 that would affect our proposed BART determination. While BOOS could be expected to increase the firing rate of natural gas to operate the unit at the same capacity factor, other control options such as SCR typically have several associated impacts as well, including increased auxiliary power requirements, waste associated with catalyst replacement and disposal, ammonia slip, and the partial conversion of SO_2 to sulfuric acid. As post combustion controls would result in increased power requirements to operate the control equipment, we expect that this too may indirectly result in increased fossil fuel use to a certain extent. However, we believe that the scope of the collateral impacts associated with the NO_X control options we evaluated do not outweigh the benefits in terms of NO_X emissions reductions and visibility improvement that would be provided by these controls. The commenter has not presented any specific data or information that establishes that the energy or nonair quality impacts of BOOS operation at Lake Catherine Unit 4 would make this option unacceptable. Thus, we continue to believe that there are no energy or non-air quality environmental impacts that warrant elimination of BOOS for Lake Catherine Unit 4.

We address elsewhere in this document the commenter's specific comments regarding consideration of compliance costs and degree of visibility improvement.

5. Reliance on CSAPR Better than BART

Comment: EPA is acting arbitrarily and inconsistently with its own past positions in requiring sources that are subject to the CSAPR to also control NO_X emissions as BART.

[ADEQ (0160) p. 4-8] ADEQ stated that presently, Arkansas is subject to a Cross-State Air Pollution Rule Federal Implementation Plan ("CSAPR FIP") for ozone-season NO_X. Despite EPA's own guidance stating that CSAPR makes greater reasonable progress than BART for ozone-season NO_X.[439] EPA makes no mention of CSAPR emissions controls in the Proposed FIP and requires BART for Electricity Generating Units ("EGUs") that are subject to CSAPR. EPA should not require sources that are subject to the CSAPR FIP to also install BART or additional emissions controls based on a reasonable progress analysis, such as is the case with the Entergy Independence Plant.

[439] *See* Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, 77 FR 33642 at 3365-33651.

ADEQ stated that on May 12, 2005, EPA published the Clean Air Interstate Rule ("CAIR"), which was intended to address interstate transport of air pollution as required by §110(a)(2)(D) of the CAA.[440] The rule affected 28 states and the District of Columbia and included a cap-and-trade program targeting SO_2 and NO_X.[441] The rule required 25 states, including Arkansas, to reduce their state-wide emissions of NO_X for the purposes of the 8-hour ozone National Ambient Air Quality Standard ("NAAQS") by specifying ozone-season NO_X emissions budgets.[442] The emission limitations were intended to reduce or eliminate each state's contributions to ozone air quality in other states, which would thereby help downwind states meet the 1997 ozone NAAQS. EPA approved Arkansas's CAIR SIP submission on August 04, 2009.[443] CAIR was heavily litigated and eventually remanded to EPA. However, CAIR remained in effect until EPA could promulgate a replacement, the result of which was CSAPR.

ADEQ stated that EPA published CSAPR as a replacement to CAIR on August 8, 2011.[444] Similar to CAIR, CSAPR requires certain states to reduce annual SO_2 emissions, annual NO_X emissions and ozone season NO_X emissions to assist with other states' attainment of the 1997 ozone NAAQS, the 1997 fine particulate matter with an aerodynamic diameter less than or equal to a nominal two and one-half (2.5) micrometers (PM2.5) NAAQS, and the 2006 fine particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers PM2.5 NAAQS. Initially, CSAPR addressed emissions from Electric Generating Units ("EGUs") beginning in the year 2012. However, CSAPR was also subject to litigation, which prompted a stay of the rule until litigation was concluded. The Supreme Court upheld CSAPR,[445] and EPA published an interim final rule on December 3, 2014 revising the CSAPR compliance deadlines.[446] CSAPR became effective on January 1, 2015.[447]

ADEQ stated that the Regional Haze Rule allows states to implement an alternative program in lieu of BART so long as the alternative program has been demonstrated to achieve greater reasonable progress toward the national visibility goal than would BART.[448] EPA proposed that a state in the CAIR trading program would be allowed to rely on EPA's determination that CAIR makes greater reasonable progress than source-specific NO_X controls.[449] In the final Transport rule, EPA demonstrated that CSAPR, which replaced CAIR, would make greater reasonable progress toward national visibility goals than would BART.[450]

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[440] *See* Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call, 70 FR 25162.
[441] *Id.*
[442] *Id.*
[443] 74 FR 38536.
[444] *See* Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208.
[445] *See E.P.A. v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1587, 188 L. Ed. 2d 775 (2014).
[446] Rulemaking To Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter, 79 FR 71663.
[447] 79 FR 71663.
[448] 40 C.F.R. § 51.308(e); 77 FR 33642.
[449] Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans" proposed rule, 76 FR 82219.
[450] *See* 77 FR 33642.

ADEQ stated that consistent with the requirements of the Regional Haze Rule, EPA found that the CSAPR trading program did not cause degradation in any affected Class I area.[451] In addition, EPA found that CSAPR implementation combined with implementation of BART elsewhere achieved greater visibility improvement on both the 20% best and 20% worst days.[452] As a result, EPA found that CSAPR met all requirements under 40 C.F.R. § 51.308(e)(4) to qualify as a substitute for BART.

ADEQ stated that EPA concluded in the final rule that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program for ozone season NO_X may rely on its determination that CSAPR makes greater reasonable progress than source-specific BART. EPA specifically noted that "[t]he states to which this aspect of our final rule applies are *Arkansas*, Florida, Louisiana, Mississippi and Oklahoma."(emphasis added).[453] Despite EPA's demonstration that CSAPR makes greater reasonable progress than source-specific BART, EPA has nevertheless proposed NO_X BART for certain units covered by CSAPR in the Proposed FIP.

ADEQ stated that the approach that EPA has proposed for Arkansas is inconsistent with that taken for other States. EPA promulgated FIPs to replace reliance on CAIR with reliance on CSAPR for the following states: Georgia, Indiana, Iowa, Kentucky, Michigan, Missouri, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia and West Virginia.[454] Similarly, Virginia is revising the Virginia Regional Haze SIP to rely on the Virginia CSAPR FIP to meet BART and reasonable progress requirements for SO_2 and NO_X.[455]

ADEQ stated that perhaps most noteworthy, EPA has proposed reliance on CSAPR in states that border Arkansas. The Texas-Oklahoma Regional Haze Plan does not require BART for sources that are subject to CSAPR.[456] In that plan, EPA reiterates its position that "CSAPR, like CAIR, provides for greater reasonable progress towards the national goal than would BART."[457] EPA proposes replacing reliance on CAIR with reliance on the trading programs of CSAPR as an alternative to BART for SO_2 and NO_X emissions from EGUs.[458]

ADEQ stated that not only is EPA requiring sources subject to CSAPR to control emissions as BART in the Proposed FIP, but EPA has not even considered CSAPR as an option for making reasonable progress. Even if EPA ultimately rejected CSAPR as a means to meet the reasonable progress requirements under the Regional Haze Rule, EPA is required to "cogently explain why

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[451] *Id.* at 33652.
[452] 77 FR 33642 at 33648.
[453] 77 FR 33642.
[454] Id.
[455] Virginia Dep't of Env. Quality, Commonwealth of Virginia State Implementation Plan, *available at* http://www.deq.state.va.us/Portals/0/DEQ/Air/PublicNotices/Drafts/mspro.pdf
[456] Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility, 79 FR 74818.
[457] 79 FR 74818 at 74851.
[458] 79 FR 74818 at 74853 (the proposed [Texas-Oklahoma] FIP … substitutes Texas' reliance on the Clean Air Interstate Rule (CAIR) to satisfy BART requirements at its EGUs with reliance on CAIR's successor, the Cross-State Air Pollution Rule (CSAPR)).”

it has exercised its discretion in a given manner."[459] EPA's failure to consider CSAPR is arbitrary and capricious in light of its treatment of other states.

ADEQ stated that as a result of EPA's position that CSAPR provides for greater reasonable progress than source-specific NO_X, facilities subject to the CSAPR FIP should not also be required to install, operate, or maintain BART for NO_X. In Arkansas, the following units should not be required to install the NO_X BART proposed by EPA in the Proposed FIP because they are also subject to CSAPR for ozone-season NO_X: (1) AEP Flint Creek Unit One; (2) Entergy White Bluff Unit One; (3) Entergy White Bluff Unit Two; and (4) Entergy Lake Catherine Unit Four.[460] Accordingly, EPA should withdraw the Proposed FIP and remove the requirements that the aforementioned units be subject to BART in addition to CSAPR emissions controls for ozone season NO_X in any subsequently proposed plan.

[Entergy Arkansas Inc. (0166) p. 13] Entergy stated that NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NO_X BART for all of Arkansas' EGUs.

[AEP-SWEPCO July 15, 2015 comments (0164) p. 1-3, and August 7, 2015 comments (0167) p. 2-4] AEP-SWEPCO stated it disagrees with EPA's proposed LNB/OFA controls for NO_X for the Flint Creek Power Plant. EPA issued a final rule allowing states that are subject to the CSAPR trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART.[461]

AEP-SWEPCO stated that EPA has an obligation to issue a FIP within 2 years of disapproving a SIP to correct identified deficiencies. In preparing a FIP to address those deficiencies, EPA should select and propose options that are in the best interests of all stakeholders. EPA makes no mention of CSAPR=BART in their proposed FIP. Although ADEQ did not propose CSAPR=BART in their submitted SIP, EPA should have evaluated that alternative in developing the FIP. AEP-SWEPCO specifically identified CSAPR=BART in the five factor analysis

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[459] *Nat'l Parks Conservation Ass'n v. E.P.A.*, No. 12-73710, 2015 WL 3559149, at *3 (9th Cir. June 9, 2015); (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 48, (1983)); *Greater Yellowstone Coalition, Inc. v. Servheen*, 665 F.3d 1015, 1030 (9th Cir.2011) (requiring "a rational connection between the data before [the agency] and its conclusion"); *Nw. Envtl. Def. Ctr. v. Bonneville Power Admin.*, 477 F.3d 668, 691 (9th Cir.2007).

[460] EPA has included Independence as a "Reasonable Progress Source" in the Proposed FIP rather than a source that is subject-to-BART. This distinction is important as there is no definitive process that EPA has described for determining the degree of control it might require for a specific "Reasonable Progress Source." Independence, being already subject to CSAPR should not be included in any discussion of BART controls.

[461] *See* Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans" 77 Fed. Reg. 33651 (June 7, 20 12).

submitted to ADEQ[462] as the primary option for compliance with NO_X at the Flint Creek facility. The BART analysis for NO_X was conducted as a second option because CAIR, CSAPR, and the state regional haze SIP were all in a state of flux during the time the five-factor analysis was being conducted. EPA did not address that issue in the section of the FIP that discusses the Flint Creek facility.

AEP-SWEPCO stated that EPA has made clear their determination that CSAPR is "better than BART" in addressing NO_X in ozone season only states. If CSAPR is indeed "better" than BART for NO_X, then EPA should have proposed the CSAPR trading program as an alternative to BART and selected that program in the regional haze FIP for addressing NO_X emissions. Regardless of implementation of the Regional Haze Rule, CSAPR will be in effect in Arkansas and NO_X emissions will be reduced accordingly. It is unnecessary to also require site-specific NO_X reduction controls which will result in reduced flexibility and increased costs without providing any additional visibility improvements. It should also be noted that EPA recently issued a FIP for Texas proposing "... reliance on the trading programs of CSAPR as an alternative to BART for SO_2 and NO_X emissions from EGUs in the regional haze plan for Texas."[463] EPA also "... found that CSAPR, like CAIR, provides for greater reasonable progress towards the national goal than would BART."[464] The same approach should be allowed in Arkansas for NO_X emissions. EPA should establish CSAPR=BART for NO_X and eliminate all site specific NO_X controls identified in the Arkansas FIP.

[AECC (0169) p. 6-7] AECC stated that the latest Transport Rule is CSAPR. Arkansas is subject to the CSAPR ozone season NO_X trading program. EPA's own guidance states that CSAPR makes greater reasonable progress than BART for ozone season NO_X. EPA specifically states, " ... a state in the Transport Rule region whose EGUs are subject to the requirements of the Transport Rule trading program only for ozone season NO_X is allowed to rely on our determination that the Transport Rule makes greater reasonable progress than source-specific BART for NO_X. The states to which this aspect of our final rule applies are Arkansas, Florida, Louisiana, Mississippi, and Oklahoma."[465]

AECC stated that there is no mention of CSAPR compliance in EPA's proposed Arkansas FIP, and yet EPA requires BART for EGUs that are subject to CSAPR. All EGUs in Arkansas rated 25 megawatts or greater are subject to the seasonal NO_X trading program under CSAPR; therefore, those EGUs should not be subject to additional BART controls for NO_X. Specifically, the NO_X controls for the Flint Creek and White Bluff units should be removed from the proposed FIP.

[Conway Corporation et. al. (0172) p. 12-13; and EEAA (0173) p. 4-5] Conway Corporation et. al. and the Energy and Environmental Alliance of Arkansas both stated that on May 30, 2012, EPA finalized the rule: "Regional Haze: Revisions to Provisions Governing Alternatives to

[462] BART Five Factor Analysis, Flint Creek Power Plant, Prepared by Trinity Consultants for American Electric Power Service Corp., September 2013, Version 4, page 6-l.
[463] 79 Fed. Reg. 74818 December 16, 2014.
[464] 79 Fed. Reg. at 74853.
[465] Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans. 77 FR 33652 (June 7, 2012).

Source-Specific BART Determinations, Limited SIP Disapprovals, and Federal Implementation Plans.[466] This rule allows the trading programs in CSAPR to serve as an alternative to determining source-by-source BART. It provides that states in the CSAPR region can substitute participation in CSAPR for source-specific BART for SO_2 and/or NO_X emissions from power plants. This determination is commonly referred to as CSAPR being "better-than-BART." EPA also determined "that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program only for ozone season NO_X is allowed to rely on our determination that CSAPR makes greater reasonable progress than source-specific BART for NO_X."[467] Arkansas is included in this determination, therefore the state's subject-to-BART EGUs were not required to perform a five factor analysis of NO_X emissions. Beginning May 1, 2015, CSAPR is in effect and being implemented in Arkansas. ADEQ is currently reevaluating the NO_X emission limits that are in the disapproved SIP and considering appropriate revisions. EPA should have proposed the CSAPR trading program as an alternative to BART and selected that program in the Proposed Rule for addressing NO_X emissions from Arkansas' subject-to-BART sources, including AECC Bailey and McClellan plants, AEP/SWEPCO Flint Creek Plant and Entergy White Bluff and Lake Catherine[468] Plants.

Conway Corporation et. al. and EEAA stated that regardless of implementation of the regional haze program, CSAPR will be in effect in Arkansas and NO_X emissions will be reduced accordingly. Thus, it is unnecessary to also require site-specific NO_X reduction controls which will result in reduced flexibility and increased costs without providing any additional visibility improvements. EPA recently issued a FIP for Texas proposing "…reliance on the trading programs of CSAPR as an alternative to BART for SO_2 and NO_X emissions from electric generating units ("EGUs") in the regional haze plan for Texas.[469] EPA also "found that CSAPR provides for greater reasonable progress towards the national goal than would BART."[470] The same approach should be allowed in Arkansas for NO_X emissions, and EPA should establish CSAPR=BART for NO_X emissions and eliminate all site-specific NO_X controls for Arkansas' EGUs identified in the Proposed Rule.

[Edison Electric Institute (0174) p. 2, 8-10] EEI stated that in the Arkansas FIP proposal, EPA makes no mention of its previous determination that "CSAPR=BART" in which EPA has previously made clear its determination that CSAPR is "better than BART" in addressing NO_X in CSAPR ozone season-only states. *See* 79 *Fed. Reg.* at 74,818. EPA should have proposed the CSAPR trading program as an alternative to BART for Arkansas given the Agency's prior determination. *Id.* EPA's CSAPR=BART policy, which would apply to several Arkansas facilities—such as the Southwestern Electric Power Company's Flint Creek facility—should be an acceptable option since the proposed site-specific NO_X reduction controls will result in reduced flexibility and increased costs without providing any additional visibility improvements.

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[466] 77 Fed. Reg. 33643 (June 7, 2012).
[467] *Id.* at 33652.
[468] Alternatively, it appears that the CALPUFF modeling relied upon in support of the BART determinations for the Lake Catherine Plant predicts visibility improvements for Arkansas' Class I areas which are within the CALPUFF model's margin of error, and therefore such visibility benefits from the proposed BART controls cannot be reasonably anticipated (*see Nat'l Parks Conservation Ass'n v. EPA,* No. 12-73710, 2015 WL 3559149 (9th Cir. June 9, 2015).
[469] 79 Fed. Reg. at 74818.
[470] *Id.* at 74853.

See 80 *Fed. Reg.* at 18965-68. EPA should establish CSAPR=BART for NO_X and withdraw all site-specific NO_X controls identified in the Arkansas FIP.

Response: Arkansas EGUs are subject to CSAPR for ozone season NO_X, and we acknowledge that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program for ozone season NO_X *may* rely on CSAPR to satisfy the NO_X BART requirement for its EGUs. However, when standing in the shoes of a state and promulgating a FIP, EPA has the same discretion as the state to choose to either conduct source-specific BART determinations or to rely on EPA's 2012 finding that CSAPR is better than BART. Our decision to make source-specific NO_X BART determinations for Arkansas is reasonable for multiple reasons: it is the approach Congress chose in the statute itself;[471] it is consistent with Arkansas' earlier decision to conduct source-specific NO_X BART determinations in lieu of relying on CAIR to meet the BART requirements; and at the time of our proposed action, it properly accounted for uncertainty in the CSAPR better-than-BART regulation created by ongoing litigation regarding the CSAPR program. Further explanation of these reasons is given below.

The Regional Haze regulations provide generally that "[a] State may opt" to rely on an emissions trading program rather than to require source-specific BART controls.[472] More specifically, in 2005 EPA revised the Regional Haze regulations to provide that a state subject to CAIR "need not require affected BART-eligible EGUs to install, operate, and maintain BART."[473] Following the D.C. Circuit's vacatur and remand of CAIR,[474] EPA issued CSAPR as a replacement rule. EPA revised its regulations in 2012 to allow states to rely on CSAPR in lieu of source-specific BART.[475]

In its 2008 regional haze SIP submittal, Arkansas decided to not rely on CAIR to satisfy the NO_X BART requirement for its EGUs.[476] In our Regional Haze FIP proposal for Arkansas, we did not rely on CSAPR (the follow up rule to CAIR) to satisfy the NO_X BART requirement for EGUs because we chose to follow the same source-specific approach to NO_X BART that Arkansas selected in its Regional Haze SIP submittal. In addition, litigation surrounding CSAPR was ongoing at the time that we issued our proposed Arkansas Regional Haze FIP. CSAPR was issued in 2011, but on December 30, 2011, the D.C. Circuit stayed the rule prior to implementation. The D.C. Circuit subsequently vacated CSAPR, an action later reversed by the Supreme Court in 2014. The case was then remanded to the D.C. Circuit. Then, after our April 2015 Regional Haze FIP proposal, the D.C. Circuit issued a July 2015 decision in *EME Homer City Generation v. EPA*[477] upholding CSAPR but remanding without vacatur a number of the

[471] See CAA section 169A(g)(2) in which Congress defined the five factor analysis for determining BART but did not expressly provide for an alternative to source by source BART.
[472] 40 CFR 51.308(e)(2).
[473] 70 FR 39104, 39156 (July 6, 2005).
[474] *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).
[475] 77 FR 33642 (June 7, 2012).
[476] As Arkansas did not rely on CAIR to satisfy requirements in the regional haze SIP, Arkansas is not included in the EPA's limited disapproval of regional haze SIPs that relied on CAIR to satisfy certain regional haze requirements. *See* 77 FR 33643, at 33654. In that same rulemaking, the EPA promulgated FIPs to replace reliance on CAIR with reliance on CSAPR in many of those regional haze SIPs; however, Arkansas was likewise not included in that FIP action.
[477] 795 F.3d 118 (D.C. Cir 2015).

Rule's state NO_X and SO_2 emissions budgets. Arkansas' ozone season NO_X budget is not itself affected by the remand. However, the Court's remand of the affected states' emissions budgets has implications for CSAPR better-than BART, since the demonstration underlying that rulemaking relied on the emission budgets of all states subject to CSAPR, including those that the D.C. Circuit remanded, to establish that CSAPR provides for greater reasonable progress than BART. As of the time EPA is taking this action to finalize Arkansas' Regional Haze FIP, we are in the process of acting on the Court's remand consistent with the planned response we outlined in a June 2016 memorandum.[478]

Our final action on the Arkansas Regional Haze FIP is consistent with our final action on the Texas Regional Haze FIP. Although we proposed to rely on CSAPR to address the NO_X BART requirements for EGUs in Texas, we did not finalize that portion of our proposed Texas FIP given the uncertainty arising from the remand of the CSAPR budgets for Texas and other states.[479] In light of the above, the comments that we are treating Arkansas differently than other states where EPA relied on CSAPR to meet the BART requirements are no longer applicable.

As we have noted throughout this document, we are willing to work with ADEQ to develop a SIP revision that could replace our FIP. Such a SIP revision will need to meet the CAA and EPA's Regional Haze regulations. In its SIP revision, ADEQ may elect to rely on CSAPR to satisfy the NO_X BART requirements for Arkansas' EGUs instead of doing source-specific NO_X BART determinations. Such an approach could be appropriate if, as we expect, the uncertainty created by the D.C. Circuit's remand of the affected states' emission budgets will shortly be resolved.

With regard to the comment that we should not require EGUs that are covered under CSAPR to also install additional emissions controls under reasonable progress analysis, we disagree. In our 2012 finding that CSAPR is better than BART, we stated that states with EGUs covered under CSAPR may rely on CSAPR to satisfy the BART requirement. However, controls under reasonable progress are a separate requirement from BART, and we disagree that states can rely on CSAPR to satisfy the reasonable progress requirements under section 51.308(d)(1). As explained in the 2005 rulemaking addressing reliance on CAIR, our determination that a trading program provides for greater reasonable progress than BART is not a determination that the trading program satisfies all reasonable progress requirements.[480]

We address elsewhere in this document comments alleging that the projected visibility improvement of NO_X controls on Lake Catherine Unit 4 are within the CALPUFF model's margin of error.

Comment: The NO_X controls EPA evaluated for Lake Catherine Unit 4 cannot be justified as BART, and instead of imposing source-specific controls on Lake Catherine Unit 4 and the other EGUs in Arkansas, EPA should find that CSAPR is better than NO_X BART. [Entergy Arkansas Inc. (0166) p.53-54] Entergy stated that if EPA finalizes a determination that

[478] https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf
[479] 81 FR 296, at 302.
[480] 70 FR at 39143; see also 77 FR at 33653

Lake Catherine Unit 4 should be subject to NO_X BART controls, EPA should not impose source-specific NO_X controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NO_X BART in Arkansas for all EGUs. Compliance with CSAPR will ensure that NO_X emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

Entergy stated that EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NO_X BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NO_X BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost-effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id.* at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as BART based on either average cost effectiveness or incremental cost effectiveness. *Id.* Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014.[481] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* At 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

Response: We address elsewhere in this document why it would not be appropriate to make a determination to rely on CSAPR as an alternative to NO_X BART for EGUs in Arkansas at this time. As discussed elsewhere in this document, we are finalizing source-specific NO_X BART determinations for Arkansas' EGUs, including Lake Catherine Unit 4.

We acknowledge the commenter's support of our proposed determination that LNB/SOFA, SNCR, and SCR are not BART for Lake Catherine Unit 4. We disagree that BOOS would result in imperceptible visibility improvements in the affected Class I areas and that we should therefore not require BOOS controls for NO_X BART. We address elsewhere in this document comments on this issue, including comments alleging that the projected visibility improvement of NO_X controls on Lake Catherine Unit 4 are within the CALPUFF model's margin of error. As discussed in our proposal and elsewhere in this document, BOOS controls are expected to result in meaningful visibility improvement in the affected Class I areas and is very cost effective ($138/ton removed). Therefore, we are finalizing our proposed determination that NO_X BART for Lake Catherine Unit 4 for the natural gas firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day average consistent with the installation and operation of BOOS.

[481] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

Comment: CSAPR could not possibly serve as a BART control because CSAPR does not regulate SO_2 emissions from Arkansas sources and regulates NO_X emissions only during the ozone season. [Sierra Club et. al. (0171) p. 46] Sierra Club et. al. stated that other commenters claim that EPA errs in not at least considering CSAPR as a potential control in the BART analysis. This argument fails for at least two reasons. First, Arkansas sources are not subject to SO_2 limits under CSAPR. *See* 77 Fed. Reg. 34,830, 34,845 (June 12, 2012).[482] Given that CSAPR does not limit SO_2 emissions from any Arkansas sources, the commenters' suggestion that CSAPR could represent the best available technology for reducing SO_2 emissions is plainly incorrect.

CSAPR contains unit-level allocations for NO_X emissions for several Arkansas sources for which EPA is proposing BART determinations. However, under CSAPR, Arkansas sources are subject to NO_X emission limits only during the ozone season. 77 Fed. Reg. at 34,845. CSAPR contains no annual NO_X emission limits for Arkansas sources.

By contrast, BART represents a year-round limit on emissions. *See* 40 C.F.R. § 51.301 (BART is the "best system of *continuous* emission reduction for each pollutant which is emitted by an existing stationary facility."). Given that CSAPR does not limit annual NO_X emissions from Arkansas sources, CSAPR cannot satisfy the NO_X BART requirements for annual emission limits on Arkansas sources. EPA therefore acted properly by not considering CSAPR as a potential control in the BART analysis for NO_X emissions.

Response: We acknowledge the background information provided by the commenter. We agree that since Arkansas is not subject to CSAPR for SO_2, Arkansas EGUs cannot rely on CSAPR to satisfy the SO_2 BART requirements. For the reasons discussed elsewhere in this document, we are finalizing source specific NO_X BART determinations for Arkansas EGUs subject to BART instead of relying on CSAPR to satisfy the NO_X BART requirement.

Comments disagreeing with our finding that CSAPR is "better-than-BART" for states subject to CSAPR for ozone season NO_X only (77 FR 33642) are outside the scope of today's rulemaking.

6. Cost

6.a. Cost Analyses and Cost Effectiveness Issues

Comment: EPA underestimated the costs of scrubbers at White Bluff by basing its cost analysis on Entergy's outdated cost estimate, eliminating legitimate costs, using the IPM cost model, and revising Entergy's assumed uncontrolled SO_2 emission rate.

[Entergy Arkansas Inc. (0166) p. 8-11] EAI stated that EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However,

[482] *See also* Unit Level Allocations Under the CSAPR FIPs After Tolling, *available at* http://www.epa.gov/crossstaterule/actions.html

EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices (CEPCI). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id.* at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis: costs for the reagent handling system; costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney; the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects; the costs associated with replacing the continuous emissions monitoring systems (CEMS) and associated recalibration and testing costs; and costs calculated as percentages of the BOP equipment, material and labor costs. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id.* At 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[483] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost (CUECost) model. Id. at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost

[483] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.

Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[484] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines, which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5. EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id.* at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMBtu unless fuel sulfur limitations were imposed. Based on historical data and

[484] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction (AFUDC) from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[485] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30-46 months of construction that would be needed to install major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[486] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit.

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[485] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.
[486] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

[AECC (0169) p. 5-6] AECC stated that EPA based its White Bluff dry scrubber technology estimates on costs associated with reports commissioned by Entergy in 2009, but these costs are now five years old and need to be updated. EPA also followed its 2002 Control Cost Manual (CCM), which is more than a decade old and significantly underestimates current market costs of designing, engineering, and installing controls. EPA erroneously believes that allowance for funds used during construction (AFUDC) should not be used in the cost analysis. AFUDC recognizes the cost of funds dedicated to construction of large projects. For major environmental control installations on units the size of the White Bluff units, this cost can reach $30 million to $60 million.[487] This is a real world cost that AECC's members will bear, and these costs should be included in the White Bluff scrubber cost analysis. EPA needs to re-evaluate the White Bluff control cost estimates with the issues listed above in mind.

Comment: EPA incorrectly excluded certain costs for White Bluff [S&L Entergy Report, page 6]. S&L objects to our removal of certain costs from the cost analysis of our White Bluff scrubber cost analysis including owner's costs and interest incurred during the construction period. S&L disagrees that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs." However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove from the SDA capital cost estimate.

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner." However, excluding financing costs will bias the cost-effectiveness comparison toward the high capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

[487] Entergy Response to 8/21/2013 EPA Region 6 comments on the White Bluff BART FFA at 2.

Response: Entergy states that we based our cost analysis for a dry scrubber for the White Bluff facility on an outdated 2009 S&L analysis, "rather than using the updated vendor pricing." This is a misrepresentation of the facts. Not disclosed by Entergy is that fact that the analysis we relied upon was not outdated at the time we were developing our Arkansas Regional Haze FIP proposal, was in fact the most recent analysis available to us, that it was used by Entergy itself, and has only been recently updated by Entergy in response to our proposed Arkansas FIP.[488] We address Entergy's new cost analysis in our responses to other comments.

Entergy criticizes our use of the CEPCI to escalate the 2009 S&L cost analysis to current dollars (at the time of our analysis). However this is a standard approach in control cost analysis and has in fact been utilized by Entergy's consultant, S&L (and many other consultants who perform control cost analyses) on numerous occasions. Again, had we had more updated cost information at the time we proposed our FIP, we would have used it, but Entergy failed to supply it. Thus, we used what was available to us, and properly escalated it using the CEPCI.

Entergy objects to our disallowance of owner's costs, stating such costs are allowed under "our" CUECost model, and our disallowance of AFUDC. Our use of the term, "overnight method" is merely a shorthand way of referring to the costing methodology required by the Control Cost Manual. The fact that the Control Cost Manual itself does not use that term does not obviate the need to adhere to that methodology. As we have noted in a number of our FIPs, AFUDC and Owner's Costs are not valid costs under our Control Cost Manual methodology. We invite Entergy to examine our response to similar comments we received in response to those actions.[489] We did not use the CUECost model, which estimates control costs using the levelized cost method developed by Electric Power Research Institute (EPRI), which is not approved for BART determinations. We followed the "overnight" methodology outlined in our Control Cost Manual. We were recently upheld in the Ninth Circuit[490] regarding our use of the overnight cost methodology.

Entergy objects to our correction of the mismatch it introduced in its BART analysis between the cost of its scrubbers and its SO_2 baseline. As we discuss in Appendix A of our TSD,[491] we noted that Entergy historically burned coals at the White Bluff and Independence plants with sulfur contents corresponding to typical Power River Basin coals, resulting in annual uncontrolled SO_2 emissions ranging from 0.46 lbs/MMBtu to 0.625 lbs/MMBtu, but designed its White Bluff scrubber systems assuming a coal with an uncontrolled SO_2 emission rate of 2.0 lbs/MMBtu. This has ramifications for the scrubber cost effectiveness calculation, in which the annualized cost of the controls are compared to the tons of SO_2 reduced from its SO_2 baseline. A scrubber capable of treating a higher sulfur coal is more expensive. Entergy is free to design a scrubber

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[488] This is described beginning on page 2 of Appendix A to the Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities, Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD).

[489] See for instance our "Response to Technical Comments for Sections E through H of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan," Docket No. EPA-R06-OAR-2010-0190, 12/13/2011.

[490] See *Ariz. ex rel. Darwin v. EPA*, 815 F.3d 519 (9th Cir. 2016), page 39: "This argument restates Petitioners' objections to EPA's reliance on the overnight costing methodology when it partially disapproved Arizona's SIP. See supra note 14. EPA's use of such a methodology in its own FIP's cost analysis is, without doubt, reasonable."

[491] See the discussion beginning on page 11 of our SO_2 Cost TSD.

capable of burning a coal with a higher sulfur content (assuming all regulatory requirements are otherwise met). However, unless this expense is balanced against the greater SO_2 removal capabilities of such a scrubber, the cost effectiveness calculation is skewed.

Nevertheless, Entergy continues to argue that it can legitimately introduce a mismatch between the cost of its scrubber systems and the SO_2 emission baseline against which its cost effectiveness will be measured, by reproducing an incomplete quote from the BART Guidelines to support its position that future fuel flexibility be considered "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."

The full quote which Entergy references above (which we reproduce in our SO_2 Cost TSD in the section referenced above) is actually: [492]

> The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Reading the full quote from the BART Guidelines reveals several points: The presumption is that the baseline emissions should be based on historical emissions. If future operations are expected to differ from past practices, and this impacts the BART analysis, an enforceable mechanism must be in place. The example in the above quote anticipates that future operations will cause the baseline to be lower, resulting in a correspondingly lower denominator in the $/ton cost effectiveness calculation, thus resulting in the cost effectiveness seeming less attractive (higher), thus triggering the need for an enforceable mechanism to ensure the integrity of the cost effectiveness calculation into the future. The same principle applies to Entergy's situation, in that using a higher scrubber cost for scrubbing a higher sulfur coal, in conjunction with using an unrepresentative (lower) baseline, both act to make the $/ton cost effectiveness of the scrubber seem less attractive (higher). In this instance, we would not require an enforceable mechanism to ensure Entergy burns a higher sulfur coal, but the need to ensure the future integrity of the cost effectiveness calculation nevertheless remains.

There are two obvious ways to address this situation: either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions. Lacking any information from Entergy regarding its preferences, we chose the latter course of action. As we discuss in our TSD, our approach was to use our IPM SDA cost model to adjust Entergy's total annualized cost, and then use that adjusted figure when calculating the cost effectiveness. We did this by calculating the ratios of the annualized capital costs and operating costs for two SDA cases: a

[492] 70 FR 39167.

2.0 lb/MMBtu case, and one based on Entergy's historical SO_2 emissions. We then applied these ratios to Entergy's annualized capital costs and the sum of its direct and indirect capital costs. We continue to believe the approach we adopted was reasonable, corrects the mismatch between the cost of its scrubbers and its SO_2 baseline Entergy introduced, and comports with the BART Guidelines. We explore this issue in more detail in other responses to comments.

Entergy also states that we have approved BART determinations that assume "worst-case coal scenarios" and cites to our proposed North Dakota and Arizona actions. We do not believe that the circumstances of these BART determinations are applicable here, or that they support Entergy's contention. In the North Dakota proposal, Coal Creek Station had recently installed a coal drying system and in performing the BART evaluation, North Dakota assumed a baseline corresponding to undried coal. As explained in our proposal, this was a "worst case" assumption. In other words, it had the effect of increasing the denominator in the $/ton cost effectiveness determinant, resulting in the true cost effectiveness of the technologies being considered being higher than what was evaluated—the opposite of what Entergy is proposing here. In addition, the issue was largely moot in that we proposed approval of what the State of North Dakota had itself proposed as BART for Coal Creek—that the existing scrubbers be upgraded to 95% efficiency, arguably a very stringent level of control. In the Arizona proposal, the Sundt Unit 4 was converted to burn coal in addition to natural gas. Its annual SO_2 emissions varied greatly, as a result of years in which more or less natural gas was burned, presently a problem when selecting its SO_2 emission baseline. We therefore chose a year in which the Sundt Unit 4 burned predominantly coal to represent the SO_2 baseline, when evaluating it for SO_2 BART. This results in a reasonably conservative, "worst case" evaluation—again, not what Entergy is proposing here.

We address all of Entergy's other comments, which are summaries of its contractor S&L's comments, in our responses to S&L's comments.

Comment: Entergy objects to our calculation of O&M costs in our White Bluff cost analysis. [S&L Entergy Report, page 13]. Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia. The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost

algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems. The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues. The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not for site-specific project and staffing needs;
- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and

- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Response: Our approach using the IPM SDA cost algorithm to recalculate the costs was necessary and reasonable. As we discuss in our TSD,[493] we had to recalculate Entergy's O&M costs for its White Bluff SDA model because of a discrepancy between Entergy's SO_2 emission baseline used in its cost analysis and the assumed SO_2 inlet it assumed in the design of its scrubber. Entergy costed a scrubber capable of treating a SO_2 level of 2.0 lbs/MMBtu, when it historically burned coal that averaged less than 0.6 lbs/MMBtu from 2009 – 2013. We could not directly adjust Entergy's O&M costs because Entergy's O&M cost estimates were based on a S&L economic model from May 2008, which it did not supply.[494] Consequently, when issues we discuss in our responses to comments elsewhere dictated a revision to Entergy's cost estimate, we were left with no choice but to seek an alternative means of estimating Entergy's O&M costs, in order to address the mismatch described above. Entergy now criticizes us for making this adjustment to its O&M costs by employing a scrubber cost model—our IPM SDA cost algorithm that its own contractor designed for us.

Entergy criticizes us for using our IPM SDA cost algorithm to estimate the O&M, stating this is in contradiction to our Control Cost Manual. On the contrary, as we stated in our TSD, we "relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual."[495] Our TSD goes on to explain that by this, it means the general costing methodology, namely the use of the overnight costing method.[496]

The BART Guidelines state: "In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible."[497] This statement is footnoted to indicate: "You should include documentation for any additional information you used for cost calculations, including any information supplied by vendors that affects your

[493] See Section 3.1 in Appendix A of our TSD.
[494] See Section 2.7 in Appendix A of our TSD.
[495] See Section 2 of Appendix A to our TSD.
[496] Ibid.
[497] 70 FR 39166.

assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual*." Our TSD satisfies this requirement.

The Control Cost Manual does not include any method for estimating the costs of any of the SO_2 control methods evaluated in this action. In fact, the Table of Contents of the Control Cost Manual indicates that the chapter on "Wet and Dry Scrubbers for SO_2," two of the three controls EPA costed, is a "planned chapter." This chapter was never developed.[498] Thus, it is not possible to use the Control Cost Manual to cost dry and wet scrubbers directly, except through the overnight cost methodology and the other general principles contained therein, which we followed. As a consequence, faced with having to perform cost analysis on an applicable control technology, we elected to use the only publically available current SO_2 costing model, the SDA cost model developed by S&L for use in our IPM.

Thus, the only relevant portion of the Control Cost Manual to our present work is the general methodology chapter, Chapter 2: Cost Estimation: Concepts and Methodology. We did adopt the Control Cost Manual general cost methodology, the overnight method, as we did in all of our previous FIPs. As explained in the Cost TSD, we modified the IPM cost models to use the overnight cost method by removing AFUDC and owner's costs and to additionally calculate cost effectiveness, rather than just total capital and O&M costs.

This comment states that the "IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates." These models were developed by Sargent & Lundy, under contract to us.[499] They were first published in 2010,[500] after the last Control Cost Manual modification (2002) and after the BART Guidelines were published in 2004.[501] Thus, it is illogical to expect the IPM cost algorithms to be cited in either the Control Cost Manual or the BART Guidelines. Regardless, the absence of a specific cite to a model in the Control Cost Manual is not evidence that the model is not acceptable. We have the authority to select the best tool for the job.

We have used IPM cost models to estimate BART costs in other similar rulemakings including our Arizona Regional Haze Federal Implementation Plans[502] the Wyoming Regional Haze Federal Implementation Plan,[503] to supplement our analysis in the Oklahoma Federal Implementation Plan,[504] and in our Texas-Oklahoma Regional Haze Federal Implementation

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[498] Control Cost Manual, Table of Contents, Section 5.2, Chapter 2, footnote 2.

[499] Section 5. Emission Control Technologies, Explaining: "EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission controls." Available at: http://www.epa.gov/airmarkets/documents/ipm/Chapter5.pdf.

[500] See Chapter 5 at http://www.epa.gov/airmarkets/programs/ipm/BaseCasev410.html.

[501] 40 CFR Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule, 69 FR 25,184 (May 5, 2004).

[502] 77 FR 42852 (July 20, 2012).

[503] Memorandum from Jim Staudt to Dough Grano, EPA, Re: Review of Estimated Compliance Costs for Wyoming Electricity Generating Units (EGUs) – Revision of Previous Memo, February 7, 2013, EPA-R08-OAR-2012-0026-0086_Feb 7 2013.

[504] 76 FR 81728.

Plan.[505] As explained in the Arizona rulemaking: "EPA's Clean Air Markets Division contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for SO_2 and nitrogen oxides NO_X emission controls."[506]

This comment also confuses "the IPM model" and the cost models that are inputs to the IPM model. The comment asserts that the IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital costs. In supporting this argument, it states: "IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia." This is an accurate description of "IPM model", but not of the cost models that generate input to the IPM.[507] The models used to generate these cost inputs are not "multi-regional, dynamic, deterministic linear programming models" but rather conventional costing models that use the same general methods set out in the Control Cost Manual to estimate total capital and O&M costs based on various design parameters. We only used the control technology cost models, not the IPM model itself.

Accuracy of IPM Cost Algorithms for Site-Specific Costs Estimates

Entergy argues that the IPM model only provides "generic order-of-magnitude costs," implying they are not acceptable for unit-specific cost estimates for the individual plants included in this rulemaking. We believe these cost models are adequate for projecting unit-level control costs for the purpose of conducting the type of cost-benefit analysis we have done in our proposal. For instance, S&L's own documentation for the wet FGD cost model states the following:

> The 2004 to 2006 industry cost estimates for wet FGD units from the "Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the wet FGD cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010. The cost increases reported from 2007 to 2008 by G. W. Sharp in "Update: What's That Scrubber Going to Cost?" published in Power Magazine, March 2009 were also considered. The published data was significantly augmented by the S&L in-house database of recent wet FGD projects. Cost data from the various sources showed similar trends versus generating capacity. Escalation based on the CEPI was deemed acceptable. All data sources were combined so as to provide a representative wet FGD cost basis. The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2007 to 2012 were included to confirm the index validity. Finally, the cost estimation tool was

[505] 81 FR 296.
[506] 77 FR 42852.
[507] http://www.epa.gov/airmarkets/programs/ipm/index.html.

benchmarked against recent wet FGD projects to confirm the applicability to the current market conditions.

As discussed above, S&L used real world cost data to construct its cost algorithms and confirm its validity. These cost models have been updated and maintained since their introduction in 2010 and have been continuously used by EPA since that time. These control costs are based on databases of actual control project costs and account for project specifics such as unit size, coal type, gross heat rate, retrofit factor, and require unit specific inputs such as reagent cost, waste disposal cost, auxiliary power cost, labor cost, gross load, and emission information. We believe that the IPM cost models provide sufficiently accurate, study-level, unit-specific costs for regulatory cost analysis such as required for BACT, BART, and reasonable progress.

This comment argues that the use of IPM algorithms is "not an appropriate choice for a unit-specific analysis consistent with BART guidelines" because: (1) it does not account for unit-specific design and operating parameters and (2) it does not consider site-specific conditions that could affect O&M costs. First, this comment redefines "case-by-case" as used in "case-by-case BART." BART means "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by . . . [a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility…."[508] In this context, case-by-case refers to each pollutant at each emission unit. We applied the IPM cost models for SO_2 at each emission unit using unit-specific inputs. Thus, the "case-by-case" requirement of the definition of BART is satisfied. Second, we accounted for "unit-specific design and operating parameters" by using unit and site-specific data as we discussed in our TSD.[509] Every input parameter to our SDA cost analysis was presented and discussed.

Accuracy of IPM Cost Estimates

Entergy asserts that the IPM cost models provide only "order of magnitude" control cost estimates. However, as the Control Cost Manual explains, the sole input required for making an "order of magnitude" estimate is "the control system's capacity (often measured by the maximum volumetric flow rate of the gas passing through the system)."[510] Such an estimate, for example, could be obtained from the cost reported in dollars per megawatt ($/MW) or dollars per million BTUs fired ($/MMBtu), metrics that are widely reported in the literature. A quick look at the many inputs to the IPM cost models[511] demonstrates that they provide more accurate estimates than "order of magnitude." The Control Cost Manual indicates that "the costs and estimating methodology in this Manual are directed toward the "study" estimate with a nominal accuracy of +/-30% percent."[512] This is the long-standing rule of thumb for cost estimate

[508] 70 FR 39163.
[509] See Section 3.2 of Appendix A to our TSD.
[510] Control Cost Manual, p. 2-3.
[511] See Cost TSD, Sections 3, 4, and 5 and Tables 6 (DSI), 6 (SDA), and 10 (WFGD).
[512] Control Cost Manual, p. 2-3.

accuracy used by the EPA for regulatory cost effectiveness analyses.[513]

Site-Specific Inputs

This comment also argues: "the cost algorithms were designed to require minimal site-specific information available from publicly available sources." The IPM SDA cost model includes a range of site-specific information, including: unit size, retrofit factor, gross heat rate, SO_2 rate, type of coal, coal factor, SO_2 removal efficiency, auxiliary power cost, lime cost, waste disposal cost, makeup water cost, operating labor rate, elevation, interest rate, equipment lifetime, and the SO_2 baseline. This large number of site-specific inputs is a clear demonstration that these cost models provide more accurate estimates than "order-of-magnitude,"[514] which only require a single parameter as the input.

We have enough confidence in the basic methodology behind the S&L cost algorithms that in our recent proposal for updating the SCR chapter of the Control Cost Manual,[515] we presented an example costing methodology that is based on the IPM S&L SCR algorithms, which were developed using a similar methodology to the wet FGD, SDA, and DSI cost algorithms discussed herein For the reasons we describe above, we disagree with S&L that our modifications to and use of the cost algorithms it has supplied us are inappropriate for use in regional haze control cost analysis.

Lastly, we note that Entergy used a number of general approximations when estimating the wet scrubbing costs for White Bluff, as we describe in our TSD:[516]

> Entergy uses a 2012 S&L wet FGD estimate for the White Bluff Units 1 and 2 as the starting point for its cost analysis. It then subtracts out all total construction and erection costs from the total project costs in order to obtain a total Equipment Cost (EC). Entergy then calculates the Purchased Equipment Costs (PEC), using this approximation from our Control Cost Manual:
>
> $$PEC = 1.18 \text{ X } EC$$
>
> Although not stated, Entergy then calculates the Total Capital Investment (TCI) using the following approximation from our Control Cost Manual:
>
> $$TCI = DC + IC = (1.85 \text{ X } B) + \text{Site Preparation} + \text{Bldg} + (0.35 \text{ X } B)$$
>
> Where DC = Direct Costs, IC = Indirect Costs, and B= PEC. It appears Entergy assumed no cost for site preparation and buildings.
>
> Entergy calculated the direct annual costs, using fixed and variable O&M costs from a 2011 S&L cost summary as a surrogate for the apparently unavailable

[513] EPA, New Source Review Workshop Manual, Draft, October 1990, p. B.35.
[514] Control Cost Manual, p. 2-3.
[515] 80 FR 33515.
[516] See discussion beginning on page 19 of Appendix A to our TSD.

> direct annual costs from the 2012 S&L estimate. Entergy then calculated the indirect annual costs using multiplier approximations from our Control Cost Manual. Lastly, Entergy calculated the annualized capital cost in the usual manner by multiplying the TCI by the capital recovery factor.

We disagree with S&L's comments. As can be seen from the above, Entergy employed a number of very general approximations that are not site-specific and there was a discrepancy between Entergy's SO_2 emission baseline used in its cost analysis and the assumed SO_2 inlet it assumed in the design of its scrubber. Therefore, our approach using the IPM SDA cost algorithm to recalculate the costs was necessary and reasonable.

Comment: EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff and used an incorrect methodology that inflates SO_2 emissions reductions. [Entergy Arkansas Inc. (0166) p. 7-8] EAI stated that the BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id.* The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015- 0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id.* This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id.* at 4, Table 2.

Response: We address these comments, which are summaries of its contractor S&L's comments, in our responses to S&L's comments.

Comment: The costs for dry scrubbers at White Bluff are too high to constitute BART based on Entergy's updated S&L cost analysis. [Entergy Arkansas Inc. (0166) p. 11-13] EAI stated that EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of $7,689-$8,599/ton at Unit 1 and of $7,642-$8,546/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost-effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id.* at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota

Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately $3.1 billion per deciview at Caney Creek and $2.7 billion per deciview at Upper Buffalo and, for Unit 2, approximately $2.9 billion per deciview at Caney Creek and $2.6 billion per deciview at Upper Buffalo.[517]

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2 of EAI's comments. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

Response: As we discuss in our responses to other comments that treat the issues raised here in more detail, we disagree with many aspects of Entergy's comments concerning the cost of installing scrubbers at the White Bluff facility. We conclude that the cost effectiveness of installing scrubbers at White Bluff is not $7,689-$8,599/ton at Unit 1 and $7,642-$8,546/ton at Unit 2, (see our response to other comments). Hence, Entergy's comparison to our previous actions is not valid. When considered in conjunction with the significant visibility benefits expected to occur from the installation of these scrubbers, we consider the cost effectiveness of installing scrubbers at the White Bluff facility to be reasonable. We discuss in a separate response our position regarding the $/deciview metric.

[517] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

Comment: EPA's cost estimates for controls on White Bluff and Flint Creek do not include significant costs that EPA says are not allowed by the EPA Control Cost Manual, even though these costs will be incurred by the owners of the facilities and ultimately passed on to ratepayers.

[Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 32-36] Nucor stated that EPA is requiring control technology for White Bluff SN-01, SN-02 and Flint Creek at a cost determined by the plant operators to be \$2,913/ton SO_2, \$3,355/ton SO_2, and \$3,845/ton SO_2, respectively. These figures do not include significant costs such as AFUDC that will be incurred by the owners of those facilities and that will be recoverable ultimately from rate-payers in rate making proceedings before the Arkansas Public Service Commission.[518] In addition, EPA believes that the costs of controls at Independence would be similar to the costs at White Bluff.

EPA claims that such additional costs, including AFUDC, are not allowable costs under EPA's Cost Control Manual. However, EPA's Cost Control Manual does not recognize the economic and financial realities of public utility operations, and thus it ignores important factors that should be considered.[519] EPA does not have any special expertise in power plant construction, public utility financing, or public utility cost recovery and rate regulation; thus its cost estimates for White Bluff, Flint Creek and Independence are not entitled to deference. See, *King v. Burwell*, 135 S. Ct. 2480 (2015) (where regulatory agency does not have expertise in the field, its interpretations are not subject to deference.) The ultimate cost of EPA's BART and Reasonable Progress determinations to Entergy, AEP/SWEPCO, and AECC and its member cooperatives is limited, because they will be entitled by law to recover their costs from ratepayers, regardless of whether those costs are "allowed" under EPA's Cost Control Manual. See Ark. Code Ann. §23-4-501 (recently amended to explicitly provide for cost recovery of AFUDC under an interim rate surcharge). Thus, for purposes of White Bluff, Flint Creek and Independence, which are public utility BART sources, the proper cost to be considered in EPA's BART and Reasonable Progress determinations is the costs that the owners of White Bluff, Flint Creek and Independence will be allowed to recover from ratepayers.

AFUDC stands for "Allowance for Funds Used During Construction." AFUDC is part of the Federal Energy Regulatory Commission Uniform System of Accounts, and is utilized by both the FERC and state regulatory commissions, including the Arkansas Public Service Commission to account for construction financing costs which are added to the cost of the plant for rate recovery when the plant is put into service. AFUDC can easily amount to tens of millions of dollars. EPA also omitted other costs in its BART and Reasonable Progress determinations that the operators of White Bluff, Flint Creek and Independence will be permitted to recover in their electric rates.[520] Another cost to ratepayers that EPA failed to take into consideration is the rate of return that will be allowed to the owners of White Bluff, Flint Creek and Independence on the total allowable costs of the control technology required by EPA. Recently, Arkansas utilities have

[518] See Entergy's White Bluff and AEP's Flint Creek Final BART Five Factor Analyses, attached as Exhibits 12 and 16 to Nucor's comments.

[519] It should be noted that EPA's Cost Control Manual is just a rough guide, with an admitted error of +/- 30%. (Docket document No. 139-3, p. 1-4)

[520] See Entergy's "Response to EPA Region 6 comments on Entergy White Bluff draft BART Report, 06/10/13," Docket Doc. No. 0043, pp. 6-10; Ex. 12 to Nucor's comments, Entergy's "Response to 8/21/2013 EPA Region 6 comments on White Bluff BART FFA," Docket Doc. No. 0045, pp. 2-3.

been permitted a rate of return between 4 and 6% on the total cost. The Arkansas Public Service Commission is obligated to allow public utilities to recover their actual costs, plus a reasonable return on investment, regardless of whether those costs are recognized under EPA's Cost Control Manual. Since these costs are legally allowed under Arkansas law, they are relevant factors that should have been taken into account by EPA in its BART and Reasonable Progress determinations. *Michigan v. EPA*, 135 S. Ct. 2699 (2015) (unreasonable for EPA to not take into consideration relevant factors).[521]

[Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 13-15] AEEC and AGC stated that the EPA's proposed FIP requires controls for White Bluff SN-01, SN-02 and Flint Creek at a cost determined by the plant's owners and operators to be $2,913/ton SO2, $3,355/ton SO2, and $3,845/ton SO_2, respectively. In addition, the EPA states that the costs of controls at Independence would be similar to the costs at White Bluff. Notably, these estimates do not include significant costs, such as Allowance for Funds Used During Construction (AFUDC)[522] and rate of return,[523] that the owners of those facilities will ultimately recover from Arkansas ratepayers.[524]

The EPA asserts that such additional costs are not allowable costs under the EPA's Cost Control Manual. The Cost Control Manual, however, fails to comprehend the realities of public utility operations in Arkansas; thus, it ignores important factors the EPA should have considered when assessing the cost-effectiveness of the controls required by the Proposed FIP. The ultimate cost of EPA's BART and Reasonable Progress determinations to the public utilities who own the facilities is limited, because Arkansas law allows them to recover their costs from Arkansas ratepayers, regardless of whether said costs are "allowed" under the Cost Control Manual.[525] Thus, for the public utility sources affected by the proposed FIP, the proper costs to be considered in the EPA's BART and Reasonable Progress determinations is the costs that Arkansas law allows the plant owners to recover from Arkansas ratepayers. Since Arkansas law allows public utilities to recover these additional costs that the EPA failed to consider due to its arbitrary and capricious application of the Cost Control Manual, these costs are relevant factors that the EPA should have considered in its BART and Reasonable Progress determinations.[526] Further, since the EPA lacks special expertise in public utility financing and public utility cost recovery and rate regulation, the EPA's cost estimates for these utility-owned sources are not

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[521] EPA's adjusted and proposed cost-effectiveness numbers for White Bluff, Flint Creek and Independence exceed the upper limit of EPA's projected cost-effectiveness range of $400 – 2,000/ton SO_2 for EPA's presumptive SO_2 BART limits in support of the national Regional Haze Rule. Exhibit 17 to Nucor's comments, Technical Support Document for BART, April 2005, p. 8.

[522] AFUDC is part of the Federal Energy Regulatory Commission's Uniform System of Accounts, and is utilized by both the FERC and state regulatory commissions, including the Arkansas Public Service Commission ("APSC"), to account for construction financing costs which are added to the cost of the plant for rate recovery when the plant is put into service.

[523] Arkansas law obligates the APSC to allow public utilities to recover their actual costs, plus a reasonable return on investment fixed by the APSC.

[524] *See* Ark. Code Ann. § 23-4-502; *see also McDaniel v. Arkansas Public Service Commission et al.*, 2014 Ark. App. 529 (Ark. App. 2014).

[525] *See also* Ark. Code Ann. § 23-4-501 (amended during the 2015 General Assembly to explicitly allow recovery of AFUDC through an interim surcharge).

[526] *Michigan v. EPA*, 135 S. Ct. 2699 (2015) (unreasonable for EPA to not take into consideration relevant factors).

entitled to deference.[527] Since the EPA failed to consider relevant factors when it rendered its BART and Reasonable Progress determinations for the power plants affected by the Proposed FIP, the Proposed FIP is unreasonable, arbitrary, and capricious, and the EPA should withdraw it.

In rejecting and adjusting Entergy's cost calculations for White Bluff, it is not clear whether EPA accounted for the differential cost of low-sulfur coal in its BART analysis. Entergy's cost calculations were based on uncontrolled SO_2 emissions of 2.0 lb/MMBtu, a level much higher than the emission rate from White Bluff's historical use of more-expensive low—sulfur coal.[528] EPA's BART analysis requires continued use of low sulfur coal, at a level of 0.65 to 0.68 lb SO_2/MMBtu, based on 2009-2013 data.[529] EPA should explain whether it took the cost difference between low-sulfur coal and high-sulfur coal into account in its BART determination, and if not, it should do so.

Response: It has been our long-standing position in the regional haze program that AFUDC is not allowed under the Control Cost Manual approach of cost estimating. A cost effectiveness analysis is a regulatory analysis that is based on current annual dollars without any inflation. AFUDC is an accounting method. Assets under construction do not provide service to current customers and thus associated interest and allowed return on equity are not charged to current customers. Instead, AFUDC capitalizes these costs and adds them to the rate base so that they can be recovered from future customers when the assets are used. Thus, these charges represent future cash income to the utility. In other words, AFUDC is the accumulated cost of carrying capital and holding it waiting to spend, so money can be made in the future by selling electricity. Future income should not be charged against the cost of a control in a BART cost-effectiveness analysis. These costs are not part of the constant dollar approach found in the Cost Manual and should not be included in BART cost-effectiveness analyses. We invite Nucor to examine our response to similar comments we received in response to those actions. Our position regarding AFUDC has been upheld in the ninth circuit court of appeals. As explained in more detail by the court:

> The purpose of the cost analysis required as part of a BART determination is to foster comparison of the cost of the visibility improvements enabled by various control technologies. As EPA's comments indicate, cross-facility comparisons of similar sources with regard to the cost-effectiveness of a given control option aid in determining cost-effectiveness at a specific source. Control options are likely to impact similar sources similarly; comparisons assure that the cost and benefit figures used for a particular site are realistic, rather than inflated in one direction or another. Consideration of AFUDC would not further this inquiry, as AFUDC is ultimately reflective of the implementing entity's financial and logistical situations, grounded in past decisions and in the

[527] *See King v. Burwell*, 135 S. Ct. 2480 (2015) (where regulatory agency lacks expertise in the particular field at issue, its interpretations are not entitled to deference).
[528] See Exhibits 15A and 15B to Nucor's comments, demonstrating the reduction in SO_2 emissions and coal sulfur concentrations for White Bluff in 2009-2011, compared to 2001-2003.
[529] 80 Fed.Reg. 18970, April 8, 2015.

> company's financial policies and attitudes, not of the hard costs of the equipment and construction, which should be consistent across sites. While AFUDC and similar concepts are relevant for sales and ratemaking, including them would undermine the sort of "apples-to-apples" comparison that EPA asserts is necessary as part—but only part—of assessing the control options.
>
> This approach is consonant with the Guidelines, which specifically advise that "reasonable range[s]" for cost effectiveness are those that are "consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time." Guidelines at 39,168; *see also Oklahoma*, 723 F.3d at 1213 ("The guidelines say that states should follow the manual's methodology so that projects can be more easily compared."). Moreover, adopting a costing methodology which focuses on achieving consistency and facilitating comparisons aligns with the CAA itself, which empowers EPA to promulgate *national* regulations concerning BART determinations. *See* 42 U.S.C. § 7491(a)(4), (b)(1).

Nucor states we should explain whether we took the cost difference between low-sulfur coal and high-sulfur coal into account in our BART determination, and if not, that we should do so. In our response to another comment, we have discussed how we addressed the mismatch Entergy introduced in its BART cost analysis by burning coals at White Bluff with sulfur contents corresponding to typical Power River Basin coals (resulting in annual uncontrolled SO_2 emissions ranging from 0.46 lbs/MMBtu to 0.625 lbs/MMBtu), while designing its White Bluff scrubber systems assuming a coal with an uncontrolled SO_2 emission rate of 2.0 lbs/MMBtu.

Comment: Entergy objects to the disallowance of owner's costs in our White Bluff cost analysis. [S&L Entergy Report, page 10]. Entergy explained that Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant

- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Entergy states that Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets. CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems. Entergy refers to the a section in S&L Report #012831 it included in its comments that describes Entergy's Owner's costs and how they were developed.

Response: As we have noted in many previous actions, owner's costs are not included in a cost analysis performed according to the Control Cost Manual methodology. None of the costs that Entergy notes in its comment is accompanied by any documentation, and in fact some appear optional. Entergy cites to the CUECost model, which estimates control costs using the levelized cost method developed by the EPRI (as opposed to the overnight method employed by the Control Cost Manual), is thus not approved for BART determinations, and thus has no relevance here.

Comment: EPA's cost analysis for the Independence Plant is legally and factually flawed, as it inappropriately relies on the White Bluff cost analysis, for which EPA inappropriately eliminated legitimate costs.

[Entergy Mississippi Inc. (0168) p. 10-11] EMI stated that EPA justifies imposition of controls at the Independence Plant on the basis that doing so is cost-effective.[530] However, there are numerous legal and factual errors affecting EPA's determination of the cost-effectiveness of the proposed controls for Independence. First, cost-effectiveness is not a stand-alone justification for imposing reasonable progress emission limitations, although it is a factor in deciding the level of control necessary to establish RPGs. Second, EPA's cost analysis for the proposed controls at the Independence Plant relies upon the control cost analysis for White Bluff, which is inappropriate. By simply relying on the White Bluff cost analysis without undertaking a site-specific analysis for the Independence Plant, EPA has arbitrarily departed from its own guidance for determining the costs of controls for reasonable progress purposes. Specifically, EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters.[531] Additionally, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, EPA's proposed FIP grossly underestimates those

[530] 80 Fed. Reg. at 18,994-97.
[531] *See* Environmental Protection Agency, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program 5-1 – 5-2 (Jun. 1, 2007).

costs. EPA's cost analysis for White Bluff and Independence contains multiple errors and inaccuracies which have resulted in a vast underestimation of the true cost of controls to the utility owners and their customers. Finally, even if EPA's cost analysis as detailed in EPA's SO_2 Cost TSD were correct, EPA's determination that the controls are cost-effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

[Entergy Mississippi Inc. (0168) p. 10-11; Conway Corporation et. al. (0172) p. 13, 14-15; and EEAA (0173) p. 6, 7-8] EMI, Conway Corporation et. al., and EEAA stated that among other errors in the White Bluff analysis which EPA relied on to develop the Independence cost analysis, EPA improperly excluded from the cost calculation legitimate costs to install scrubbers, thereby eliminating millions of dollars in costs from Entergy's cost analysis.[532] EPA mistakenly assumed certain costs were included in the vendor estimates, so it eliminated these costs as duplicative, including costs for: the reagent handling system; the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney; the application of acid resistant coating to the chimney shell; replacing the continuous emissions monitoring systems; and, material and labor costs.[533] EPA also inexplicably eliminated the costs for one absorber vessel and cited no basis for its assumption that two absorber vessels are adequate for the White Bluff Plant despite the fact that dry scrubbers of this type have not been applied to units the size of the White Bluff Plant. EPA, which has no expertise in the design of FGD systems, offered no explanation for overriding the FGD supplier's determination regarding the number of absorber vessels that would be needed at the White Bluff Plant. These errors alone result in significant underestimation of the costs to be borne by the White Bluff Plant's owners and their customers, therefore rendering EPA's cost analysis clearly erroneous.

EPA also wrongly eliminated and/or failed to consider millions of dollars of owner's costs such as capital suspense costs, operating and maintenance costs attributable to site-specific factors, post-control fuel costs, and costs related to Allowance for Funds Used During Construction ("AFUDC"). EPA's elimination of these costs is contrary to EPA's own guidance[534] and previously approved regional haze implementation plans for other states.[535] Also, although the subject-to-BART sources removed AFUDC from the final five-factor BART analysis in response to comments from EPA, we disagree with EPA that AFUDC should not be considered in the control costs.[536] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30 - 46 months of construction that would be needed to install major control equipment such as scrubbers on a large unit. AFUDC, which can be thought of generally as carrying costs on not-

[532] *See* S&L FIP Cost Report at 7, 9 (attached as Exhibit A to Entergy Arkansas, Inc.'s comments on the Proposed FIP, filed July 15, 2015).
[533] *Id.* at 6-7.
[534] The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2015) (codified at 40 C.F.R. Part 51 App. Y). EPA's elimination of certain operating and maintenance costs and post-control fuel costs contravenes this requirement.
[535] For example, EPA previously approved BART determinations that assumed "worst-case coal scenarios." *See e.g.*, Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sep. 21, 2011).
[536] As noted in the White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future control cost analyses. White Bluff BART Analysis, at 5-4.

yet-rate-based capital costs (*i.e.*, includes interest as part of capital cost), is *standard* accounting and rate-making treatment of such costs, and it was appropriate to include AFUDC in the sources' cost analyses. Contrary to EPA's assertions, the EPA Control Cost Manual does not preclude inclusion of AFUDC and, in fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable.[537] The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but actually is a recognition of that category of costs. Plain and simple, carrying costs (AFUDC) accumulate on any capital project until it is placed into rate base. That is Utility Rate Regulation 101. Accordingly, the costs of controls for the subject-to-BART sources should appropriately include AFUDC.

For all these reasons, EPA should reject the existing cost analysis for the proposed controls and conduct an appropriate and accurate estimate of the cost of controls for the Independence Plant.

[Entergy Arkansas Inc. (0166) p.43-44; Conway Corporation et. al. (0172) p. 10-11; and EEAA (0173) p. 16-17] Entergy Arkansas Inc., Conway Corporation et. al., and EEAA stated that EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost-effective to do so. 80 Fed. Reg. at 18,994-97. EPA's determination that the proposed controls for the Independence Plant are cost-effective is arbitrary and capricious and represents a clear error of judgment.

First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, we disagree with EPA's estimated costs for the installation of dry scrubbers at White Bluff. EPA inappropriately revised Entergy's control cost analysis by eliminating the consideration of appropriate costs. EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed elsewhere in Entergy's comments, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B to EAI's comments. As discussed elsewhere in EAI's comments, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over $1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost-effectiveness at Independence Unit 1 of $4,234 and of $3,909 at Independence Unit 2, which is not cost effective on a $/ton basis for reasonable progress purposes and is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that

[537] *See* Control Cost Manual at 1-32, 2-44.

would result from installing these controls is estimated at approximately $1.33 billion at Caney Creek and $1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

Entergy Arkansas Inc., p.43-44, (0021); Entergy Mississippi Inc., p. 12-13, (009); Conway Corporation et. al., p. 10-11, (008); and EEAA, p. 17, (0014)] EAI, EMI, Conway Corporation et. al., and EEAA stated that despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost-effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost-effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost-effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton removed for Unit 1 and $2,286/$SO_2$ ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of $2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Such an acknowledgement is particularly appropriate in the present case where the state's Class I areas are already meeting and exceeding the URP necessary to achieve the national visibility goal. Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost-effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

Response: We have addressed AFUDC and owner's costs in our responses to other comments. We agree with Entergy that cost-effectiveness is not a stand-alone justification for imposing reasonable progress emission limitations, although it is one of the statutory factors. We believe we followed our regulations when assessing reasonable progress for the Independence facility, as we describe in our proposal.[538] We also believe we were consistent with our reasonable progress Guidance. We disagree that for the purposes of assessing reasonable progress, we erred in using our scrubber cost analysis for the White Bluff facility as a good starting point for assessing the scrubber cost-effectiveness of the Independence facility. As we note in more detail in our proposal, the White Bluff and Independence Plants are sister facilities with nearly identical units.

[538] See the discussion in our proposal beginning on 80 FR 18989 regarding how we assessed reasonable progress at the Independence facility.

We explained that we verified that the two plants are sister facilities by constructing a master spreadsheet that contains information concerning ownership, location, boiler type, environmental controls, and other pertinent information. Based on the similarities between the two facilities, in our analysis of costs for controls on Independence we relied on the total annualized costs of controls we developed for White Bluff. Due to the similarities in the facilities and the identical requirement for consideration of cost of controls under reasonable progress and BART, using the cost of controls from White Bluff was a reasonable approach for estimating the cost of controls for Independence Units 1 and 2. Using control costs from similar (let alone sister facilities, as in this case) as the basis to assess the cost of controls is a common practice. We do note that in calculating the cost effectiveness of SO_2 controls for Independence Units 1 and 2, we used baseline SO_2 emissions data specific to the Independence units to estimate the annual SO_2 emissions reductions due to controls. Entergy has submitted comments critiquing our White Bluff scrubber cost analysis, and has submitted a revised White Bluff scrubber cost analysis. We incorporate Entergy's revised White Bluff cost analysis into our White Bluff cost analysis. However, Entergy has not submitted any scrubber cost analysis for the Independence facility or other information that would cause us to conclude that the cost of installing scrubbers would be significantly higher at the Independence facility in comparison to the White Bluff facility. Thus, considering the information we have available to us, we conclude that the cost to install scrubbers at the Independence facility is similar to what we have calculated for the White Bluff facility. In any case, we have not seen any information presented by Entergy to conclude that the differences in scrubber costs between the White Bluff and Independence facilities are outside the +/-30% accuracy required for study level estimates, which are based on "rough sketches," "preliminary sizes," "approximate sizes," "rough estimates," etc., which is the level of accuracy required for regional haze cost analyses.[539] Thus, we continue to base our Independence scrubber cost analysis on our White Bluff cost analysis, which we have revised based on Entergy's comments. We address this issue, as well as other criticisms our White Bluff cost analysis in more detail in our response to other comments.

Entergy states that our proposed costs for the installation of scrubbers at the Independence facility are higher than other reasonable progress costs that we have deemed to be too high in other instances. As an initial matter, cost is only one of four required factors that must be considered in determining reasonable progress for Independence, as Entergy itself acknowledges earlier in its comments.[540] We note that the cost of compliance is also a factor that must be considered in a BART analysis.[541] In addition, in our reasonable progress analysis for Independence, we also considered the visibility improvement of controls. We discuss elsewhere in this document that although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. As we have discussed in our Texas and Oklahoma FIP final decision, "…we believe that states (or EPA when promulgating a FIP) can

[539] Control Cost Manual, p. 2-3.

[540] See section 51.380(d)(1)(i): "(i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must: (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

[541] CAA section 169A(g)(2) and 40 CFR section 51.308(e)(1).

consider visibility when determining reasonable progress….". Regardless, we have recently finalized reasonable progress and long-term strategy SO_2 emissions in our Texas and Oklahoma FIP based on scrubber retrofits, similar to those discussed herein, at cost-effectiveness figures above those for the Independence facility.[542]

Regarding the Kentucky proposal cited by Entergy, we disagree that requiring SO_2 controls for Independence is inconsistent with our approvals of the Kentucky and North Carolina RH SIPs. As discussed elsewhere in this document, in response to comments we received, we have revised our initial cost analysis for Independence Units 1 and 2. We have determined that dry scrubbers are estimated to cost \$2,853/SO_2 ton removed for Unit 1 and \$2,634/SO_2 ton removed for Unit 2. Even with these cost adjustments, we continue to believe that these controls are cost effective and disagree that requirement of these controls is inconsistent with our approvals of the Kentucky and North Carolina RH SIPs. The commenter contends that in our proposed approval of the Kentucky RH SIP, we approved the state's use of a \$2,000/SO_2 ton threshold. This is incorrect. In the preamble of our proposed approval of the Kentucky RH SIP, we discussed that the state identified 10 units for evaluation under reasonable progress, and that 9 of these were EGUs subject to CAIR. The remaining facility, Century Aluminum, is not an EGU. We further discussed that for the limited purpose of evaluating the cost of compliance for the reasonable progress assessment in this first regional haze SIP for the non-EGU Century Aluminum, Kentucky concluded that it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy. As a result, Kentucky decided to use CAIR as a guide, using a cost of \$2,000 per ton of SO_2 controlled or reduced as a threshold for cost-effectiveness for that particular non-EGU source. We stated the following regarding Kentucky's evaluation of the Century Aluminum facility:

> The Century Aluminum facility in Hawesville, Kentucky, has four potlines with 2002 base year emissions of 4,985 tons per year of SO_2 which were identified as having a significant contribution at the Mammoth Cave Class I area. VISTAS evaluated control options and costs for sources within the AOI for the Class I areas of concern. VISTAS used EPA's AirControlNet software to evaluate control options and costs for controls. The cost effectiveness of SO_2 control suggested by the VISTAS control cost spreadsheet for potlines 1– 4 at Century Aluminum is \$14,207 per ton of SO_2 removed. Since the cost of compliance for the control option is over seven times greater than the Commonwealth's cost-effectiveness threshold [\$2,000] for reasonable progress, KYDAQ concludes that there are no cost-effective controls available for these Century Aluminum units at this time within the cost threshold established for this reasonable progress assessment for the first implementation period.[543]

[542] See Table 32 on our proposal for this action at 79 FR 74876 for a cost-effectiveness summary. As we discuss in our final action, 81 FR 317, "We received other comments relating to our scrubber retrofit cost analyses, but none of them caused us to revise our scrubber retrofit cost-effectiveness basis."
[543] 76 FR 78206.

We proposed to approve Kentucky's determination that there are no reasonable controls available for the Century Aluminum units for the first implementation period, but we also stated the following concerning our position on Kentucky's use of a \$2,000/SO_2 ton screening threshold:[544]

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the Kentucky SIP still ensures reasonable progress. In proposing to approve Kentucky's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP submittal that Kentucky, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I area. EPA notes that given the emissions reductions resulting from CAIR, Kentucky's BART determinations, and the measures in nearby states, the visibility improvements projected for the affected Class I area are in excess of that needed to be on the uniform rate of progress glidepath.

It is clear that in our proposed approval of Kentucky's reasonable progress determination for the Century Aluminum units, we were not approving or otherwise advocating Kentucky's use of a \$2,000/SO_2 ton threshold in the reasonable progress analysis. On the contrary, we expressed concern that the use of a specific threshold for assessing cost may result in a state not fully considering potential reasonable control measures above that threshold that would have meaningful visibility improvement on its Class I areas. But in this particular instance, we do not believe that the use of a cost threshold in Kentucky's SIP resulted in the state overlooking potential controls in its reasonable progress analysis. Furthermore, our statements in the proposal indicate that had there been evidence of controls available above the \$2,000/SO_2 ton threshold used by the state that provide meaningful visibility improvement at the Class I areas, we might have arrived at a different decision concerning the approvability of Kentucky's reasonable progress analysis.

North Carolina took a similar approach as Kentucky in its reasonable progress analysis. In our proposed approval of the North Carolina RH SIP, we discussed that the state identified 11 units (non-EGU) for evaluation under reasonable progress. We noted that North Carolina decided that for the limited purpose of evaluating the cost of compliance for the reasonable progress assessment in this first regional haze SIP for these non-EGs, it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy. Regarding Entergy's reference to our North Carolina reasonable progress proposal, we stated:

> NCDAQ believed that it was not equitable to require non- EGUs to bear a greater economic burden than EGUs for a given control strategy. The facility-by-facility costs for EGUs under CSA ranged from 912 to 1,922 dollars per ton of SO_2 removed (\$/ton SO_2), and the average costs per utility system ranged from \$1,231 to \$1,375/ ton SO_2. These costs were estimated using the capital costs from the

[544] 76 FR 78206.

> CSA 2006 compliance plans and the projected operating costs provided by Duke Energy and Progress Energy. These costs were used as a guide in determining cost effectiveness.[545]

We proposed to approve North Carolina's determination that there are no reasonable controls available for sources in the state for the first implementation period, but we also stated the following concerning our position on North Carolina's use of a specific screening threshold:

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the North Carolina SIP ensures reasonable progress. In approving North Carolina's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP revision that North Carolina, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I areas.[546]

Thus, we do not believe that the use of a cost threshold in North Carolina's SIP resulted in the state overlooking potential controls. As in the case of Kentucky, it is clear that in our proposed approval of North Carolina's reasonable progress determination, we were not approving or otherwise advocating North Carolina's use of that specific screening threshold in the reasonable progress analysis.

Entergy also points to our North Dakota final decision as evidence that we have concluded that cost-effectiveness values for BART may be too high for reasonable progress determinations. This conclusion is not borne out by the facts. First, the unit in question in our North Dakota decision already had a dry scrubber, albeit one that is underperforming relative to typical dry scrubber efficiencies. The control cost evaluation discussed in the response to comment that Entergy cites would have replaced the existing dry scrubber with a new wet scrubber. Thus, the basic facts between our Independence reasonable progress analysis and our North Dakota decision are not comparable. Beyond that, we did not make the kind of blanket statement concerning the acceptability of reasonable progress cost-effectiveness in comparison to that of BART that Entergy claims. The full quote that Entergy partially reproduces is:

> As stated in our proposal, while this value is within the range of cost effectiveness values that North Dakota, other states, and we have considered reasonable in the BART context, it is not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context.

As can be seen from an examination of the full quote, this statement in no way constitutes a blanket comparison of the acceptability of BART cost-effectiveness to that of reasonable progress determinations.

Entergy further states that re-applying its revised White Bluff cost analysis to the Independence

[545] 77 FR 11870.
[546] 77 FR 38189.

facility would result in a cost-effectiveness $4,234 at Unit 1 and $3,909 at Independence Unit 2. Entergy states that those figures are not cost effective and results in a much higher cost per ton than values we have rejected for reasonable progress determinations in other states. As we discuss in our response to other comments, we do not agree with Entergy's revised scrubber cost analysis for the White Bluff facility and believe it is much lower.

Comment: EPA and Entergy's evaluations of the cost of dry and wet scrubbers for White Bluff contained conservative assumptions and included errors that inflated the cost of these controls. [Sierra Club et. al. (0171) p. 19-21] Sierra Club et. al. stated that EPA proposed that SO_2 BART for White Bluff Units 1 and 2 is an emission limitation of 0.06 lb/MMBtu on a 30-day rolling average based on the operation of a dry scrubber or another technology. 80 Fed. Reg. at 18,972-73. EPA estimated that this technology would have an average cost-effectiveness of $2,227 per ton of SO_2 removed for Unit 1 and $2,101 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,972. We strongly support EPA's proposal to require the installation of a scrubber at White Bluff and to set a limit on SO_2 emissions. The attached Stamper report confirms EPA's conclusion that the controls proposed in the FIP are cost-effective and readily satisfy the other BART requirements, and any less effective controls would not comply with BART. Stamper Report at 30-32. In fact, Ms. Stamper conducted her own analyses of the proposed controls and concludes that the proposed controls are even more cost-effective than EPA considered, can achieve an emission rate of 0.04 lb/MMBtu, will provide greater visibility benefit, and are reasonable compared to costs borne by sources in other states. *Id.* As such, EPA should determine that SO_2 BART for the White Bluff units is an emission rate of 0.04 lb/MMBtu based on the use of either a wet or a dry scrubber.

The Technical Support Document to Comments of Conservation Organizations, Prepared by Victoria R. Stamper, August 5, 2015 ("Stamper Report"), discusses several ways in which EPA and Entergy used conservative assumptions that inflated the cost of the controls EPA is proposing and concludes that these controls are even more cost-effective than EPA calculated.

First, EPA itself identified several flaws with Entergy's cost analysis but failed to correct the analysis. Ms. Stamper's revised cost analysis addresses the problems EPA identified with Entergy's dry and wet scrubber cost estimates. First, Entergy based its operation and maintenance ("O&M") costs on burning coal with an uncontrolled SO_2 rate of 2.0 lb/MMBtu. *See* 80 Fed. Reg. at 18,970. As EPA correctly noted, actual uncontrolled SO_2 emissions rates for the White Bluff units have been 35% of what Entergy assumed. *Id.* The Clean Air Act requires that EPA determine BART using a "baseline emission rate [that] represent[s] a realistic depiction of anticipated annual emissions." 40 C.F.R. Part 51, App. Y § (D)(4)(d)(1). As such, a lower uncontrolled SO_2 rate than that assumed by Entergy is appropriate for BART evaluation.

Second, EPA found that Entergy included undocumented costs that, under EPA's Cost Control Manual, are inappropriate and could constitute double counting. *See* 80 Fed. Reg. at 18,971. EPA should require that Entergy appropriately document all costs and prohibit the inclusion of costs that other EGUs in other states were precluded from including pursuant to the Cost Control Manual. Similar cost estimate rules across states are necessary for reasonable comparison of cost-effectiveness.

Ms. Stamper revised the cost analyses for a wet scrubber, a dry scrubber, and a NID scrubber that reflect achievable emission rates. Ms. Stamper used the SO_2 control cost spreadsheets that EPA recently used in the Texas regional haze rulemaking, which are based on Sargent & Lundy Integrated Planning Model ("IPM") cost modules. Stamper Report at 30-32. EPA's conservative cost-effectiveness calculations and Ms. Stamper's revised cost-effectiveness calculations both demonstrate that EPA should base the SO_2 BART emission limit on installation of scrubbers:

Revised SO_2 Control Cost-Effectiveness Evaluation for White Bluff Units 1 and 2[547]

White Bluff Unit	SO_2 Control	Total Annualized Costs	Tons SO_2 Removed	Cost Effectiveness	EPA's Cost Effectiveness[548]
1	Wet FGD	$38,113,408	18,569 tpy	$2,053/ton	$3,336/ton
1	NID™ CDS	$40,584,907	18,569 tpy	$2,186/ton	--
1	Dry FGD (SDA)	$40,103,035	17,995 tpy	$2,229/ton	$2,227/ton
2	Wet FGD	$37,304,852	15,975 tpy	$2,335/ton	$3,152/ton
2	NID™ CDS	$39,191,891	15,975 tpy	$2,453/ton	--
2	Dry FGD (SDA)	$39,046,260	15,459 tpy	$2,526/ton	$2,101/ton

These cost-effectiveness estimates, assuming actual uncontrolled SO_2 emissions during the 2001-2003 baseline period—which are lower than the emissions assumed by Entergy—show that a wet scrubber, a dry scrubber, and a NID scrubber are all cost effective as compared to BART determinations in other states. *See* Section I.A.1.a.i of the Sierra Club et. al.'s comments (providing SO_2 BART costs from other states).

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. We confirm that we intended to construct conservative cost analyses. The Sierra Club states that we identified several flaws with Entergy's cost analysis but failed to correct the analysis. We do not find any flaws in the White Bluff BART analysis that we did not propose to correct, except for minor oversights (noted in our responses to Entergy's comments) that do impact our proposed BART determinations.

Ms. Stamper proposes that we should have required the installation of scrubbers in three years, citing to a letter to Senator Carper dated November 3, 2010, in which David Foerter, executive director of the Institute of Clean Air Companies (ICAC), which stated that wet scrubbers could be installed in 36 months, dry scrubbing technology could be installed in 24 months, and dry sorbent injection could be installed in 12 months. Ms. Stamper also cites to a number of scrubber installations that are planning on completing within three years, or thereabouts. We agree that in some cases scrubbers can be installed in less than the five years that we proposed. However, this is site-specific and we cannot guarantee that an installation timeframe of less than

[547] Stamper Report at 31.
[548] 80 Fed. Reg. 18,971, Tables 32 and 33.

five years would be achievable for White Bluff. Thus, we have defaulted to the maximum time allowed under the Regional Haze Rule for BART, which is five years. This has been our position on all scrubber installations we have required in our FIPs.

We disagree with the position Ms. Stamper takes in her report that wet scrubbers are, in the specific cases of the White Bluff and Independence facilities, more cost effective than dry scrubbers (SDA; we discuss NID below) and that BART should have been based on a wet scrubber control level of 0.04 lbs/MMBtu for the White Bluff facility (Independence is not subject to BART). Our scrubber cost analyses was built off of the analyses supplied by Entergy, and we determined that wet scrubbers were significantly less cost effective—again, in the specific cases of the White Bluff and Independence facilities for BART and reasonable progress respectively. The scrubber analysis that Ms. Stamper performs, uses a modified version of the IPM cost algorithms we used in our TX-OK FIP. Although we find the use of those algorithms perfectly adequate for cost analysis for both BART and reasonable progress, we disagree with the SO_2 baseline Ms. Stamper uses, rendering her scrubber cost analysis and ours not directly comparable. However, we generally agree with Ms. Stamper that an independent cost analysis such as she presents does support our basic position that scrubbers are cost effective at the White Bluff and Independence facilities.

We agree that the Alstom NID circulating dry scrubber is a promising SO_2 control option. We reviewed NID in our preliminary work but ultimately decided not to evaluate it as a control because we had no relevant operating data and no method to estimate costs. As part of our work related to our recent TX-OK FIP,[549] we addressed a similar comment. In so doing, we reviewed the proposed NIDs at Flint Creek (2016[550]), Homer City 1 & 2 (2016), Indian River Unit 4 (2011), Brayton Point Unit 3 (2013), and (Clay) Boswell Unit 4 (2016). We researched each one of these facilities and learned that only Indian River Unit 4 and Brayton Point Unit 3 were currently operating.

We downloaded the SO_2 CEMS data for these two facilities from CAMD, computed 30-day BOD averages, achieved SO_2 control efficiencies, and determined the maximum 30-day BODs. This analysis is present in the final docket for our TX-OK FIP.[551] Neither of these units is performing at the level of a wet FGD – 98% SO_2 control or 0.04 lb/MMBtu.

Indian River Unit 4 has achieved only 86% SO_2 removal based on a design level of 96%, rather than our target of 98% using wet FGD.[552] The maximum 30-day BOD is 0.94 lb/MMBtu and the lowest 30-day BOD, representing its best performance, is 0.07 lb/MMBtu. Brayton Point Unit 3 has achieved 94% SO_2 removal and the maximum 30-day BOD is 0.16 lb/MMBtu. Brayton

[549] 81 FR 296.
[550] Parenthetical dates are projected or actual startup dates, as reported in the McIlvaine Utility Tracking System or in CAMD.
[551] http://www.regulations.gov/#!docketBrowser;rpp=50;po=0;dct=PS;D=EPA-R06-OAR-2014-0754. See "Selected NID BOD SO_2 Averages.xlsx."
[552] Burns & McDonnell, Indian River Unit 4, http://www.burnsmcd.com/Resource_/Project/1302/ProjectPdf/Indian-River-Unit-4.pdf.

Point Unit 3 is scheduled for shutdown in 2017.[553] Further, these facilities are not similar to the White Bluff units as they burn bituminous coal with higher sulfur contents.[554]

However, this technology is promising, and we will continue to monitor NID performance for consideration in the next round of SIPs, when the technology has more relevant operating history.

The other NIDs we reviewed are "polishing" scrubbers on circulating fluidized bed boilers, which are not similar boiler types. Further, none of them burn PRB coal. For example, Seward burns high sulfur waste coal; Gilbert Unit 3 burns high sulfur bituminous coal; and Spurlock Unit 4 burns high sulfur bituminous coal and switchgrass.[555]

Finally, we note that as NID technology is theoretically capable of achieving the same SO_2 control efficiency as the wet FGD scrubber retrofits that we evaluated, the facilities in question are free to choose NID or any other technology to satisfy their emission limits.

Comment: EPA has overestimated the costs of SCR and underestimated the cost-effectiveness of SCR and SNCR for White Bluff Units 1 and 2. [Sierra Club et. al. (0171) p. 22-25] Sierra Club et. al. stated that EPA proposed that NO_X BART for White Bluffs Units 1 and 2 is an emission limitation of 0.15 lb/MMBtu based on the installation of Low NO_X Burners (LNB) and separated overfire air ("SOFA"). 80 Fed. Reg. at 18974. EPA estimated that operation of LNB/SOFA would have an average cost effectiveness of $350 and $340 per ton of NO_x removed for Unit 1 and Unit 2, respectively. *Id.* EPA's proposal to require LNB/SOFA represents a cost-effective way to achieve some NO_X emission reductions at White Bluff and, therefore, is the absolute minimum that EPA must require as selection of anything less stringent would be arbitrary, capricious, and contrary to law. The LNB/SOFA proposal, however, does not satisfy BART, which requires "the application of the *best* system of continuous emission reduction." Such best system is an SCR. The Stamper Report concludes that EPA has overestimated the costs of SCR, underestimated the visibility benefits of SNCR and SCR, and underestimated the cost-effectiveness of SCR and SNCR. Stamper Report at 35-45. The costs of these controls are reasonable compared to costs borne by sources in other states. *Id.* at 40-43. For these reasons, we urge EPA to conclude that NO_x BART at White Bluff Units 1 and 2 requires an emission limit of 0.04 lb/MMBtu based on installation of SCR with LNB/SOFA.

To more appropriately consider the cost of controls, Ms. Stamper revised the cost-effectiveness calculations for all of the NO_X BART controls evaluated by EPA and Entergy for the White Bluff Units 1 and 2. Ms. Stamper's cost-effectiveness estimates rely on the Sargent & Lundy IPM SCR Cost Module and assume an achievable NO_x emission rate of 0.04 lb/MMBtu for LNB/SOFA

[553] Dorothy Davis Ballard, Brayton Point Coal-Fired Power Plant Confirmed for Shut Dow by 2017, Power, January 29, 2014, http://www.pennenergy.com/articles/pennenergy/2014/01/brayton-point-coal-fired-power-plant-confirmed-for-shut-down-by-2017.html.

[554] http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=8&ved=0CFEQFjAHahUKEwifqrrXvc_HAhWFjw0KHQL9Cc8&url=http%3A%2F%2Fpennwell.websds.net%2F2013%2Fbangkok%2Fpga%2Fpapers%2FT2S4O1-paper.pdf&ei=GkXiVZ-1GoWfNoL6p_gM&usg=AFQjCNFWrXl39kOm6Ya_4YnvwtYZItZDOQ&cad=rja

[555] http://www.ekpc.coop/pressreleases/2009%20press%20releases/2009-04-01_Spurlock4_commercial_start.pdf

plus SCR. As noted elsewhere in the Sierra Club et. al.'s comments, EPA has relied on the Sargent & Lundy cost modules to estimate the cost for SCR in its evaluation of NO_X BART in other states. Stamper Report at 40-42. Ms. Stamper's revised cost analysis relies on baseline NO_x emissions from 2012-2014. Entergy used a 2009-2011 baseline for its NO_X BART analysis because the company had installed in 2006 a "neural network system" and conducted "extensive boiler tuning" at White Bluff Units 1 and 2 that resulted, according to Entergy, in reduced NO_X emission rates. 80 Fed. Reg.18,969. In fact, NO_x emission rates have increased from the NO_X rates achieved during the 2009-2011 timeframe at both of the White Bluff units. Stamper Report at 35-39. Based on data from EPA's Clean Air Markets Database, White Bluff Unit 1's NO_X rates have been steadily increasing since the neural network installation, whereas White Bluff Unit 2's NO_x rates have oscillated higher and lower. *See id.*

The BART guidelines require that the "baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, Appendix Y, Section IV.D.4.c. Given the variability of NO_x emission rates, Entergy's selection of a 2009-2011 baseline period is not a realistic depiction of anticipated annual NO_x emissions from the White Bluff units. In fact, Entergy's selection of the 2009-2011 timeframe for a baseline period reflects the period of lowest annual average NO_x emissions for White Bluff Unit 1 since the 2006 installation projects. Stamper Report at 37. For White Bluff Unit 2, the 2009-2011 annual average NO_x emissions were the second lowest three-year period of NO_X emissions after 2006, and more recent periods of NO_x emissions have been about 3% higher than the 2009-2011 timeframe. *Id.* Based on data compiled by Ms. Stamper, the period 2012-2014 appears to most realistically depict anticipated annual emissions for White Bluff. As such, Ms. Stamper's cost analysis assumes baseline emissions over the period 2012-2014 timeline, which is the highest three year period since the installation of the neural network system.

Ms. Stamper's revised estimates (and even Entergy's unrevised estimates) show that LNB/SOFA plus SCR and LNB/SOFA plus SNCR are both cost effective as NO_x BART for White Bluff:

Revised NO_x Control Cost-Effectiveness Evaluation for White Bluff Units 1 and 2 to Reflect a 2012-2014 Baseline and to Recalculate Costs for SCR to Achieve a 0.04 lb/MMBtu Emission Rate[556]

White Bluff Unit	NOx Control	Total Annualized Costs	Tons NOx Removed	Cost Effectiveness	EPA's Cost Effectiveness[557]
1	LNB/SOFA	$1,085,904	4,262 tpy	$255/ton	$350/ton
1	LNB/SOFA plus SNCR	$6,430,580	4,826 tpy	$1,332/ton	$1,758/ton
1	LNB/SOFA plus SCR (Aug 2010 IPM SCR Cost Module)	$17,708,428	7,364 tpy	$2,405/ton	$3,552/ton

[556] Stamper Report at 41-42.
[557] 80 Fed. Reg. 18973, Table 36.

1	LNB/SOFA plus SCR (Mar 2013 IPM SCR Cost Module)	$21,713,253	7,364 tpy	$2,949/ton	$3,552/ton
2	LNB/SOFA	$1,403,376	3,968 tpy	$354/ton	$340/ton
2	LNB/SOFA plus SNCR	$6,759,102	4,537 tpy	$1,490/ton	$1,449/ton
2	LNB/SOFA plus SCR (Aug 2010 IPM SCR Cost Module)	$18,083,166	7,099 tpy	$2,547/ton	$2,749/ton
2	LNB/SOFA plus SCR (Mar 2013 IPM SCR Cost Module)	$22,099,642	7,099 tpy	$3,113/ton	$2,749/ton

The above table demonstrates that the use of the higher NOx emissions during 2012 to 2014 results in greater NOx reductions and lower cost-effectiveness numbers for LNB/SOFA, LNB/SOFA plus SNCR, and LNB/SOFA plus SCR (when SCR costs are based on the August 2010 module). As discussed in Section I.A.2.b of Sierra Club's comments, EPA and states have found that costs of SCR plus combustion controls in the range of $2,000/ton to $4,500/ton were reasonable and cost-effective. Therefore, it is cost effective for White Bluff Units 1 and 2 to install LNB/SOFA plus SCR, and such controls will provide for the greatest improvement in visibility impairment due to White Bluff's NOx emissions compared to all other NOx controls evaluated by EPA.

Ms. Stamper states that we have not proposed to require installation of low NOx burners and separated overfire air as expeditiously as possible. Specifically, EPA proposed to allow three years from the effective date of the final rule to install low NOx burners/SOFA at White Bluff Units 1 and 2. 80 Fed. Reg.18,975. While three years from the effective date of EPA's final rulemaking may be necessary to install an SCR system, low NOx burners and SOFA can be installed in much shorter timeframes.

Specifically, the Institute of Clean Air Companies (ICAC) has indicted that the typical installation timeframe for low NOx burners would take between 6-8 months from bid evaluation through startup of the technology. Most of the components can be installed while the boiler is operating, and the boiler may need to be shut down for as little as 1 day or up to a week. Based on the ICAC report, eight months from the effective date of EPA's final regional haze rule for Arkansas should be sufficient time for Entergy to install low NOx burners and SOFA at White Bluff Units 1 and 2, and thus reflects implementation of BART as expeditiously as practicable.

With respect to SCR systems, three years is more than sufficient time for installation of SCR systems at White Bluff Units 1 and 2. In fact, other utilities have installed SCR systems on multiple units within very short periods of time.

As previously discussed, SCRs were installed and began operation on the W.A. Parish Units 5-8 over a period of about one year and three months. Specifically, an SCR was installed on W.A. Parish Unit 6 in Jan 2003, on W.A. Parish Unit 5 in April 2003, on W.A. Parish Unit 8 in Dec 2003, and on W.A. Parish Unit 7 in March 2004. SCRs were installed at four units of the Big Bend power plant over four year – one unit per year – during 2007-2010.177 SCR systems were installed at five units at Kyger Creek power plant over 2002 to 2003.178 SCR systems were installed at Units 1-5 of the Clifty Creek power plant also over 2002 to 2003.179 In 2005, Santee Cooper installed SCR systems on Cross Units 1 and 2 and Winyah Units 1-4, all in South Carolina.18

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. We disagree with the Sierra Club's apparent position that BART controls must be selected based on which are the "best system of control," without apparent consideration of the five BART factors: cost, energy and nonair quality environmental impacts, pollution controls in use at the source, remaining useful life, and visibility improvement.[558]

In critiquing our NO_X BART evaluation for White Bluff, Ms. Stamper argues that Entergy's 2009-2011 NOx baseline of 7,255 tons/yr for Unit 1 and 8,193 tons/yr for Unit 2 were not reflective of anticipated future actual emissions. Based on the annual emissions Ms. Stamper presents in Table 7, we agree that a three year average of the annual emissions from 2009-2011, 7,255 tons/yr does not represent the highest emitting three year average period for Unit 1, which was 10,041 in 2001-2003, seconded by the 8,492 value from 2012-2014. Similarly, the 2009-2011 average for Unit 2 of 8,193 tons/yr lags behind the 8,586 value from 2001-2003, the 8,297 value in 2011-2013, and the 8,238 value from 2012-2014. However, the BART Guidelines do not require that the baseline used in the cost effectiveness analysis be constructed from the highest emissions from any given year or years, only that, as Ms. Stamper acknowledges, the "baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[559] As a first matter, we believe it was reasonable to select a baseline after the neural network was installed in 2006, which eliminates from consideration the highest NO_X annual emission average for Unit 1 from the 2001-2003 period. We further note that were we to have selected a NOx baseline from the most recent three year average, 2013 to 2015, which arguably more "represent[s] a realistic depiction of anticipated annual emissions for the source," the result would have been 7,731 tons/yr for Unit 1 and 7,406 tons/yr for Unit 2. This would have produced a baseline only slightly higher for Unit 1, decreasing the cost-effectiveness calculation by 6.6%, which would not have materially impacted our proposed NOx BART determination. In contrast, this would have produced a baseline lower for Unit 2, increasing the cost-effectiveness calculation by 9.6%, making the NO_X controls less attractive. Hence, we find that no change is necessary to the White Bluff NOx baseline.

Ms. Stamper goes on to select a revised NO_X baseline based on a maximum three year NO_X average emissions calculation and inputs that, along with a rejection of our acceptance of Entergy's SCR NOx emission rate of 0.55 lbs/MMBtu in favor of a lower SCR outlet of 0.04 lbs/MMBtu, into a revised SCR cost analysis. She supports her 0.04 lbs/MMBtu NO_X rate by

[558] Summarized from Section 51.308(e)(1)(ii)(A).
[559] 70 FR 39167.

pointing to a number of high performing SCR installations, including those we presented in our San Juan SCR cost analysis in our New Mexico FIP, and a number of others that we did not include in our New Mexico FIP. We have re-reviewed/reviewed the information Ms. Stamper presents and conclude that, as we did in our New Mexico FIP, that it supports a 30 Boiler Operating Day (BOD) NO_X average of 0.05 lbs/MMBtu for a SCR installation at the White Bluff facility. We disagree with Ms. Stamper that it supports a 30 BOD average of 0.04 lbs/MMBtu, as she contends. We see no evidence of an SCR operating at that level for extended periods of time, such that we would feel comfortable that a 30 BOD average of 0.04 lbs/MMBtu would be sustainable at the White Bluff facility absent site-specific engineering information.

Although in our proposal we made corrections to Entergy's NO_X BART cost analyses, we did not criticize its choice of a SCR NO_X emission limit of 0.055 lbs/MMBtu. Entergy's SCR NO_X emission rate of 0.055 lbs/MMBtu was based on "permitted emission compliance"[560] which for this type of rate is generally based on 30 day calendar compliance period. Entergy confirms this on page 6-3 of its BART analysis.[561] Our New Mexico FIP decision to which Ms. Stamper cites, is based on a 30 BOD compliance period. As we discuss in our New Mexico FIP, "[Use of a] BOD would ensure that, when an outage occurs, the emissions following startup will be averaged with the emissions data from before the outage, rather than with the period of time during which the unit did not have any emissions at all because it was offline."[562] In other words, a 30 BOD averaging period is in effect less stringent than a straight 30 calendar averaging period because it does not overweigh emissions spikes as a 30 calendar day average can do during an extended outage. As a consequence, we considered Entergy's 0.055 lb/MMBtu average to be essentially equivalent to, or potentially more stringent than the 0.05 lb/MMBtu 30 BOD average we required in our New Mexico FIP, which forms the bulk of Ms. Stamper's support. Thus we (1) disagree with Ms. Stamper that SCR for White Bluff should be evaluated on the basis of a NO_X rate of 0.04 lbs/MMBtu, and (2) we believe Entergy's use of a 30 day calendar NO_X rate of 0.055 in its evaluation of SCR was reasonable (although as discussed elsewhere, we had other issues with Entergy's White Bluff BART analyses).

Ms. Stamper goes on to incorporate her adjusted NO_X baseline and a NO_X emission rate of 0.4 lbs/MMBtu into a revised SCR cost analysis, using the IPM SCR Cost algorithms. Due to the issues we discuss above concerning her revised baseline and NO_X emission rate, and the significant impact these two inputs have to such an analysis, we cannot agree that her revised SCR cost estimate is more representative of the cost of installing SCR at the White Bluff facility. Ms. Stamper ends her critique of our SCR cost analysis by arguing that SCR + combustion controls in the range of $2,000 to $4,500/ton have been found to be reasonable by us in other situations. That statement is true, and our SCR cost-effectiveness calculations for the White Bluff facility fall within that range. However, we note that the mere fact that the cost-effectiveness of a control (the familiar $/ton calculation) falls within a range that we have previously found to be acceptable is not the sole determinant we rely upon when either approving a state's BART determination or in finalizing BART in a FIP. As required by the CAA and reflected in Section 51.308(e)(1)(ii)(A), visibility improvement is also one of the five

[560] See page 8 of Appendix E (the Sargent & Lundy NOx control cost study for Entergy) to the White Bluff Plant Revised BART Five-Factor Analysis, dated 10/14/13.
[561] Id. "this rate includes consideration of normal fluctuations which may occur over a 30-day compliance period."
[562] 76 FR 52402.

required factors. In other words, the other BART factors aside, cost must balance visibility benefit. In this case, we do not believe that the cost effectiveness of SCR or SNCR fall within a range that justifies the relatively small incremental visibility improvement (over our NO_X BART determination based on LNB/SOFA) that would result from the installation of SNCR or SCR at the White Bluff facility.

We agree with Ms. Stamper that the typical installation timeframe for LNB/SOFA is a shorter timeframe than the three years we proposed for the White Bluff facility. As we discuss elsewhere in this document, we are finalizing an 18-month compliance date for White Bluff to comply with its NO_X BART emission limit. We are not requiring SCR controls for White Bluff and we discuss this elsewhere in this document. Because we are not requiring that SCRs be installed at the White Bluff facility, this comment is moot and we will not further address it.

Comment: The costs of both a wet and a dry scrubber are reasonable at the two Independence units, and EPA's cost-estimates are actually conservative. [Sierra Club et. al. (0171) p. 31-33] Sierra Club et. al., stated that the costs of both a wet and a dry scrubber are reasonable at the two Independence units. This along with consideration of the other reasonable progress factors supports EPA's requirement of the installation of scrubbers for Independence under the reasonable progress requirements. EPA largely relied on Entergy's cost calculations to conclude that a dry scrubber would cost $2,477 per ton for Unit 1 and $2,286 per ton for Unit 2, while a wet scrubber would cost $3,706 per ton for Unit 1 and $3,416 per ton for Unit 2. 80 Fed. Reg. at 18,993. All of these costs are within the range of costs that EPA has found reasonable in other reasonable progress determinations. *See*, below; Stamper Report at 60-62.

Moreover, Ms. Stamper independently calculated the costs of scrubbers at Independence Units 1 and 2, and her calculations confirm that a scrubber is cost-effective. *See* Stamper Report at 60-62. Ms. Stamper used the Sargent & Lundy IPM cost modules for wet and dry scrubbers. She concluded that EPA's cost-effectiveness estimates are conservative, given that a wet scrubber has a cost-effectiveness of $2,657 per ton for Unit 1 and $2,540 per ton for Unit 2. *Id.* at 61. Additionally, Ms. Stamper noted that EPA should have evaluated a NID circulating dry scrubber, which has a higher removal efficiency than traditional dry scrubbers for the same cost. Ms. Stamper calculated that a NID scrubber would cost $2,816 per ton for Unit 1 and $2,676 per ton for Unit 2. *Id.* The costs that Ms. Stamper calculated for dry and wet scrubbers are reasonable costs in light of other reasonable progress determinations. *See* pages 11-12, above (citing Stamper Report) and, below. As discussed in the Stamper Report, *id.* at 4-9, these cost-effective controls can achieve a SO_2 emissions rate of 0.04 lb/MMBtu, which is lower than the 0.06 lb/MMBtu rate that EPA assumed could be achieved with a scrubber.

This significant visibility improvement from a scrubber at Independence Units 1 and 2 would equal or exceed the visibility improvement from other reasonable progress controls EPA has approved. For example, EPA approved as reasonable progress measures Wyoming's decision to require SCR at the Jim Bridger units after finding that the costs would range from $2,258 to $2,961 per ton of NO_x removed and the visibility improvement would range from 0.26 to 0.45 deciviews at the most impacted area. *See* 79 Fed. Reg. 5,032, 5,040-41 (Jan. 30, 2014). EPA approved dry FGD controls as reasonable progress measures at the Colorado Springs Nixon

plant, after finding that the controls would cost $3,744 per ton of SO_2 removed (which is more than FGD would cost at Independence) and would improve visibility by 0.46 deciviews at the most impacted area (which is less improvement than a scrubber at Independence would achieve). *See* 77 Fed. Reg. 18,052, 18,082 (Mar. 26, 2012), finalized by 77 Fed. Reg. 76,871 (Dec. 31, 2012). In addition, EPA's proposed reasonable progress determination for the Tolk units in Texas would require scrubbers that have cost-effectiveness values of $3,178 per ton and $2,998 per ton, *see* 79 Fed. Reg. at 74,876; scrubbers would cost less per ton of SO_2 removed at the Independence units than at the Tolk units. Moreover, the visibility improvement from a scrubber at the Independence units exceeds the visibility improvement from the scrubbers EPA is proposing for the Tolk units. *See* 79 Fed. Reg. at 74,882 (scrubbers at both Tolk units would result in a combined improvement of 0.188 deciviews at Guadalupe Mountains, the most impacted area).

Cost-Effectiveness of Final Reasonable Progress Determinations[563]

Facility	Reasonable Progress Control	Cost, $/ton
Hawaii Electric Co., Kanoelehua Power Plant	SO_2 emissions cap[564]	5,587
Hawaii Electric Co., Puna Power Plant	SO_2 emissions cap	5,583
Hawaii Electric Co., Shipman Power Plant	SO_2 emissions cap	5,583
Tri-State Generation, Craig Unit 3	SNCR	4,887
Colorado Springs Utilities, Nixon Unit1	Dry FGD	3,744
PacifiCorp Jim Bridger Unit 2	SCR	3,015
PacifiCorp Jim Bridger Unit 3	SCR	2,961
PacifiCorp Jim Bridger, Unit 4	SCR	2,492
PacifiCorp Jim Bridger, Unit 1	SCR	2,393
Holcim Florence Cement Plant	SNCR	2,293
Colorado Springs Utilities, Nixon Unit 1	ULNB/OFA	1,372
Phoenix Cement, Clarkdale Kiln 4	SNCR	1,142
Rillito Cement Kiln 4	SNCR	1,047
Basin Electric, Antelope Valley Unit 2	LNB	661
Montana Dakota Utilities, Heskett Station	Limestone Injection	651
Platte River Power Authority, Rawhide Unit 101	ECC	644
Basin Electric, Antelope Valley Unit 1	LNB	586
Devon Energy Blaine County #1 Compressor	NSCR	282

[563] Sources for the table are as follows: partial FIP for Arizona, 79 Fed. Reg. 9,318, 9,354-56 (Feb. 18, 2104) and 79 Fed. Reg. 52,420 (Sept. 3, 2014); approval of Colorado's SIP, 77 Fed. Reg. 18,052, 18,082, 18,084, 18,087 (Mar. 26, 2012) and 77 Fed. Reg. 76,871 (Dec. 31, 2012); FIP for Hawaii, 77 Fed. Reg. 31,691, 31,711 (May 29, 2012) and 77 Fed. Reg. 61,478, 61,506 (Oct. 9, 2012); FIP for Montana. 77 Fed. Reg. 23,988, 24,069 (Apr. 20, 2012) and 77 Fed. Reg. 57,864 (Sept. 18, 2012); partial SIP approval and partial FIP for North Dakota, 76 Fed. Reg. 58,570, 58,626, 58,630-32 (Sept. 21, 2011) and 77 Fed. Reg. 20,894, 20,897 (Apr. 6, 2012); FIP for Wyoming, 78 Fed. Reg. 34,738, 34,754-56, 34,757-78 (June 10, 2013) and 79 Fed. Reg. 5,032 (Jan. 30, 2014).

[564] "This cap [the SO_2 emissions cap] was derived from EPA's analysis of the costs of switching these units to 1% sulfur fuel." Therefore, the cost-effectiveness for the three Hawaii plants represents the cost to meet the SO2 cap by switching to low-sulfur fuel.

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. We take no position on the separate cost analysis that Ms. Stamper has conducted for dry and wet scrubbers that she uses to conclude that our cost analyses are reasonable. We agree with the Sierra Club that a reasonable progress determination based on a positive assessment of the cost-effectiveness alongside consideration of the visibility benefit of dry scrubbers at the Independence facility was proper.[565] Ms. Stamper incorporates her comments concerning our White Bluff scrubber cost analyses, that we should have required that scrubbers be installed in three years, and further notes that the Independence facility will benefit from coordinated and shared engineering design and FGD fabrication, economies of scale benefits with FGD suppliers, and more consistent staffing levels with on-site contractors for concurrent FGD installations. We refer Ms. Stamper to our general response to her similar comment regarding the White Bluff facility. We add that certain economies of scale may well present opportunities for a quicker installation of scrubbers at the Independence facility. However, we have no way to quantify to what extent that may be the case. We therefore stay with our five year installation requirement.

Ms. Stamper emphasizes that there will be no significant energy and non-air quality impacts of these controls, stating that auxiliary power requirements were included with the costs of controls and thus this non-air quality issue is reflected in the cost effectiveness numbers. Further, she notes that these SO_2 controls are commonly utilized, and thus it is not expected that there would be any adverse energy or non-air quality impacts that would justify excluding any of these controls from being adopted as a reasonable progress measure. We agree with these statements.

Ms. Stamper states that we should have required a SO_2 control level of 0.04 lbs/MMBtu in our reasonable progress determination for the Independence facility, citing to the ability of wet scrubbing and NID scrubbing to meet that level. We take no position on the separate cost analysis that Ms. Stamper has conducted for dry and wet scrubbers that she uses to conclude that our cost analyses are reasonable. We agree with the Sierra Club that a reasonable progress determination based on a positive assessment of the cost-effectiveness alongside consideration of the visibility benefit of dry scrubbers at the Independence facility was proper.[566]

We disagree with the Sierra Club, as we have discussed in our response to the previous comment, that for the purposes of determining reasonable progress, the cost-effectiveness of a control falling into a range we have previously found acceptable obviates the need to consider the visibility of that control. As we have discussed in our responses to other comments, we disagree that in this instance the cost of wet scrubbers was reasonable, in light of their higher cost and the relatively low additional improvement in visibility over dry scrubbers. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering

[565] Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.
[566] Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.

the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. Therefore, in our reasonable progress analysis for Independence, we considered the visibility benefits of controls alongside the four statutory factors, and we discuss this in more detail elsewhere in this document. Lastly, as we have discussed in our response to another comment, we disagree that we should have considered NID in our reasonable progress of the Independence facility.

Comment: EPA should have evaluated SNCR and SCR for the Independence facility. [Stamper Report]. Ms. Stamper stated that because the Independence facility is "potentially one of the largest single contributors to visibility impairment at Class I areas in Arkansas," EPA found it was appropriate to evaluate NOx controls for reasonable progress measures. 80 Fed. Reg. at 18,995. Due to the similarity between Independence Units 1 and 2 and White Bluff Units 1 and 2, EPA applied the same costs for low NOx burners/SOFA that were developed for the White Bluff units, but determined cost effectiveness of these controls based on the NOx emissions reductions that would occur at the Independence units. Id.

However, EPA did not evaluate SNCR or SCR at Independence Units 1 and 2. EPA's reasoning was that, since they did not find the visibility benefits of SCR or SNCR at White Bluff Units 1 and 2 to be worth the additional costs of these controls, the visibility benefits of such post-combustion controls at Independence Units 1 and 2 would not be worth the additional costs either. *Id.*

However, SCR along with low NOx burners/SOFA can meet lower NOx emission rates than evaluated by Entergy and EPA, thus providing greater visibility benefits than modeled by Entergy for White Bluff, and such controls were cost effective. Thus, EPA should have evaluated low NOx burners/SOFA + SCR as reasonable progress measures for the Independence units. Ms. Stamper presents her own cost analyses for LNB/SOFA/SCR.

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. First, there is no requirement in the Regional Haze Rule that all possible controls be analyzed conducting a reasonable progress analysis of a source. As we discussed in our proposal,[567] our modeling indicated that the cumulative visibility improvement of LNB/SOFA at the Independence facility was less than at the White Bluff facility:

Class I Area	Visibility improvement of LNB/SOFA at Independence over baseline (deciviews)	Visibility improvement of LNB/SOFA at White Bluff over baseline (deciviews)
Caney Creek	0.459	0.391

[567] See our supplemental NOx modeling results for the Independence facility in 80 FR 24872 vs. our NOx modeling results for the White Bluff facility in 80 FR 18974.

Upper Buffalo	0.198	0.240
Hercules-Glades	0.173	0.366
Mingo	0.148	0.085
Cumulative	0.978	1.082

As can be seen from the above comparison, the visibility improvement due to the installation of LNB/SOFA at the Independence facility is of a similar magnitude to that of the White Bluff facility. We reasoned that because (1) the Independence and White Bluff facilities were sister facilities and very similar, and (2) we found that the incremental costs of SNCR and SCR for White Bluff were not worth the resulting incremental visibility improvement,[568] we had no reason not to conclude the same for the Independence facility.[569] We therefore disagree with Ms. Stamper that the incremental visibility benefits due to the installation of SNCR or SCR at the Independence facility justify the additional cost of those controls. We discuss in a separate response to comment the issues we identified with Ms. Stamper's cost analysis for SCR for White Bluff, and we find that the same issues we identified there apply to her cost analysis of SCR for Independence. We do agree with Ms. Stamper's support for Option 1—requiring reductions corresponding to both dry SO_2 scrubbers and LNB/SOFA.

Comment: EPA's determination that SO_2 BART for AEP Flint Creek is a Novel Integrated Desulfurization (NID) dry scrubber is appropriate, but that control technology is even more cost-effective than what AEP and EPA have estimated. [Sierra Club et. al. (0171) p. 9-12] Sierra Club et. al. stated that EPA must base BART determinations on an analysis of the five statutory BART factors: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) existing pollution controls in use at the source, (4) the remaining useful life of the source, and (5) the degree of visibility improvement. 42 U.S.C. §7491(g)(2); 40 C.F.R. §51.308(e)(1)(ii)(A).

Sierra Club et. al. stated that EPA has proposed to determine that BART for SO_2 at Flint Creek Unit 1 is an emission limit of 0.06 lb/MMBtu on a 30-day rolling average based on the operation of a Novel Integrated Desulfurization ("NID") dry scrubber. 80 Fed. Reg. at 18,966. We strongly support EPA's proposal to require the installation of a NID scrubber at Flint Creek and to set a limit on SO_2 emissions. AEP's evaluation, which EPA relied on in its proposal, shows that a NID scrubber is cost effective, would produce significant visibility improvements at the affected Class I areas, and readily satisfies the other BART requirements. *See* 80 Fed. Reg. 18,966-67; Stamper Report, at 3-14. EPA's proposed FIP represents a minimum floor for SO_2 BART compliance and any less effective controls would not comply with BART.

[568] See the section of this RTC document where we discuss visibility issues for a more detailed discussion of the incremental visibility improvement of SCR controls.
[569] We discuss elsewhere throughout this RTC document that it is appropriate for us to consider visibility alongside the four statutory factors in a reasonable progress analysis.

EPA estimated that a NID scrubber would have an average cost-effectiveness of $3,845 per ton of SO_2 removed. *See* 80 Fed. Reg. 18,966-67. The attached Stamper Report confirms EPA's conclusion that the controls proposed in the FIP are cost-effective. Ms. Stamper conducted her own analyses of the proposed controls and concludes that the proposed controls are even more cost-effective than EPA assumed, can readily achieve even lower emission rates than EPA assumed, and cost a reasonable amount compared to costs borne by sources in other states. The Stamper Report discusses several ways in which EPA and AEP used very conservative assumptions that inflated the cost of the controls

AEP escalated costs to 2016 dollars, which is inconsistent with the EPA's Control Cost Manual. Stamper Report at 4 (citing 80 Fed. Reg. at 18,965). Despite acknowledging AEP's inappropriate cost escalation, EPA did not correct the estimate to reflect present dollars. *Id.* Ms. Stamper's cost-effectiveness figures (presented below) rely on present dollars. Furthermore, as discussed elsewhere in Sierra Club et. al.'s comments, a NID scrubber can achieve a lower emission rate than assumed by AEP, so Ms. Stamper's cost-effectiveness analysis assumes the lower emission limit (0.04 lb/MMBtu).

To provide a cost estimate for the wet scrubbers and NID dry scrubber that is based on present dollars and reflects the emission rates achievable with a NID scrubber, Ms. Stamper revised AEP's cost analyses using EPA's SO_2 control cost spreadsheets that it recently used in the Texas regional haze rulemaking. Stamper Report at 9-11. These cost spreadsheets are based on Sargent & Lundy cost modules for wet and dry scrubbers. Based on Ms. Stamper's revised cost-effectiveness estimates, both a wet scrubber and a NID dry scrubber are highly cost-effective as SO_2 BART for Flint Creek:

Revised SO_2 Control Cost-Effectiveness Evaluation for Flint Creek Unit 1[570]

Flint Creek Unit 1	SO_2 Control	Total Annualized Costs	Tons SO_2 Removed	Cost-Effectiveness	AEP's Cost-Effectiveness[571]
1	Wet FGD	$27,189,756	10,866 tpy	$2,498/ton	$4,919/ton
1	NID™ CDS	$26,183,791	10,886 tpy	$2,405/ton	$3,845/ton

As the above table demonstrates, the costs for both wet and NID scrubbers are significantly lower than AEP's cost estimates and the technologies are equally cost effective. Moreover, wet and NID scrubbers can achieve an emission rate of 0.04 lb/MMBtu, which is lower than EPA assumed in its proposed BART determination.

EPA's conservative cost-effectiveness calculations and Ms. Stamper's revised cost-effectiveness calculations both demonstrate that it was reasonable to establish an SO_2 BART emission limit based on installation of scrubbers, as shown by SO_2 control determinations in other regional haze plans. Stamper Report at 12-13. As discussed in the Stamper Report, data compiled by the National Park Service on state SO_2 BART determinations show that the costs of SO_2 controls to

[570] Stamper Report at 11.
[571] 80 Fed. Reg. 18966, Table 26.

meet BART at EGUs range from $1,571 to $7,309 per ton of SO_2 removed.[572] Wyoming, for example, found that a new dry scrubber and baghouse at Dave Johnston Unit 4 was cost effective at $5,028 per ton of SO_2 removed.[573] EPA proposed a FIP of reasonable progress measures based on switching to a lower sulfur fuel oil at the fuel oil-fired boilers at the Kanoelehua Hill Power Plant, the Puna Power Plant, and the Shipman Power Plant at a cost-effectiveness of approximately $5,600 per ton.[574] Colorado based its SO_2 BART determination for Martin Drake Units 6 and 7 on installation of dry scrubbers at a cost effectiveness of $2,808/ton and $2,345/ton, respectively.[575] In EPA's recently proposed FIP for Texas, EPA has proposed to find that scrubber retrofits are cost effective at costs ranging from $1,255/ton to $3,500/ton of SO_2 removed.[576] EPA approved installation of a dry FGD at the Colorado Springs Nixon Unit 1 as a reasonable progress measure at a cost effective of $3,744/ton.[577] Wyoming also found that the costs of SO_2 retrofit controls at Naughton Units 1 and 2 were cost effective at $1,622 to $2,654/ton.[578,579]

Ms. Stamper's revised cost-effectiveness calculations of $2,498 (wet scrubber) and $2,405 (NID scrubber) per ton of SO_2 removed for Flint Creek are comparable to, or lower than, the cost-effectiveness of each of the referenced approved controls. Stamper Report at 12-13. Thus, either a wet scrubber or a NID dry scrubber can meet an SO_2 BART limit of 0.04 lb/MMBtu and is cost effective for Flint Creek. *See* 42 U.S.C. § 7491(g)(2) (requiring consideration of the costs of compliance and degree of visibility improvement).

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. We agree with the Sierra Club that we must base BART determinations (and judge those submitted to us by states) on the five statutory BART factors it cites.

We also confirm that the NID cost analysis we employed was largely derived from AEP's own cost analysis. As we discuss in our TSD,[580] we noted a number of issues with AEP's NID and wet scrubber cost analyses that if corrected would have resulted in more favorable (lower $/ton)

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[572] Stamper Report at 12 (citing March 2011 National Park Service spreadsheet "EGUs with Proposed BART Controls." (Ex. 27 to Stamper Report)).
[573] *See* Stamper Report at 13 (citing May 28, 2009 Wyoming Department of Environmental Quality BART Application Analysis, Dave Johnston Plant, at 23 (Ex. 28 to Stamper Report)).
[574] 77 Fed. Reg. 61,478, 61,490 (Oct. 9, 2012); *see also* 77 Fed. Reg. 31,692, 31,711-2 (May 29, 2012).
[575] 77 Fed. Reg. 18051, 18,070-1 (Mar. 26, 2012).
[576] *See* 79 Fed. Reg. 74,818 (Dec. 16, 2014).
[577] 77 Fed. Reg. at 18,082.
[578] *See* Stamper Report at 12 (citing May 28, 2009 Wyoming Department of Environmental Quality BART Application Analysis, Naughton Plant, at 26-28 (Ex. 26 to Stamper Report)).
[579] Even AEP's unrevised cost estimates are reasonable compared to the costs other similar sources have had to bear to comply with regional haze requirements.
[580] See page 65 of our TSD: "[W]e believe that AEP's escalation of the cost of controls to 2016 dollars has likely resulted in the over estimation of the average cost-effectiveness values. Therefore, we believe a wet scrubber and NID are more cost-effective (i.e., less dollars per ton of SO_2 removed) than estimated by AEP (see table above). However, we did not adjust the cost numbers and cost-effectiveness values because we do not believe that doing so would change our proposed BART determination. We believe that the average cost-effectiveness of both control options was likely over-estimated and the costs associated with a wet scrubber would continue to be higher than the costs associated with NID if the estimates were adjusted, yet the installation and operation of a wet scrubber is projected to result in minimal incremental visibility improvement over NID.

cost-effectiveness values. Nevertheless, even disregarding those errors, we concluded that NID was cost-effective and worth the visibility benefit that will result from its installation. We also concluded that Ms. Stamper presents her own cost analyses for wet and NID scrubbing, based on the IPM cost algorithms we used in our recent Texas-Oklahoma FIP. In so doing, she applies the SDA cost algorithm to NID, citing to documentation that indicates that NID may be 1-2% lower in cost to an SDA system. Ms. Stamper concludes that AEP's wet FGD and NID cost analyses (largely accepted by us) employed overly conservative inputs and are likely high. In instances in which NID cost information is totally lacking, it may be reasonable to rely on the SDA IPM cost algorithms as a substitute for NID cost analysis. However, in this case, we do not believe that enough information has been presented by Ms. Stamper for us to conclude that her reliance on SDA costing as a substitute for NID should supplant AEP's more site-specific cost analysis. We also determined that wet scrubbing would remain less cost-effective than NID, and that the incremental visibility benefit of wet scrubbers over NID at each impacted Class I area is very small (ranging from 0.007 dv to 0.014 dv).[581] We therefore concluded that wet scrubbing was not worth the small additional visibility that would result from its installation in this particular instance.

As we have discussed above, we do not believe that cost-effectiveness comparisons ($/ton) to other decisions can be effectively made absent consideration of the other statutory factors. Visibility is one of the five statutory factors we are required to consider in a BART analysis. In a reasonable progress analysis, although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls. In our reasonable progress analysis for Independence, we chose to also consider visibility alongside the four reasonable progress factors.

Ms. Stamper argues that both wet and dry scrubbers are capable of even greater levels of control than what we assumed. She presents a number of examples of documentation to support her conclusion consisting of vendor advertisement summaries, contractor statements, industry literature, and some actual monitoring data. Of these, we place the highest priority on the latter – actual monitoring data that demonstrates that on similar units burning similar coals the control technology is capable of the level of control we are requiring. We believe it is important in making such an analysis to focus on the level of control, rather than on just the emission limit. We do not believe emission limits can be compared across units, unless similarity can be demonstrated, including the sulfur content of the coal being burned. We extensively analyzed the performance potential of wet scrubbers in our recent Texas-Oklahoma FIP.[582] We accounted for the many factors that could influence wet scrubber performance, including principally, the type of coal burned and the sulfur level in that coal. We concluded that a control level of 98%, not to go below an emission rate of 0.04 lbs/MMBtu on a 30 BOD average, was a reasonable lower level of control. This same reasoning was applied to our Arkansas proposal. None of the information presented by Ms. Stamper causes us to conclude that reasoning is in error. As we

[581] 80 FR at 18966.

[582] See response to comment beginning on page 310 of our Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, Docket No. EPA-R06-OAR-2014-0754, 12/9/2015.

discuss in our response to another comment, although we regard NID as a promising technology that may in fact be capable of greater levels of control than what we have assumed, there is no real long-term monitoring data to substantiate such a conclusion. Therefore, because we have concluded that in this instance the cost-effectiveness of wet scrubbers is not justified by their relatively small additional visibility benefit, we disagree that SO_2 BART for Flint Creek Unit 1 should be 0.04, based on the performance of a wet scrubber. We agree with Ms. Stamper that the emission rate proposed for the Flint Creek Unit 1 can be achieved by SDA, NID, or wet FGD, and depending on the technology used, that emission rate may not represent the greatest achievable level of control. We are, however, confident that we have correctly determined BART for this facility, based on the five BART statutory factors and the data that is available to us.

Ms. Stamper also makes a number of observations regarding our cost analyses. We agree with her that an equipment life of 30 years is appropriate for a scrubber cost analysis. We also agree that our use of a 7% interest rate may be higher than the actual cost that AEP may incur in financing the cost of a scrubber system that were we to adopt a lower interest rate, the cost effectiveness of our proposed controls would become much more attractive (lower $/ton). For cost analyses related to government regulations, an appropriate ''social'' interest (discount) rate should be used, not the source's actual rate of borrowing. OMB Circular A–4, providing Federal agencies guidance on developing regulatory analyses, and dated September 17, 2003,[583] reiterates the guidance found in the earlier Circular A–94:[584]

> As a default position, OMB Circular A–94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy, based on historical data. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

The yearly updates to OMB Circular A-94 to which the commenter references, are to Appendix C. However, as the letter that transmits these yearly updates explains:[585] "The rates presented in Appendix C do not apply to regulatory analysis or benefit-cost analysis of public investment. They are to be used for lease-purchase and cost-effectiveness analysis, as specified in the Circular." Note that the reference to "cost-effectiveness analysis" here does not refer to that used in the regional haze program, but rather to the analysis of programs requiring the expenditure of federal funds.

Ms. Stamper also argues that because it appears that construction has already begun on the Flint Creek NID system, and AEP will be using it to comply with our MATS Rule, we should truncate the 5 years we have proposed for compliance to May, 2016, which by the publication of this rule, will already have passed. As discussed elsewhere in this document, we were unaware at the time

[583] https://www.whitehouse.gov/sites/default/files/omb/assets/omb/circulars/a004/a-4.pdf
[584] https://www.whitehouse.gov/sites/default/files/omb/assets/a94/a094.pdf
[585] https://www.whitehouse.gov/sites/default/files/omb/memoranda/2015/m-15-05.pdf

of our proposal that the Flint Creek NID system installation was already underway and anticipated by the company to be complete by May 2016. We agree with the commenter that BART controls must be installed as expeditiously as practicable. 42 U.S.C. § 7491(b)(2)(A). After carefully considering the information the commenter has brought to our attention, we believe that a five year compliance date is not appropriate for the SO_2 BART controls we are requiring for Flint Creek. Therefore, based on the information that was made available to us during the comment period, we are finalizing a shorter compliance date. As discussed in more detail in a separate response, we are finalizing an 18-month compliance date for the SO2 BART emission limit for Flint Creek Unit 1.

Comment: Control scenarios that include SCR and SNCR are both cost-effective as NO_X BART for Flint Creek Unit 1. [Sierra Club et. al. (0171) p. 17-18] Sierra Club et. al. stated that for NOx, EPA has proposed to determine that BART for Flint Creek is an emission limit of 0.23 lb/MMBtu on a 30-day rolling average based on the operation of new low- NOx burners ("LNB")/over-fired air ("OFA"). 80 Fed. Reg. 18968. EPA estimated that LNB/OFA would have an average cost-effectiveness of $1,761 per ton of NOx removed. EPA's proposal to require LNB/OFA represents a cost-effective way to achieve some NOx emission reductions at Flint Creek and, therefore, is the absolute minimum that EPA must require as selection of anything less stringent would be arbitrary, capricious, and contrary to law. The LNB/OFA proposal, however, does not satisfy BART, which requires "the application of the *best* system of continuous emission reduction." Such best system is an SCR, which Ms. Stamper explains in her report is far more cost-effective than EPA calculated, would achieve lower emission rates and greater visibility benefits, and satisfies all of the BART standards. As such, we urge EPA to find that NOx BART for the Flint Creek plant is an emission rate of 0.04 lb/MMBtu based on the installation of an SCR.

Sierra Club et. al. stated that the Stamper Report discusses several ways in which EPA and AEP used very conservative assumptions that inflated the cost of the SCRs and SNCRs as NOx BART options for Flint Creek. Ms. Stamper's analysis shows that these controls are even more cost-effective than EPA calculated.

AEP overestimated the costs of LNB/OFA plus SNCR at Flint Creek. AEP amortized the SNCR over a 20 year life rather than the 30 year life assumed for all other controls. By amortizing the SNCR over a shorter time period, AEP's annualized costs for SNCR are overstated and must be revised. Stamper Report at 14, 16. Ms. Stamper's revised cost-effectiveness estimates (provided below) use a 30-year life.

To more properly evaluate the cost effectiveness of LNB/OFA plus SCR and LNB/OFA plus SNCR at Flint Creek, Ms. Stamper has provided revised cost-effectiveness analysis of these controls using the Sargent & Lundy SCR Cost Module. As noted by Ms. Stamper, EPA has relied on the Sargent & Lundy module to estimate SCR costs in its evaluation of NOx BART for rulemakings in other states. Stamper Report at 22-23. Using the Sargent & Lundy modules, Ms. Stamper calculated revised cost effectiveness for LNB/OFA plus SCR at Flint Creek. This revised cost-effectiveness analysis assumes that LNB/OFA plus SCR at Flint Creek can achieve a 0.04 lb/MMBtu emission limit on a 30-day average basis.

Revised NO_x Control Cost-Effectiveness Evaluation for Flint Creek Unit 1[586]

NOx Control	Total Annualized Costs	Tons NOx Removed	Cost Effectiveness	AEP's Cost Effectiveness[587]	Incremental Cost Effectiveness Relative to LNB/OFA/SNCR
LNB/OFA	$1,454,621	956 tpy	$1,521/ton	$1,761/ton	
SNCR plus LNB/OFA	$4,177,782	1,518 tpy	$2,752/ton	$3,099/ton	
LNB/OFA plus SCR (Mar 2013 IPM SCR Cost Module)	$15,851,747	4,515 tpy	$3,511/ton	$3,805/ton	$3,895/ton
LNB/OFA plus SCR (Aug 2010 IPM SCR Cost Module)	$13,399,388	4,515 tpy	$2,968/ton	$3,805/ton	$3,077/ton

As this analysis shows, LNB/OFA plus SCR to meet a NOx limit of 0.04 lb/MMBtu is very cost effective (based on either version of the Sargent & Lundy SCR cost module). These NOx controls would also remove close to 700 tons per year more NOx than evaluated by AEP. As this analysis also shows, LNB/OFA plus SNCR is also very cost effective.

Moreover, as demonstrated in the Stamper Report, these costs are well within the range of costs that EPA has required similar sources to bear to meet BART in other states. EPA has required SCR as BART for the Four Corners Units 1 - 5 at a cost effectiveness of $2,515 to $3,163 per ton of NOx removed in 2008 dollars,[588] or $2,560 to $3,220 per ton in 2011 dollars. Stamper Report at 24-25. In its FIP for Montana, EPA found that the cost effectiveness of SCR controls for Colstrip Units 1 and 2 of approximately $3,200 per ton (in 2010 dollars), or $3,403 per ton in 2011 dollars, was reasonable.[589] In its Arizona regional haze FIP, EPA required SCR along with combustion controls to meet BART at the Apache, Cholla, and Coronado power plants at cost-effectiveness values ranging from $2,275 to $3,472 per ton of NOx removed.[590] EPA proposed SCR as BART at the Leland Olds Unit 1, Milton R. Young Unit 1, and Milton R. Young Unit 2 at costs of $1,800/ton, $2,600/ton, and $2,700/ton in 2009 dollars (or $2,020/ton, $2,918/ton, and $3,030/ton in 2011 dollars), respectively.[591] For the Wyoming regional haze plan, EPA found that costs for SCR plus LNB/OFA ranging from $2,635 to $4,461 per ton of NO_x removed (2008 dollars) are reasonable to require SCR as BART.[592] These costs range from $2,682 to $4,541 per ton in 2011 dollars. Stamper Report at 25.

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[586] Stamper Report at 24.
[587] 80 Fed. Reg. 18,966, Table 28. AEP only evaluated SCR alone, to meet a less stringent NOx limit of 0.07 lb/MMBtu. *See* 80 Fed. Reg. at 18,967.
[588] *See* 75 Fed. Reg. 64, 221, 64,227 (Oct. 19, 2010); *see also* 77 Fed. Reg. 51,619, 51,621-22 (Aug. 24, 2012).
[589] *See* 77 Fed. Reg. 23,987, 24,026-27, 24,034-35 (Apr. 20, 2012).
[590] 77 Fed. Reg. 42,833, 42,857, 42,860, 42,862 (July 20, 2012).
[591] *See* 76 Fed. Reg. 58,569, 58,599 (Sept. 21, 2011). While EPA did not ultimately require SCR as BART for these North Dakota EGUs in its final regional haze action, EPA's decision was based on whether SCR was technically feasible for these lignite-fired units and not based on costs of controls. *See* 77 Fed. Reg. 20,893, 20,897-98 (Apr. 6, 2012).
[592] 79 Fed. Reg. 5,031, 5,039-43 (Jan. 30, 2014).

In addition, the incremental costs of SCR plus LNB/OFA compared to the next most stringent control technology—SNCR plus LNB/SOFA—are also reasonable to justify SCR plus LNB/OFA as BART. In past regional haze rulemakings that required SCR plus combustion controls on EGUs, EPA did not consider incremental cost-effectiveness numbers ranging from $1,903/ton to as high as $8,968/ton to be unreasonable and did not eliminate SCR from consideration. Stamper Report at 25. Based on the SCR costs that EPA has deemed reasonable in other haze rulemakings, the costs of SCR plus LNB/OFA are reasonable to justify requiring this combination of control technologies to meet the NOx BART requirements at Flint Creek.

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. We disagree with the Sierra Club's apparent position that BART controls must be selected based on which are the "best system of control," without apparent consideration of the five BART factors: cost, energy and nonair quality environmental impacts, pollution controls in use at the source, remaining useful life, and visibility improvement.[593]

We note that we provided comments to ADEQ[594] which included stating that 30 years should be used as an equipment life for SNCR. This, was subsequently not adopted by AEP in its September 2013 BART analysis for the Flint Creek facility. However, as we discuss in our TSD,[595]

> AEP assumed a 30-year amortization period in the evaluation of LNB/OFA and SCR and a 20-year amortization period in the evaluation of SNCR. We disagree with AEP's assumption of a 20-year amortization period in the cost analysis of SNCR. Any air pollution controls on the unit are expected to have the same life as the boiler. Therefore, we believe it is appropriate to assume a 30-year amortization period for SNCR, as was done for SCR and combustion controls. Assuming a 30-year amortization period, SNCR would have a lower estimated total annual cost and would therefore be more cost-effective (i.e., less dollars per ton removed) than estimated in AEP's evaluation. However, we did not adjust the amortization period assumed in AEP's evaluation because we do not believe this has an impact on our proposed BART decision. [T]he incremental visibility benefit expected from the installation and operation of SNCR is too small to justify the cost of these controls compared to combustion controls alone. Therefore, we did not revise the amortization period and the average cost effectiveness calculations for SNCR.

Ms. Stamper also states that AEP overestimated the cost of SNCR because it based it on a reduction of from 0.31 lbs/MMBtu to 0.2 lbs/MMBtu, when in fact, the first-in-line LNB/OFA controls would have already reduced the NOx to 0.23 lbs/MMBtu, resulting in a lesser loading to the SNCR system and reducing its operating costs. We agree with Ms. Stamper on this point. We have corrected this error, and the error in AEP SWEPCO's 20 year equipment life. The

[593] Summarized from Section 51.308(e)(1)(ii)(A).
[594] See email from Dayana Medina to Mary Pettyjohn on 8/21/13.
[595] See discussion beginning on page 68.

following table provides AEP SWEPCO's SNCR cost analysis with another column added to include these corrections:

Parameters/Costs	Equation	AEP SWEPCO	EPA
Boiler design capacity, mmBtu/hr (Q_B)	Q_B	6324	6324
Total operating time (t_{op}, hrs/yr)	$t_{op} = CF_{total} \times 8760$ hrs/yr	7752	7752
Total Capacity Factor (CF_{total})	$CF_{total} = CF_{plant} \times CF_{SNCR}$	0.92	0.92
Plant Capacity Factor (CF_{plant})[2]		0.92	0.92
SNCR Capacity Factor (CF_{SCNR})[3]	$CF_{SNCR} = t_{SNCR}/365$	1	1
Assumed NOx removal efficiency (η_{NOx})[4]		35%	**13.04%**
Uncontrolled NOx rate ($NOx_{in,}$ lb/MMBtu)[5]		0.33	**0.23**
Electricity Cost ($Cost_{elect}$, $/kwh)[6]		$0.05	$0.05
Water Cost ($Cost_{water}$, $/gal)[7]		$0.00362	$0.00362
Coal Cost ($Cost_{coal}$, $/MMBtu)[8]		$2.50	$2.50
Coal HHV (Btu/lb)[9]		9,000	9,000
Cost of Ash Disposal (C_{ash}, $/ton)[10]		$9.0	$9.0
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life	0.0944	**0.0806**
	a. Equipment CRF, 20-yr life, 7% interest		
Cost Index[11]			
a. 2011 Cost Index	585		
b. 1998 Cost Index	389.5		
Capital Costs			
Direct Capital Cost (A)	DC ($) = ($950/MMBtu) × Q_B × ((2375 MMBtu/hr/Q_B)^0.577) × (0.66 + 0.85η_{NOx}) × (CI_{2011}/CI_{1998})	$5,007,199	$4,031,069
Indirect Installation Costs ($)			
General Facilities	0.05 × A	$250,360	$201,553
Engineering and Home Office Fees	0.10 × A	$500,720	$403,107
Process Contingency	0.05 × A	$250,360	$201,553
Total Indirect Installation Costs (B)	= General Facilities Cost + Engineering and Home Office Fees + Process Contingency	$1,001,440	$806,214
Other Installation Costs ($)			
Project Contingency (C)	C = 0.15 × (A + B)	$901,296	$725,592.50
Total Plant Cost (D)	D = A + B + C	$6,909,934	$5,562,876

Allowance for Funds During Construction (E)	E = 0 (Assumed for SNCR)	$0	$0
Royalty Allowance (F)	F = 0 (Assumed for SNCR)	$0	$0
Preproduction Cost (G)	G = 0.02 × (D + E)	$138,199	$111,258
Inventory Capital (H)[12]	$H = Vol_{reagent}$ (gal) × $Cost_{reagent}$ ($/gal)	$76,102	$8,957
$Cost_{reag}$, 50% Urea solution ($/gal)[13]		1.54	1.54
Volume of Reagent Tank ($Vol_{reagent}$ (gal))	$Vol_{reagent}$ (gal) = q_{sol} x days of reagent supply × 24 hr/day	49,417	5,817
Urea solution volumetric flow rate (q_{sol}, gal/hr)[14]	$q_{sol} = (m_{sol} \times 7.481\ gal/ft^3)/\rho_{reagent}$	147.07	17.31
Mass flow rate of urea solution (m_{sol}, lb/hr)[15]	$m_{sol} = m_{reagent}/C_{ureasol}$	1,395.84	164.30
Mass flow rate of reagent ($m_{reagent}$, lb/hr)[16]	$m_{reagent} = (NOx_{in} \times Q_B \times \eta_{NOx} \times NSR \times M_{reagent})/(M_{NOx} \times SR_T)$	697.92	82.15
Normalized Stoichiometric Ratio (NSR)	$NSR = ([2 \times NOx_{in} + 0.7] \times \eta_{NOx})/NOx_{in}$	1.43	0.66
Initial Catalyst and Chemicals (I)	I = 0 (Assumed for SNCR due to no catalyst)	$0	$0
Total Capital Investment (TCI) (Capital Cost)	**TCI = D + E + F + G + H + I**	**$7,124,235**	**$5,683,091**
Annual Costs ($)			
Annual Maintenance Cost (J)	J = 0.015 × TCI	$106,864	$85,246
Annual Reagent Cost (K)	$K = q_{sol} \times Cost_{reag} \times t_{op}$	$1,755,781	$206,662
Annual Electricity Cost (L)	$L = P \times Cost_{elect} \times t_{op}$	$58,064	$18,344
Power (P, kW)	$P = (0.47 \times NOx_{in} \times NSR \times Q_B)/9.5$	149.80	47.33
Annual Water Cost (M)	$M = q_{water} \times Cost_{water} \times t_{op}$	$18,775	$2,210
Water flowrate for SNCR system (q_{water}, gal/hr)[17]	$q_{water} = (m_{sol}/\rho_{water}) \times [(C_{ureasolstored}/C_{ureasolinj}) - 1]$	669.06	78.75
Annual ΔCoal Cost (N)	$N = \Delta Coal \times Cost_{coal} \times t_{op}$	$109,558	$12,895
Additional coal required (ΔCoal, MMBtu/hr)[18]	$\Delta Coal = (Hv \times m_{reagent} \times [(1/C_{ureasolinj}) - 1])/10^6$ Btu/MMBtu	5.65	0.67
Annual ΔAsh Cost (O)	$O = (\Delta Ash \times Cost_{ash} \times t_{op})/2000$ lb/ton	$1,643	$193
Additional ash generated (ΔAsh , lb/hr)[19]	$\Delta Ash = (\Delta Coal \times ashproduct \times 10^6$ Btu/MMBtu)/HHV	47.11	5.54
Direct Annual Costs (DAC)/Variable O&M	**DAC = J + K + L + M + N + O**	**$2,050,684**	**$325,551**
Indirect Annual Costs (IDAC)/Annualized Capital Cost	**IDAC = CFR × TCI**	**$672,477**	**$457,980**
Total Annualized Costs (TAC)	**TAC = DAC + IDAC**	**$2,723,162**	**$783,531**

TAC = DAC + IDAC $2,723,162

Note in the above table, we have added another column with our corrections to (1) the assumed NOx removal efficiency (ηNOx), (2) the uncontrolled NOx rate (NOxin, lb/MMBtu), and (3) a recalculation of the capital recovery factor (CRF), corresponding to a 30 year life. The resulting annualized cost drops from $2,723,162 to $783,531.

We have also recalculated AEP SWEPCO's cost-effectiveness calculation.[596] Below is the AEP SWEPCO's cost-effectiveness calculation as presented in its BART analysis,[597] along with our corrections. The first table is AEP SWEPCO's cost-effectiveness calculation. In the second table, we make corrections to errors in both AEP SWEPCO's summing of the total annual costs, and in the tons reduced calculations. In the third table, we carry those corrections forward, and incorporate the corrections to the SNCR cost analysis we discuss above.

[596] See the file, AR020-0037-02_Consolidated_Spreadsheet_2013-09-09-EPA.xlsx.
[597] Bart Five Factor Analysis, Flint Creek Power Plant, September 2013, Version 4. Table 6-3.

AEP SWEPCO

Control Technology	Baseline NOx Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOx tpy)	Annual Emissions Reductions (NOx tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	4,294.65	825.62	$16,000,000	$1,289,382	$240,000	$132,364	$1,454,621	$1,762	-
LNB/OFA/SNCR	5,120.27	0.20	3,771.82	1,348.45	$16,000,147	$1,398,940	$240,000	$133,033	$4,177,782	$3,098	$5,209

AEP SWEPCO (tons reduced and total annl cost corrected)

Control Technology	Baseline NOx Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOx tpy)	Annual Emissions Reductions (NOx tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	3,798.91	1,321.36	$16,000,000	$1,289,382	$240,000	$132,364	$1,661,746	$437	-
LNB/OFA/SNCR	5,120.27	0.20	3,303.40	1,816.87	$23,124,235	$1,961,859	$240,000	$2,183,048	$4,384,908	$2,413	$5,496

EPA (tons reduced, total annl costs, control level and control efficiency corrected)

Control Technology	Baseline NOx Emission Rate (tpy)	Controlled Emission Level (lb/MMBtu)	Controlled Emission Rate (NOx tpy)	Annual Emissions Reductions (NOx tpy)	Capital Cost ($)	Annual Capital Cost ($.yr)	Annual Fixed O&M ($/yr)	Annualized Variable O&M ($/yr)	Total Annual Cost ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
LNB/OFA	5,120.27	0.23	3,798.91	1,321.36	$16,000,000	$1,289,382	$240,000	$132,364	$1,661,746	$1,258	-
LNB/OFA/SNCR	5,120.27	0.20	3,303.40	1,816.87	$21,683,091	$1,747,362	$240,000	$457,915	$2,445,277	$1,346	$1,581

As can be seen from the third table above, we calculate that SNCR + LNB/OFA has a revised cost-effectiveness of $1,346/ton, as opposed to cost effectiveness of $1,258/ton for LNB/OFA alone. Also, we calculated that the incremental cost effectiveness of SNCR + LNB/OFA over LNB/OFA alone is $1,581/ton. We re-apply the BART five factors, with emphasis on cost and visibility improvement. The incremental visibility improvement of SNCR + LNB/OFA over LNB/OFA alone is 0.033 dv at Caney Creek and ranges from 0.005 to 0.01 dv at each of the other affected Class I areas. As discussed in our proposal, we consider the incremental visibility improvement of SNCR + LNB/OFA to be relatively small at Caney Creek and to be very small in the remaining three affected Class I areas.[598] We conclude that despite the improvement in the cost-effectiveness of SNCR + LNB/OFA over LNB/OFA alone, the resulting relatively small incremental visibility improvement is still not worth the additional cost of the more stringent controls.

We agree with Ms. Stamper's statement in her report that BART cost determinations should be based on the Control Cost Manual in order to result in a consistent basis for comparisons to other cost determinations. We note Ms. Stamper's separate SCR cost analysis, in which she assumes a NOx control level of 0.04 lbs/MMBtu, using the IPM SCR cost algorithms. Ms. Stamper makes a case that because her resulting $/ton figures are in line with other required SCR installations, the Flint Creek facility should similarly be required to install SCR. First, as we discuss in our response to another comment concerning the White Bluff facility, we do not believe that Ms. Stamper has demonstrated that her assumed level of control has been maintained on a 30 day BOD average at other similar facilities, such that it can be applied to the Flint Creek facility. However, we have re-reviewed/reviewed the information Ms. Stamper presents and conclude, as we did in our New Mexico FIP, that it supports a 30 Boiler Operating Day (BOD) NOx average of 0.05 lbs/MMBtu for a SCR installation at the Flint Creek facility.

Second, as we indicate in Table 44 of our TSD and Ms. Stamper notes in her report, the maximum visibility improvement due to SCR at Flint Creek based on the modeled rate of 0.067 lb/MMBtu was 0.245 dv, which occurred at Caney Creek. We further note that AEP SWEPCO's SCR cost analysis is almost completely undocumented. However, due to the relatively low visibility improvement expected from SCR, cost was not the only factor in our BART decision making. For instance, if we make reasonable, conservative adjustments to the anticipated visibility benefit, based on a control level of 0.055 lbs/MMBtu rather than the modeled rate of 0.067 lbs/MMBtu[599], we estimate that the resulting visibility improvement at Caney Creek would be no higher than 0.26 dv.[600] Based on this adjustment, the incremental visibility improvement of SCR + LNB/OFA over SNCR + LNB/OFA is 0.146 dv. Even accepting Ms. Stamper's SCR cost analysis of $3,511/ton (which would be higher were it revised using a controlled NOx rate of 0.05 lbs/MMBtu) and taking into consideration the adjustments we have made to the cost analysis for SNCR + LNB/OFA, the incremental cost effectiveness of SCR + LNB/OFA over

[598] 80 FR at 18968

[599] Modeled emission rates were based on a maximum heat input of 6,324 MMBtu/hr multiplied by the anticipated control rate (e.g. 0.067 lb/MMBtu) Baseline emissions determined from 2001-2003 CAMD data were 1,945 lb/hr, approximately 0.308 lb/MMBtu.

[600] Modeled visibility benefit at CACR over baseline from SCR at 0.067lb/MMBtu was 0.245 dv. SCR at 0.055 lb/MMBtu would result in an additional reduction in emissions from baseline of only 4%. Assuming a linear relationship between emission and visibility impacts, this would also result in an increase in visibility benefit of only 4%.

SNCR + LNB/OFA is $4,969/ton. We do not consider the relatively small incremental visibility improvement to be worth the incremental cost of the SCR installation.

Comment: EPA's NO_X BART analysis for Lake Catherine Unit 4 is legally flawed because it did not appropriately consider the costs of compliance and other statutory BART factors. [Sierra Club et. al. (0171) p. 26-27] Sierra Club et. al. stated that EPA proposed a FIP for Lake Catherine Unit 4 that requires an emission limit of 0.22 lb/MMBtu on a 30 boiler operating-day rolling average based on the installation and operation of burners out of service (BOOS). 80 Fed. Reg. at 18,978. EPA conducted its own analysis of NO_x BART controls at Lake Catherine, making adjustments to Entergy's BART analysis to reflect costs not allowed in the EPA's Control Cost Manual but relying on other elements of Entergy's analysis. *Id.*

EPA must base BART determinations on an analysis of the five statutory BART factors: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) existing pollution controls in use at the source, (4) the remaining useful life of the source, and (5) the degree of visibility improvement. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). The Lake Catherine Unit 4 BART analysis fails to accurately consider compliance costs, non-environmental impacts, and the degree of visibility improvement. EPA's Lake Catherine Unit 4 determination is based on an invalid five-factor BART analysis because it over-estimated the costs for SCRs, SNCRs, low NO_x burners, and over-fired air, underestimated the cost effectiveness of all control scenarios by using an unenforceable capacity factor that is below actual averages, assumed an achievable emission rate despite contrary evidence, failed to consider the increased greenhouse gas emissions associated with its selected control technology, and overstated the visibility benefits of each control scenario due to a reliance on Entergy's flawed maximum daily average NO_x emission rate. Therefore, EPA must do a new NO_x BART analysis that corrects these flaws and considers whether SCR represents the best system of continuous emission reduction for NO_X at Lake Catherine Unit 4.

EPA miscalculated the cost effectiveness for all control scenarios. While EPA disapproved and corrected some of Entergy's inflated costs, EPA nonetheless significantly underestimated the costs of BOOS in its FIP. As Ms. Stamper's report explained, installation and operation of the BOOS will require modifications to the existing "fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions." Stamper Report at 54 (citing to the Sargent & Lundy report relied on by Entergy for its NO_x BART analysis). EPA failed to include these additional costs in its BOOS cost estimate. Including all of the costs for BOOS installation and operation will make BOOS less cost effective. In addition, EPA likely overestimated the labor installation costs of low NO_x burners, over-fired air, SNCRs, and SCRs in its FIP. As Ms. Stamper's report noted, EPA likely double-counted labor costs for installation of all of these pollution control equipment. Stamper Report at 53. Removal of these duplicative costs would make SCRs, SNCRs, LNB, and OFA more cost effective than calculated by EPA.

Moreover, EPA's cost-effectiveness analysis is based on an unenforceable 10% capacity factor for Lake Catherine Unit 4. Entergy based all of its cost-effectiveness analyses for NO_x controls

on an unenforceable 10% capacity factor.[601] In 2011, EPA found this assumption problematic as it was unenforceable, inconsistent with actual operations (as the unit had operated at a 46% average capacity factor between 2001 and 2005), and would likely "significantly inflate the cost per ton of controlling this unit." *Id.* Nonetheless, EPA found that "based on information provided by [Entergy], we agree that the source has historically operated at less than a 10% capacity factor." 77 Fed. Reg. at14,641 (Mar. 12, 2012). This was an error. As Ms. Stamper's report explained, for the 2001-2003 timeframe used by Entergy for the BART NOx analysis, this unit had an average capacity factor of 21.2% based on heat input. Stamper Report at 52. In fact, Lake Catherine Unit 4 has operated at a capacity factor based on operating days more than 10% for all but three of the last 14 years. *Id.* EPA skewed the cost-effectiveness analysis by using a lower than actual (and unenforceable) capacity factor. Had EPA used a higher capacity factor, it would have found an increase in the tons of NOx emissions removed by the various pollution control equipment and an increase in cost-effectiveness.

The Sierra Club et. al. stated that EPA's Lake Catherine Unit 4 NOx BART analysis fails to accurately consider the cost of compliance, as well as the non-environmental impacts and visibility impacts of controls. Therefore, EPA's analysis is legally flawed. EPA must conduct a new NOx BART analysis that corrects these flaws and considers whether SCR represents the best system of continuous emission reduction for NOx at Lake Catherine Unit 4. In doing so, we urge EPA to not place inappropriate weight on the incremental cost-effectiveness of controls in its revised analysis. Undue focus on "incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost-effectiveness, in terms of dollars per ton removed [average cost effectiveness], is well within the normal range of acceptable" BART costs. *See*, *e.g.*, NSR Manual at B-45 – B-46. Focusing on incremental cost-effectiveness is especially inappropriate when dealing with a widely-used control technology, such as SCR. *See*, *e.g.*, NSR Manual B-44. EPA should instead place greater emphasis on average cost-effectiveness of the controls options. The average cost-effectiveness of SCR for Lake Catherine Unit 4 from EPA's revised BART analysis should be well within the range of acceptable costs as EPA has considered costs as high as $7,309/ton acceptable for EGUs to meet BART. *See* Section A.1.a.i of the Sierra Club et. al.'s comments.

Response: We have reviewed the section of the Stamper report that treats this issue in more detail and respond to both it and this comment here. Again, we agree with the Sierra Club that we must base BART determinations (and judge those submitted to us by states) on the five BART statutory factors it cites. The Sierra Club alleges that we over-estimated the costs for SCRs, SNCRs, low NOx burners, and over-fired air, underestimated the cost effectiveness of all control scenarios for the Lake Catherine Unit 4 by using an unenforceable capacity factor that is below actual averages, assumed an achievable emission rate despite contrary evidence, failed to consider the increased greenhouse gas emissions associated with its selected control technology, and overstated the visibility benefits of each control scenario due to a reliance on Entergy's flawed maximum daily average NOx emission rate.

[601] *See* Revised BART Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014, at 6-7 [EPA-R06-OAR-2015-0189-0055].

As a first order issue, we cannot consider the increase in greenhouse gas emissions that may occur as a result of a potential control strategy, as there is no basis for doing so in the Regional Haze Rule.[602]

Ms. Stamper states that we erred in agreeing to the use of a 10% capacity factor in our cost calculations. She states that we previously noted that Unit 4 had previously operated at a 46% capacity factor in our 2011 proposal.[603] The language that Ms. Stamper refers to is as follows:

> The computer model Entergy used to estimate the cost effectiveness of post-combustion controls likewise assumed a 10% capacity factor in the calculation of the metrics for tons removed and $/ton removed. Given that there are no permit requirements in place that would limit the operation of this unit to 10% capacity, the facility can legally be operated well above the 10% capacity factor assumed by Entergy. Thus, any cost effectiveness analysis based on a 10% capacity factor is likely to significantly inflate the cost per ton of controlling this unit. In support of the 10% capacity utilization factor, Entergy stated that the unit has operated, on average, at a capacity of 6.9% for the past three years. However, past use of this unit was much higher— approximately 46% on average—over the 2001–2005 period.[604]

As the footnote indicates, our reference to the 46% figure was taken from Entergy's BART analysis, which was a reference to the percent of hours of operation. As we note in that proposal in the footnote just preceding this one:

> 40 CFR 72.2 defines capacity factor as either ''(1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or (2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

Thus, a capacity factor is usually better calculated on the basis of heat input or electric output. Nevertheless, Ms. Stamper states that she believes that we should have calculated the Lake Catherine Unit 4 capacity on the basis of operating time. In response, we investigated the correlation between heat input and operational time to NO_X emissions for Lake Catherine Unit 4, reasoning that because our cost analyses was for NO_X control, changes in capacity should correlate to changes in NO_X.[605] As the following graph indicates, there is a good correlation between heat input and NO_X, but no correlation between operational time and NO_X for Lake Catherine Unit 4:

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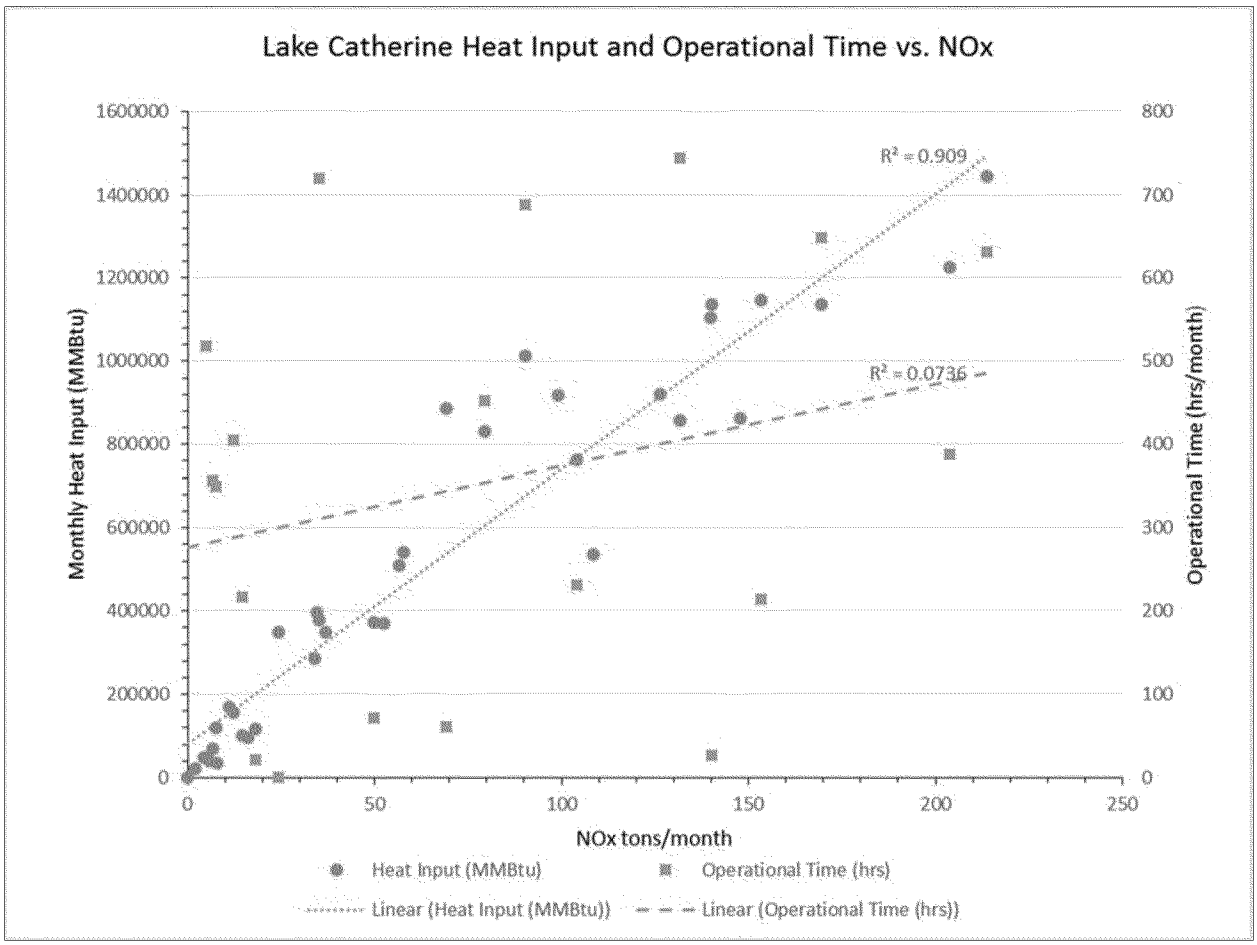
[602] See the BART requirements at 40 CFR 51.308.
[603] 76 FR 64204.
[604] Note that we footnoted this passage in 76 FR 64204 with the following reference: Table 2–1 of the ''BART Analysis for Lake Catherine Plant- Unit 4,'' prepared by Robert Paine, December 2006 notes that Unit 4 was operated 6,988 hours in 2001 (79.7% utilization); 5,651 hours in 2002 (64.5% utilization); 3,972 hours in 2003 (45.3% utilization); 1,534 hours in 2004 (17.5% utilization); and 2,059 hours in 2005 (23.5% utilization).
[605] See the file, "Lake Catherine Monthly Data.xlsx," which is in our docket.



Thus, we disagree with Ms. Stamper that capacity should be based on hours operated per year, and conclude that the historical capacity factor for Lake Catherine should be based on heat input. On 3/29/13, we provided comments to Entergy that addressed this issue. We calculated the historical capacity for this unit from 2001 to 2012. Below we reproduce that data and update it to 2015:[606]

Lake Catherine Unit 4 Historical Capacity

Year	Capacity Factor (%)
2001	28.2
2002	24.2
2003	11.3
2004	3.7
2005	4.7

[606] See the file, "R6 Comments 3-23-13.pdf" and the spreadsheet "Lake Catherine Monthly Data.xlsx," both of which are in our docket.

2006	0.6
2007	0.8
2008	2.3
2009	2.8
2010	3.5
2011	2.9
2012	14.3
2013	11.1
2014	2.0
2015	3.9

We do agree with Ms. Stamper that the Lake Catherine Unit 4 historical capacity has sometimes exceeded the 10% capacity Entergy has assumed in its control cost analyses. However, the average from the last ten years of data (2006 to 2015) has been 4.4%. When we questioned Entergy about its assumption of a 10% capacity factor in its cost analyses, it responded[607] by pointing us to our BART Guidelines, which states that, "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[608] Our conclusion is that like an emission baseline, the assumed capacity factor should "represent a realistic depiction of anticipated annual emissions for the source," and be based on an annual average. Typically, we place the most emphasis on the last five years of data, and our recent practice has been to discard the high and low values and average the remaining three years.[609] Applying that procedure to the Lake Catherine Unit 4 capacity factor results in a value of 6.0%. Alternatively calculating a straight average of the last five years results in a value of 6.8%. Thus, assuming a 10% capacity factor is conservative, and we disagree with Ms. Stamper that we erred in accepting Entergy's assumption of a 10% capacity factor in its control cost analysis. We note that in its response to us, Entergy stated, "If future capacity factors change, ADEQ and EPA may impose further NO_X emission reductions on Unit 4, if necessary, in later planning periods to show reasonable progress." We believe that is an appropriate strategy and we will re-examine Lake Catherine's historical capacity in our review of Arkansas' next regional haze SIP.

Ms. Stamper alleges that the Sargent & Lundy documentation submitted by Entergy to support its analysis and cost calculations is not consistent with the BART analysis presented in Entergy's 2013 revised BART analysis or with our proposed rulemaking. She also states that the documentation is also inconsistent with the 2006 BART analysis submitted for Lake Catherine Unit 4, and that Entergy's revised analysis also did not evaluate the full suite of controls the company had evaluated in 2007. To the extent these comments are generalized summaries of more specific comments, we address them below. Otherwise, we conclude that Ms. Stamper does not present any specific information to substantiate these allegations or why they are germane, so we are unable to assess them.

Ms. Stamper states that the NO_X BART analysis for Lake Catherine Unit 4, found in the May 2013 Sargent & Lundy report, includes an Estimate No. 31815A, for low NO_X burners and separated overfire air at Lake Catherine Unit 4 with a total cost of $7,803,995. She states:

[607] See the file, "Response to R6 Comments – Lake Catherine – 6-25-13.pdf," which is in our docket.
[608] 70 FR 39167.
[609] This was our approach in calculating the SO_2 baselines used in our recent TX-OK FIP.

> Entergy added costs to that total including $1,634,363 in Entergy employee labor and loaders. Yet, the Sargent & Lundy cost estimate included costs for labor of $331,677, as well as costs for subcontract (which likely covered labor) of $2,850,000, and another $2,000,000 under the category of "other." Thus, Entergy increased the Sargent & Lundy's cost estimate for LNB/SOFA by 20%, and it seems very likely that Entergy's additional cost for Entergy labor and loaders was already included in the Sargent & Lundy low NO_X burner/SOFA estimate. Further, Entergy added the same amount of $1,634,363 in Entergy employee labor and loaders to the Sargent & Lundy estimates for low NO_X burners/SOFA plus SNCR and to the Sargent & Lundy costs for low NOx burners/OFA plus SCR.

The estimate Ms. Stamper cites, Estimate No. 31815A, refers to the Lake Catherine, Unit 4 – SNCR estimate (not LNB/OFA). Also, the total Ms. Stamper refers to, $7,803,995.193, is the total to install LNB/OFA to Lake Catherine Unit 1 (not Unit 4). Nevertheless, we were able to find the $1,634,363 charge that Entergy added to the S&L cost estimate, for Entergy employee labor and loaders.[610] Ms. Stamper contends that the S&L estimate likely already includes these charges. We confirm that the Lake Catherine Unit 4 LNB/OFA estimate contain entries for costs for labor of $331,677, as well as costs for subcontract of $2,850,000. However, based upon the information discussed previously, these costs cover the labor and subcontract to install the LNB/OFA system, whereas the $1,634,363 Entergy added refers to its own employee labor and loaders. We therefore conclude that Ms. Stamper has not demonstrated that the additional charge of $1,634,363 in Entergy employee labor and loaders was inappropriate for the LNB/OFA, SNCR, and SCR cost estimates.

Ms. Stamper states that it appears that Entergy overstated the NO_X reductions from BOOS at Lake Catherine Unit 4. She states the Entergy 2013 revised report assumes lower NO_X emission rates for BOOS than previously evaluated in the 2007 BART analysis for Lake Catherine, and Entergy's 2013 revised BART analysis assumed a NO_X rate of 0.22 lb/MMBtu with BOOS, despite the Sargent & Lundy analysis of Lake Catherine Unit 4 found the achievable NO_X rate with BOOS to be 0.24 lb/MMBtu. She states it is unclear that Entergy has any operating experience to rely on to estimate the NO_X rate may be met with BOOS and an increase in fuel flow of 25% (required to make up for the lost capacity). She concludes there is a lack of adequate justification that Entergy can meet its proposed NO_X limit with BOOS. Regarding this, Entergy itself states, "Based on the level of control expected to be achieved by BOOS and the expected utilization levels at Unit 4, Entergy believes that an emission rate of 0.22 lb/MMBtu is achievable on a 30-day rolling average basis."[611] We see no reason to conclude that Entergy cannot achieve the NO_X limit that it itself claims to be able to achieve. We therefore disagree with Ms. Stamper. Furthermore, as we discuss elsewhere, the 0.22 lb/MMBtu emission limit refers to the 30-day BOD limit and the 0.24 lb/MMBtu emission rate is a short-term emission rate based on a 50% reduction of the maximum 24-hr emission rate.

Ms. Stamper states that the cost analysis for BOOS also appears to be incomplete and likely underestimates costs. Specifically, Sargent & Lundy stated that, to achieve current generation

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[610] Appendix A to the Revised Bart Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014. See pdf page 32.

[611] Revised Bart Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014. See pdf page 16.

rates with BOOS, there would need to be an increase in the original high burner header pressure to increase fuel flow to the boiler, and this might require modifications to the existing "fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions, for the new operating conditions." However, she states that none of these boiler modifications were included in the costs for BOOS. She also states that the costs for BOOS at Lake Catherine Unit 4 were based on vendor cost data adjusted to $/kW to Lake Catherine, and were not based on site-specific estimates. S&L's full statement regarding this situation is:

> Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original "high" burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated "fuel rich", lowering NO_X formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions. The expected NO_X reduction would range from 40% at low load to 50% at full load and NO_X levels of 0.24 lb/MMBtu.

It appears to us that the costs Ms. Stamper references for BHP are covered in the costs S&L states, were "based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine." It appears that the only costs that may not have been included are any "modifications to the boiler." Regarding these, S&L states that "A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions." However, Entergy states, "It is anticipated that BOOS can be implemented on the unit without any capital expenditures."[612] We therefore conclude that the "any modifications to the boiler" costs discussed above were not specifically applicable to Lake Catherine Unit 4 and disagree with Ms. Stamper.

Ms. Stamper criticizes our determination that BART of the Lake Catherine Unit 4 is BOOS, stating that the cost effectiveness of LNB/SOFA, LNB/SOFA/SNCR, and LNB/SOFA/SCR are likely lower than we have determined, and are all within a range that has previously been found to be acceptable for BART. She also cites to BACT determinations for SCR determinations at coal-fired and gas-fired units with incremental cost-effectiveness as high as $30,000 to $57,000/ton. She states that we must correct these errors by properly calculating the cost and

[612] Revised Bart Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014. Appendix A. See pdf page 31.

achievable emission reductions from NOx controls and then redo the five factor NOx BART analysis for Lake Catherine. As we have discussed in our replies to other comments, in a BART analysis, the cost of controls must balance visibility benefit. Visibility is one of the five statutory factors under CAA section 169A(g)(2) and 40 CFR section 51.308(e)(1) we are required to consider in a BART analysis. In this case, we do not believe that Ms. Stamper has demonstrated that we erred in our cost estimate of BOOS and we do not believe that the increased cost effectiveness of these technologies over BOOS justify their increased visibility benefit for the Lake Catherine Unit 4 to meet BART. We address specific comments concerning the modeled visibility benefit of controls at Lake Catherine elsewhere in this document where we address modeling comments. If we were convinced that this unit was going to operate substantially in excess of the 10% capacity we have assumed in our analysis, we would perhaps have reached a different conclusion. As we state above, we may revisit our determination when we review Arkansas' next regional haze SIP.

Comment: EPA did not appropriately consider the true cost of controls on the Independence Plant because it eliminated costs that it says are not allowed by EPA's Control Cost Manual. [AEP-SWEPCO July 15, 2015 comments (0164) p. 5, and August 7, 2015 comments (0167) p. 6] AEP-SWEPCO stated that the analysis EPA conducted for Independence included a cost analysis where EPA estimated $/ton costs based on similarities with the White Bluff units and, therefore, according to the methodology found in EPA's Cost Manual.[613] As noted by EPA numerous times in their RH evaluations, EPA's Cost Manual, does not allow inclusion of all actual costs associated with retrofitting various control technologies. The Cost Manual results serve as a reasonable tool for comparing one technology to another, but in the case of the Independence facility, it does not represent a true $/ton value and underestimates the cost relative to the actual $/ton by excluding these significant real costs. Therefore, EPA has not properly considered the four RPG factors by accurately considering the whole cost impact. The Cost Manual is fundamentally flawed (" ... this Manual does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources.") relative to producing a value to be compared to actual $/ton by excluding real costs and should not be used to justify cost-effectiveness compared to market value.[614] Based on our experience in other BART cost analyses, these costs could be only 60% of the actual installed costs.

Response: We address specific criticisms concerning our reasonable progress cost analysis for the Independence facility in our responses to other comments. AEP SWEPCO does not provide any references to support its statement, that we have noted in our regional haze evaluations numerous times that our Control Cost Manual does not allow inclusion of all actual costs associated with retrofitting various control technologies. We cannot find any specific reference to our making such a statement and we believe AEP SWEPCO's statement is inaccurate and misleading. Certain costs (e.g., AFUDC) are disallowed (see our response to related comments), but that does not invalidate the use of the Control Cost Manual—it merely points to the fact that the Control Cost Manual's overnight methodology uses a different accounting approach than is used by power companies. As we state in our AR Cost TSD Appendix A:

[613] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001 (hereinafter "EPA Cost Manual").
[614] *See,* EPA Cost Manual at p. 3-1.

In developing our cost estimates for the units in Table 1, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual. As we describe in our Oklahoma final action the CCM uses the "overnight" method of cost estimation:

The Control Cost Manual uses the overnight method of cost estimation, widely used in the utility industry. The U.S. Energy Information Administration (EIA) defines ''overnight cost'' as ''an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs.'' EIA presents all of its projected plant costs in terms of overnight costs. The overnight cost is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight method is appropriate for BART determinations because it allows different pollution control equipment to be compared in a meaningful manner. Because ''different controls have different expected useful lives and will result in different cash flows, the first step in comparing alternatives is to normalize their returns using the principle of the time value of money ... The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value analysis. In either case, the calculation is the same: Adjust the value of future money to values based on the same point in time (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together.'' Our proposed approach is as follows:

- Start with material we and Arkansas received from Entergy to support its White Bluff control cost analysis.
- Analyze that material for compliance with the Regional Haze Rule and our guidance.
- Critique that material and adjust it as necessary.
- Justify and extend that analysis to the Independence facility.

The BART Guidelines require that the Control Cost Manual be used when possible, when conducting a BART analysis,[615] and we have not seen an instance where the Control Cost Manual's overnight methodology cannot be used. Furthermore, we believe the overnight methodology is appropriate for use in reasonable progress cost evaluations as well, to ensure consistency in evaluating cost-effectiveness calculations across BART and non-BART evaluations. Although the Control Cost Manual provides for specific methods for estimating capital costs in some instances, its use of the overnight method, the issue here, is applicable to every control cost analysis. We also disagree with AEP SWEPCO's statement that the Control Cost Manual is fundamentally flawed. AEP SWEPCO's statement that the Control Cost Manual

[615] 70 FR 39166. In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible.

does not directly address the controls needed to control air pollution at electrical generating units is based on an incomplete and misleading reproduction of a quote. The full quote is actually:[616]

> This Manual provides up-to-date information on point source and stationary area source air pollution controls for volatile organic compounds (VOCs), particulate matter (PM), oxides of nitrogen (NOX), and some acid gasses (primarily SO_2 and HCl). It is not a source of information for non-stationary area (e.g. emissions from fugitive dust sources, agricultural sources) and mobile sources. Furthermore, this Manual does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources. Electrical utilities generally employ the EPRI Technical Assistance Guidance (TAG) as the basis for their cost estimation processes.[1] Finally, new and emerging technologies are not generally within the scope of this Manual. The control devices included in this Manual are generally well established devices with a long track record of performance
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> [1] This does not mean that this Manual is an inappropriate resource for utilities. In fact, many power plant permit applications use the Manual to develop their costs. However, comparisons between utilities and across the industry generally employ a process called "levelized costing" that is different from the methodology used here.

As can be seen from the portion of the quote that AEP SWEPCO left out, the Control Cost Manual (specifically the overnight methodology) can be used for estimating the cost of controls for power plants, which is why the BART Guidelines require its use, and why it has in fact been used to do so in numerous instances.

Comment: EPA did not justify why it refused to take into account actual costs of emission controls when evaluating BART. [UARG (0176) p. 8-9] UARG stated that the CAA and EPA's BART rules require EPA to take actual costs of emission controls into account when it evaluates a control technology as BART. *See, e.g.*, *Am. Corn Growers*, 291 F.3d at 6-7 (emphasizing the need to address real-world costs of controls in relation to projected Class I area visibility improvements that may result from installation and use of such controls). In several regional haze rulemaking proceedings, including the present rulemaking, EPA instead has taken the position that rigid adherence to the cost-accounting methodology in its Control Cost Manual – or, to be more precise, EPA's current interpretation of that methodology – is legally mandated. For instance, with respect to the White Bluff Plant, EPA proposes to reject elements of a cost analysis prepared by the facility's owner because that analysis "includes line items that … do not appear to be valid costs under our Control Cost Manual methodology." 80 Fed. Reg. at 18,971; *see also id.* at 18,973 (stating, in proposing to reject capital suspense costs, that those costs "do not appear to be valid costs under the Control Cost Manual methodology"). EPA's proposed rule excludes similar costs in its NOx BART assessment for Lake Catherine Unit 4. *Id.* at 18,977 (rejecting capital suspense and "allowance for funds used during construction" because such

[616] Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002. Section 1, page 1-3.

costs are not, or "do not appear to be," "valid costs under the Control Cost Manual methodology" as construed by EPA).

The BART Guidelines make clear the nonbinding nature of the Control Cost Manual methodology; they state that the basis for BART control-equipment cost estimates "should be documented, *either* with *data supplied by an equipment vendor* (*i.e.*, budget estimates or bids) *or* by *a referenced source* (*such as* the *OAQPS Control Cost Manual* …)." 70 Fed. Reg. at 39,166 (emphases added) (footnote omitted).

> BART determinations properly take into account additional information … used for the cost calculations, including any information supplied by vendors that affects … assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that *differs from* the *Control Cost Manual.*

Id, at n.15 (emphasis added). Similarly, the rules' preamble states:

> …the Control Cost Manual provides *a* good *reference tool* for cost calculations, *but* if there are *[cost] elements or sources that are not addressed by the Control Cost Manual* or there are *additional cost methods* that could be used, we [*i.e.*, EPA] believe that these could serve as useful supplemental information.

Id. at 39,127 (emphases added). Thus, the Control Cost Manual is "a … reference tool" but is not binding in any way,[617] and EPA has no legitimate basis for excluding real-world costs identified by facility owners and operators from BART analyses. EPA should withdraw any of its proposed BART determinations that is based on an inadequate or incomplete cost assessment.

Response: We disagree with UARG on all points. See our responses to other similar comments regarding the use of the Control Cost Manual when performing BART cost analyses. There is no conflict between considering real capital costs and the use of the Control Cost Manual's overnight methodology and in fact, we often use vendor quotes for various controls in conjunction with the overnight methodology. We address specific line item cost comments in our responses to other more specific comments.

Comment: Economic and social factors must be factored into EPA's analysis of controls, especially for the Domtar Ashdown Mill, where the asserted visibility gains cannot be predicted to occur. [Domtar Supplemental Comments (0170) p. 2] Domtar stated that related to the Trinity Consultants analysis of the CALPUFF model's margin of error for Power Boiler 2, there is the need for EPA to consider the adverse economic and social effects of environmental rules. As noted in the Ashdown Mill's prior comments, adding millions in additional annual operating costs threatens the competitive position of the Ashdown Mill. Loss of competitive

[617] Regarding design parameters for emission controls, the BART Guidelines call for "documentation of … assumptions regarding design parameters" and explain that the Control Cost Manual would be one – but only one – "*[e]xample[]* of [a] supporting reference[]" that could be used for documentation. 70 Fed. Reg. at 39,166 (emphasis added).

position means lost profits translating into lost jobs and significant adverse social consequences. The United States Supreme Court recognized these economic and social costs are a significant factor that must be considered before imposing costly regulatory requirements. Michigan v. EPA, 576 U.S. __ (June 29, 2015) ("[t]he Agency must consider cost … including, most importantly, cost of compliance, … before deciding whether regulation is appropriate and necessary"). In addition, the D.C. Circuit Court explained in vacating portions of the Regional Haze Rule that it is arbitrary and capricious for EPA to force an emission source "to spend millions of dollars for new technology that will have no appreciable effect on the haze in a Class I area." *Am. Corn Growers Ass'n*, 291 F.3d at 7.

In the case of the Ashdown Mill, where the asserted visibility gains cannot be predicted to occur, these economic and social factors are of paramount importance and must be factored into the analysis. On this basis alone, the lack of a cost and social affects analysis requires withdrawal of the Ashdown Mill's proposed BART rules.

Response: The CAA and the Regional Haze Rule require that when assessing BART, the state or we must take into consideration five factors:[618]

> the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[619]

As we have discussed in our TSD,[620] we have complied with that requirement, which includes the consideration of cost. We are certainly sensitive to the need of the facilities affected by the regional haze program to remain competitive. However, in every instance we are aware of, the installation of pollution controls necessary for compliance with the CAA and the Regional Haze Rule requires the expenditure of capital, which carries with it the possibility of reduced profits. Domtar has not supplied any specific information that would cause us to conclude that compliance with BART would impact its continued viability. Consequently, we see no reason to conclude that we should change our proposed BART determinations for Domtar.

We address Domtar's comments on the CALPUFF model margin of error in the section of this document where we address modeling issues.

Comment: EPA failed to consider the cost of controls for the Independence Plant relative to the visibility benefit that would result. [Entergy Arkansas Inc. (0166) p.43-44; and Conway Corporation et. al. (0172) p. 10-11] Entergy and Conway Corporation et. al. stated that EPA failed to consider the cost-effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a

[618] 40 CFR 51.308(e)(1)(ii)(A).
[619] 40 CFR 51.308(e)(1)(ii)(A).
[620] See the discussion beginning on page 100.

dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately $1.33 billion per dv improvement at Caney Creek and $1.53 billion per dv improvement at Upper Buffalo based on Entergy's revised S&L cost analysis. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

Ultimately, the insignificant level of projected visibility improvement does not justify the costs associated with adding a dry FGD, does not meet the statutory RPG requirement for proper consideration of the cost of controls, and is patently unreasonable, arbitrary, and capricious.

[Entergy Mississippi Inc. (0168) p. 12-13; AEP-SWEPCO July 15, 2015 comments (0164) p. 5, and August 7, 2015 comments (0167) p. 6; and Conway Corporation et. al. (0172) p. 10-11] EMI, AEP-SWEPCO, and Conway Corporation et. al. stated that the Independence Plant is not a BART-eligible source and therefore, cost-effectiveness should be determined not only on the calculated $/ton cost, but also relative to the installed capital cost and the resulting visibility improvement for the determination of reasonability.[621]

[Entergy Mississippi Inc. (0168) p. 12-13] EMI stated that EPA notes that its BART-type evaluation for NO_X for the Independence Plant would result in visibility improvements ranging from 0.148 to 0.459 dv with a cumulative improvement of 0.978 dv.[622] EPA recognized that these improvements were relatively small and proposed an option (Option 2) that did not include the LNB/SOFA NO_X controls.[623] EPA, however, did not recognize that the Independence Plant is subject to the Cross-State Air Pollution Rule ("CSAPR") and that NO_X reductions "better than BART" would already be achieved by participation in that program without specifically requiring emissions limits based on the installation of low NO_X burners and separated overfire air as proposed in the FIP. For SO_2 emissions, EPA estimated improvements with dry FGD ranging from 1.045 to 1.178 dv with a cumulative benefit of 4.375 dv. Three of the four Class I areas would realize visibility improvements barely discernible to the human eye (< 1.1 dv). The best improvement is for Upper Buffalo and is only 1.178 dv. It is not appropriate to use the cumulative values as a representation of the visibility benefit of adding controls since only the improvement at each individual Class I area could actually be recognized (*see* Comment III.F., below). This level of visibility improvement is virtually insignificant and does not justify the costs associated with adding a dry flue gas desulfurization ("FGD"). Therefore, EPA's proposal does not meet the statutory RPG requirement for proper consideration of the cost of controls and so is not "reasonable."

Response: See our response to another comment concerning the use of the $/dv metric. In our reasonable progress analysis, alongside the four statutory factors, we also considered the

[621] 80 Fed. Reg. at 18993 (SO2 costs, Unit 1, Unit 2 are $3,706 and $3,416.)
[622] 80 Fed. Reg. at 24,873 (supplemental modeling values).
[623] 80 Fed. Reg. at 18,995 and 18,997.

visibility improvement of controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. We disagree with Entergy that the projected visibility improvement does not justify the installation of controls at the Independence facility to meet reasonable progress. As we state in our TSD,[624] "The Entergy Independence Plant is not subject to BART, but its emissions were 30,398 SO_2 tpy and 13,411 NOx tpy based on the 2011 NEI. The Entergy Independence Plant is the second largest source of SO_2 and NOx point-source emissions in Arkansas, accounting for approximately 36% of the SO_2 point-source emissions and 21% of the NOx point-source emissions in the State.[625] As we discuss in detail elsewhere in this document, the installation of the controls on Independence we are finalizing in this action will result in significant visibility benefits and meaningful progress towards the goal of natural visibility conditions.

We agree with Entergy that the Independence facility is not a BART-eligible source. However, Entergy cites to no justification in the Regional Haze Rule to support its contention that, "cost-effectiveness should be determined not only on the calculated $/ton cost, but also relative to the installed capital cost and the resulting visibility improvement," nor does Entergy provide specifics as to how this should be done. In addition, capital costs are already considered, as they are an input (along with operational and maintenance costs) to the total annualized costs that form the numerator in the $/ton metric.

We address elsewhere in this document comments stating that we should substitute CSAPR participation for source-by-source NO_X BART.

We disagree that the Regional Haze Rule requires that controls on a source or group of sources result in perceptible visibility improvement and discuss that issue in more detail in our responses to other comments regarding modeling.

Comment: The cost-effectiveness of dry FGD at Independence far exceeds the cost-effectiveness standards reviewed and approved by EPA for the Kentucky and North Carolina Regional Haze SIPs, and are not justified based on the low visibility improvement. [Conway Corporation et. al. (0172) p. 5-6; and EEAA (0173) p. 10-11] Conway Corporation et. al. and EEAA stated that EPA's disregard for consistent reasonable progress review and analysis continued into the statutory four-factor analysis. After making the arbitrary and capricious determination to target only the Independence Plant, EPA approved dollar per ton cost-effectiveness estimates and visibility improvement rates for the proposed controls that are out of line with the standards applied in other regional haze SIPs and FIPs. EPA's proposal attempts to justify a cost-effectiveness of dry FGD at the Independence Plant totaling $2,477/$SO_2$ ton removed for Unit 1 and $2,686/$SO_2$ ton removed at Unit 2.[626] However, this far exceeds the

[624] See page 133 of our TSD. Based on 2011 data, Entergy's White Bluff facility is the largest sources of SO_2 and NOx in the state, with slightly higher totals than the Independence facility.
[625] The first and third largest sources of SO_2 and NOx point-source emissions in Arkansas (White Bluff and Flint Creek) are being controlled under the BART requirements in this action.
[626] *Id.* at 18933.

cost-effectiveness standards reviewed and approved by EPA for the Kentucky[627] and North Carolina[628] state implementation plans.

Further, relying on the multisource CENRAP model, EPA projected that the visibility benefits from all proposed FIP controls (*i.e.* BART and Reasonable Progress Determinations) would be 0.19 dv (Upper Buffalo) and 0.21 dv (Caney Creek) over 2018 projections.[629] These benefits represent the same type of negligible improvement in visibility that was specifically avoided in previous EPA actions.[630] Proposing controls with such a low amount of visibility benefit also ignores EPA's previous determination that improvements of less than 0.5 dv are "relatively small" and are not reasonable justification for additional controls -- even when the controls may be cost-effective.[631]

Response: As discussed in our responses to other comments, we do not judge the appropriateness of controls based solely on cost-effectiveness (the $/ton metric). Rather, we weigh the cost with the other statutory factors. In our reasonable progress analysis we also considered the visibility improvement of controls alongside the four statutory factors. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. In some cases, for reasonable progress determinations, we have calculated cost-effectiveness values for controls that fall within a range we have previously found to be acceptable, but the visibility improvement was not large enough to consider as beneficial at this time.[632] Thus, it is inappropriate to simply compare cost-effectiveness values. Nevertheless, the Independence cost-effectiveness values fall squarely within a range of value we have previously found to be acceptable—again, even if the visibility benefits are not considered—for the same types of controls.[633]

We have responded to arguments that we have been inconsistent with regards to our Kentucky and North Carolina actions, and comments concerning the estimated visibility benefits from all controls in our responses to other comments.

The commenter incorrectly compares the CAMx photochemical model results for the overall visibility benefit of controls on the average of the 20% Worst days for 2018 to the CALPUFF modeled visibility benefit from controls that is modeled based on maximum emission levels and using a natural background approach. As we discuss in more detail elsewhere in this document,

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[627] 76 Fed. Reg. 78194, 78206 (Dec. 16, 2011) (approving the use of a $2,000 per ton SO_2 screening threshold).
[628] 77 Fed. Reg. 11858, 11870 (Feb. 28, 2012) (approving state's decision not to implement additional controls for reasonable progress despite cost-effectiveness determinations ranging from $912 to $1,922 per ton of SO_2 removed).
[629] 80 Fed. Reg. at 18998 (Table 67).
[630] *See e.g.,* 77 Fed. Reg. at 24012 (Montana Proposed) (EPA determined that 0.18 dv improvement was too low to justify additional SO2 controls on one facility); 76 Fed. Reg. 12651, 12661 (Oregon Proposed) (Mar. 8, 2011) (EPA rejected relatively low-cost per ton controls that yielded only 0.18 dv improvement).
[631] 77 Fed. Reg. 30454, 30464 (Oregon Final). (May 23, 2012).
[632] For instance, see the reasonable progress control determination for the Parish facility in our recent Texas-Oklahoma FIP. 81 FR 296.
[633] 76 FR 81746. Note that Option 2 concerning dry scrubbers included cost-effectiveness values that ranged to $3,032/ton.

these CAMx modeled values are not directly comparable to the CALPUFF modeled improvement from controls cited to by the commenter, due to differences in models, model inputs and metrics. The commenter does not provide a direct comparison between the modeled visibility benefit of controls in Montana and Oregon to the CALPUFF modeled visibility benefit of controls on the Independence facility and is incorrect in their assertion that the benefits from controls at Independence are the same type of improvement that was avoided in other EPA actions. Our CALPUFF modeling estimated that the required SO2 controls at Independence provide for improvements in visibility on any single Class I area ranging from 1.05 to 1.18 dv and the required NOx controls result in improvements ranging from 0.15 to 0.46 dv.[634] These visibility benefits are much larger than the CALPUFF estimated visibility benefits of 0.18 dv for scrubbers at the Ash Grove facility in Montana or the 0.18 dv incremental benefit of NOx controls at PGE Boardman in Oregon cited to by the commenter.

The commenter also implies that our evaluation of controls for Independence was different and more stringent compared to other states because, for other states, EPA determined that "a predicted impact on a Class I area of 0.5 deciview ("dv") was "relatively small" and that a source with a predicted impact on a Class I area at or below 0.5 dv should not be required to install additional emission controls to meet reasonable progress." The inference from the commenter that a modeled impact of 0.5 dv is a "bright line" for reasonable progress decision has been improperly taken out of context. The actual passage that the commenter cites is:

> All sources with a Q/d ratio of less than 26.1 had visibility impacts of less than 0.5 dv. The resultant average of the range is about 0.3 dv, which is more conservative than the 0.5 dv that was used in determining which sources would be subject-to-BART under the federal BART regulations. Since the threshold is more conservative than the subject-to-BART threshold, we believe that a Q/d value of 20 is reasonable for determining which point sources the State should consider for the reasonable progress analysis. … Since all of these sources have Q/d values below 20, EPA believes that their impacts on nearby Class I areas are expected to be less than 0.5 dv. Thus, EPA agrees with Oregon's conclusion that additional controls of non-BART point sources for reasonable progress purposes are not reasonable in the first planning period, because even though there are cost effective controls identified, visibility improvement is anticipated to be relatively small.[635]

We therefore disagree with the commenter that our determination of controls for Independence is inconsistent with previous EPA actions.

Comment: EPA did not propose to require the Bailey and McClellan units to burn natural gas exclusively. [Stamper Report, page 47]. Ms. Stamper stated that visibility modeling for the Bailey and McClellan facilities reveals that the units have much lower impacts when burning natural gas compared to when burning fuel oil. The modeling for the Bailey unit did not predict any days with impacts greater than 0.5 dv when combusting natural gas and the modeling for the McClellan unit only shows three days in excess of 0.5 dc impacts over three years of modeling

[634] See Summary of Additional Modeling for Entergy Independence available in the docket for this action
[635] 77 FR 30464

when burning natural gas. In contrast, the Bailey plant was modeled to have 6-12 days over the three years of meteorological data modeled with impacts greater than 0.5 dv at each Class I area when burning fuel oil. When burning fuel oil, the McClellan plant was modeled to have as high as 23 days over the three years of meteorological data modeled with 0.5 dv impacts or greater at Caney Creek, and 2-5 days greater than 0.5 dv at the other Class I areas modeled. Clearly, the combustion of fuel oil is the reason these units are subject to BART and should be EPA's primary focus for BART. Ms. Stamper presented information that indicated that based on 2012 and 2013 data, these plants have not burned much fuel oil. She concludes that switching to natural gas at the Bailey and McClellan units would provide the greatest improvement to visibility at the four Class I areas modeled.

She questions why we did not propose to require the Bailey and McClellan units to burn natural gas exclusively. She notes it appears the main reason for not requiring the Bailey and McClellan units to only burn natural gas was because of AECC's concern that during periods of natural gas curtailment and other emergencies, the units would not be able to burn fuel oil. 80 Fed. Reg. at 18,951, 18,958. She acknowledges that we stated that the BART Guidelines provide that it is not EPA's intent to direct sources to switch fuel forms. 80 Fed. Reg. at 18,953, 18,959. She concludes that if AECC is only concerned with the need to burn fuel oil during periods of natural gas curtailment and emergencies, which are rare events, that means the primary fuel for Bailey and McClellan is natural gas and it would not necessarily be considered fuel "switching" to require the Bailey and McClellan units that primarily burn natural gas to stop burning fuel oil altogether to meet BART. Natural gas constitutes the majority of the heat input to these boilers. Not only would the cessation of burning fuel oil satisfy SO_2 BART, but it would also satisfy BART for PM.

Ms. Stamper notes that in contrast, Entergy is willing to be restricted from burning fuel oil at the 558 MW Lake Catherine Unit 4 to meet BART. 80 Fed. Reg. at 18,975-76. Entergy acknowledged that it might want to burn fuel oil in the future, and if that was the case, it would apply for a BART determination before doing so. Id. She questions why, if Entergy can take a fuel restriction for the much larger Lake Catherine plant, it can't do the same at the Bailey and McClellan plants. EPA should impose such a restriction for these units, along with allowing the Bailey and McClellan plants to burn fuel oil if the units obtain a BART determination first.

She concludes that the cessation of fuel oil burning at the Bailey and McClellan plants will reduce the plants' operational expenses and will provide for the greatest improvement in visibility impairment caused by the Bailey and McClellan plants. Thus, EPA should require the cessation of burning fuel oil at the Bailey and McClellan plants to meet BART for both SO_2 and PM. If AECC needs the ability to burn fuel oil in the future, EPA could allow the plant to do so, but only after obtaining a BART determination for fuel oil, consistent with what it has proposed as BART for Lake Catherine Unit 4. 80 Fed. Reg. at 19,002.

Relatedly, Ms. Stamper supports our proposed determination that no additional NO_X controls to meet BART at the Bailey and McClellan plants should be required, agreeing that the small visibility benefits do not justify the costs.

Response: As Ms. Stamper notes, in our proposal we noted that the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to gas (40 CFR part 51, Appendix Y, section IV.D.1). Whether or not gas is in fact the primary source of fuel for these facilities has no bearing on this. Therefore, we cannot require a facility to cease burning a particular type of fuel unless the facility itself offers to switch fuels or to voluntarily accept a restriction on burning a particular type of fuel as part of a BART determination. We can, however, require that these facilities include consideration of that fuel in their BART analyses, which is what we have done. In addition, Lake Catherine Unit 4 voluntarily offered to accept a restriction on burning any fuel oil until BART determinations are made for the fuel oil firing scenario through either promulgation of a FIP and/or through EPA approval of a SIP revision. Therefore, we proposed to promulgate this restriction on Lake Catherine Unit 4 in our FIP. On the other hand, AECC Bailey and McClellan did not offer to accept a restriction on burning fuel oil and we therefore cannot impose such a restriction in our FIP. They did, however, offer to accept a restriction on the sulfur content of the fuel burned and our SO_2 and PM BART determinations for these two facilities is based on this voluntary acceptance. Therefore, we disagree that our treatment of Lake Catherine Unit 4 is inconsistent with how we address AECC Bailey and McClellan in this FIP.

Comment: EPA incorrectly calculated baseline emissions for White Bluff and Independence [S&L Entergy Report, page 2]. S&L objects to our approach of calculating a SO_2 baseline for the White Bluff and Independence facilities, in which we eliminated the high and low annual emission values from 2009 to 2013, and averaged the remaining values. S&L presents the following table contrasting our approach to calculating SO_2 baseline emissions with 4 alternative approaches:

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

S&L concludes that in all cases, there is at least one other approach that would result in lower baseline SO_2 emissions.

Response: We disagree with S&L that we erred in the procedure we used in estimating baseline emissions for our BART and reasonable progress scrubber upgrade cost analyses. The fact that S&L can construct alternative approaches to our baseline calculation that result in lower values does not invalidate our BART and reasonable progress approaches. As can be seen from an examination of S&L's own data, regardless of whether a three year average or a five year average of a particular set of years is employed, the results are all similar. In fact, for three out of four units one of S&L's alternative approaches would have produced higher SO_2 baselines,

which if used would have resulted in the cost analyses we performed being even more cost-effective.

Regarding the calculation of baseline emissions, the BART Guidelines state[636]:

> How do I calculate baseline emissions?
>
> 1. The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.
>
> 2. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in Section 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. One of these areas is in the calculation of the baseline emissions in determining cost effectiveness.

We believe the procedure we used is in compliance with this language. We calculated our baseline SO_2 emissions by first acquiring the 2009 to 2013 emissions as reported to us by the facilities in question.[637] We eliminated the high and low values from the 2009-2013 emission to better address potential yearly variations in coal sulfur data, capacity usage, etc., and make the baseline more representative of plant operations. The difference between our baseline calculations and any of the alternative procedures S&L outlines is small and would not change our proposed conclusions for the White Bluff BART determinations and the Independence reasonable progress determinations.

Comment: EPA incorrectly calculated the SO_2 emissions reductions for White Bluff and Independence [S&L Entergy Report, page 3]. S&L states that SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages,

[636] 70 FR 39167.
[637] http://ampd.epa.gov/ampd/

which are significantly higher than the annual averages actually used to calculate baseline emissions. The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA. S&L presents its calculations below. We added the percent difference column:

Unit	EPA Approach Using Maximum Monthly SO_2 emission and 3-Year Baseline (tons)	Using 5-Year Average Heat Input and Baseline (tons)	Percentage difference EPA vs. S&L (%)
White Bluff 1	14,363	14,264	0.7
White Bluff 2	15,221	14,353	5.7
Independence 1	12,912	12,607	2.4
Independence 2	13,990	13,655	2.4

Response: We disagree with S&L that our methodology for calculating the SO_2 tons reduced was incorrect for the White Bluff BART determinations and the Independence reasonable progress determinations. We began by selecting the monthly maximum emission rate from 2009 to 2013 emissions data. We then had to test to ensure we did not assume a scrubber percentage reduction that exceeded the ability of the technology.[638] We set this test at a 95% control efficiency, not to exceed a floor of 0.06 lbs/MMBtu. Because we condition emission limits on the basis of monthly data, we selected the maximum monthly emissions from 2009-2013 and applied the aforementioned test to this figure to establish our control efficiencies. This control efficiency was then applied to the SO_2 baseline. Using S&L's proposed methodology of simply multiplying 0.06 by the average heat input to the boiler would not have tested to ensure that 0.06 lbs/MMBtu was actually achievable, and achievable on a monthly basis. We note there are more involved methods for ensuring the technology is capable of achieving the control emission rate on a monthly basis that involve a more detailed examination of the historical data, but we believe the one we selected is technically adequate. We also note that S&L's method of using an annual average heat input introduces a mismatch in that annual data would be used to set an emission rate that is required to be met on a monthly basis. In any event, as can be seen from the data in the above table, the differences between our method and S&L's method are small, with a maximum difference of less than 6%. This would not have changed our proposed determinations for either the White Bluff BART or Independence reasonable progress facilities. Lastly, as S&L has not provided any specific references to instances in which its methodology has been found to be acceptable, we cannot check its claim.

[638] See that tab, "Cost Effectiveness" in the file, "AR020.0093 White Bluff_R6 cost revisions2.xlsx," in our docket.

Comment: EPA' proposed SO_2 emission limit for White Bluff and Independence is too stringent [S&L Entergy Report, page 4]. S&L states that EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions. S&L then presents information that it states represents permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which it states are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu. S&L concludes that EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

Response: As we indicate in our TSD, we accepted Entergy's own use of the 0.06 lbs/MMBtu emission limit in its cost analysis, so we find it odd that S&L would now argue against that figure.[639] Nevertheless, we address S&L's objection.

First, S&L does not provide the source of its information or even name the facilities it cites to in its comment, so we are unable to verify any of the information it presents. Second, there is no reason to conclude that a permit limit represents the maximum performance potential of any control device to limit emissions. Third, we do not believe a limit (or even a verified maximum control level) can be used as a basis for the comparison of the performance potential of one scrubber to another, because doing so does not consider the sulfur content of the coal.

Our conclusion that the White Bluff and Independence dry scrubbers are capable of 95% control, not to exceed a floor of 0.06 lbs/MMBtu, is an often cited, widely accepted statement of the capability of dry scrubbers. S&L itself has published papers that cite to this capability.[640] As we state in our TSD,[641] we demonstrated in our Oklahoma FIP that this level of performance is achievable on a long term basis for this type of technology, considering the type of coal that is being burned.[642] We therefore disagree with S&L that our proposed SO_2 emission limit of 0.06

[639] See page 2 of appendix A to our TSD.

[640] See for instance, Sargent & Lundy, Flue Gas Desulfurization Technology, Dry Lime vs. Wet Limestone FGD, Prepared for National Lime Association, March 2007, pp. 6, 14 (Table 4.1-1), 25 (Table 5.1-1), p. 41 (Table 7.2). See also S&L's more recent study, White Bluff Station Units 1 And 2, Evaluation Of Wet Vs. Dry FGD Technologies, SL-009510, Rev. 3, October 28, 2008, Project 12303-004. Figure 2-1

[641] See footnote 7 in appendix A to our TSD.

[642] Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, 12/13/2011. See discussion beginning on page 93.

lbs/MMBtu on a 30 BOD average is improper, or that it results in our overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

Comment: Entergy states EPA incorrectly subtracted BOP costs for White Bluff [S&L Entergy Report, page 7]. S&L states that we mistakenly subtracted BOP costs because we believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system was not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NOx control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope. EPA mistakenly deleted a total of $255,000 to paint the chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate. EPA mistakenly removed a total of $390,000 for costs associated with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these monitors including conducting a Relative Accuracy Test Audit (RATA) test. Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Excluded BOP Costs (Corrected, Total for Both Units)

Equipment		Material	Labor	Total
Total BOP Cost	$45,561,000	$35,120,000	$80,863,000	$161,544,000
Eliminate U1 NOx Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Eliminate U2 NOx Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Total Eliminated Cost	$7,244,000	$3,200,000	$6,146,000	$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In the table below, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5. EPA excluded a total of $51,733,667 from the estimate, but Tables 4 and 5 show that only $20,724,543 was justified because NOx control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed $31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions			
DESCRIPTION	**Equipment**	**Material**	**Labor**	**Total**	**Equipment**	**Material**	**Labor**	**Total**
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A)	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337

@5% OF MATERIAL AND LABOR								
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								**$20,724,543**

Response: In Appendix A to our TSD, we noted that Entergy used the Balance of Plant (BOP) costs from a 2008 S&L quote to supplement its adjusted 2009 Alstom quote in its 2013 SDA cost analysis for the White Bluff BART determination. However, due to a lack of documentation, it appeared that a number of items were either not appropriate for a SO_2 scrubber, or were already covered as part of the Alstom quote. We removed those items from our proposed SDA cost analysis and invited Entergy to supply additional documentation to verify these costs. S&L now points to a S&L Report #012831, which contains a 2015 White Bluff SDA cost estimate, for that documentation.

First, Entergy states that its 2015 SDA cost estimate is based on a 2013 Alstom quote. As with the 2009 Alstom quote it used to support its 2013 SDA cost analysis, Entergy does not provide this Alstom quote. Consequently, and as we discuss in a later response to comments, we have no way of verifying Entergy's 2015 cost calculations. Second, Entergy points to a description of the reagent handling system in its 2015 SDA cost analysis (which depends on the 2013 Alstom quote), as proof that the updated reagent handling system was not included within the scope of the 2009 Alstom quote. Not having access to the 2009 and 2013 Alstom quotes, we have no reason to conclude that their scopes are the same. Therefore, we have no choice but to conclude that Entergy has not demonstrated that our removal of $20,542,000 in reagent preparation enclosure and reagent handling system BOP costs in its 2013 SDA cost analysis due to overlap with the 2009 Alstom quote was incorrect.

Similarly, Entergy states that the $1,754,000 in ductwork we subtracted from the BOP quote was not in Alstom's scope. Again, because we do not have the 2009 Alstom scope of work, we cannot verify this. Therefore, we have no choice but to conclude that Entergy has not demonstrated that our removal of $1,754,000 in ductwork BOP costs in its 2013 SDA cost analysis due to overlap with the 2009 Alstom quote was incorrect.

Entergy states it agrees with our exclusion of NO_X controls from its BOP costs. However, it does not discuss our exclusion of $1,166,000 for booster fans. We noted in our TSD that Alstom's payment schedule indicated that booster fans were scheduled to be delivered in month 22, and installed in month 30. We assume Entergy agrees with this exclusion. However, due to an oversight on our part this charge was never subtracted from the BOP costs. Because this change would have further improved the cost-effectiveness (lower $/ton) of the White Bluff and Independence SDA scrubbers, it adds to the conservativeness of our calculation.

We also accept Entergy's explanation that a $390,000 charge to replace and recalibrate the CEMS was justified because the existing system was not capable of measuring SO_2 in the range that would result from the SDA control. Again, due to an oversight on our part, this charge was never subtracted from Entergy's BOP costs, so no change is needed, and it adds to the conservativeness of our calculation.

We accept Entergy's explanation that $255,000 to paint the chimney was justified to mitigate the potential effects of acid corrosion of the chimney due to flue gas downwash as a result of the SDA installation. We have revised our cost analysis to include these costs,[643] which are

[643] See the file, "White Bluff_R6 cost revisions2-revised.xlsx" in our docket.

inconsequential to our final determination that dry scrubbers are cost-effective for the White Bluff facility.

Comment: Entergy objects to the escalation calculation in our White Bluff scrubber cost analysis. [S&L Entergy Report, page 11]. Entergy states that it agrees with our assertion that the application of escalation is allowed by the CCM. However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units. Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services." Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown below:

Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown above, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that de-escalated costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.

Response: For our proposal, we used Entergy's revised BART analysis for the White Bluff facility, as submitted by it on October 14, 2013, because at the time it was the latest information available to us.[644] In our proposal, our control cost analysis used the same basic information that Entergy previously presented to us in 2013. As we describe in Appendix A of our TSD, Entergy stated that it received two different SDA cost estimates for White Bluff: an early 2009 Sargent and Lundy (S&L) estimate with a total contractor cost of $291,930,000, and a December 2009

[644] See section 2.1 of Appendix A to our TSD.

estimate from Alstom of $247,856,184. Entergy stated that unlike the S&L quote, the Alstom estimate was not itemized and only included a total price. Entergy used the 2009 Alstom price quote as the basis for its BART cost analysis for White Bluff by increasing it by 10%, and scaling the S&L itemized cost to match the 110% adjusted Alstom total price. As we describe elsewhere in our response to comments, we critiqued certain aspects of Entergy's use of this information. For example, Entergy mistakenly included certain NOx controls in its 2013 cost analysis. It also failed to document certain BOP costs that we had no choice but to exclude. However, between the 2009 S&L and the 2009 Alstom quotes, and with these corrections, we were able to construct a reasonable control cost estimate. In so doing, we used the same 2009 Alstom total, and the Alstom payment schedule for its quote, as the actual Alstom quote was not supplied and no better information was presented by Entergy. Because Entergy's 2013 cost estimate used 2009 Alstom pricing, we had no choice but to escalate it to 2013—more recent information was not available.

Entergy did not provide its updated 2015 cost estimate, which it references in its comment, until after our proposal. Entergy's 2015 report uses updated 2013 pricing from Alstom as its basis. As we discuss in a previous comment, we reviewed this 2015 cost analysis and found that it presents problems that prevent us from using it, primarily because it is undocumented.

In this comment, Entergy attempts to use its newly submitted 2015 cost analysis to discredit the escalation technique we employed to adjust its previous 2013 cost analysis. It does so without even presenting the 2013 Alstom quote on which it states the 2015 cost estimate relies. Thus, we have no basis to conclude that the costs Entergy presents in its first table above even cover the same scope of work. This is an important consideration and a different scope can cause a significant difference in cost. Entergy itself noted this when it used a revised BOP estimate to adjust its 2009 Alstom quote because the scope had changed. Even different cost estimates received in the same year can result in significantly different totals. For instance, as we also note in our TSD, Entergy stated that it received two different SDA cost estimates for White Bluff: an early 2009 S&L estimate with a total contractor cost of $291,930,000, and a December 2009 estimate from Alstom of $247,856,184.[645] We note that the difference between these two quotes is $44,073,816, which is more than Entergy calculates in its first table above is the difference between our escalated 2013 quote ($261,581,119) and its revised 2015 cost estimate, based on the its 2013 Alstom quote ($297,904,000).

Escalation from one year's cost basis to another[646] is not only allowed by the Control Cost Manual, it is a required procedure in order to allow an apples-to-apples comparison between control cost analyses. Our use of the Chemical Engineering Plant Cost Index (CEPCI) is a standard method of escalating costs,[647] and one that power companies have also used on numerous occasions. Entergy itself has used the CEPCI in an attempt to escalate its costs. Unfortunately, as we explain in our TSD, Entergy did so incorrectly and we corrected that error.[648] We certainly prefer revised vendor quotations to escalating older cost estimates.

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[645] See section 2.1 of Appendix A to our TSD.

[646] Note that escalation during the construction period is disallowed, however, because that is not a part of the overnight method.

[647] Vatavuk, William, M., "Updating the CE Plant Cost Index," Chemical Engineering, January 2002.

[648] See section 2.6 of Appendix A to our TSD.

However, when revised vendor quotes are not available as in this case, we have no choice but to escalate older cost estimates in order to bring the cost basis to the present.

Entergy also apparently objects to any escalation technique that results in a reduction in a future year's cost basis, holding it up as evidence of our error.[649] This is a fundamental misunderstanding of escalation. Although most cost escalation does result in an increase in the cost basis, occasionally the opposite occurs. This is mainly due to broad economic factors that influence the cost of raw materials, supply and demand, vendor profit, etc. This can be illustrated by the following table of the CEPCI Composite Index:

Year	Composite CE Index	Percent Change over Previous Year
2004	444.2	
2005	468.2	5.40%
2006	499.6	6.71%
2007	525.4	5.16%
2008	575.4	9.52%
2009	521.9	-9.30%
2010	550.8	5.54%
2011	585.7	6.34%
2012	584.6	-0.19%
2013	567.3	-2.96%
2014	576.1	1.55%

As the above table indicates, although the Composite CE index usually increases from year to year, it does occasionally decrease, due to various broad economic factors, such as it did from 2008 to 2009, and again from 2011 to 2013. Thus, Entergy's objection over the "de-escalation" of cost from 2008 to 2013 is entirely misplaced. In other words, escalation is escalation: most of the time it is positive but sometimes it is negative. We therefore do not agree with Entergy's objections to our escalation technique. We take up the issue of Entergy's 2015 cost estimate in our response to another comment.

Entergy states that our cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs. As noted in the first sentence of our response to this comment, we were constrained to use Entergy's revised BART analysis for the White Bluff facility, as submitted by Entergy on October 14, 2013 (hereafter referred to as the "2013 SDA Cost Analysis"). These costs employed a 2008 vintage total direct annual cost, as we indicate in Appendix A of our TSD.[650] Regarding its direct annual costs, Entergy further states, "The cost estimates were scaled to reflect 2012 dollars."[651] We therefore agree that Entergy did provide

[649] Entergy's reference to de-escalated costs.
[650] See section 2.7 of Appendix A to our TSD.
[651] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas (AFIN 35-00110).

what it stated was 2012 vintage direct annual costs. We did not use those costs because Entergy incorrectly escalated them from 2008, as we discuss above. For instance, Entergy presented its 2008 direct annual cost as $7,901,369. It then "scaled" them to 2012 using a 2008 CEPCI index of 530.7 and a 2012 CEPCI index of 593.6, resulting in a 2012 value of $8,837,861. As we discuss in Appendix A of our TSD, Entergy appears to have incorrectly used the January monthly CEPCI value for each year instead of the annual CEPCI value. Entergy should have used a 2008 CEPCI index of 575.4 and a 2012 CEPCI index of 584.6, resulting in a 2012 escalated direct annual cost of $8,027,703 ($7,901,369 X 584.6/575.4). As we also discuss in our TSD, because we were conducting our analysis later, we escalated Entergy's 2008 direct annual cost to 2013, resulting in a value of $7,790,140 ($7,901,369 X 567.3/575.4). These facts appear to have been ignored by Entergy in its comment. We therefore have no choice but to disagree with Entergy's comment concerning our not using its 2012 direct annual cost.

Comment: Entergy summarizes its objections to our escalation calculations in our White Bluff scrubber cost analysis. [S&L Entergy Report, page 12]. Continuing from its previous comment on escalation, Entergy presents the table below. Entergy states it summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. Entergy states that information from Alstom showed their pricing escalated nearly equivalently for equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible Entergy applied the average 4.7% in the revised costs shown in the table below. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Entergy's Summary of EPA's Escalation Errors (Per Unit)

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023

Appendix A, SDA cost analysis, June 2013, Appendix A.

Insurance @ 1% of TCI	$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs	$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA			$42,607,547

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis,
SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012
BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

Response: Entergy's comments concerning its 2015 cost estimate present several problems that prevent us from being able to properly review them. We discuss these problems below and we treat each of the items in the table it presents below:

- As we state in our response to the previous comment, Entergy does not supply the 2013 Alstom quote which it references in its comments. In fact, Entergy has not supplied any information that indicates the scope of the Alstom quote. As we stated in our TSD, Entergy's similar failure to supply the 2009 Alstom quote and its scope was a key problem in our observations that Entergy's 2013 SDA cost analysis contained inappropriate cost items and double counting.

- Entergy states that it applied an escalation rate of 4.7% per year in the revised costs shown in the table it presents. We are able to duplicate its figures for the Total Contractor Costs and the Contingency (2010) using following formula:

  $$Pn = P(1+i)^n$$

  Where:

  Pn = Future Cost
  P = Present Cost
  i = Annual percentage increase
  n = Difference between base year and future year. Ex: 2013 - 2010 = 3

  However, as we discuss in our response to another comment, we must reject Entergy's escalation technique. Entergy does not provide either the 2009 or the 2013 Alstom quotes on which it states its cost estimates rely. Thus, we have no basis to conclude that the costs Entergy presents in its 4.7% escalation calculation even cover the same scope of work. We find it perplexing that Entergy did not just supply the 2013 Alstom quote, eliminate the usual disallowed cost items (AFUDC, escalation during construction, owner's costs, etc.) and provide an updated cost analysis. Instead, its comments seem to

be focused on attempting to shore up an older 2013 cost analysis it has apparently already replaced.

- We have addressed Entergy's objections to our BOP cost revisions in a previous comment and have concluded that $255,000 to paint the chimney was a justified BOP costs. We will add those costs back into our revised White Bluff cost analysis.

- Entergy provides a footnote to its BOP Indirect Costs (2012): "In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA." First, we did not incorrectly use a 2008 BOP Indirect Cost in lieu of one for 2012. Rather we excluded Entergy's 2008 BOP indirect costs because they were undocumented and appeared to be captured elsewhere in its costs. As we explain in our TSD:[652]

  > In addition to the BOP costs that we discuss above, Entergy also includes a BOP indirect cost of $8,733,104 per unit. Regarding this, Entergy states:[653]
  >
  > > BOP indirect costs are costs associated with engineering, construction management, startup and commissioning and are estimates provided by the contractor. Miscellaneous contractor labor is inclusive of legal support, owner's insurance, S&L engineering costs, and Entergy's environmental permitting costs.
  >
  > No documentation of these costs was provided. We agree that BOP indirect costs are certainly legitimate under the Control Cost Manual. However, the BOP quote discussed above already contains Item 360, entitled "Non Contractor Indirects," under which is the subcategory Item 360.8 entitled "Engineering BOP," for $9,855,000. Furthermore, we note that the BOP quote also contains two additional charges for "General and Administration" (Items 307.5 and 307.6) for a total of $6,355,000. These General and Administrative and Non Contractor Indirects categories are broad in scope, unspecific in description, and undocumented. Together, they total $16,210,000. Lacking any documentation to the contrary, we must assume any work associated with the support or administration of the BOP items are contained within these cost items. We therefore propose to delete the additional BOP indirect cost item from the SDA costs.

  Entergy does not address this lack of documentation and simply adds the costs back in. Second, despite Entergy's note, $1,035,071 does not appear to be included in "the column for Escalation Costs Omitted by EPA." Rather, a figure of $1,494,175 appears,

[652] See section 2.5.2 of Appendix A to our TSD.
[653] Original footnote from our Cost TSD: "Entergy Response to EPA Region 6 comments on Entergy White Bluff draft BART Report 06/10/13. Page 9."

which is not explained. Third, we suspect that Entergy may be confusing this cost item with its Direct Annual Costs. As we discuss in our response to another comment, we did not use those costs because Entergy incorrectly escalated them from 2008. We instead properly escalated the 2008 Direct Annual Costs to 2013. Consequently, we cannot accept Entergy's revision to our BOP Indirect Costs.

- Entergy has added in the figures shown in its above table for Misc. Contract Labor, Entergy Internal Costs (2012), and Capital suspense. We assume Entergy disagrees with our exclusion of these costs,[654] and we invited it to provide documentation to the contrary. However, we cannot locate any documentation of these costs in its comments. Consequently, we cannot accept Entergy' corrections to our cost analysis.

- In our response to a previous comment, we have discussed our rejection of Entergy's revision to our Direct Annual Cost calculation due to errors in Entergy's escalation.

- For the same reasons we must reject Entergy's escalation of its Total Contractor Costs and Contingency, we must similarly reject its escalation of its Overhead (2008) cost.

- Because the Administrative Charges, Property Tax, and Insurance are all percentages of the TCI, they will be adjusted in our final cost analysis after we make the adjustments to the BOP costs we discuss above.

Comment: Entergy objects to our adjustment of O&M costs due to coal sulfur content in our White Bluff cost analysis. [S&L Entergy Report, page 14]. EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first

[654] See Section 2.5 of Appendix A to our TSD.

conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Entergy presents the figure below to illustrate why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient.

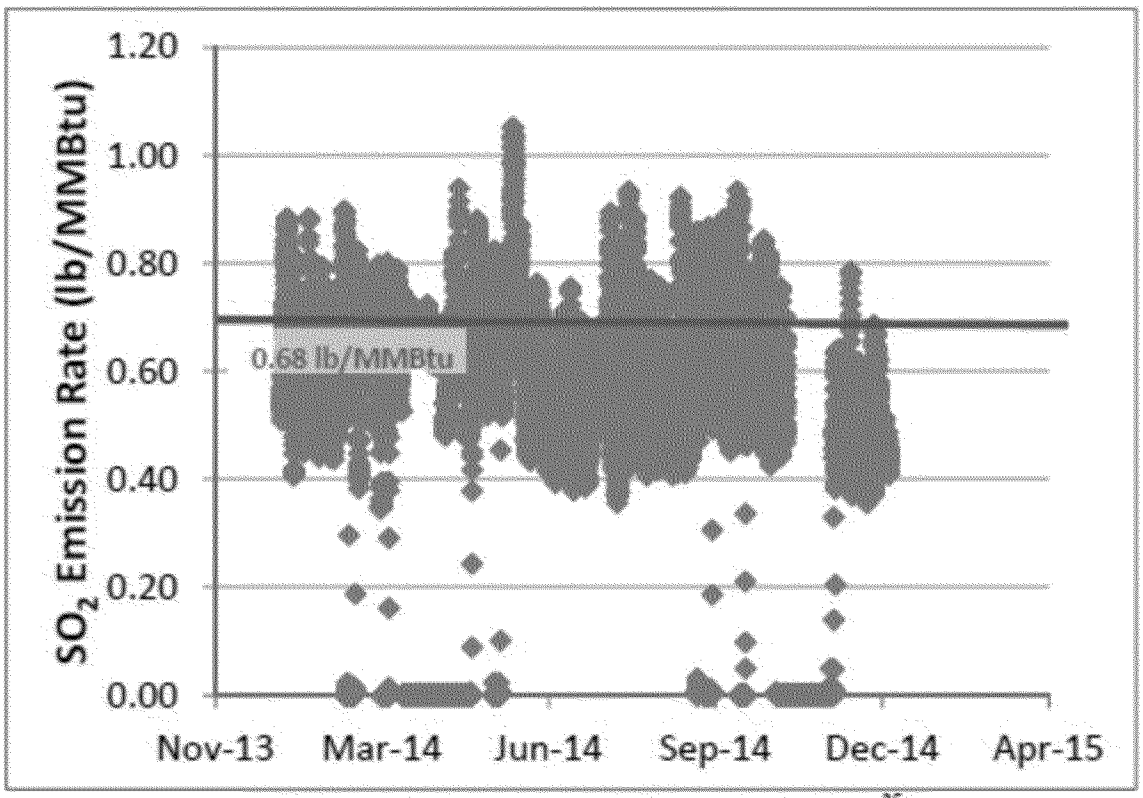


Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA

selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

Entergy states that while it believes that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in the above figure confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831. As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being included in its cost-effectiveness calculation. This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost. Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

Response: Entergy states that we correctly assumed that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but our conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with the BART guidelines. We thoroughly explained our reasoning for this statement in our TSD,[655] including appropriate references to the BART Guidelines. As we noted in our TSD, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions." Entergy chose to do neither and costed a scrubber capable of treating a coal far in excess of what it historically burned, but continued to base the capabilities of the scrubber on its historical SO_2 baseline. Thus, either Entergy's annualized cost (the "$") or its tons reduced (the "tons") in the $/ton cost effectiveness calculation are misrepresented. Our approach was to recalculate Entergy's scrubber cost to bring its scrubber design in line with the historical coal it has burned. Entergy could have taken the alternative approach of calculating a new baseline on the basis of its higher sulfur design coal, but it chose not to. We see nothing in Entergy's comments that would cause us to conclude our reasoning was in error. We therefore disagree

[655] See Section 3.1 of Appendix A to our TSD.

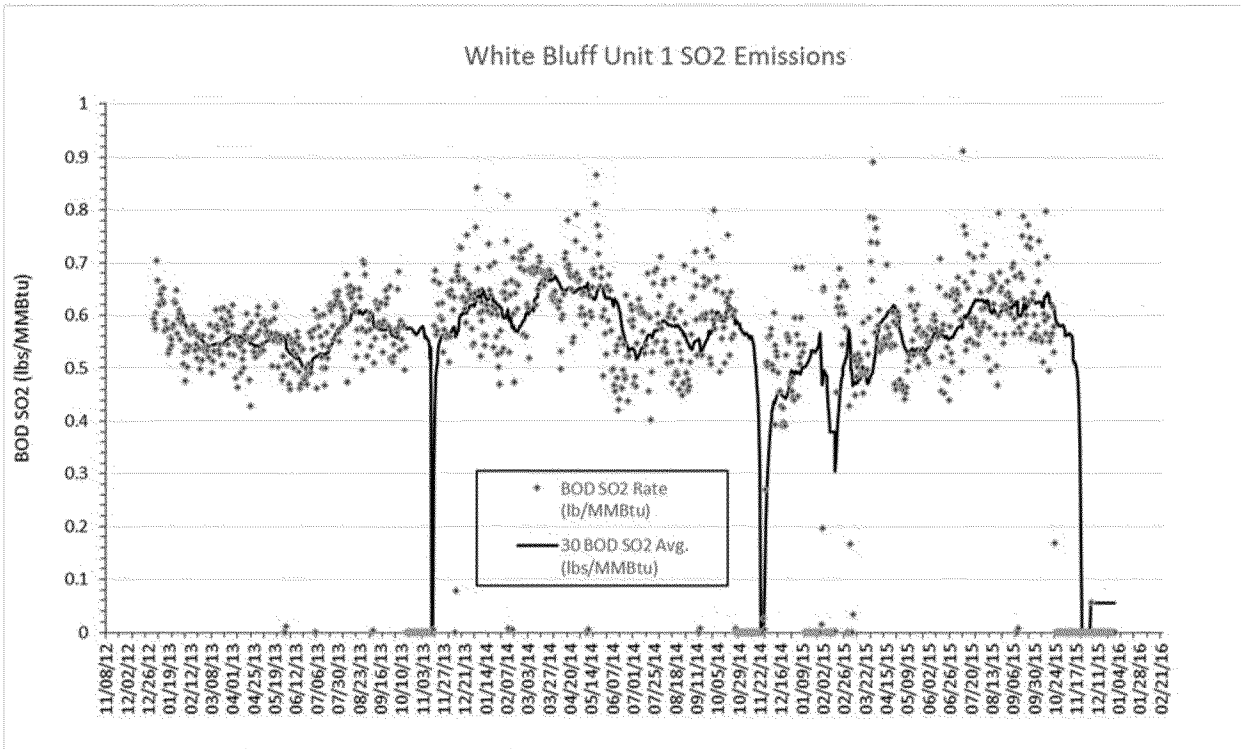
with Entergy's assertion that our conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Entergy also states, "While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis." Entergy then presents the above SO_2 emissions plot as evidence of our error. We do not believe this statement accurately represents our approach. We did not choose 0.68 lbs/MMBtu as a *design basis* for Entergy's scrubber systems. As we explain in our TSD,[656] we ran two IPM SDA cost model cases: one using Entergy's 2.0 lb/MMBtu design value, and one using a design value of 0.68 lbs/MMBtu. We then constructed a table that included a ratio of certain capital and operating costs of the 0.68 lbs/MMBtu case to the 2.0 lbs/MMBtu case. We then applied these ratios to Entergy's own cost analysis (with the corrections we discuss in our responses to Entergy's comments). That table is reproduced below:

	0.68 lb/MMBtu Case	**2.0 lb/MMBtu Case**	**Ratio of Selected 0.68 lb /MMBtu to 2.0 lb/MMBtu Costs**
Capital, engineering and construction cost	$328,680,000	$342,944,000	**0.9584**
Capital Recovery factor	0.0806	0.0806	
Annualized capital costs	$26,487,139	$27,636,624	
Variable operating costs	$8,581,744	$17,332,840	**0.5823**
Fixed operating costs	$3,812,705	$3,953,100	
Total annualized costs	$38,881,588	$48,922,564	

Furthermore, Entergy does not state so, but it appears that its SO_2 plot contains *hourly* SO_2 emissions data. Thus, Entergy appears to argue that its scrubber systems must be designed to treat every hourly fluctuation in SO_2, which is borne out by its statement, "[EPA's] design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance." This is incorrect, as we did not propose that the White Bluff facility meet an hourly SO_2 limit. Our proposed limit is a 30 Boiler Operating Day (BOD) average. Thus, individual hourly SO_2 emissions are inconsequential. In fact, even daily SO_2 averages are relatively unimportant, since they constitute only one day out of a 30 day average. Below we present a plot of the White Bluff Unit 1 daily emissions for the last three years:[657]

[656] See Sections 3.2 and 4 of Appendix A to our TSD.
[657] See the file, White Bluff Daily and Hourly Emissions.xlsx" in our docket.



The above is a plot of the average daily averages and the running 30 BOD average for White Bluff Unit 1. A plot of White Bluff Unit 2 yields similar results. This plot illustrates two things: First, the maximum daily averages are significantly below the maximum hourly averages Entergy presents in its plot. Thus the individual hourly data fluctuations Entergy presents are inconsequential. Second, the running 30 BOD average indicates that our decision to fix the mismatch between Entergy's scrubber costs and its historical SO_2 baseline on the basis of a SO_2 inlet of 0.68 lbs/MMBtu is reasonable.

Entergy states that it has determined its assumption that a 2.0 lb/MMBtu scrubber inlet was in error and a 1.2 lb/MMBtu inlet assumption is now appropriate. As we demonstrated, the primary change to Entergy's SDA cost analysis is to the variable operating costs, which reflects the need for less reagent to treat the low sulfur coal Entergy has traditionally burned, and the associated equipment to unload, transfer, and store that reagent. In apparent agreement with our basic approach, Entergy states it is also appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. Entergy proceeds by recalculating its variable O&M costs in Report #012831,[658] using a 0.68 lbs/MMBtu inlet. The results of that calculation are presented below:

S&L Report #012831 Variable O&M Rates and First Year Costs, per Unit

	Units	Design 0.68 lb SO_2/MMBtu
Dry FGD System Parameters		

[658] S&L Report #012831. Page 23.

Reagent Consumption	lb/hr	7,000
Byproduct Waste Production	lb/hr	16,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	75
Low Quality Water Consumption	gpm	775
First Year Variable O&M Costs (@CF)		
Reagent Cost	$/year	$2,888,000
Byproduct Waste Disposal Cost	$/year	$380,000
Aux Power Cost	$/year	$3,027,000
Water Cost	$/year	$214,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,881,000**

Entergy then calculates its fixed O&M costs using a 0.68 lbs/MMBtu inlet. The results of that calculation are presented below:

First Year Fixed O&M Costs for Dry FGD, per Unit

First Year Fixed O&M Costs	**Units**	**Design 0.68 lb SO_2/MMBtu**
Operating Labor	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

S&L notes that its variable and fixed O&M costs are "first year costs" that are provided in 2015 dollars. As can be seen from a comparison of S&L's variable and fixed O&M costs for a 0.68 lb/MMBtu inlet to those we have calculated, our variable and fixed O&M costs are actually greater, at $8,581,744, and $3,812,705, respectively. Were we to adopt Entergy's variable and fixed O&M costs, our White Bluff and Independence SDA cost-effectiveness calculations would become even more attractive (lower $/ton).

Entergy then states that to illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), it has included a sensitivity analysis in S&L Report #012831. Entergy concedes there is a, "small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu) …." As can be seen from the table we present above, this conclusion is borne out by our own figures which indicate there is a small difference in capital costs *to even the 2.0 lbs/MMBtu case*: The capital, engineering and construction costs, which cover the fundamental design parameter of a scrubber—gas flow rate, were only changed by less than 5%. Thus, Entergy's assertion that our cost analysis improperly designed the White Bluff scrubber system is without merit.

As we discuss in our TSD,[659] we applied the capital, engineering and construction cost ratio of 0.9584 to our annualized capital costs, and the variable and fixed O&M ratio of 0.5823 to our total direct and indirect costs. We did this in order to adjust Entergy's White Bluff SDA costs to account for the sulfur level of the fuel it historically burned. Entergy argues that our O&M factor of 0.5823 should not have been applied to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost. Therefore, argues Entergy, even if our capital cost scaling methodology for capital cost is correct (which it does not believe is the case), then we should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. We agree with Entergy that it would have been more appropriate to apply the 0.9584 factor to the indirect annual costs and will incorporate that correction in our final SDA cost analysis for the White Bluff and Independence facilities, which we discuss in more detail in our response to other comments. However, this correction is relatively minor.

Comment: Entergy objects to our noting certain aspects of conservativeness in our White Bluff cost analysis. [S&L Entergy Report, page 17]. EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers," and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

Response: We disagree with Entergy regarding our conclusion that a 30 year equipment life is a conservative value for the White Bluff scrubbers. Entergy's own contractor, S&L used a 40 year scrubber life in its cost analysis.[660] This indicates that Entergy concluded that was an appropriate value when S&L performed that cost analysis. The fact that we typically assume a 30 year equipment life in BART determinations has no bearing on this. Our use of a 30 year life reflects our conclusion that a 30 year equipment life is a minimum value that can be applied to any scrubber cost analysis, not secured by a federally enforceable document for a shorter life. Just as we occasionally adopt a shorter equipment life (given an appropriate federally enforceable

[659] See discussion beginning on page 14 of Appendix A to our TSD.
[660] See our discussion of this in Section 4.1 of Appendix A to our TSD.

document), we are free to assume a longer equipment life, given the appropriate evidence that life is justified. This is clearly the case in this instance.

Regarding Entergy's second objection, again, we drew upon information that Entergy itself had supplied.[661] As we discussed in our TSD, S&L noted in its 2008 cost analysis that an Alstom cost estimate assumed that its SDA FGD system is based on the use of three absorber modules. Alstom had proposed two modules on units with a similar gas flow in the past, which would result in an approximately 7% savings in capital cost. In fact, S&L itself presents Figure 3-3, "Impact of Two Dry FGD Absorber Modules on Levelized Cost," documenting this potential cost savings.[662] Thus, our expertise in designing scrubber systems is not an issue, as we were relying on statements made by Entergy's own contractor. Furthermore, we are aware of industry publications that conclude that single SDA modules can be fitted to EGUs of 450-500 MW in size, one of which is again from Entergy's own contractor.[663] Consequently, White Bluff's nominal 850 MW units may well only require two SDA modules, and we believe our statement that this represents a conservative point in our cost analysis remains correct.

Comment: Entergy objects to our assumption of a 30 year operating life in our White Bluff cost analysis. [S&L Entergy Report, page 17]. EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown." Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls on White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of 2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

Response: As we discussed in the section of our TSD that Entergy quotes, in order for us to incorporate a shorter scrubber life into the White Bluff SDA cost analysis, Entergy must be subject to a federally enforceable document to shut down the units in question. We have not received such an enforceable document. We discuss this issue in more detail elsewhere in this document.

Comment: Entergy objects to our scrubber cost analysis for Independence. [S&L Entergy Report, page 19]. EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility. It is beyond the scope of S&L's comments to address the

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[661] Ibid.

[662] White Bluff Station Units 1 And 2, Evaluation of Wet Vs. Dry FGD Technologies, SL-009510, Rev. 3, October 28, 2008. See page 3-21.

[663] See for instance: Wet & Dry Scrubbers, Paul Farber, Sargent & Lundy, LLC, Chicago, IL. 2012 Mega Symposium. Page 10: Maximum SDA absorber size is listed as 450 MW.
GEA Niro Spray Drying Absorption, page 4: "SDA is suitable for power plants of all sizes, requiring only a single absorber and a single rotary atomizer per 500 MWe.

basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units." EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source. Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system; therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;

- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines." We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. Considering that Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NOX emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. The table below shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement	0.08	0.07
Revised Annualized Costs	$106,765,022	$106,765,022
$/Δdv	$1,334,562,775	$1,525,214,600

Note: Entergy's revised annual costs in the above table refer to its 2015 S&L cost analysis.

Response: Entergy presents a number of reasons why it believes our scrubber cost analysis for the Independence facility is flawed. In other responses to comments, we address Entergy's objections to our White Bluff cost analysis, so they will not be repeated here. Entergy alleges that we failed to properly identify the design parameters for emission controls; and develop cost estimates based upon those design parameters. Entergy lists a number of areas it believes differentiates the White Bluff and Independence facilities to the extent these differences would impact the Independence scrubber cost analysis.

We agree that there are likely differences between the two facilities that would have some minor impact on the scrubber cost analyses. As we discuss in our TSD:

> The White Bluff and Independence facilities are sister facilities. According to EIA,[664] the boilers were manufactured by Combustion Engineering with in-service dates of 1980 and 1981 for White Bluff, and 1983 and 1985 for Independence. All four units are tangentially firing boilers having nameplate capacities of 900 MW and similar gross ratings. As we indicate above, all four units burn coal from the Powder River Basin of Wyoming with similar characteristics. All four units employ cold side electrostatic precipitators for particulate collection. Other pertinent characteristics are similar.

We further presented satellite photographs to demonstrate that the layout of these facilities are extremely similar. We consequently expect that the differences Entergy describes in its comments result in minor differences in cost. We are not obligated to conduct such a detailed cost analysis that would include these relatively minor differences. As we have discussed in our response to another comment, as the Control Cost Manual explains, the sole input required for making an "order of magnitude" estimate is "the control system's capacity (often measured by the maximum volumetric flow rate of the gas passing through the system)." Such an estimate, for example, could be obtained from the cost reported in dollars per megawatt ($/MW) or dollars per million BTUs fired ($/MMBtu), metrics that are widely reported in the literature. The Control Cost Manual indicates that "the costs and estimating methodology in this Manual are directed toward the "study" estimate with a nominal accuracy of +/-30% percent." This is the long-standing rule of thumb for cost estimate accuracy used by the EPA for regulatory cost effectiveness analyses.

We see nothing in Entergy's comments that would suggest that the differences between these two facilities are so significant they would impact this required level of accuracy. Indeed, Entergy does not attempt to estimate the capital costs of these differences.

We address the $/dv metric in our responses to other comments. We see no reason in the Regional Haze Rule, despite the fact that we evaluated the Independence facility in our proposed Arkansas FIP under the reasonable progress section of the Regional Haze Rule, to deviate from our view of the dollar per deciview metric here.

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[664] See "EIA Consolidated Data_WB and IND_Y2012.xlsx."

Comment: Entergy summarizes its objections to our White Bluff scrubber cost analysis. [S&L Entergy Report, page 22]. Entergy presents the table below which it states shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831) *	$536,185,000	$109,681,936 to $122,657,613
Differential from EPA FIP*	+ $99,853,852	+ $54,993,838 to $63,400,600

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, the table below shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	-99	-868

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). The table below summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As the table below indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831) *	$7,689 to $8,599	$7,642 to $8,546
Differential from EPA FIP	+ $5,462 to $6,372	+ $5,541 to $6,445

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

Response: With the exception of the 2015 estimate that is based on the S&L Report #012831, which we address in another comment, we have discussed each of the cost items Entergy presents above in our responses to other comments. Below we summarize our determinations:

- Regarding the Corrected Baseline Emission Calculation and the Corrected SO_2 Emission Reduction Calculation, we determined that Entergy's recalculations were not justified.
- Regarding the Corrected BOP Exclusions, we have determined that Entergy has provided an adequate explanation or otherwise demonstrated that a $255,000 charge to paint the chimney was justified. We add that charge back into our BOP costs correction in our final SDA cost analysis for the White Bluff and Independence facilities.
- Regarding the Corrected Owner's Cost Exclusions and Corrected Escalation, we determined that Entergy's recalculations were not justified.
- Regarding the Corrected Operating Cost, we agreed with Entergy that it would have been more appropriate to apply the 0.9584 factor to the indirect annual costs and will

incorporate that correction in our final SDA cost analysis for the White Bluff and Independence facilities.

- Regarding the Corrected Remaining Useful Life, we determined that Entergy has not supplied an enforceable commitment to shut down the units in question by the dates it assumes in its calculation.

The corrections to our White Bluff and Independence SDA cost estimates are contained in the file, "White Bluff_R6 cost revisions2-revised.xlsx," which appears in our docket. Below we summarize those corrections:

Unit	Proposed Cost-Effectiveness ($/ton)	Final Cost-Effectiveness ($/ton)
White Bluff Unit 1	$2,227	$2,565
White Bluff Unit 2	$2,101	$2,421
Independence Unit 1	$2,477	$2,853
Independence Unit 2	$2,286	$2,634

We find that these revised cost-effectiveness calculations do not change our proposed findings for BART and reasonable progress for these units.

In addition, we have examined the effect of adding back in a number of the BOP and other costs we excluded (based on these costs being either disallowed by the Control Cost Manual, or having lacked documentation from Entergy). This exercise also appears in the file "White Bluff_R6 cost revisions2-revised.xlsx." These costs include:

- BOP Costs associated with the reagent prep enclosure and the reagent handling system, totaling $21,229,000.
- BOP Costs associated with the flue gas system ductwork, totaling $1,754,000.
- BOP indirect costs of $8,474,666 (escalated to 2013).
- Miscellaneous contract labor costs of $4,448,074 (escalated to 2013).
- Entergy internal costs of $19,482,518 (escalated to 2013).
- Capital suspense costs of $8,101,226 (escalated to 2013).

Unit	Alternate Cost-Effectiveness ($/ton)
White Bluff Unit 1	$3,013
White Bluff Unit 2	$2,843
Independence Unit 1	$3,351
Independence Unit 2	$3,093

We continue to believe that these costs are either disallowed by the Control Cost Manual, or are properly disallowed because they lack documentation from Entergy. We have presented this information to indicate that these costs have a relatively minor effect on the final cost effectiveness. Although our final decision regarding BART and reasonable progress for the White Bluff and Independence units does not rest upon these cost-effectiveness determinations,

had we included these costs in our cost-effectiveness calculations, we would have reached the same conclusions regarding BART and reasonable progress for these units.

Comment: Entergy refers to a revised 2015 cost estimate [S&L SL-012831, July 14, 2015]. In various places in its comments,[665] Entergy refers to "S&L Report #012831." We are unsure of the exact significance of this report, as it appears it is primarily used by Entergy to support its previous 2013 Cost estimate. We have addressed these issues in our responses to other comments. However, in other comments, Entergy states, "At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B to EAI's comments." Based on this general comment, we will review Entergy's revised 2015 report. Our observations follow:

- As we note in the response to one of our comments, Entergy states that its 2015 SDA cost estimate is based on a 2013 Alstom quote. As with the 2009 Alstom quote it used to support its 2013 SDA cost analysis, Entergy does not provide this Alstom quote. Consequently, we have no way of verifying Entergy's 2015 cost calculations.

- The S&L Report #012831 uses an Engineering, Procurement and Construction (EPC) contract, which S&L describes as follows:[666]

  > [T]he EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors. With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor." The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee

- This is in contrast to Entergy's previous cost estimates, and the majority of control cost analyses conducted for other projects we have reviewed, which did not use EPC contacts, and the corresponding higher fees associated with EPC contracts. For instance, the S&L 2015 SDA cost analysis includes an EPC Engineering Services Fee of $23,000,000, for which S&L provides no documentation, except to state, "The EPC engineering services was estimated based on recent projects with similar scopes and schedules." The S&L 2015 SDA cost analysis also includes an EPC risk fee of 10% of the total EPC project cost, or $60,898,000. Regarding that, S&L states, "[t]he EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and

[665] Review Of EPA's Cost Analysis For Arkansas Regional Haze Proposed Federal Implementation Plan, SL-012913, Final July 14, 2015.
[666] S&L Report #012831, page 1.

management of the project as well as the additional risk assumed by the contractor."[667] The additional cost of an EPC contract for the White Bluff SDA cost analysis makes it difficult to compare the cost-effectiveness ($/ton) to other non-EPC SDA cost estimates.

- In addition to the EPC risk fee, S&L includes a contingency of $111,145,700, which represents 18.3% of the total EPC project cost. First, we question the use of such a high contingency for a mature technology like SDA, in combination with an EPC risk fee. Both the EPC risk fee and the contingency appear to be basic assessments of risk. Because S&L does not describe the scope of the EPC risk fee, we cannot determine if these charges overlap. However, the Control Cost Manual defines contingency in the context of separating it from a retrofit factor:[668]

  > Retrofit factors should be reserved for those items directly related to the demolition, fabrication, and installation of the control system. A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation.

  S&L states this contingency was based on cost qualitative risk assessment (QRA) using Palisade Corporation's @RISK software. The contingency risk inputs appear to be based on assigned probabilities of various events with the possibility of causing the cost of the project to increase. No documentation was provided for any of these risks. It appears that a number of the inputs to this calculation are outside of the above definition of contingency. In addition, a number of the risk items appear to be related to issues that are separate from the actual construction or are otherwise risks to Entergy itself, and not S&L as the EPC contractor. For instance, one assessed risk is a delay in receiving the air permit. This does not appear to be a risk that S&L should assume since it is separate from the actual construction of the scrubber system. Another questionable S&L risk is the cost of capital increasing over the life of the project. S&L states it assumed our Control Cost Manual value of 7%, causing us to assume this risk deals with the possibility of the interest used in calculating the annualized capital cost. Since Entergy is required to use a 7% interest rate in this calculation under the Control Cost Manual, assessing the risk of it increasing is inappropriate. S&L appears to assess both the risks due to a longer compliance timeframe and a shorter compliance timeframe. Since we are not changing our proposed compliance timeframe from what we proposed, the latter is plainly not appropriate

- The S&L 2015 SDA cost estimate includes a number of cost items disallowed under the Control Cost Manual's overnight methodology. These include an AFUDC charge of $134,949,000; an owner's cost of $58,546,000; an escalation during construction charge

[667] S&L Report #012831, page 18.
[668] Control Cost Manual, Chapter 2, Section 2.5.4.2.

of $83,034,100; and a separate escalation charge of $2,273,000 on owner's costs, third party services, and contingency.

As described above, we have noted many problems with Entergy's 2015 White Bluff SDA cost analysis, as contained in S&L Report #012831. We therefore cannot accept it. In instances like this, we often present our own cost analysis, eliminating the disallowed costs and making other necessary corrections in order to bring the flawed cost analysis in conformance with the Control Cost Manual. However, in this instance, we would still be left with many unanswered questions concerning the EPC fees and the contingency. As a consequence, we cannot present such an analysis, and we must fall back on our previous White Bluff SDA cost analysis, with the corrections we describe in our responses to other comments.

6.b. Cost vs. Visibility Benefit

Comment: EPA should have evaluated the visibility improvement of controls for BART and Reasonable Progress on a $/dv basis. [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 36-37] Nucor stated that EPA's BART and Reasonable Progress determinations are inconsistent with other EPA BART determinations, which would have been evident if EPA had evaluated visibility improvements on a $/dv basis. When evaluated on that basis, the costs of EPA's Proposed FIP are as follows:

Flint Creek $65,769,250/yr./dv

White Bluff 1 $39,337,306/yr./dv

White Bluff 2 $42,415,424/yr./dv

Independence 1 $64,219,337/yr./dv

Independence 2 $52,171,663/yr./dv

Although EPA claims that the costs of its BART and Reasonable Progress determinations are justified here, in its BART determination for the Corette facility in Montana, EPA found that costs/dv of $30,477,272 for DSI and $50,308,300 for a semi-dry scrubber were excessive (even though EPA determined that both of those controls were "cost-effective" on a $/ton SO_2 basis), and determined that BART constituted the low-sulfur coal already in use at that facility.[669] Existing use of low-sulfur coal as BART also avoids the additional energy costs and water/land impacts of scrubber technology. This is an important factor that EPA failed to consider in its analysis of the energy and nonair quality environmental impacts of compliance that must be considered. All $/dv calculations for White Bluff, Flint Creek and Independence based on EPA's adjusted costs are higher than the $/dv ratio that EPA determined was not justified in its Corette BART determination. EPA has failed to explain why it did not consider use of low-sulfur coal as

[669] See Exhibit 18 to Nucor's comments, Comparison of Scrubber Cost- Effectiveness in Dollars per Deciview, attached hereto as Exhibit 18. See 77 Fed.Reg. 23998 (April 20, 2012), for the explanation of EPA's BART determination for Corette.

BART for the Arkansas facilities, and further has failed to explain how its determinations in the Proposed FIP are justified, consistent with its Corette BART determination.

Comment: EPA is not required to consider the dollar per deciview cost of controls, and in any event, the dollar per deciview cost of controls EPA is proposing to require is within the range of other approved controls. [Sierra Club et. al., p. 47-48, (0042)] Sierra Club et. al. stated that Nucor contends that EPA has failed to consider the cost of the proposed controls relative to their visibility improvement using the dollar per deciview metric. Furthermore, had EPA done so, Nucor contends that the dollar per deciview values for the proposed controls are unreasonably high. Neither of Nucor's arguments has merit.

First, EPA is not required to assess BART or reasonable progress controls based on the dollar per deciview metric. Tellingly, Nucor fails to cite to any legal authority for the proposition that EPA must consider the dollar per deciview value of controls. For BART determinations, the statute instructs EPA to consider the costs of compliance and the expected visibility improvement from controls. 42 U.S.C. § 7491(g)(2). The statute does not direct EPA to consider costs and visibility improvement using any particular method.

The BART Guidelines recommend considering costs in part by considering the cost-effectiveness of controls, measured as the annualized control costs divided by the tons of pollutants removed. 40 C.F.R. pt. 51 App. Y § (IV)(4)(b)-(c). The Guidelines state that EPA should consider visibility improvement by using dispersion modeling to calculate the improvement from controls. *Id.* § (IV)(5). The BART Guidelines mention the dollar per deciview metric in only one place, as an example of one method among many for displaying the costs of compliance. *Id.* § (E)(1). Put simply, the BART Guidelines do not require the use of a dollar per deciview metric.

Setting aside that EPA is not required to consider the dollar per deciview value of controls, the dollar per deciview values for the proposed controls are comparable to other controls EPA has approved, given that EPA has approved SO_2 controls that cost as much as approximately $50 million per deciview. *See* Stamper Report, Ex. 6. As described elsewhere in the Sierra Club et. al.'s comments and in the Stamper Report, the costs and visibility benefits of the proposed controls are comparable to the costs and benefits of other control determinations EPA has approved or made itself. *See* pages 11-12 of the Sierra Club et. al.'s comments; and Stamper Report at 11-13.

Response: We disagree with Nucor that we erred in not using the $/dv metric. We agree with the Sierra Club that we are not required to consider the $/dv metric, but take no position on its statement that the dollar per deciview values for the proposed controls are comparable to other controls we have previously approved. We disagree that the $/dv metric is more meaningful than our use of the $/ton metric in conjunction with our consideration of the visibility benefit from the

installation of controls.[670] As we note in our Oklahoma FIP:[671]

> [T]he BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton.[672] OG&E provided a $/deciview analysis for its units and comparable BART determination performed by us. In our analysis for our BART FIP for OG&E and AEP/PSO, we did not evaluate $/deciview. We explain that the BART Guidelines list the $/deciview metric as an optional cost effectiveness measure that can be employed along with the required $/ton metric for use in a BART evaluation. The metric can be useful in comparing control strategies or as additional information in the BART determination process; however, due to the complexity of the technical issues surrounding regional haze, we have never recommended the use of this metric as a cutpoint in making BART determinations. We note that to use the $/deciview metric as the main determining factor would most likely require the development of thresholds of acceptable costs per deciview of improvement for BART determinations for both single and multiple Class I analyses. We have not developed such thresholds for use in BART determination made by us. As OG&E acknowledges, EPA did not use this metric as part of its proposed BART determinations for either the Four Corners Power Plant FIP in AZ, or the San Juan Generating Station FIP in NM. Generally speaking, while the metric can be useful if thoughtfully applied, we view the use of the $/deciview metric as suggesting a level of precision in the calculation of visibility impacts that is not justified in many cases. While we did not use a $/deciview metric, we did, however, consider the visibility benefits and costs of control together, as noted above by weighing the costs in light of the predicted visibility improvement.

Our decision was reviewed and upheld in *Oklahoma v. EPA*, 723 F.3d 1201 by the Tenth Circuit which ruled:

> Oklahoma first suggests EPA should not have rejected the visibility analysis it conducted in the SIP, which used the dollar-per-deciview method. This argument is misguided. The EPA rejected the SIP because of the flawed cost estimates. When promulgating its own implementation plan, it did not need to use the same metric as Oklahoma. The guidelines merely permit the BART-determining

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[670] Visibility is one of the five statutory factors we must consider in a BART analysis under CAA section 169A(g)(2) and 40 CFR 51.308(e)(1)(ii)(A). In our reasonable progress analysis, alongside the four statutory factors, we also considered the visibility improvement of controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress.

[671] Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, 12/13/2011, pdf 116.

[672] 70 FR 39167.

> authority to use dollar per deciview as an optional method of evaluating cost effectiveness. *See* 40 C.F.R. pt. 51 app. Y(IV)(E)(1).[673]
>
> And in the final rule, the EPA explained why it did not use the dollar-per-deciview metric used by Oklahoma. "Generally speaking, while the metric can be useful if thoughtfully applied, we view the use of the $/deciview metric as suggesting a level of precision in the calculation of visibility impacts that is not justified in many cases." 76 Fed.Reg. at 81,747. The EPA has never mandated the use of this metric, and has not developed "thresholds of acceptable costs per deciview improvement." *Id.* While the federal land managers have developed thresholds, these thresholds were apparently developed without input from the EPA and without notice-and-comment review. EPA Br. at 54 n. 13. In light of this, we do not find it arbitrary or capricious that the EPA chose not to use the dollar-per-deciview metric in evaluating BART options in creating the FIP. We therefore also conclude that any argument by the petitioners that the dollar-per-deciview measurement proves the scrubbers are not cost effective lacks merit. *See* Pet. Reply Br. at 16.

We see no reason to deviate from our view of the dollar per deciview metric here.

Nucor is also incorrect in its assertion that we used the $/dv metric in determining BART for the Corette facility. This can be seen from Table 138 in our Montana proposal, which summarizes cost-effectiveness in $/ton,[674] and this quote concerning the Corette facility from our Montana final decision:[675]

> The BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton. 70 FR 739167. The BART Guidelines list the $/deciview ratio as an additional cost effectiveness metric that can be employed along with $/ton for use in a BART evaluation. However, we did not use this metric for the reasons that were explained in other responses. As we stated in the proposed FIP, we weighed costs against the anticipated visibility impacts and we explained that any of the control options would have a positive impact on visibility; however, the cost of controls was not justified by the visibility improvement. As we have explained elsewhere, in our proposal, we considered the visibility improvement at all Class I areas within 300 km of the subject BART unit.

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[673] We note, however, that in both its final rule and in its brief the EPA asserts that the guidelines require the use of the dollar-per-ton metric in evaluating cost effectiveness. The guidelines themselves are a bit unclear. In the section on cost effectiveness, the guidelines mention only the dollar-per-ton metric. 40 C.F.R. pt. 51 app. Y(IV)(D)(4)(c). However, the guidelines later state that in evaluating alternatives, "we recommend you develop a chart (or charts) displaying for each of the alternatives" that includes, among other factors, the cost of compliance defined as "compliance — total annualized costs ($), cost effectiveness ($/ton), and incremental cost effectiveness ($/ton), and/or any other cost-effectiveness measures (such as $/deciview)." Id. app. Y(IV)(E)(1) (emphasis added).
[674] 77 FR 24046.
[675] 77 FR 57895.

Nucor is also incorrect that we failed to consider the additional energy costs and water/land impacts of scrubber technology. Any costs associated with these energy and nonair quality environmental impacts of compliance were included in our analysis. Thus we see no inconsistency with our Corette BART determination.

Comment: EPA does not complete the analysis by giving a rational explanation as to why the costs of the proposed controls were justified by the visibility improvement. [Arkansas Attorney General (0162) p. 4-6] The Attorney General for the State of Arkansas stated that in *Nat'l. Parks Conservation Ass'n. v. EPA*, -- F.3d --, 2015 WL 3559149 (9th Cir. 2015), the Ninth Circuit Court of Appeals struck down parts of the EPA's Regional Haze FIP for Montana as arbitrary and capricious. The Court found that EPA "failed to explain what makes a cost reasonable in light of potential visibility benefits." The same fatal flaw plagues the proposed FIP for Arkansas.

This is an aesthetic standard, not a public health standard. As such, EPA must justify its decision in terms of improving visibility. As with the Montana FIP, EPA fails to explain why the costs are reasonable in light of the limited visibility improvements cited in the proposed FIP. EPA provides the cost calculations and it provides the visibility calculations; however, the agency does not connect the two. It does not complete the analysis by giving a rational explanation as to why the costs of the chosen controls were justified by the visibility improvement.

In *Michigan v. EPA*, 135 S. Ct. 2699 (2015), the United States Supreme Court reaffirmed that "[f]ederal administrative agencies are required to engage in reasoned decision making." (Internal quotes and citation omitted). As the Ninth Circuit clearly stated, "[T]he law does require EPA to 'cogently explain why it has exercised its discretion in a given manner." *Nat'l Parks* at *5 (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Auto Ins. Co.,* 463 U.S. 29 (1983)). The Eighth Circuit has agreed, stating: "A rule is arbitrary and capricious if 'the agency fails to articulate a satisfactory explanation for its action, including a rational connection between the facts found and the choice made." *Menorah Medical Center v. Heckler*, 768 F.2d 292, 295 (8th Cir. 1985) (internal quotations omitted). Thus, without a satisfactory explanation of its decision, there is no way that EPA can justify its decision.

Without an adequate explanation, the EPA cannot prove that it adequately considered costs in developing the proposed FIP. Costs are an important factor in both determining appropriate BART controls and in setting reasonable progress goals. In fact, it is the first factor listed for both determinations. Based on the data provided in the proposed rule, the total capital costs for compliance with the proposed FIP will be over $278 million.[676] Other commenters to the FIP argue that the actual cost is much higher than has been determined by EPA. Total annual costs for compliance will be over $175 million.[677] When compared to the imperceptible visibility improvements that will be gained, this is too costly for the State of Arkansas and its citizens.

In *Michigan v. EPA*, supra, the United States Supreme Court reiterated its support for sensible consideration of cost within a regulatory scheme:

[676] 80 Fed. Reg. 18944 (April 8, 2015).
[677] *Id.*

> Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions. It also reflects the reality that too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems.

Id., Slip Opinion at 7 (citing *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 233 (2009)). EPA should seriously consider the costs imposed by the proposed FIP to achieve minimal aesthetic improvement. Resources are likely more wisely spent on public health programs under the Clean Air Act.

Justice Scalia succinctly sums up my concern with the proposed FIP. "One would not say that it is even rational, never mind 'appropriate' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Id.*, Slip Opinion at 7. EPA fails to explain its rationale from imposing significant costs upon Arkansans without significant environmental benefits. As such, the proposed FIP is unlawful and should be withdrawn by the EPA.

Additionally, the Arkansas Department of Environmental Quality ("ADEQ") will be filing extensive comments on the proposed FIP. I support the comments of ADEQ. I encourage EPA to carefully consider the comments from ADEQ and the parties affected by the proposed FIP.

Response: The commenter states that EPA failed to conduct a rational cost-benefit analysis and makes improper comparisons to suggest that our proposed costs do not justify the expected visibility benefits. These arguments are without merit. We conducted a robust and detailed analysis of costs in the Rule using the same approach we have used in multiple regional haze BART rulemakings and that has been affirmed by multiple circuit courts. We then weighed the costs against predicted visibility benefits. Visibility is one of the five statutory factors we must consider in a BART analysis under CAA section 169A(g)(2) and 40 CFR 51.308(e)(1)(ii)(A). In our reasonable progress analysis, alongside the four statutory factors, we also considered the visibility improvement of controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. Our long-standing approach in conducting these analyses was neither arbitrary nor capricious.

Additionally, commenter's focus on the total cost of the proposal is misleading because it is not the appropriate metric for evaluating "the costs of compliance." Consistent with guidance and prior regional haze rulemakings, we evaluated the cost-effectiveness of available control options on a dollar-per-ton of emissions reduced ($/ton) basis. Our analyses conservatively estimated many individual cost parameters, resulting in higher cost estimates. We then validated the cost effectiveness of each control option with a detailed technical record and thorough consideration of comments.

The commenter's reliance on *Michigan v. EPA*, which interprets a different part of the CAA, is misplaced. The Supreme Court expressly stated that we were not required to conduct a formal

cost-benefit analysis, which commenter appears to claim is required here. *Michigan v. EPA*, 135 S. Ct. 2699, 2711 (2015). Instead, the Court held that it was arbitrary and capricious for EPA to fail to consider costs at all when determining whether regulating hazardous air pollutants was "necessary and appropriate." Id. at 2706, 2711.

The proposal's controls fall within the range of cost-effectiveness values established across a range of regional haze actions. The Ninth Circuit recently affirmed EPA's costing method, see *Arizona*, 2016 WL 722685 at **16-18, explaining that "cross-facility comparisons of similar sources with regard to the cost-effectiveness of a given control option aid in determining cost effectiveness at a specific source." Id. at *17. Further, in *Oklahoma v. EPA*, the Tenth Circuit affirmed our disapproval of Oklahoma's "cost of compliance" analysis and affirmed as reasonable our FIP that required scrubber retrofits with cost effectiveness values similar to those here. 723 F.3d at 1206, 1224.

7. Modeling

7.a. Cumulative Visibility Impairment

Comment: EPA's reliance on a "cumulative visibility improvement" metric has no basis in the CAA and EPA's regulations and mischaracterizes visibility improvements in Class I areas.

[Entergy Arkansas Inc. (0166) p.54-55; Entergy Mississippi Inc. (0169) p. 13; Conway Corporation et. al. (0172) p. 13; and EEAA (0173) p. 5-6] EAI, EMI, Conway Corporation et. al., and EEAA stated that EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, Independence, Bailey, McClellan, and Flint Creek, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18951-59 (Tables 8-18); 18961 (Tables 20 and 21); 18966 (Tables 27 and 29); 18972 (Tables 34 and 35); 18974 (Tables 37 and 38); 18,978 (Table 42); and 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). EPA also appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed BART determinations and reasonable progress determinations for the other aforementioned facilities. It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas. Furthermore, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls, and may mask the fact that no individual Class I area would experience any discernible visibility improvement from control of emissions at any particular source.

[Entergy Arkansas Inc. (0166) p.54-55; and EEAA (0173) p. 5-6] EAI and EEAA stated that the preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

[Entergy Arkansas Inc. (0166) p.54-55] In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[678] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

[Entergy Arkansas Inc. (0166) p.54-55; and EEAA (0173) p. 5-6] EAI and EEAA stated that on a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. A deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

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[678] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

[Edison Electric Institute (0174) p. 2, 4] EEI stated that EPA's reliance on a "cumulative visibility improvement" metric has no basis in the CAA or EPA's own regulations and is misleading. EPA's practice of summing up the predicted visibility improvements at all affected Class I areas resulting from emissions controls at one specific facility, to yield a cumulative visibility improvement, is improper and meaningless. For example, the cumulative visibility improvement metric frequently will be constructed by summing up visibility improvements that may be perceptible for one or more Class I areas with visibility improvements that are not perceptible for one or more other Class I areas. The only purpose of the cumulative visibility improvement indicator is to imply that facilities are having a large impact across numerous Class I areas, but this indicator can be deceptive if it includes imperceptible visibility improvements for some Class I areas. EPA should not use a cumulative metric and should instead assess only the impacts of controls at individual Class I areas directly.

[Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 7-8] AEEC and AGC stated that on page 18951 of the Proposed FIP, the EPA uses the term "cumulative visibility benefits" and indicates that this concept factored into its determinations in the Proposed FIP.[679] In various tables contained in the Proposed FIP, the EPA adds visibility improvement values at one Class I area to the visibility improvement values at other Class I areas to arrive at a "cumulative visibility improvement."[680] The "improvement" referenced in the tables refers to "cumulative visibility benefits." Similarly, in other tables, EPA adds the visibility impacts at individual Class I areas to arrive at a "total visibility impact."[681] The Proposed FIP, however, does not contain a discussion of the origin or purpose of a "total visibility impact" metric, nor does it provide a sound scientific explanation for either the "total visibility impact" metric or the "cumulative visibility improvement" metric.

Neither the Regional Haze Rule nor the EPA's own guidelines provide a basis for a cumulative visibility metric or a total visibility impact metric. Since the Regional Haze Rule aims to improve visibility in individual Class I areas, adding slight improvements in visibility from separate areas together does not offer a useful method for measuring overall visibility improvement. Many small incremental changes in perception in various locations do not create one large uniform incremental change in perception when aggregated. Providing cumulative numbers as a measure of overall visibility improvement, when the incremental changes may be minor, barely perceptible, and/or separated by large distances, lacks a scientific and legal basis. Since the cumulative visibility metrics in the Proposed FIP lack a legal or scientific basis, the EPA should withdraw the Proposed FIP.

[ADEQ (0144) p. 2-3] ADEQ stated that the cumulative visibility effects metric used in many tables and discussions in the Proposed FIP is not scientifically sound, has no legal basis in the Regional Haze Rule, and is grossly misleading. On page 18951 of the Proposed FIP, EPA first uses the term "cumulative visibility benefits" and indicates that this was a factor in its deliberations.[682] In Tables 8, 10, 11, 13, 18, 20, 21, 23, 27, 29, 37, 38, 42, 47, 49, 51, and 53,

[679] 80 Fed. Reg. 18944 at 18951.
[680] Id.
[681] Id.
[682] 80 FR 18944 at 18951.

EPA adds visibility improvement values at one Class I area to the visibility improvement values at other Class I areas to arrive at a "cumulative visibility improvement.[683] This "improvement" referenced in the tables refers to the "cumulative visibility benefits." EPA does not discuss any purpose for calculating the "cumulative visibility benefits" in the Proposed FIP. Similarly, EPA adds the visibility impacts at individual Class I areas to arrive at a "total visibility impact" in Tables 34, 35, 62, 63, 64, and 66.[684] EPA also provides no discussion of the origin or purpose of a "total visibility impact" metric. In fact, EPA does not provide a sound scientific explanation for either the "total visibility impact" metric or the "cumulative visibility improvement" metric anywhere in the Proposed FIP.

There is no basis in the Regional Haze Rule or EPA guidelines for either a cumulative visibility metric or a total visibility impact metric. In the "Guidelines for BART ("Best Available Retrofit Technology") Determinations under the Regional Haze Rule," EPA only requires an evaluation of the change at each receptor located "at the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source."[685] (*emphasis added*). This requirement is clearly intended to help "identify the likely visibility effects" of the specific visibility improvement of a particular source. Using data from these receptors to create a global visibility increase metric is improper.

Given that the purpose of the Regional Haze Rule is to provide improved visibility in individual and unique Class I areas, adding together slight improvements in visibility from separate areas is not a useful method for measuring overall increased visibility improvement. EPA's chosen measurement of visibility impairment is a "deciview," which is defined in part as "uniform incremental changes in perception."[686] Many small separate incremental changes in perception in various locations do not create one large uniform incremental change in perception when added together. These metrics simply do not convey any meaningful information related to progress toward reaching the ultimate goal of restoring background visibility conditions at Class I areas.

It is grossly misleading to provide cumulative numbers as a measurement of overall improvement when the incremental changes may only be slight, barely perceptible, and separated by large distances. The methodology behind these metrics lacks any scientific basis. Due to the misleading nature of the cumulative visibility metric and the total visibility impact metric, EPA should withdraw the Proposed FIP and remove all references to either of these metrics in any subsequently proposed plan.

Comment: [Arkansas Attorney General (0162) p. 2-3] The Attorney General for the State of Arkansas stated that the purpose of the Regional Haze Rule is to improve visibility in the nation's national parks and wilderness areas. For Arkansas, the Caney Creek and Upper Buffalo Wilderness Area are the areas where visibility must be improved. EPA measures visibility impairment and improvement in terms of "deciviews." A deciview is "a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform

[683] *Id.*
[684] *Id.*
[685] 40 C.F.R. § Pt. 51, App. Y, § IV, D.5, Step 5
[686] 40 C.F.R. § 51.301

incremental changes in perception across the entire range of conditions." 40 C.F.R. § 51.301. One deciview equals a slightly perceptible change in visibility to the human eye.

The required improvements for each area will yield a less than one deciview improvement to visibility. The fraction of improvement will be imperceptible to the human eye. If a deciview is a measurement of perception of a landscape, it is essentially a snapshot in time. It is physically impossible for a person to look at the vistas of all class I Federal areas at the same time. Thus, small, imperceptible changes in visibility across the four class I Federal areas cannot be combined to manufacture a measure of perceptible improvement in visibility. It is, therefore, not logical then to aggregate the visibility improvements across all four class I Federal areas for each source, as is done in the proposed FIP. As such, one may question how the cost can be justified when visibility will not be perceptibly improved.

EPA has invented the concept of "cumulative visibility improvement" to get around this question. The Clean Air Act does not define, nor even mention "cumulative visibility improvement" ("CVI") as a measurement under the five-factor analysis for choosing an appropriate Best Available Retrofit Technology ("BART"). CVI is a construct of the EPA that defies common sense and cannot be used to justify its chosen BART controls. The deciview is not a measurement that can be added together to get a total sum and have that total sum indicate positive results. It defies logic that the affect in the Caney Creak area can be added to the affect in the Upper Buffalo Wilderness Area and that such will result in overall improvement. At best, this standard confuses the public and incorrectly represents the actual visibility improvements that will result from the chosen controls. At worst, this inflated number was impermissibly used by EPA to justify the enormous costs of BART controls.

The use of CVI is not grounded in law or fact. As such, its use is arbitrary and capricious.

Comment: EPA has the legal authority to consider cumulative visibility improvement when promulgating a FIP. [Sierra Club et. al. (0171) p. 41-44] The Sierra Club et. al. stated that in claiming that EPA inappropriately considered the cumulative visibility improvement of controls, commenters invent facts and overlook the law. To begin, commenters misunderstand how EPA is considering how pollution controls improve visibility at multiple Class I areas. EPA modeled the visibility improvement from controls at four separate Class I areas: two areas in Arkansas and two areas in Missouri. In addition to presenting the improvement at each Class I area, EPA sums the improvement at the four areas. *See, e.g.*, 80 Fed. Reg. at 18,966.

In presenting, and summing, the improvement at the four Class I areas, EPA is not implying that the improvements are visible simultaneously to a single observer, as some of the commenters accuse EPA of doing. Instead, EPA is showing that where a source has baseline impacts at multiple Class I areas, operating pollution controls will improve visibility at multiple Class I areas. As EPA explained in the Wyoming regional haze rule, "a summation of visibility benefits is not intended to suggest that individually imperceptible levels of improvement are somehow perceptible, but rather to provide a single metric that can simultaneously capture both the number of Class I areas affected and the magnitude of improvement at those areas for comparison purposes." 79 Fed. Reg. at 5,120. There is nothing inappropriate, much less anything unlawful, about considering the visibility improvement at multiple Class I areas from controls at a source.

To the contrary, it is within the spirit of the statutory mandate and expressly permissible within the regulation to consider cumulative impacts.

Commenters do not dispute that operating pollution controls will improve visibility at multiple Class I areas, nor could they. All of the evidence in the record suggests that the BART and reasonable progress sources for which EPA proposed controls impair visibility in at least four Class I areas, and that reducing pollution from these sources would improve visibility in at least these areas.

Given the uncontroverted evidence that Arkansas sources impact multiple Class I areas, it would be inconsistent with the record, the statute, and with EPA's approach to other haze plans for EPA to fail to consider the cumulative visibility improvement here. The legal requirement to consider cumulative visibility impacts is rooted in the Clean Air Act's goal to eliminate haze at all Class I areas, not just certain Class I areas. *See* 42 U.S.C. § 7491(a)(1) ("Congress hereby declares 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."). EPA has interpreted the statutory goal of improving visibility at all Class I areas as requiring states to consider the cumulative visibility improvement from potential BART controls. *E.g.*, 76 Fed. Reg. 52,388, 52,430 (Aug. 22, 2011) ("Given that the national goal of the program is to improve visibility at all Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area."); 77 Fed. Reg. 51,620, 51,631-32 (Aug. 24, 2012) ("EPA believes that it is important to consider the visibility impact on multiple Class I areas. The goal of the visibility program is to remedy visibility impairment at all Class I areas.").

Around the country, EPA has disapproved plans in which the state failed to consider the cumulative visibility improvement from pollution controls, and the state indicated that the cumulative visibility improvement was significant. Similarly, when developing federal plans, EPA has considered cumulative visibility improvement in its BART determinations. For example, in reviewing the Arizona regional haze plan, EPA stated that:

> [I]nstallation of more stringent controls . . . would result in visibility benefits at multiple Class I areas, yet [Arizona] chose to consider the benefits only at the most impacted area. Where, as here, the benefits of controls have been modeled for a number of surrounding areas and consideration of these benefits is useful in determining the appropriate level of controls, EPA does not agree that these benefits may be ignored . . . EPA disagrees that state flexibility extends to categorically excluding consideration of visibility improvements occurring at multiple Class I areas.

77 Fed. Reg. 72,512, 72,519 (Dec. 5, 2012). EPA disapproved several of Arizona's BART determinations because "while the State has some flexibility in choosing a specific procedure to consider these cumulative area and multiple unit benefits, when such benefits are significant, it is not reasonable to ignore them altogether as ADEQ did." *Id.*

Similarly, EPA disapproved the state of New York's determination as to the controls that are BART for SO2 pollution from the Danskammer power plant after finding that "EPA's analysis of the cumulative visibility improvements at all 7 Class I areas justifies a more stringent BART emission limit [than the State proposed]." 77 Fed. Reg. 24,794, 24,814 (Apr. 25, 2012), finalized by 77 Fed. Reg. 51,915, 51,916 (Aug. 28, 2012). EPA explained its decision by noting that "[i]n making BART determinations, EPA also recommends the consideration of cumulative impacts and improvements that could occur at all of the Class I areas a particular facility might impact." *Id.* EPA also disapproved several BART determinations in Oklahoma's regional haze SIP, and EPA considered cumulative visibility improvement in developing a federal implementation plan. 76 Fed. Reg. 81,728, 81,736 (Dec. 28, 2011) ("[c]learly, the visibility benefits from . . . emission reductions will be spread among all affected Class I areas, not only the most affected area, and should be considered in evaluation of benefits from proposed reductions.").

With one exception, EPA has approved state plans that entirely failed to consider cumulative visibility improvement only where the cumulative visibility improvement was too small to have changed the ultimate BART determination. *E.g.*, 77 Fed. Reg. 76,871, 76,875 (Dec. 31, 2012) ("… as we suggested during the State's public comment period, the State [of Colorado] should have more thoroughly considered the visibility impacts of controlling emissions from Craig 1 on the various impacted Class I areas and not just have focused on the most impacted Class I area.");[687] 78 Fed. Reg. 53,250, 53,262 (Aug. 29, 2013) ("As a general matter, EPA agrees that Florida should have considered the visibility improvements at all affected Class I areas in its BART visibility assessments.").[688]

And in at least one case where a state never submitted a regional haze SIP, and thus EPA developed a federal implementation plan, "[EPA] did assess cumulative visibility impacts." 77 Fed. Reg. 57,864, 57,869 (Sept. 18, 2012). In explaining the final regional haze plan for Montana, EPA noted that "[i]n our analysis of visibility impacts, we considered the visibility improvement at all Class I areas within 300 km of the subject BART unit." *Id.* Likewise, after EPA disapproved the SO2 BART determination for the Intalco aluminum smelter in Washington State, EPA considered cumulative visibility impacts when developing a FIP. 79 Fed. Reg. 33,438, 33,447 (June 11, 2014) (". . . [A]s explained in the proposal, the EPA considered cumulative visibility impacts, as well as the other BART factors in reaching its BART determination for this facility."). Of particular relevance to this case, EPA announced the principle that "where a control might not be warranted as BART based on the improvement at a single Class I area, significant cumulative benefits are an additional consideration that could warrant that the control be selected as BART." 79 Fed. Reg. 5032, 5050 (Jan. 30, 2014).

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[687] After parties challenged EPA's approval of the BART determination for Craig Unit 1, and consistent with parties' Settlement Agreement on November 20, 2014, the Air Quality Control Commission of Colorado adopted revisions to Regulation Number 3, Part F and Colorado's regional haze SIP revising the NOx emissions limit, compliance date, and BART determination for Craig Unit 1 encompassing a more stringent BART determination than in Colorado's initial regional haze plan. The State of Colorado has advanced this revision to EPA for approval. *See Nat'l Parks Conservation Ass'n v. EPA*, Settlement Agreement, July 10, 2014, No. 13-9525 (10th Cir.).

[688] The Colorado and Florida examples demonstrate that EPA has approved plans that failed to consider cumulative visibility benefits only where the cumulative benefits were not significant. As discussed herein, that is not the case for the Arkansas proposed FIP. For several Arkansas sources, installing pollution controls would significantly improve visibility if the improvement at all affected Class I areas is considered.

In short, the record, the statute, and EPA's approach to other haze plans all support EPA's practice of considering how proposed controls would improve visibility at all affected Class I areas. We believe that EPA is required to consider the visibility improvement at all affected Class I areas as this approach gives meaning to the statute's visibility goal for all Class I areas. But even if EPA were not *required* to do so, EPA is *authorized* to do so when promulgating a FIP, just as a state would be authorized to do so when submitting a SIP.

Response: We agree with the comments supporting the consideration of cumulative visibility impacts and benefits. We disagree with the other commenters that cumulative improvement over multiple areas is an inappropriate metric, or that examining a single Class I area is sufficient. The cumulative improvement metric (i.e., the simple sum of impacts or improvements over all the affected Class I areas) is not intended to correspond to a single human's perception at a given time and place. The approach is simply one way of assessing improvements at multiple areas, for consideration along with other visibility metrics. Another approach would be to simply list visibility improvements at the various areas, and qualitatively weigh the number of areas and the magnitudes of the improvements. The cumulative sum is simply an easily understood and objective way of weighing cumulative visibility improvement, as part of the overall control evaluation along with the visibility improvement at each impacted Class I area. As noted by some comments, we have calculated cumulative visibility in a number of Regional Haze actions evaluating the benefits of controls under BART and when visibility is considered in the reasonable progress analysis. Furthermore, the FLMs have provided comments in support of the use of this metric in past actions.[689]

The comment opposing cumulative modeling does not provide the full context when citing to the BART guidelines. The portion referred to by the commenter discusses the development of a modeling protocol and establishing the receptors to model. The full portion of the BART Guidelines that the commenter referenced states:

> The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.[690]

This section of the BART Guidelines addresses how to determine visibility impacts as part of the BART determination. Several paragraphs later in the BART Guidelines it states: "You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment," emphasizing the flexibility in method and metrics that exists in assessing the net visibility improvement.

[689] For example see 76 FR 52429
[690] 40 CFR 51 Appendix Y, IV.D.5

In fully considering the visibility benefits anticipated from the use of an available control technology as one of the factors in selection of BART, it is appropriate to account for visibility benefits across all affected Class I areas and the BART guidelines provide the flexibility to do so. One approach as noted above is to qualitatively consider, for example, the frequency, magnitude, and duration of impairment at each and all affected Class I areas. Where a source significantly impacts more than one Class I areas, the cumulative visibility metric is one way to take magnitude of the impacts of the source into account.

With respect to our analysis of controls under reasonable progress, we rely on our reasonable progress Guidance.[691] Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in Section 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. Also, similar to a BART analysis, we are also considering the projected visibility benefit in our analysis following the BART guidelines and the use of CALPUFF.[692] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling. This includes the flexibility in metrics that exists in assessing the net visibility improvement, and the use of cumulative visibility, along with visibility impacts at individual Class I areas, as one way to take magnitude of the impacts of the source into account where a source evaluated under reasonable progress significantly impacts more than one Class I area.

For each subject-to-BART source and the source evaluated for reasonable progress controls, we evaluated the visibility impacts from the source and benefits of controls at four separate Class I areas. In addition to providing the visibility impacts and potential benefits at each Class I area in the proposal, we also summed the impact and improvement across the four Class I areas. The results show that some sources significantly impact visibility at more than one Class I area, emission reductions result in visibility benefits at all impacted class I areas, and in some situations, the largest visibility benefits from controls can occur at Class I areas other than the most impacted.

Therefore, consistent with the BART Guidelines, and based upon these facts, we determined additional analyses were not only warranted but necessary. The BART Guidelines only indicate that additional analyses may be unwarranted at other Class I areas, and in no way exclude such analyses, as the commenter suggests. We concluded that a quantitative analysis of visibility impacts and benefits at only the most impacted area would not be sufficient to fully assess the impacts and benefits of controlling emissions from the sources evaluated for BART and reasonable progress.

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[691] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007

[692] As we explain in our proposed action (80 FR 18993): "While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress". See 79 FR at 74838, 74840, and 74874.

Nothing in the Regional Haze Rule suggests that a state (or EPA in issuing a FIP) should ignore the full extent of the visibility impacts and improvements from controls at multiple Class I areas. Given that the national goal of the program is to improve visibility at ***all*** Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area. We believe such information is useful in quantifying the overall benefit of controls. As discussed in our proposal, we evaluated the statutory factor, visibility benefits anticipated due to controls, at each Class I area in making BART determinations and considered the visibility benefits in consideration of controls for reasonable progress.

We respond to comments regarding visibility improvements that may be imperceptible elsewhere in this section of the response to comments document.

7.b. Imperceptible Visibility Improvement

Comment: EPA must withdraw the proposed FIP because the FIP would only achieve visibility improvements below one deciview, which is not discernible to the naked eye.

[ADEQ (0144) p. 15-16; and Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 9-10] ADEQ, AEEC, and AGC stated that EPA's revisions to Arkansas's proposed RPGs are unnecessary and beyond the authority granted by Congress. EPA's own estimates of the effects of the Proposed FIP are reductions for the 20% worst days of -0.21 deciviews for Caney Creek and -.19 deciviews for the Upper Buffalo.[693] Since these reductions would not be visible to the naked eye,[694] achieving these slight reductions exceeds the scope of regulatory regime specifically designed to address "the impairment of visibility."

The CAA only provides EPA with the authority to regulate the "impairment of visibility."[695] Visibility extends only to things that humans can see with their naked eyes.[696] By extension, EPA only has authority to regulate the impairments of visibility that are perceptible to the human eye. A "deciview" is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired."[697] The human eye can only detect a change in haziness of 1.0 or more deciviews.[698] Measurements of 0.21 and 0.19 deciviews are both well below amount of haze discernable to the naked eye. Under both the plain language and dictionary definitions of "visibility," the statute does not provide EPA with the authority to

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[693] 80 FR 18944 at 18998.
[694] The human eye can only detect a change in haziness of 1.0 or more deciviews. *See, e.g.* 79 Fed. Reg. 58302 at 58303.
[695] 42 U.S.C.A. § 7491 ("Congress hereby declares 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.)(emphasis added).
[696] *E.g.* Webster's Third New International Dictionary 2557 (1981)("visible" means "capable of being seen"; "visibility" means "the degree or extent to which something is visible … [by] the observer's eye unaided by special optical devices").
[697] 40 C.F.R. § 51.301.
[698] *e.g.*79 FR 58302 at 58,303.

regulate haze below a single deciview, which would be invisible to the naked eye. Since the Proposed FIP will only achieve visibility improvements smaller than one deciview, the EPA lacks authority to revise the RPGs suggested by Arkansas, and it should withdraw the Proposed FIP

Comment: [Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 12; and Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 5] Nucor and AEEC/AGC both stated that the sole purpose of the regional haze program is to address visibility impairment. *See* 42 U.S.C. §7491(a)(1). It is not a health based standard, and EPA may not require emissions reductions just for sake of doing so under the guise of imperceptible visibility improvements or solely for the sake of reducing emissions.[699] Consistent with this purpose, the Clean Air Act requires that EPA's BART determination take into account, among other things, the cost of compliance and the "degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." Id. §7491(g)(2) [emphasis supplied]. EPA may not require a source "to spend millions of dollars for new technology that will have no appreciable effect on haze in any Class I area." Am. Corn Growers v. EPA, 291 F.3d 1, 7 (D.C. Cir. 2002) (vacating EPA's BART determinations because EPA left open the possibility that it could require a source to install technologies even when those technologies had no appreciable effect on visibility). Yet that is precisely what EPA has done here. Despite these limits on its authority, through the proposed FIP, the EPA requires certain stationary sources of immense value to the State of Arkansas and its citizens to install controls that will cost billions of dollars in order to achieve imperceptible visibility improvements.

Response: We disagree with commenters that the Regional Haze Rule requires that controls on a source or group of sources result in perceptible visibility improvement.[700] We believe, for reasons we have outlined in our proposal and elsewhere in our response to comments, that the controls we proposed under our FIP will result in significant improvements in visibility at a number of Class I areas. In a situation where the installation of BART may not result in a perceptible improvement in visibility, the visibility benefit may still be significant, as explained by the Regional Haze Rule:[701]

> Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Thus, we disagree that the degree of improvement should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."

Section 169A of the CAA requires that certain major sources that emit any pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in Class I Areas install BART. The following factors must be taken into account in determining BART: the costs of

[699] National Parks Conservation Association v. EPA, No. 12-73710, 2015 WL 3559149 (9th Cir. June 9, 2015).
[700] It is generally recognized that a change in visibility of 1.0 deciview is humanly perceptible.
[701] 70 FR 39104, 39129

compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[702]

The CAA also requires that in determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. Our Reasonable Progress Guidance[703] notes the similarity between some of the reasonable progress factors and the BART factors contained in Section 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable, including visibility improvement even though it may not be perceptible from an individual source. Also, similar to a BART analysis, we are also considering the projected visibility benefit in our analysis of reasonable progress controls following the BART guidelines.[704] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

We accordingly disagree that selection of control measures under BART or for reasonable progress should be contingent upon perceptible visibility improvement. As we stated in our previous rulemaking addressing the BART determinations in Oklahoma:[705]

> Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews, it would be inconsistent to automatically rule out additional controls where the improvement in visibility may be less than 1.0 deciview or even 0.5 deciviews. A perceptible visibility improvement is not a requirement of the BART determination because visibility improvements that are not perceptible may still be determined to be significant.

The Regional Haze Rule provides that BART–eligible sources with a 0.5 dv impact at a Class I area "contribute" to visibility impairment and must be analyzed for BART controls. BART determining authorities, however, are free to establish thresholds less than 0.5 dv. Consequently, even though the visibility improvement from controlling an individual source may not be perceptible, it should still be considered because the contribution to haze may be significant when the aggregate contribution of other sources in the Class I area is taken into account and because the contribution to haze from the source may be significant relative to other source contributions in the Class I area. Thus, in our visibility improvement analysis for BART sources

[702] CAA section 169A(g)(2).
[703] "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 1, 2007
[704] As we explain in our proposed action (80 FR 18993): "While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress". See also 79 FR at 74838, 74840, and 74874.
[705] 76 FR 81739.

and in consideration of visibility benefits from controls under our reasonable progress analysis, we have not considered perceptibility as a threshold criterion for considering improvements in visibility to be meaningful.

We have considered visibility improvement in a holistic manner, taking into account all reasonably anticipated improvements in visibility, and the fact that, in the aggregate, improvements from controls on multiple sources (either under BART or reasonable progress) will contribute to visibility progress towards the goal of natural visibility conditions. Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area. In this action, we found that the required cost-effective controls reduce visibility impairment from those BART sources that contribute or cause visibility impairment at nearby Class I areas and result in meaningful visibility benefits towards the goal of natural visibility conditions. Similarly, we also found that the required cost-effective controls at the Entergy Independence facility reduce visibility impairment from the source with the largest potential visibility impacts (among all Non-BART sources) and result in meaningful visibility benefits towards the goal of natural visibility conditions.

The commenter mischaracterizes a statement made by the D.C. Circuit Court of Appeals in *Am. Corn Growers Ass'n v. EPA.* The statement made by the Court is as follows: "[u]nder EPA's take on the statute, it is therefore entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area." [706] The Court made this statement based on EPA's approach to the BART requirements in the Regional Haze Rule promulgated in 1999 which did not require the source-specific assessment of a BART eligible source's visibility impacts at any step of the process..[707]

The Court disagreed with the approach used by EPA to determine what BART eligible sources are reasonably anticipated to cause or contribute to regional haze and therefore subject to BART.[708] The approach in the Regional Haze Rule required a State to analyze "the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area."[709] The Court held that the Rule's treatment of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" factor infringed on states' authority with respect to BART determinations under the Act.[710]. The Court noted that the Act does not assign a specific weight with which to consider each factor, it solely mandates that all the factors be considered in making a BART determination.[711]. The Court's issue was not with the weight, or lack thereof, placed on this factor by EPA. It found issue with what it considered to be "dramatically" different treatment of the visibility factor by EPA. Id. While the court in *American Corn Growers Ass'n. v. EPA* found that we had impermissibly constrained State authority, it did so

[706] *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002).
[707] Id.
[708] Id. at 7-8.
[709] 40 C.F.R. § 51.308(e)(1)(ii)(B).
[710] Id.
[711] 291 F.3d at 6

because it found that we forced States to require BART controls without first assessing a source's particular contribution to visibility impairment. This is not the case with our action in Arkansas. In response to this court decision and to address these concerns we finalized revised Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations.[712]

Our analysis does not give greater weight to one factor over another; rather, we considered all five BART factors fully, revealing that costs and visibility improvement were the two most important factors in our decisions. In *American Corn Growers Ass'n. v. EPA*, the D.C. Circuit Court faulted how EPA assessed the statutory fifth factor of visibility improvement in a BART determination by using a regional, multi-source, group approach to assessing the visibility improvement factor, while assessing the other four statutory BART factors on a source-specific basis. Here, we did not give greater weight to our consideration of visibility improvement or consider the visibility in a different fashion from the other factors. All BART factors were evaluated on a source-specific basis.

The Court also noted that it is the State's and not EPA's duty to determine what BART is (provided that the State's determination complies with the Act and EPA guidelines.[713]) When EPA promulgates a FIP, it is acting in the place of the State, and thus has the same authority a state has when the state promulgates a SIP. It is therefore our duty to determine what BART is since we are proposing a FIP for Arkansas. We must also consider the same factors that the State is mandated to consider by the CAA. The "degree of improvement in visibility which may reasonably be anticipated to result from the use of such [best available retrofit] technology" is just one of several factors the State, or EPA in the case of a FIP, must consider in determining what BART is for a specific source.

We also disagree with commenter's statement that we required emissions reductions just for the sake of doing so under the guise of imperceptible visibility improvements or solely for the sake of reducing emissions and their citation to *National Parks Conservation Association v. EPA, No. 12-73710, 2015 WL 3559149* (9th Cir. June 9, 2015). As discussed above, we considered all the statutory factors, including the "degree of improvement in visibility which may reasonably be anticipated to result from the use of such [best available retrofit] technology" in our BART determinations. We do not consider perceptibility as a threshold criterion for considering improvements in visibility to be meaningful. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.

Comment: Comments that suggest that each control measure by itself must lead to perceptible improvement to the human eye reflects a misunderstanding of the nature of the Regional Haze problem. [Sierra Club et. al. (0171) p. 39-41] The Sierra Club et. al. stated that various commenters criticize the proposed FIP on the grounds that the expected visibility improvement will not be perceptible to the human eye because it will be less than 1.0 deciview. This argument fails for several reasons. First, the argument is factually incorrect. The scrubbers

[712] 70 FR 39104

[713] 291 F. 3d at 8-9.

EPA proposes to require at Independence Units 1 and 2 will lead to more than one deciview of improvement at Hercules-Glades, and approximately one deciview improvement at Caney Creek and Upper Buffalo. 80 Fed. Reg. at 18,994. Similarly, if EPA had presented the improvement expected from both of the new scrubbers combined at White Bluff Units 1 and 2 (instead of separately as EPA did in the proposed rule), the results would be greater than one deciview in improvement at Caney Creek. *See id.* at 18972.

Moreover, when the different Arkansas sources are operating the new controls, the emissions reductions from each source will result in combined visibility improvement that is greater than the improvement from controls on any one source. For example, when Flint Creek, White Bluff, and Independence operate new scrubbers, the resulting visibility improvement at Caney Creek will reflect the total reduction in emissions from all three facilities. The combined improvement in visibility from scrubbers at these three facilities is not linear so cannot be determined by simply summing the CALPUFF results for each individual unit, but the combined improvement from controls will exceed one deciview.

Not only is it appropriate to consider the combined visibility benefits from all of the SO_2 controls at all of the controlled sources, it is appropriate to consider the combined benefit from both SO_2 and NO_x controls. In the real world, the benefits from operating SO_2 and NO_x controls are not experienced separately; actual visibility conditions depend on the effects of both SO_2 and NO_x emissions on atmospheric chemistry. The visibility improvement from all the SO_2 and NO_x controls EPA is proposing far exceeds one deciview. Thus, when all the controls are considered together, the proposed FIP will result in visibility improvement far greater than one deciview, and will be perceptible.

Moreover, it is factually incorrect to assume, as the commenters do, that a change of less than one deciview is not perceptible to the human eye. EPA made precisely this point in the preamble to the original regional haze regulations, stating that:

> The EPA agrees with the comment that a one deciview change should not be considered the threshold of perception in all cases for all scenes. The EPA believes that visibility changes of less than one deciview are likely to be perceptible in some cases, especially where the scene being viewed is highly sensitive to small amounts of pollution. 64 Fed. Reg. 35,714, 35,726 (July 1, 1999).

The comments regarding the perceptibility of controls are based on factual errors. And they also misapprehend the legal requirements. There is no requirement in the statute or the regulations that visibility improvement exceed one deciview from each control at each unit. The statute requires each haze plan to make "reasonable progress" toward the goal of eliminating haze. 42 U.S.C. § 7491(a)(1), (b)(2). Congress defined reasonable progress to include consideration of four factors, *id.* § 7491(g)(1), but Congress did not dictate the minimum amount of improvement that it would deem reasonable. Instead, Congress specifically delegated to EPA the task of issuing regulations that specify the requirements for haze plans. *Id.* § 7491(b)(2). The commenters have pointed to no provision in EPA's regulations requiring that control measures at

each source individually produce visibility improvement equal to at least one deciview—because no such provision exists.

To the contrary, EPA promulgated the regional haze rule after finding that much of the haze pollution that Congress wants eradicated is caused by emissions from a large number of sources, each of which, aside from the largest EGUs, makes only a small contribution to the haze problem. *See, e.g.*, 64 Fed. Reg. 35,715, 35,715 (July 1, 1999) ("Regional haze is visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors and which are located across a broad geographic area."). The regional haze regulations reflect EPA's finding that the Congressional goal of eliminating haze can be achieved only by tackling the multitude of sources that contribute to haze in national parks and wilderness areas. For this reason, EPA has stated that "visibility improvement does not need to be perceptible to be deemed significant for BART purposes." 79 Fed. Reg. 5,032, 5,120 (Jan. 30, 2014). In arguing that each control must produce visually perceptible visibility improvement, the commenters advance a position that is inconsistent with EPA's long-standing interpretation of the regional haze rule. Commenters' suggestion would also thwart Congress's goal of ensuring progress toward the national visibility goal given EPA's recognition that the visibility problem is caused by a multitude of sources, many of which have only a relatively small impact on visibility.

Response: We agree with the commenter. As we discuss in response to comments above, the Regional Haze Rule does not require that controls on a source or group of sources result in perceptible visibility improvement. We also agree that in some cases required controls either individually or in combination with other required controls will result in perceptible visibility improvements at impacted Class I areas on some days.

Comment: The purported visibility improvement that would result from the SO_2 BART limit on Domtar Power Boiler 2 would not be perceivable to the human eye and is beyond the CALPUFF model's ability to predict with confidence. [Domtar (0161) p. 10] Domtar stated that EPA's analysis identifies a purported visibility improvement of 0.139 dv. The purported level of visibility improvement will not lead to any reasonably anticipated visibility improvements as this claimed level of improvement is beyond the CALPUFF model's ability to predict with confidence. At the same time, imposing the BART requirement will add $1.96 million per year in additional operating cost for the Ashdown Mill. As noted in *Nat'l Parks Conservation Ass'n*, it is arbitrary and capricious for EPA to compel a facility (such as the Ashdown Mill) to spend millions with no reasonable anticipation of any visibility improvements. (*Domtar's detailed* comments discussing the CALPUFF model's Ashdown Mill specific margin of error and the *Nat'l Parks Conservation Ass'n* decision are found elsewhere in this RTC document.)

Moreover, even assuming the purported visibility can be shown to be reasonably anticipated, the predicted visibility improvement is almost 10 times less than what can be perceived by the human eye. While on a dollar per ton removal basis the limit may appear to be cost effective, the significant increase in annual operating expense will adversely affect the Mill's competitiveness in global markets and negatively affect its economic viability. Such a minor incremental

visibility improvement, so small as to be insignificant and not perceivable to the human eye, does not justify the very high additional operating expense proposed to be imposed on the Ashdown Mill.

Response: We respond to comments concerning the "margin of error" and comments that modeled visibility benefits are below the capabilities of the CALPUFF model and cannot be reasonably anticipated elsewhere in this section of the Response to Comments document. We address comments concerning the perceptibility of visibility benefits in a separate response to comment above. In our analysis, we determined that the BART-eligible source, Domtar, "causes" or "contributes" to visibility impairment at downwind Class I areas. As discussed in our proposal and demonstrated in our technical record, the FIP emission limit can be achieved by additional scrubber reagent in the existing scrubber, which is cost-effective and results in a decrease in the visibility impacts from this source at the nearest Class I area.

We note that the commenter's characterization of the court's decision in *Nat'l Parks Conservation Ass'n* elsewhere in their submitted comments is incorrect. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF. Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law. [714]

Comment: Some of EPA's proposed BART determinations are not justified based on the negligible projected visibility improvements. [UARG (0176) p. 4-7] UARG stated that EPA proposes BART determinations for certain facilities that are based on EPA projected "visibility improvements" that are so minimal – indeed, hypothetical, because they are below, and in most cases far below, the level of human perceptibility – that they cannot support any BART requirement that entails installation and operation of additional emission controls. EPA's BART Guidelines contemplate use of threshold targets of visibility improvement as appropriate tools for evaluating whether a BART-eligible source is properly deemed subject to BART and therefore, at least potentially, subject to BART emission limits. 70 Fed. Reg. 39,104, 39,120-21 (July 6, 2005). The BART Guidelines refer to a 1.0-dv threshold for a source's "causation" of visibility impairment at a Class I area and a 0.5-dv threshold for a source's "contribution" to visibility impairment at a Class I area. *Id.* at 39,161. Indeed, in promulgating the BART Guidelines, EPA stated that "for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment." *Id.* at 39,120. A 1.0 dv impact is EPA's threshold for human perceptibility of visibility impairment. *Id.* at n.32. EPA's proposed FIP includes proposed BART determinations that would produce projected visibility improvements (as estimated by EPA) that do not even approach these thresholds.

Particularly in light of the significant costs that most of these BART determinations would impose, these proposed EPA actions are unreasonable because they would not appreciably

[714] "Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances." Nat'l Parks Conservation Ass'n vs. EPA

mitigate any contribution to visibility impairment. These unreasonable proposed BART determinations include the following:

- **Sulfur dioxide ("SO2") BART for Bailey Unit 1:** EPA projects that its proposed SO_2 BART emission limit will result in visibility improvement ranging from 0.188 dv to 0.233 dv at the Class I areas the Agency modeled. 80 Fed. Reg. at 18,952. EPA estimates this proposed BART limit has an average cost-effectiveness of $2,559 per ton of SO_2 removed. Id.

- **SO_2 BART for McClellan Unit 1:** EPA projects that its proposed SO_2 BART limit will result in visibility improvement ranging from 0.3 dv down to only 0.12 dv or less at the Class I areas the Agency modeled. Id. at 18,959 & Table 18. EPA estimates this proposed BART limit has an average cost-effectiveness of $3,823 per ton of SO_2 removed. Id. at 18,959.

- **Nitrogen oxide ("NOx") BART for Flint Creek Unit 1**: EPA projects that its proposed NOx BART limit will result in visibility improvement ranging from only 0.014 dv to 0.081 dv at the Class I areas the Agency modeled. *Id.* at 18,968 & Table 29. EPA estimates this proposed BART limit has an average cost-effectiveness of $1,761 per ton of NOx removed and entails $16 million in capital costs. *Id.* at 18,967 Table 28.

- **NOx BART for White Bluff Units 1 and 2**: EPA projects that its proposed NOx BART limit will result in visibility improvement ranging from only 0.038 dv to 0.176 dv at the Class I areas EPA modeled for Unit 1 and only 0.047 dv to 0.225 dv at the Class I areas modeled for Unit 2. *Id.* at 18,974 & Tables 37 & 38. Even with estimated average cost-effectiveness values of $350 per ton of NOx removed for Unit 1 and $340 per ton of NOx removed for Unit 2, *id.* at 18,974, such negligible – indeed, merely hypothetical – visibility improvements are insufficient to justify a requirement of additional emission controls to satisfy BART, particularly given that EPA estimates the required controls will entail more than $9.5 million in capital costs at Unit 1 and more than $13.5 million in capital costs at Unit 2, *id.* at 18,973 Table 36.[715]

- **SO_2 BART for Domtar Ashdown Mill Power Boiler No. 2**: EPA projects that its proposed SO_2 BART determination will result in visibility improvement ranging from only 0.139 dv down to 0.05 dv or less at the Class I areas EPA modeled. *Id.* at 18,985 & Table 51. EPA estimates this proposed BART determination has an average cost-effectiveness of $1,411 per ton of SO_2 removed, *id.* at 18,984 & Table 50, 18,985, and would cost almost $2 million annually, according to EPA, *id.* at 18,984 & Table 50.

[715] EPA's proposed rule properly recognizes that the minuscule additional visibility improvement that could be achieved through installation and operation of more stringent NOx emission controls at White Bluff Units 1 and 2 (*i.e.*, low NOx burners and separated overfire air together with selective noncatalytic reduction or selective catalytic reduction) is far too small to justify the very high additional incremental costs of such controls. *See* 80 Fed. Reg. at 18,975; *id.* at 18,973 Table 36. EPA should apply the same reasoning to withdraw its proposed BART requirement for the less costly, but still unjustified, NOx combustion controls for these units.

- **NO_X BART for Domtar Ashdown Mill Power Boiler No. 2:** EPA projects that its proposed NO_X BART determination will result in visibility improvement ranging from only 0.005 dv to 0.181 dv at the Class I areas modeled. *Id.* at 18,987 & Table 53. EPA estimates this BART determination has an average cost-effectiveness of $1,951 per ton of NO_X removed and entails more than $6.1 million in capital costs. *Id.* at 18,987 & Table 52.

The visibility improvements that these proposed BART emission limits are projected to produce are, according to EPA, far from being humanly imperceptible and thus entirely hypothetical. Yet the costs these proposed BART controls would impose are very real and quite significant – totaling, in some cases, several million dollars. The proposed FIP thus presents a result that Congress sought to prevent in enacting the Act's BART provisions – *i.e.*, to avoid the possibility "that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area." *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). EPA cannot square these proposed BART determinations with the statutory BART provisions as interpreted in *American Corn Growers* because the controls EPA proposes to impose would force sources "to spend millions of dollars" on new controls that, under EPA's own definition of humanly perceptible visual change, "will have no appreciable effect on the haze in any Class I area." To avoid taking actions that would be inconsistent with the Act, EPA should withdraw these unjustified proposed BART limits.

Response: We address comments concerning the perceptibility of visibility improvements in a separate response to comments above. We disagree with the commenter that imperceptible visibility benefits are "hypothetical." As we state in the Regional Haze Rule, "Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."[716]

The commenter confuses the threshold applied to total visibility *impacts* from all BART-eligible units at a facility and the potential visibility *improvement* from controls at individual units. The Regional Haze Rule provides that BART–eligible sources with a 0.5 dv impact at a Class I area "contribute" to visibility impairment and must be analyzed for BART controls. BART determining authorities, however, are free to establish thresholds less than 0.5 dv. The 0.5 dv threshold in the context of BART is used to assess the maximum total visibility impact from all BART units at a facility, typically based on CALPUFF modeling. If the impact from all the BART sources at a facility is above the threshold, then each BART unit must be evaluated for controls, and therefore the visibility *improvement* anticipated from controls would be less than 0.5 dv on a facility basis, and may be much less than 0.5 dv on a unit specific basis for BART sources with multiple BART units. For example, a facility comprised of four identical BART-eligible units, would be subject to BART if the total visibility impact of the source was 0.5 dv. In this case, the maximum visibility benefit that could be achieved from controls on both NOx and SO2 on any individual unit would be 0.125 dv (one-fourth of 0.5 dv). The level of visibility benefit would be one factor to consider along the cost of controls and other factors in informing

[716] 70 FR 39104, 39129

the BART determination. For each of the required controls listed by the commenter, we evaluated the cost of controls along with the anticipated visibility benefit due to controls, the remaining useful life of the source, energy and non-air quality environmental impacts, and existing pollution control technology of all potential available controls in arriving at a BART determination.

The commenter mischaracterizes a statement made by the D.C. Circuit Court of Appeals. The statement made by the Court is as follows: "[u]nder EPA's take on the statute, it is therefore entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area."[717] The Court made this statement based on its interpretation of our Regional Haze Rule, and merely alluded to the possibility that, as is, the Rule may result in a situation where new retrofit technology is required for a source when the technology will not have an appreciable effect on visibility.[718] We note that the court does not establish perceptibility as a threshold in determining what an appreciable effect on visibility is. As discussed elsewhere, "Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."[719] Furthermore, the "degree of improvement in visibility which may reasonably be anticipated to result from the use of such [best available retrofit] technology" is just one of several factors the State, or EPA in the case of a FIP, must consider in determining what BART is for a specific source.

In Am. Corn Growers Ass'n, the Court disagreed with the approach used by EPA to determine what BART eligible sources are reasonably anticipated to cause or contribute to regional haze and therefore subject to BART.[720] The approach in the Regional Haze Rule required a State to analyze "the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area."[721] The Court held that the Rule's treatment of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" factor infringed on states' authority with respect to BART determinations under the Act.[722] The Court noted that the Act does not assign a specific weight with which to consider each factor, it solely mandates that all the factors be considered in making a BART determination.[723] The Court's issue was not with the weight, or lack thereof, placed on this factor by EPA. It found issue with what it considered to be "dramatically" different treatment of the factor by EPA.[724] While the court in American Corn Growers found that we had impermissibly constrained State authority, it did so because it found that we forced States to require BART controls without first assessing a source's particular contribution to visibility impairment. This is not the case with our action. In response to this

[717] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 7 (D.C. Cir. 2002)
[718] Id.
[719] 70 FR 39104, 39129
[720] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 7 (D.C. Cir. 2002) at 7-8
[721] 40 C.F.R. § 51.308(e)(1)(ii)(B)
[722] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 7 (D.C. Cir. 2002)
[723] 291 F.3d at 6
[724] Id.

court decision and address these concerns we finalized a revised Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations.[725]

With regard to the comment we properly recognize that the minuscule additional visibility improvement that could be achieved through installation and operation of LNB/SOFA and SNCR at White Bluff Units 1 and 2 is too small to justify the very high additional incremental costs of controls, and that the same reasoning should apply to the required NOx combustion controls for these units, we disagree that the same reasoning would apply. As we detail in our proposal, LNB/SOFA was determined to be very cost-effective (approximately $350/ton) and result in visibility improvements ranging from 0.038 to 0.176 dv for Unit 1 and 0.047 to 0.225 dv for Unit 2 at each of the affected Class I areas (98th percentile basis). We determined that the addition of SNCR was not justified given the smaller additional visibility benefits (ranging from 0.007 to 0.034 dv for Unit 1 and 0.007 to 0.033 dv for Unit 2 at each of the affected Class I areas) and incremental costs in excess of $9,000/ton.

7.c. Model Selection

Comment: CALPUFF modeling cannot be used to justify controls at Independence under the reasonable progress requirements.

[Entergy Arkansas Inc. (0166) p.35-37] Entergy Arkansas Inc. stated that it acknowledges that, under the Regional Haze Rule, "the URP does not establish a "safe harbor" for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id.* EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id.* At 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

[725] 70 FR 39104.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id.* at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model) ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the application of a chemical transport grid model." Draft Modeling Guidance at 22.[726] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id.* at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport

[726] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3-PMRH_Modeling_Guidance-2014.pdf.

models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone. 80 Fed. Reg. at 45,349.

CALPUFF is clearly inferior in this regard. Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[727] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal…. Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

[Entergy Mississippi Inc. (0168) p. 8-10; Conway Corporation et. al. (0172) p. 8-9; and EEAA (0173) p. 14-15] EMI, Conway Corporation et. al., and EEAA stated that EPA improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, significantly over-estimated the Independence Plant's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at the Independence Plant.[728] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources[729]- not by Arkansas point sources such as power plants. Therefore, EPA's singular focus on the Independence Plant will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal.

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[727] Docket ID EPA-HQ-OAR-2015-0310-0004.

[728] Notably, EPA issued on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[729] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, Introduction to Area Source Emission Inventory Development, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id.*

EPA admits that it did not perform the refined, multi-state modeling necessary to determine the amount of visibility improvements that would be achieved because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail"/abbreviated and unlawful approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels.[730] The failure to perform a necessary and proper analysis is not insignificant and only undermines the basis of EPA's proposal to require the installation and operation of controls at the Independence Plant.

EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at the Independence Plant is misplaced and clearly in error. While CALPUFF may be appropriate for a BART analysis, CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question.[731] CALPUFF is overly simplistic, greatly overstates the effect of single source emissions, does not show the effects of multiple sources and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx, which EPA has recognized is the more appropriate modeling tool for reasonable progress purposes.[732] Accordingly, EPA's inappropriate use of CALPUFF for reasonable progress purposes vastly overstates the visibility improvements that would result from the proposed controls for the Independence Plant.[733]

Comment: [EarthJustice/ Dr. Gray] On Page 13 of ADEQs comments23, ADEQ claims: "The Reasonable Progress Goals chosen by EPA are based on admittedly flawed methods that reject the refined modeling approach used by EPA in states such as Texas."

Firstly, USEPA made it clear why they did not use CAMx to determine the impact of FIP controls on visibility. The RPG modeling must consider impacts from all sources which would require much larger and more comprehensive modeling than the "comparatively simple single source CALPUFF modeling used for individual BART assessments." A "refined" modeling approach would require compilation of a very large emission inventory for Arkansas and the surrounding states, and more sophisticated modeling to account for the interactions of many pollutants. (The objective of a BART analysis using CALPUFF is to determine the impact of a single source against a "clean background".) As EPA states: "Developing all of the necessary input files, running the photochemical model, and post-processing the model outputs would take several months at a minimum." The modeling system is being used to determine the change in visibility (delta dV) at Class I areas due a relatively small change in the overall emissions patterns within the entire modeling domain. The only change within the entire model, which includes the emissions from thousands of sources, is the emission level of a single modeled Arkansas source (Independence). In other words, the model is being used for the RPG analysis to determine the sensitivity of the computed visibility metrics (due to all sources) to changes in emission rates at just one source within the modeling system.

Secondly, ADEQs assessment of the methodology used for Texas sources is incorrect. In fact,

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[730] 80 Fed. Reg. at 18,997-98.
[731] TX FIP TSD at A-35.
[732] Texas Regional Haze FIP, 79 Fed. Reg. 74,877-78.
[733] EPA's CALPUFF modeling indicates that the SO2 and NOx controls proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo.

EPA Region 6 also used an emission "scaling" approach to determine the effects of various control scenarios for their evaluation of Texas sources. For Arkansas, EPA Region 6 used the CENRAP 2018 base case projections as its starting point. For Texas, EPA Region 6 also used the same CENRAP 2018 base case projections, but supplemented it with a couple additional CAMx model runs (with updated emission levels), representing low and high control levels. The modeled species concentrations (contributions from individual sources) for the evaluated control scenarios were determined using interpolation (or extrapolation, in many cases) of the two (low and high) modeled levels using a similar source-by-source SO_2 and NOX emissions scaling approach that is currently being applied for the evaluation of the sources in Arkansas. EPA Region 6 did not run the CAMx model repeatedly to determine the visibility effects of controlling individual sources.

In Texas, the model results were used to demonstrate that the overall change in species concentrations was very nearly linearly proportional to the change in emission levels for an individual source (with very high linear correlation coefficients near 1.0). This strongly supports their use of the emission scaling approach for Arkansas. If the CAMx model were used to determine the impact of emission controls on a single source in Arkansas (such as Independence), it is therefore expected that the modeled reductions in sulfate and nitrate concentrations at each of the Class I areas will be very nearly proportional to the SO2 and NOX concentration reductions. In other words, the emission scaling approach has been shown to be mathematically sound and quite appropriate, especially considering the resources that would be required to exercise CAMx separately for each control measure at each evaluated source.

Response: The commenters confuse the single source analysis for evaluating the visibility impact and benefits of controls on units at the Independence facility and the analysis to estimate the visibility benefits of all controls on the 20% worst days in establishing a new reasonable progress goal for 2018. We utilized CALPUFF modeling following the same modeling protocol relied on for the BART analyses to assess the visibility impacts and potential benefits of controls for the units at the Independence facility. For estimating the total visibility benefit from all controls and estimating a new reasonable progress goal that reflects those controls, we relied on the CENRAP's 2018 CAMx modeling results, including source apportionment results, and the projected emission inventories, and scaled the results as described in the TSD. While we acknowledge that this approach is not as refined an estimate as would be attained in performing a new photochemical modeling run, it is based on scaling of earlier photochemical modeling results and not on CALPUFF modeling, as the commenter suggests. We disagree with the commenter's characterization of our analysis as a "thumbnail" approach and noted in our proposal that similar approaches have been used in other actions in Hawaii and Arizona. As discussed in the proposed action, our determination that controls were reasonable for the Independence units was based on our evaluation of the four-factors and including consideration of the visibility benefit of controls. For consideration of the visibility benefits, we relied on the results of our CALPUFF modeling, the CENRAP CAMx source apportionment results, and point source emission inventory data that initially identified the Independence facility as having the greatest potential to impact visibility at nearby Class I areas among all sources not already controlled under the BART requirements.

The 2005 BART Guidelines recommended the use of CALPUFF for assessing visibility (secondary chemical impacts) but noted that CALPUFF's chemistry was fairly simple. The visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[734] The BART guidelines also provided the option to potentially use photochemical grid models (such as CAMx) in the future if modeling tools available were appropriate and EPA approved of the technical approaches and how the model would be utilized.[735] Appendix W gives us discretionary authority in the selection of what models to use for visibility assessments with modeling systems, and models such as CALPUFF, CMAQ, REMSAD, and CAMx have all been used for that purpose. Specifically for single-source reasonable progress assessments similar to that done here for Independence, CALPUFF has been used for the majority of sources, while CAMx has been used in some situations, most notably and as noted by the commenter, in evaluating specific Texas sources for reasonable progress. In 2006/7, EPA OAQPS and EPA Region 6 consulted with FLM representatives and approved Texas' BART screening modeling protocol using source apportionment tools in CAMx.[736]

Under the BART guidelines, CALPUFF should be used as a screening tool and appropriate consultation with the reviewing authority is required to use CALPUFF in a BART determination as part of a SIP or FIP. The BART Guideline cited and referred to EPA's Guideline on Air Quality Models (GAQM)[737] which includes provisions to obtain approval through consultation with the reviewing authority. Moreover, we also note that in EPA's document entitled Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze (EPA-454/B-07-002), that Appendix W does not identify a particular modeling system as 'preferred' for modeling conducted in support of state implementation plans under 40 CFR 51.308(b). A model should meet several general criteria for it to be a candidate for consideration. These general criteria are consistent with the requirements of 40 CFR 51.112 and 40 CFR 51, Appendix W. Therefore, it is correct to interpret that no model system is considered 'preferred' under 40 CFR 51, Appendix W, Section 3.1.1 (b) for either secondary particulate matter or for visibility assessments. Under this general framework, we followed the general recommendation in Appendix Y to use CALPUFF as a screening

[734] 70 FR 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.'

[735] 70 FR 39123, 39124. "The use of other models and techniques to estimate if a source causes or contributes to visibility impairment may be considered by the State, and the BART guidelines preserve a State's ability to use other models. Regional scale photochemical grid models may have merit, but such models have been designed to assess cumulative impacts, not impacts from individual sources. Such models are very resource intensive and time consuming relative to CALPUFF, but States may consider their use for SIP development in the future as they are adapted and demonstrated to be appropriate for single source applications."

[736] See "Revised Draft Final Modeling Protocol, Screening Analysis of Potentially BART-Eligible Sources in Texas" Prepared for TCEQ by ENVIRON, September 27, 2006; "Modeling Guidance: Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas," Prepared for TCEQ by ENVIRON, December 13, 2007.

[737] 40 CFR part 51 Appendix W, Guideline on Air Quality Models, 70 FR 68218

technique since the modeling system has not been specifically approved for chemistry. The use of CALPUFF is subject to GAQM requirements in section 3.0(b), 4, and 6.2.1(e) which includes an approved protocol to use the current version.

We and some states have used CALPUFF to model visibility benefits as part of the reasonable progress analysis, and have used largely the same methodology as in BART modeling (i.e. use of 24 hour or hourly maximum emissions, a "clean" background condition, and a maximum or 98th percentile metric).[738] This approach provides information on the relative visibility benefits of controls to inform the evaluation of cost-effectiveness as part of the four factor analysis and has the benefit that it is immediately comparable to modeling used for BART determinations. Compared to a CAMx modeling exercise, CALPUFF modeling of one or more sources requires much less resources and time. However, the CALPUFF approach models the impacts from the single facility with limited chemistry and focuses on the maximum impacts from the source rather than the visibility impairment on the 20% worst days. We agree with the commenter that the CAMx model, may be better suited for evaluating the average visibility impairment due to individual sources during the 20% worst days as part of reasonable progress analysis. Photochemical models, like the CAMx model, provide a complete representation of emissions, chemistry, transport, and deposition, while CALPUFF treats a single source with simplified chemistry and parameterized physical processes. Furthermore, the CAMx model can be used to evaluate a large number of individual sources, and there are concerns in using CALPUFF for modeling impacts at distances much greater than 300 km from the source. In our analysis of source-specific impacts of Texas sources, we determined that CAMx was best suited for the complex analysis that we needed to perform in evaluating a large number of sources (38 separate facilities for our initial analysis) at distances from impacted Class I areas much larger than 300km, and in focusing on the 20% worst days. We discuss our selection of CAMx modeling in our Texas analysis in depth in the Response to Comments Document that accompanies that action.[739] As noted by EarthJustice, we did not perform a final CAMx model scenario to obtain the new RPGs in our Texas action, and instead relied on a scaling analysis similar to the methodology used in this action to adjust the CENRAP modeled RPG values based on the source apportionment data and emissions data available. As discussed above, RPGs were adjusted in actions in Arizona, Hawaii, Texas/Oklahoma and in this action by estimating the visibility improvement due to required controls based on scaling the anticipated emission reductions and the source apportionment modeling. In Texas/Oklahoma, source-specific source apportionment data and emissions were utilized. In the other states, emissions and source-apportionment data on a state and source category level were utilized.

Consistent with the examples discussed above[740], in evaluating the sources in Arkansas, we determined that CALPUFF was adequate since we determined that only one source needed to be assessed for a reasonable progress evaluation, and that source was well within the recommended range for CALPUFF modeling of under 300km from the Class I areas of interest. In fact, three

[738] For example see summary of the reasonable progress analyses for specific sources in Arizona (79 FR 9353), North Dakota (76 FR 58631), Montana (77 FR 24065), and Wyoming (78 FR 34785)
[739] Texas Regional Haze FIP, EPA Response to Comments Document, available at www.regulations.gov, Document ID: EPA-R06-OAR-2014-0754-0087.
[740] For example see summary of the reasonable progress analyses for specific sources in Arizona (79 FR 9353), North Dakota (76 FR 58631), Montana (77 FR 24065), and Wyoming (78 FR 34785)

of the four impacted Class I areas lie within 200km of the source. We discuss comments concerning why our reasonable progress screening analysis focused on NOx and SO2 emissions from Arkansas point sources and our determination that additional analysis was necessary for the Independence facility in response to comments elsewhere in this document. In evaluating visibility impacts and benefits for those sources subject to BART, we relied on CALPUFF modeling prepared by the facilities. Utilizing CALPUFF for the reasonable progress analysis on Independence provided for a consistent approach for all facilities and allowed for direct comparison of the visibility impacts and benefits across all facilities impacted by the proposed rulemaking. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the worst 20% monitored days at the Class I area. Therefore, the visibility benefits modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days from those specific controls. However, our analysis of the CENRAP 2018 CAMx photochemical modeling showed that: on the 20% worst days, Arkansas point sources contribute significantly to visibility impairment at Arkansas' Class I areas (greater than 4% of total visibility impairment at each Arkansas Class I area); review of the emission inventory revealed that a very small number of point sources are responsible for the majority of the point source emissions of NOx and SO2 and therefore a very small number of point sources are responsible for the portion of visibility impairment due to Arkansas point sources on the 20% worst days; and the Independence facility is one of the very largest emission sources and it is located relatively close (under 200 km) to three Class I areas. Therefore, we identified Independence as having the greatest potential to impact visibility on the 20% worst days based on emissions and location and should be evaluated for reasonable progress controls. We determined that CALPUFF modeling was appropriate and sufficient to provide information on the degree of visibility benefits of controls on Independence to inform the reasonable progress assessment. Through our evaluation of the four statutory factors, we identified cost-effective controls. We then considered visibility benefits of the cost-effective controls. We conducted CALPUFF modeling to determine the level of visibility impacts and benefits anticipated by SO_2 and NOx controls at nearby impacted Class I areas, evaluating the 98th percentile visibility impacts.[741]

As we discuss elsewhere, Entergy submitted CAMx model results as part of their comments. The modeled contribution to visibility impairment due to baseline emissions from the Independence facility alone were approximately 1.3% of the total visibility impairment at each Arkansas Class I area. In terms of deciviews, the average impact over the 20% worst days based on Entergy's CAMx modeling (adjusting to natural background conditions) is over 0.5 dv at the Arkansas Class I areas and even larger at the Class I areas in Missouri. These results estimate the visibility impacts from the source on the 20% worst days and confirm and provide additional support to our determination that Independence significantly impacts visibility, both in terms of maximum visibility impairment and visibility impairment on the 20% worst days, and that emissions controls provide for meaningful visibility benefits towards the goal of natural visibility conditions. In conclusion, both approaches, CALPUFF and CAMx, support the determination that the required controls are reasonable.

[741] See Summary of Additional Modeling for Entergy Independence and Appendix C to the TSD, available in the docket for this action

The commenter cites the BART guidelines and asserts that EPA recognizes that the CALPUFF model is overly simplistic and overstates the effect of single-source emissions. This is not an accurate characterization. The CALPUFF model can both under-predict and over-predict visibility impacts. For example, the 2012 ENVIRON report on *Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other criteria pollutants and AQRVs* found that CALPUFF predicted highest 24-hr nitrate and sulfate concentrations lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[742] In a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010)[743] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model which has a much more rigorous treatment of photochemical reactions. EPA recognized the uncertainty in the CALPUFF modeling results when EPA made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[744] While recognizing the limitations of the CALPUFF model in the Preamble, EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process.[745]

With regard to comments concerning the draft *EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM 2.5, and Regional Haze* (Dec. 2014), the commenter confuses the single-source analysis to evaluate visibility impacts and benefits of controls on an individual source with the analysis of overall visibility conditions at a Class I area due to the complete emission control strategy for all sources developed under the reasonable progress and long-term strategy requirements. The draft modeling guidance (as does the current guidance[746]) discusses the projection of overall visibility conditions and the need for photochemical grid modeling to account for all emission sources to model current visibility conditions and project future visibility conditions in response to the overall emission control scenarios. The section of the modeling guidance on regional haze[747] describes the recommended modeling analysis to assess overall future visibility improvement relative to the uniform rate of progress or "glidepath" (for each Class I area) as part of a reasonable progress analysis, and does

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[742] Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.

[743] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder "Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements" Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11-15, 2010) can be found at http://www.cmascenter.org/conference/2010/agenda.cfm.

[744] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121.

[745] 70 FR 39123

[746] 2007 *EPA modeling Guidance on the Use of Models and other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM 2.5, and Regional Haze*

[747] draft *EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM 2.5, and Regional Haze* (Dec. 2014)Section 4.8 "What Is The Recommended Modeling Analysis for Regional Haze?"

not discuss source-specific analyses that may be completed to inform a reasonable progress assessment.[748] Because the CALPUFF model only evaluates visibility impacts from a single-source or a limited group of sources, it is not capable of projecting overall visibility conditions due to all sources and controls. Consistent with this draft guidance and the current guidance, CENRAP and Arkansas utilized CAMx and CMAQ modeling to project future visibility conditions for 2018 for establishment of the RPGs and comparison with the URP. Similarly, we utilized the CENRAP CAMx model results and adjusted them based on source apportionment and emissions data, to estimate the new RPGs for the Arkansas Class I areas considering the anticipated changes in emissions due to all required controls. We discuss the selection of models for assessing individual visibility impacts and benefits of controls above.

The commenters cite to the proposed revisions to the Guideline on Air Quality Models (Appendix W) and the IWAQM Phase 3 modeling report[749] and assert that they support the conclusion that the use of CALPUFF for Independence was inappropriate. We disagree with the commenter. As we discuss above, we agree with the commenter that the CAMx model, may be better suited for a reasonable progress analysis in certain situations. Proposed revisions to Appendix W discuss removing the requirement to use CALPUFF for long-range transport assessments and as a preferred model due to the need to provide flexibility in estimating single-source secondary pollutant impacts and concerns about management and maintenance of the CALPUFF modeling code.[750] These proposed changes do not affect EPA's recommendation that States use CALPUFF to determine the applicability and level of BART in regional haze implementation plans. The proposed changes also do not preclude the use of CALPUFF for any other non-BART analysis, such as long-range transport PSD increment assessment, but recognizes that modern chemical transport models have evolved sufficiently and provide a credible platform for estimating potential visibility impacts from a single or small group of emission sources.[751]. The proposed Appendix W rule simply proposes to remove CALPUFF as a preferred model. If the proposed changes are finalized, CALPUFF or any other model can still be used for any non-BART analysis with the appropriate justification as an "alternative model".

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[748] draft *EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM 2.5, and Regional Haze* (Dec. 2014) at 173: "The modeling can be used to determine the predicted improvement in visibility and whether the visibility levels are on, above, or below the glidepath. It cannot by itself determine the reasonable progress goals or determine whether the reasonable progress goal is met, and it does not satisfy the requirements for the statutory four factor analysis. See the Regional Haze Rule and related guidance documents for more information on the four factor analysis, including control strategy analysis for single sources."

[749] Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values (July 2015)

[750] 80 CFR 45349: "in order to provide the user community flexibility in estimating single-source secondary pollutant impacts and given the availability of more appropriate modeling techniques, such as photochemical transport models (which address limitations of models like CALPUFF [37]), the EPA is proposing that the Guideline no longer contain language that requires the use of CALPUFF or another Lagrangian puff model for long-range transport assessments. Additionally, the EPA is proposing to remove the CALPUFF modeling system as an EPA-preferred model for long-range transport due to concerns about the management and maintenance of the model code given the frequent change in ownership of the model code since promulgation in the previous version of the Guideline. [38] The EPA recognizes that long-range transport assessments may be necessary in certain limited situations for PSD increment. For these situations, the EPA is proposing a screening approach where CALPUFF along with other appropriate screening tools and methods may be used to support long-range transport PSD increment assessments"

[751] 80 CFR 45349.

The IWAQM Phase 3 modeling report[752] discusses in detail the difference between the CALPUFF analysis typically followed under BART and the use of photochemical grid models for assessing reasonable progress and overall visibility conditions. The report does not identify a preferred model for single-source analysis but rather identifies the difference between the modeling approaches and cautions that the model results are not directly comparable.[753] The report also states that puff-models, such as CALPUFF, are not suited for reasonable progress demonstrations assessing overall visibility conditions and improvement because they are only able to model a single or small group of sources. Accordingly, we utilized CAMx model results to project overall future visibility conditions and establish the new RPGs in our reasonable progress demonstration. We used CALPUFF visibility modeling along with our evaluation of the costs of controls to inform our decision on the reasonableness of controls at the Independence facility. We also used CALPUFF visibility modeling as only one factor to inform our decisions on BART for subject-to-BART facilities. We also note that both the proposed revisions and the IWAQM report were published after the proposed rule for Arkansas regional haze was published and well before the technical analysis and modeling were completed.

We address comments concerning the contribution to visibility impairment from Arkansas point sources and the benefit of controls on Independence on Arkansas Class I areas elsewhere. We find that the contribution to visibility impairment from Arkansas point sources to be significant and that controls on Independence will result in meaningful visibility improvements towards the goal of natural visibility conditions and addresses a significant portion of the visibility impairment due to Arkansas sources.

Comment: Use of CALPUFF modeling does not support EPA's determination to require controls at the three coal-fired power plants. [Nucor Steel-Arkansas and Nucor-Yamato Steel (0163) p.40-50] Nucor stated that the EPA's reliance on CALPUFF modeling results to make regulatory decisions in this case is not justified due to CALPUFF's well-known overestimation of visibility impacts.[754] Under the circumstances here, it is highly likely that CALPUFF overestimated the visibility impacts of White Bluff, Flint Creek and Independence by at least five (5) times. One component of this overestimation is the failure to incorporate the puff splitting option within the CALPUFF model into the development of visibility results. Appendix B of the CENRAP BART Modeling Guidelines specifically recommends that the option for incorporating puff splitting in the model not be included; yet the CALPUFF User's Manual (Scire et al. 2000) states on page 2-37 that "across-puff shear is likely to be important for well mixed puffs after stable surface flows develop in the evening' as an example of when puff

[752] Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values (July 2015)

[753] IWAQM Phase 3 Report (July 2015) at 9: "In sum, the differences in the types of models, the inputs to the models, and how the models and model results are used means that the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal. If recommended procedures change for either BART determination impact assessments or reasonable progress goal impact assessments the comparability between approaches would also change. Photochemical grid models could be applied to estimate single source impacts and post-processed in a manner consistent with requirements for a BART-like assessment but Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources"

[754] Coincidentally, the EPA Administrator on July 14, 2015, signed a proposed notice to remove CALPUFF as a model for long-range transport in EPA's Guideline on Air Quality Models in Docket No. EPA-HQ-OAR-2015-0310.

splitting should be employed. While the use of puff-splitting alone does not resolve all potential issues with regard to the accuracy of the CALPUFF model, it is a component that when eliminated will cause visibility impacts to be overestimated. CALPUFF's overestimation of visibility impacts by a factor of 2-10 times under similar circumstances has been previously identified[755] and is described with specific reference to EPA's Proposed FIP for Arkansas in a report by Dr. Richard T. McNider.[756] Dr. McNider's report explains that the CALPUFF protocols used in the Proposed FIP fail to account for several well-known meteorological phenomena and processes, and causes it to overestimate visibility impacts by a factor of 2-3 times at distances between 40-100 km. At distances beyond 100 km, CALPUFF likely overestimates visibility impacts by a factor of 5-10 based on observations of plume widths at long-range.[757] Among other things, this is due to the impact of plume transport during the overnight period in which the plume is distorted by wind shear resulting in a very wide plume. By not utilizing the puff-splitting option, this wind shear effect is ignored. As noted above, the developers of CALPUFF explicitly stated that puff splitting should be used if an evening transition is encountered. Because a majority of sources affected by the Proposed FIP have plume transport times that exceed 9 to 12 hours — resulting in some measure of overnight transport — the failure to account for overnight decoupling within the model likely understates plume widths by a factor of at least five and corresponding overstatement of concentrations by a similar factor. These evening transitions and associated plume distortion are a regular part of atmospheric behavior and cannot be neglected in regulatory actions assessing the cost benefits of controls.

As described in Dr. McNider's report, the CALPUFF and CALMET protocols employed in the Proposed FIP neglect important physical behavior that control plume growth beyond a travel distance of 40-50 km. As found in observations of power plant plumes in Tennessee, wind fluctuations at a scale above boundary layer turbulence not captured in CALMET or realized in CALPUFF likely cause a plume to grow at 2 to 3 times that produced in CALPUFF. The neglect of these intermediate scales of motion is likely part of the reason the Hoffnagle report (Ex. 19) found CALPUFF to over-estimate concentrations.

The electric generating units that are the subject of the Proposed FIPs sit at distances between 100 and 400 kilometers from the closest Class I areas. Using the dates of the 98th percentile visibility impacts, transport wind speeds were found to be generally less than 3 m/s. Thus, transport times for all plumes would have exceeded 10 hours and most transport times were 15-24 hours. Thus, almost all plumes would have encountered an evening transition and overnight transport. The following tables demonstrate the distance in kilometers (km) and plume transport times for White Bluff, Flint Creek, and Independence.

Travel Time at 3m/s

Re centor	Caney Creek	Upper Buffalo	Hercules Glades	Mingo

[755] See Exhibit 19 to Nucor's comments, Hoffnagle, G., "Accuracy of Visibility Protocol Modeling in BART Evaluations" (June 15, 2012); EPA Docket EPA-R08-OAR-2011-0851.
[756] See, McNider, R. "Inadequacy of CALPUFF and CALMET Protocols for Visibility Impact Analysis in the Arkansas RHR FIP," July 13, 2015, attached hereto as Exhibit 20 to Nucor's comments.
[757] White Bluff, Flint Creek and Independence are all more than 100 km from the nearest Class I area.

Facility	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)
Entergy-White Bluff	176	16.3	200	18.5	266	24.6	335	31.0
Flint Creek	204	18.9	104	9.6	153	14.2	395	36.6
Entergy-Independen	270	25.0	188	17.4	186	17.2	191	17.7

Travel Time at 2m/s

Receptor	Caney Creek		Upper Buffalo		Hercules Glades		Mingo	
Facility	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)	Distance	Travel Time (hrs)
Entergy-White Bluff	176	24.4	200	27.8	266	36.9	335	46.5
Flint Creek	204	28.3	104	14.4	153	21.3	395	54.9
Entergy-Independen	270	37.5	188	26.1	186	25.8	191	26.5

This table demonstrates that the plume transport times for each facility and Class I area crosses into evening and overnight mixing zones. The choice of not including the puff splitting option for the FIP modeling means that CALPUFF most likely is underestimating the effects during these overnight hours, which results in underestimating plume widths by a factor of five to ten, and corresponding overestimations of plume concentrations. This results in visibility impacts that

are not accurate and should not be utilized to make regulatory decisions that have significant economic impacts.

EPA has acknowledged the shortcomings of CALPUFF and that it is primarily limited to use as a screening tool to evaluate dv changes of at least 2-3 dv. Indeed, the Hoffnagle report demonstrates that CALPUFF modeling has not been validated by real world observations and that the current regulatory version of CALPUFF used by EPA is outdated.[758] Consequently, CALPUFF is not "sufficiently accurate to make determinations of deciview differences of 1 deciview."[759]

It is not appropriate under the circumstances here to rely on CALPUFF beyond use as a screening tool. Specifically, it is inappropriate to utilize CALPUFF as a screening tool to qualify a source as subject to BART and subsequently use it to determine a facility's required implementation of a control technology at a significant financial cost. EPA in its final regional haze rules stated that "because of the scale of the predicted impacts from these sources, CALPUFF is an appropriate or a reasonable application to determine whether such a facility can reasonably be anticipated to cause or contribute to any impairment of visibility. In other words, to find that a source with a predicted maximum impact greater than 2 to 3 deciviews meets the contribution threshold adopted by the States does not require the degree of certainty in the results of the model that might be required for other regulatory purposes." 70 F.R. 39104, 39123; July 6, 2005; Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule [emphasis supplied]. For regulatory action such as evaluating the level of controls for a FIP, much more realistic modeling should be used to determine visibility impacts. For the Arkansas FIP, this should include at a minimum usage of the puff splitting option in CALPUFF. It should also include an evaluation of CALMET to ensure that its assimilation of winds at the 00Z and 12Z GMT times are not adversely impacting boundary layer decoupling and the development of inertial oscillations in the wind field. If at a minimum, the CALPUFF model results are overestimated by a factor of 5, the maximum 98th percentile baseline visibility impact for White Bluff, Flint Creek, or Independence would be lowered to a level that removes any reasonable likelihood that it would exceed 0.5 deciviews and thus even be subject to BART, much less result in visibility improvement that may be reasonably anticipated.

There has been no explanation or justification by EPA that demonstrates that the visibility impacts obtained from the CALPUFF model are precise enough to reliably differentiate results that are fractions of a deciview apart. In the proposed FIP, the maximum visibility improvement reported for any single Class I area for the subject to BART units is 0.813 dv.[760] Not only is this overstated as discussed elsewhere in Nucor's comments, this is below even EPA's 1 dv level at which a discernible difference in visibility can be registered by a human.[761] In evaluating the

[758] Hoffnagle, Exhibit 19 at p. 4.
[759] Hoffnagle, Exhibit 19 at p. 23.
[760] See Proposed FIP and Exhibit 7 to Nucor's comments.
[761] See 62 Fed.Reg. 41138, 41145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."); 70 Fed.Reg. 39104, 39120 (July 6, 2005) (1.0 deciview is the "appropriate perceptibility threshold"); but see, Henry, R. "Just Noticeable Differences in Atmospheric Haze", J. Air and Waste Management Assoc. 52: 1238, 1243, attached hereto as Exhibit 21 ("A 1- deciview change is never noticeable.")

significance of the modeled visibility improvements in the proposed FIP, EPA subjectively labels them as "considerable" (7 times), "significant" (1 time), and "meaningful" (1 time),[762] even though each of these impacts is below the admitted minimum level of visual perceptibility. EPA does not explain how these impacts can be considerable, significant or meaningful from a visibility standpoint, when these impacts are not able to be perceived.[763]

If adjusted to account for the overestimation of the CALPUFF model and the distances and transport times involved in this case, the modeled visibility improvements would be even further below the 1dv perceptibility threshold. As explained in Dr. McNider's report, based on the studies of observed plume width versus modeled plume width, dispersion results beyond 100 kilometers can be expected, at a minimum, to be overestimated by a factor of at least 5. This would bring the modeled visibility improvement results down to a level well below anything that would be observable and far below what CALPUFF can reasonably predict.

EPA's visibility analysis in the Proposed FIP systematically overstates both the baseline visibility impacts of White Bluff, Flint Creek and Independence, and the visibility benefits that would result from installation of EPA's required controls.[764] EPA's Proposed FIP presumes greater accuracy and precision than is reasonable or that may be expected from CALPUFF under the circumstances here. The EPA has utilized a model that was developed as a screening method, and has improperly utilized it as a way to make regulatory determinations to establish mandatory control technologies. As indicated in the Hoffnagle and McNider reports, the errors in this model make it impossible to predict with a reasonable degree of confidence visibility changes at the levels involved, and call into question EPA's predictions of the tiny visibility benefits projected from installation of additional controls. As indicated, EPA has not validated that the results within CALPUFF align with any real-world data or observations; however, the Hoffnagle and McNider reports demonstrate that at the distances and transport times involved here, CALPUFF does not align with observed plume dispersion. EPA has failed to update its model or to address any of these deficiencies considering currently available state-of-the-art modeling science. EPA's consideration of visibility impacts is fundamentally flawed and should be withdrawn and corrected.

EPA's admission that CALPUFF is a reasonable tool to evaluate a facility's visibility impacts only if those impacts exceed 2 to 3 deciviews, combined with the inability of the model to make accurate determinations below the 1 deciview threshold of perceptibility, discredits the results of the baseline visibility analyses in the Proposed FIP, as well as the claimed level of visibility improvement that can reasonably be anticipated from EPA's BART and Reasonable Progress determinations. For these reasons, EPA has not adequately explained how the baseline and subsequent controlled visibility analyses in the Proposed FIP justify the selected control technologies.

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[762] "Considerable" - pp. 18952; 18959; 18959; 18966; 18972; 18978; 18994; "Significant" - p. 18994; "Meaningful" — p. 18952.

[763] To the extent EPA's decisions in the Proposed FIP were based on "cumulative visibility benefits" or "total visibility benefits," that is misleading, has no legal basis, and is not scientifically defensible. See, Exhibit 19, Hoffnagle Report, p. 3 (deciviews cannot be directly added or subtracted.)

[764] As well as the other sources that were modeled using CALPUFF.

Response: In promulgating the 2005 BART guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF. There we respond:

> CALPUFF is the best modeling application available for predicting a single source's contribution to visibility impairment. It is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for some purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO2 and NOX. As explained above, simulating the effect of precursor pollutant emissions on PM2.5 concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. *We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.*

The use of CALPUFF in the context of the Regional Haze rule provides results that can be used in a relative manner and are only one factor in the overall BART determination. We determined the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[765]

EPA's modeling in this action was consistent with the BART Guidelines and Appendix W. In recommending the use of CALPUFF for assessing source specific visibility impacts, EPA recognized that the model had certain limitations but concluded that "[f]or purposes of the regional haze rule's BART provisions . . . CALPUFF is sufficiently reliable to inform the decision-making process."[766] To the extent that the comment takes issue with the provisions in the BART Guidelines for use of CALPUFF, the legal deadline for challenging the use of CALPUFF has passed.

The commenters also refer to the 2005 Rule where we discuss the use of CALPUFF as a screening tool to qualify a source as subject to BART[767] and claim that we state that CALPUFF is only a reasonable tool when impacts exceed 2 to 3 deciviews. This is incorrect. The BART Guidelines finalized in the 2005 Rule establish a maximum threshold of 0.5 deciviews for determining whether sources cause or contribute to visibility impairment for purposes of

[765] 70 FR 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.'
[766] 70 FR 39123.
[767] 70 FR 39123.

BART[768] and recommends the use of CALPUFF[769] to predict the visibility impacts from a single source at a Class I area to compare against this threshold. The commenters fail to note that later in that same section of the Rule we also discuss the recommended use of CALPUFF to evaluate visibility benefits of controls. There we state:

> "…we ***also*** recommend that the States use CALPUFF as a screening application in estimating the degree of visibility improvement that may reasonably be expected from controlling a single source in order to inform the BART determination. As we noted in 2004, this estimate of visibility improvement does not by itself dictate the level of control a State would impose on a source; ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of [BART]'' is only one of five criteria that the State must consider together in making a BART determination. "[770]

We note that the 0.5 dv threshold in the context of BART is used to assess the maximum total visibility impact from all BART units at a facility based on CALPUFF modeling. If the impact from all the BART sources at a facility is above the threshold, then each BART unit must be evaluated for controls, and therefore the modeled visibility *improvement* anticipated from controls would be less than 0.5 dv on a facility basis, and may be much less than 0.5 dv on a unit specific basis for BART sources with multiple BART units. For example, a facility comprised of four identical BART-eligible units, would be subject to BART if the total modeled visibility impact of the source was 0.5 dv. In this case, the maximum visibility benefit that could be achieved from controls on both NOx and SO2 on any individual unit would be 0.125 dv (one-fourth of 0.5 dv). The level of visibility benefit would be one factor to consider along the cost of controls and other factors in informing the BART determination.

With respect to our analysis of controls under reasonable progress, we rely on our Reasonable Progress Guidance.[771] Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress 4 statutory factors and the BART 5 statutory factors contained in the Act and repeated in the Guidance, and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. Also, similar to a BART analysis, we are also considering the projected visibility benefit in our reasonable progress analysis following the BART guidelines and the use of CALPUFF.[772] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

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[768] 40 CFR 51 Appendix Y, III(A)(1): "As a general matter, any threshold that you use for determining whether a source ''contributes'' to visibility impairment should not be higher than 0.5 deciviews."
[769] 40 CFR 51 Appendix Y, III(A)(3): "CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment"
[770] Id.
[771] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007
[772] As we explain in our proposed action (80 FR 18993): "While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress". See 79 FR at 74838, 74840, and 74874.

We also disagree with the commenters conclusions concerning CALPUFF model performance and assertions that model predictions are overestimated by a factor of 5. We note that our regulations do not allow for the calibration of model results to try to adjust for potential biases as suggested by the commenter.[773]

In order to develop a coherent understanding of performance of long-range transport (LRT) models used for regulatory purposes, we examined all of EPA's prior LRT model evaluation efforts. These evaluation studies included the 1986 8-Model Study (Carhart , et al., 1989), Rocky Mountain Acid Deposition Model Assessment Project (Godowitch, 1989a, 1989b), IWAQM Phase I and II (EPA, 1998a, 1998b), and the 2012 EPA LRT model evaluation study (ENIVRON, 2012a).[774] From this review, we drew the following conclusions that are relevant to commenters concerns:

1. The results of both the 1986 and 2012 EPA evaluation efforts clearly identified that LRT model performance is highly sensitive to the quality of the meteorological inputs, meaning that LRT model performance will vary with the performance of the meteorological simulation used to supply meteorological information to the LRT model. Thus, in context, one cannot arbitrarily conclude that any modeling platform will consistently over-predict with every application as LRT model performance is inextricably linked to prognostic meteorological model performance.
2. Carhart et al. (1989) concluded that, in general, LRT models tend to underestimate the horizontal spreading of the plume at ground level resulting in too high peak (centerline) concentrations when compared to the observations. For Lagrangian models compared in the 1986 study, this was believed to be due to using sigma-y dispersion (Turner) curves that are representative of near-source and are applied for longer (> 50 km) downwind distances. The underestimation of the lateral spread of plumes will consistently result in over-prediction of ground level concentrations, resulting in higher bias and error scores. This observation is consistent with the findings of the EPA 2012 model study which showed that the model CALPUFF underestimated the observed lateral distance of the plume by as much as 51% for the SRL75 database and 34% for the GP80 on the 100-km

[773] App. W, Section 7.2.9(a) "…Therefore, model calibration is unacceptable."

[774] Carhart, R.A., A.J. Policastro, M. Wastag, and L. Coke, 1989: Evaluation of Eight Short-Term Long-Range Transport Models Using Field Data. Atmos. Environ., 23, 85 – 105
Godowitch, J.M. 1989a. Evaluation and Sensitivity Analyses Results of the MESOPUFF II Model with CAPTEX Measurements. EPA-600/3-89-056. U.S. Environmental Protection Agency, Atmospheric Research and Exposure Assessment Laboratory, Research Triangle Park, NC.
Godowitch, J.M., 1989b: Evaluation and Testing of the MESOPUFF II Model System with CAPTEX Measurements. 6th Joint Conference On Applications of Air Pollution Meteorology, American Meteorological Society, Anaheim, CA, 56-59.
USEPA, 1998a: A Comparison of CALPUFF Modeling Results to Two Tracer Field Experiments. Tech. Rep., EPA-454/R-98-009, Research Triangle Park, NC, 48 pp. http://www.epa.gov/scram001/7thconf/calpuff
USEPA, 1998b: Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Tech Rep., EPA-454/R-98-009, Research Triangle Park, NC, 160 pp. http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf
USEPA, 2012a: Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data. Tech. Rep., EPA-454/R-12-003, Research Triangle Park, NC. https://www3.epa.gov/scram001/reports/EPA-454_R-12-003.pdf

monitor arcs (ENVIRON, 2012). This phenomenon was also observed in the original report published in 1998 as part of the IWAQM Phase II process. CALPUFF underestimated lateral plume spread by as much as 24% for the GP80 study and as much as 49% for SRL75 (EPA, 1998a). At greater distances, both the 1998 and 2012 studies showed that this phenomena reversed itself, with much greater lateral distances compared to observed (GP80, 600-km arc). This would result in a lower model bias at greater distances.

The graphical analysis of the 1994 European Tracer experiment (ETEX) results provided in the 2012 report also shows an underestimation of the lateral spread of almost all models compared to observations. This appears to be an artifact that affects most models used for LRT purposes, irrespective of whether the dispersion is based upon Turner stability classes or not. We do not disagree that some elements of scales of motion are potentially neglected by the CALMET/CALPUFF system. CALPUFF modeling utilizes CALMET to construct the meteorological inputs using surface and aloft meteorological observations and three-dimensional output from the MM5 prognostic numerical model. Performance evaluations of MM5 generated data sets against surface meteorological observations were completed for the datasets used to evaluate CENRAP BART sources, including the modeling performed to support this action. [775] EPA's overall analysis of the CALPUFF/CALMET system focused on the end result impacts, which includes any potential issues with use of upper air observations and boundary layer interaction. All air quality models are a simplification of a very complex and dynamic system. Events are characterized by known or measured conditions that are input into the model, such as emissions and observed meteorological conditions at specific locations, and unknown or unresolved details of atmospheric flow, such as the turbulent velocity field throughout the model domain. The approach employed is consistent with all relevant guidance provided by EPA and FLM's, with consideration for the limitations and capabilities of the available models.

The CALPUFF model can both under-predict and over-predict visibility impacts. For example, the 2012 ENVIRON report on *Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other criteria pollutants and AQRVs* found that CALPUFF predicted highest 24-hr nitrate and sulfate concentrations lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[776] In a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010)[777] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model which has a much more rigorous treatment of photochemical reactions. EPA recognized the uncertainty in the CALPUFF modeling results when EPA made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the

[775] Performance evaluations of the 2001, 2002, and 2003 MM5 generated data sets are discussed in the CENRAP BART Modeling Guidelines available in the docket for this action

[776] Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.

[777] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder "Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements" Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11-15, 2010) can be found at http://www.cmascenter.org/conference/2010/agenda.cfm.

98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[778] Therefore, in recognizing some of the limitations of the CALPUFF model, we determined that use of the maximum modeled impact may be overly conservative and recommended the use of the 98th percentile value. While recognizing the limitations of the CALPUFF model in the Preamble of the Regional Haze Rule, EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process.[779]

We disagree with the commenter's assertion that we were incorrect in not utilizing the puff-splitting option[780] and that this resulted in an overestimation of model results Tests conducted by the EPA and the FLM's have shown that the CALPUFF puff-splitting algorithm does not behave in the manner posited in Dr. McNider's document. The EPA 2012 report summarizes tests of the puff-splitting algorithm for the 1994 European Tracer experiment (ETEX). That sensitivity analysis determined that "the CALPUFF puff splitting sensitivity tests did not have any significant effect on CALPUFF model performance. Whether puff splitting was used or not produced essentially identical model performance for the ETEX experiment and certainly did not improve the CALPUFF model performance."[781] Tests of puff-splitting with the GP80 mesoscale tracer experiment at a distance of 600 km showed that CALPUFF underestimated concentrations and the use of puff-splitting resulted in higher concentrations.

Additionally, we ran the puff splitting feature in its default configuration for the Four Corners Air Quality Task Force CALPUFF dataset[782] modeling visibility impacts due to emissions from the San Juan Generating Station. This test also confirmed that the use of puff-splitting does not result in a uniform decrease in concentrations. In our tests of puff-splitting, visibility impacts (and thus concentrations) both increased and decreased across various Class I areas.[783] All of these results are contrary to the claims of the commenter that CALPUFF over-predicts downwind concentrations at distances beyond 100 km and that the use of puff-splitting would result in lower concentrations. Furthermore, commenters have not provided any additional CALPUFF modeling to support their claims concerning model performance using the non-default puff splitting option.

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[778] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121.

[779] 70 FR 39123

[780] CALPUFF contains an optional puff splitting algorithm that can further account for vertical wind shear effects across individual puffs when this is of specific concern. Dispersion and transport can act on separate puffs generated from the original puff. This option is not part of the regulatory default set-up.

[781] See page 134 of Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data, ENVIRON, May 2012.

[782] See Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.for description of dataset.

[783] See CALPUFF_SJGS_SPLIT_summary.xls

The analysis that appears in Table 1 of the McNider analysis is flawed because surface wind speeds do not define puff transport. According the CALPUFF User's Guide[784], the transport wind is defined as the average wind across the depth of the puff. This means that if a puff is in a well-mixed environment, the puff is in contact with both the surface and the planetary boundary layer, and the transport wind is the average across the depth of the puff. The McNider analysis incorrectly relies on observed wind speeds at two ground sites rather than the transport wind to estimate the travel time to the Class I areas.

The commenter states that the largest visibility benefit from controlling a single EGU is 0.813 dv, an imperceptible amount and that impacts cannot be considerable, significant or meaningful from a visibility standpoint, when they are imperceptible. We disagree and address this comment elsewhere where we discuss that perceptibility is not a threshold criterion for considering improvements in visibility to be meaningful.

The commenter refers to the Hoffnagle report (Ex. 19 of Nucor comments) to support claims that the CALPUFF model over-predicts concentrations. The Hoffnagle report claims that comparisons of CALPUFF modeled visibility impacts to observed data demonstrates that CALPUFF over-predicts nitrate extinction by a factor of 2 to 10, that the model is unreliable beyond 200km, and that the modeling is not sufficiently accurate to make determinations of deciview differences of 1 dv. We disagree with the conclusions of the Hoffnagle report and note significant flaws in that analysis. Regarding the use of CALPUFF beyond 200km, EPA concluded from the evaluation of the IWAQM phase 2 report case studies that the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300km.[785],[786] Furthermore, we note that all the large EGU sources modeled in this action are less than 200 km for at least one Class I area. We specifically address Hoffnagle's analysis of modeled to measured results in response to comments elsewhere where we address comments concerning the "margin of error" of the model and case study comparisons of CALPUFF modeled values to measured values.

We disagree with the commenter that the model we utilized is outdated. We used the regulatory version of the CALPUFF model at the time we performed our analysis.[787] The Hoffnagle report discusses CALPUFF version 6.4 and alleges that that it is more scientifically robust and included updated chemistry and technical enhancements to improve the model's performance and accuracy. We responded to a similar comment in depth in our response to comments on our FIP for New Mexico.[788] We disagree that the newer versions of CALPUFF should be used in this

[784] A User's Guide for the CALPUFF Dispersion Model (Version 5), Scire, et al., January 2000. Available at: http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf

[785] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.

[786] 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models

[787] On December 4, 2013, EPA approved an update to v5.8.4 that contains bug fixes to the previous version. See December 3, 2013 CALPUFF Update Memo for a discussion of model changes.

[788] See response beginning page 124 of Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, August 5, 2011. Available at: https://www.regulations.gov/#!documentDetail;D=EPA-R06-OAR-2010-0846-0127

action to determine potential visibility impacts. The newer version(s) of CALPUFF have not received the level of review required for use in regulatory actions subject to EPA approval and consideration in a BART decision making process. Based on our review of the available evidence we do not consider these newer versions of CALPUFF to have been shown to be sufficiently documented, technically valid, and reliable for use in a BART decision making process.

The commenters also refer to the proposed revisions to the Guideline on Air Quality Models (Appendix W). Proposed revisions to Appendix W discuss removing the requirement to use CALPUFF for long-range transport assessments and as a preferred model due to the need to provide flexibility in estimating single-source secondary pollutant impacts and concerns about management and maintenance of the CALPUFF modeling code.[789] These proposed changes do not affect EPA's recommendation that States use CALPUFF to determine the applicability and level of BART in regional haze implementation plans. The proposed changes also do not preclude the use of CALPUFF for any other non-BART analysis. The proposed changes to the Appendix W rule simply propose to remove CALPUFF as a preferred model for long-range transport assessments. If the proposed changes are finalized, CALPUFF or any other model can still be used with the appropriate justification as an "alternative model."

Finally, the CAMx modeling provided by Entergy Arkansas provides additional information that directly contradicts the commenter's assertion that CALPUFF greatly overestimates visibility impacts by at least a factor of 5. As we discuss elsewhere, the CAMx visibility modeling estimates a maximum visibility impact (limited to only the days comprising the 20% worst days and based on annual emissions) of over 1.5 dv from the Independence facility at both Caney Creek and Upper Buffalo. For the White Bluff facility, the CAMx maximum visibility impact is approximately 3.5 dv at Caney Creek and 0.8 dv at Upper Buffalo. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the worst 20% monitored days at the Class I area, therefore the true maximum impact considering all days based on CAMx modeling could be even higher. This compares to a CALPUFF modeled visibility 98th percentile impact (based on maximum emissions) due to the Independence facility of 2.5 dv at Caney Creek and 2.3 at Upper Buffalo. For White Bluff, the CALPUFF modeled impact (98th percentile) is approximately 3.3 dv at Caney Creek and 2.3 dv at Upper Buffalo.

We address more general comments concerning the use of CALPUFF modeling and model uncertainty in separate response to comments.

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[789] 80 CFR 45349: "in order to provide the user community flexibility in estimating single-source secondary pollutant impacts and given the availability of more appropriate modeling techniques, such as photochemical transport models (which address limitations of models like CALPUFF [37]), the EPA is proposing that the Guideline no longer contain language that requires the use of CALPUFF or another Lagrangian puff model for long-range transport assessments. Additionally, the EPA is proposing to remove the CALPUFF modeling system as an EPA-preferred model for long-range transport due to concerns about the management and maintenance of the model code given the frequent change in ownership of the model code since promulgation in the previous version of the Guideline. [38] The EPA recognizes that long-range transport assessments may be necessary in certain limited situations for PSD increment. For these situations, the EPA is proposing a screening approach where CALPUFF along with other appropriate screening tools and methods may be used to support long-range transport PSD increment assessments"

7.d. Margin of Error in CALPUFF modeling

Comment: [ADEQ (0144) p. 28-30] ADEQ stated that in determining what specific controls are BART, EPA is required to take into consideration a number of factors including "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[790] *In Nat'l Parks Conservation Ass'n v. E.P.A.,* PPL Montana, a part-owner of a coal-fired power plant, objected to EPA's use of the CALPUFF visibility model in determining BART for two units at one of its coal-fired power plants.[791]

The basis of PPL Montana's objection was that the maximum potential incremental visibility benefit of emissions control technology chosen by EPA fell within the model's margin of error, meaning such improvement cannot be "reasonably ... anticipated" as required by the Act.[792] The Ninth Circuit Court of Appeals recently held that EPA had not "considered the relevant factors and articulated a rational connection between the facts found and the choice made."[793] As a result, EPA acted in an arbitrary and capricious manner by failing to provide an adequate explanation as to how the degree of visibility improvement could be reasonably anticipated.[794]

At least one facility affected by the Proposed FIP has conducted an analysis to determine whether or not the maximum potential incremental visibility benefit of emissions control technology chosen by EPA fell within the margin of error. Specifically, ADEQ is aware that Domtar is currently performing modeling to determine whether or not predicted visibility improvements fell within the margin of error at its Ashdown Mill.[795] Other facilities are likely performing modeling to make similar determinations. Accordingly, ADEQ reserves the right to comment on this issue until such time as Arkansas's facilities have had adequate time to make those determinations.

As the D.C. Circuit explained in vacating a portion of the Regional Haze Rule itself, it is arbitrary and capricious for EPA to force an emissions source "to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area."[796] In its Proposed Rule, EPA dictates the imposition of control equipment for emissions reduction under BART in instances where CALPUFF predicted minor visibility improvements. EPA did so without first undertaking any site specific analytical analysis to determine if the visibility improvements were in fact within the CALPUFF margin of error.

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[790] 42 U.S.C.A. § 7491.
[791] *See generally, Nat'l Parks Conservation Ass'n v. E.P.A.*, No. 12-73710, 2015 WL 3559149, at *13 (9th Cir. June 9, 2015).
[792] *See* 42 U.S.C. § 7491(g)(2); *Nat'l Parks Conservation Ass'n v. E.P.A.,* No. 12-73710, 2015 WL 3559149, at *8 (9th Cir. June 9, 2015).
[793] *Nat'l Parks Conservation Ass'n v. E.P.A.*, No. 12-73710, 2015 WL 3559149, at *13 (9th Cir. June 9, 2015).
[794] *Id.*
[795] Letter from Annabeth Reitter, Corporate Manager, Domtar, to Guy Donaldson, Chair of the Air Planning Section, E.P.A., (July 6, 2015) attached as Exhibit 4.
106 *Nat'l Parks Conservation Ass'n v. E.P.A.,*
[796] *Nat'l Parks Conservation Ass'n v. E.P.A., No. 12-73710, 2015 WL 3559149, at *10 (9th Cir. June 9, 2015)(citing Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 7 (D.C.Cir.2002)*

Specifically, it appears from the Proposed FIP that the highest modeled visibility improvement after EPA's BART determinations for any of the three Arkansas EGUs at any Class I area is 0.813 deciviews attributed to SO_2 controls at the Entergy White Bluff Unit I at Caney Creek, which is below the 1 deciview threshold of visibility perception. Furthermore, EPA required the installation of low-NOx burners and over fire air at SWEPCO's Flint Creek Unit, even though the highest modeled visibility improvement was 0.081 deciviews for NOx. Given the acknowledged over-prediction of the CALPUFF model and its inaccuracy at these low levels, the actual visibility impact for the State's EGUs (and most likely the other subject-to-BART sources as well) would be much lower.

The CAA does not require visibility improvements that cannot be reasonably anticipated. Conversely, visibility improvements that are less than the margin of error were expressly found to be invalid. Until such time as EPA can provide assurance that the CALPUFF model is a reliable indicator of visibility projections, many of the numerical projections contained in the Proposed FIP are themselves, unreliable. For this reason, the Proposed FIP is flawed and is overly expansive and should be withdrawn.

Comment: [Domtar (0161) p. 2-3] Domtar stated that in response to the recent June 9, 2015 decision of the 9th Circuit Court of Appeals in *Nat'l Parks Conservation Ass'n v. EPA*, No. 12-73710, 2015 WL 3559149 (9th Cir. June 9, 2015), the Ashdown Mill engaged a study to determine if the visibility improvement claimed to be derived from the proposed BART FIP can be reasonably anticipated. Since the 9th Circuit decision became available late in the public comment period for the proposed Arkansas Regional Haze FIP and in order to complete the full study for the Ashdown Mill, Domtar requested a short, limited extension of the comment period to allow for a full and complete analysis for the Ashdown Mill to be performed and submitted to the Agency.

Domtar stated it understands the Agency will be reopening the comment period. The full report will be submitted during the reopened comment period. Domtar stated it appreciates EPA's accommodation of its request and believes the additional analysis will be very useful and informative in the Agency's review of the Mill's situation. In particular, Domtar stated the analysis will show that the purported visibility improvement for the Ashdown Mill is within the Mill specific margin of error for the CALPUFF model, and as such, visibility improvements cannot be reasonably anticipated to occur. *See* 42 U.S.C. §7491(g)(2); *Nat'l Parks Conservation Ass'n v. EPA*, No. 12-73710, 2015 WL 3559148 at *8 (9th Cir. June 9, 2015).

In the record supporting the proposed BART FIP for the Ashdown Mill, there is no demonstration by the Agency that the purported visibility improvements can be reasonably anticipated to occur as required by 42 U.S.C. § 7491(g)(2). As noted by the court in *Nat'l Parks Conservation Ass'n*, the Agency needs to show that the anticipated improvement from the imposition of BART is within the CALPUFF model's capability to measure and not in the model's margin of error. If the model cannot predict visibility gains that are capable of being measured by the CALPUFF model, then the Agency fails to show that visibility improvements can be reasonably anticipated – a crucial statutory prerequisite to proceeding with the BART FIP for the Ashdown Mill.

No analysis exists in the record of the model's margin of error with respect to the Ashdown Mill's alleged visibility improvement. Without such an analysis, there is no means of knowing if the predicted values are within the model's ability to predict or in the model's margin of error.

The Ashdown Mill will be submitting its full analysis showing that the purported visibility improvements associated with the proposed Ashdown Mill BART requirements are within the Mill specific margin of error for the CALPUFF model, and as such, there is no reasonably anticipated visibility improvement achieved by the imposition of BART on the Ashdown Mill. The report will be provided during the reopened comment period.

Response: We disagree with the commenter's characterization of the Ninth Circuit decision regarding the "margin of error" of the CALPUFF model. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF or the "margin of error". Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law. [797]

We discuss below in a separate response to comment in this section that the analysis performed by Trinity Consultants[798]that purports to calculate a "margin of error" of the CALPUFF modeling for the Arkansas BART sources (Domtar and Lake Catherine), is flawed for many reasons and fails to provide any assessment of the ability of the CALPUFF model to evaluate "the degree of visibility improvement that may be expected from available control technology" to inform BART and reasonable progress evaluations. Whether or not the modeled visibility impacts or benefits lie below this erroneous, calculated "margin of error" is immaterial to any assessment of whether or not the visibility impairment or benefits from controls can reasonably be anticipated to occur. The notion of a calculated "margin of error" is not part of any modeling guidance and has no legal or regulatory basis or applicability here. We disagree that we must undertake a "site-specific analytical analysis" for every application of the CALPUFF model to assess uncertainty in model results.

In response to the court's finding in *American Corn Growers Ass'n. v. EPA*[799] that we failed to provide an option for BART evaluations on an individual source-by-source basis, we had to identify the appropriate analytical tools to estimate single-source visibility impacts. The 2005 BART Guidelines recommended the use of CALPUFF for assessing visibility (secondary chemical impacts) but noted that CALPUFF's chemistry was fairly simple and the model has not been fully tested for secondary formation and thus is not fully approved for secondary-formed particulate. In the preamble of the final 2005 BART guidelines we identify CALPUFF as the best available tool for analyzing the visibility effects of individual sources, but we also recognized

[797] "Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances." Nat'l Parks Conservation Ass'n vs. EPA

[798] Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. – Lake Catherine Plant, available as Exhibit H to comments submitted by Entergy Arkansas, Inc.; "Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Domtar A. W. LLC, Ashdown Mill" Prepared by Trinity Consultants, August 2015

[799] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1 (D.C. Cir. 2002).

that it is a model that includes certain assumptions and uncertainties.[800] Evaluation of CALPUFF model performance for dispersion (no chemistry) to case studies using inert tracers has been performed.[801] It was concluded from these case studies the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300km.[802],[803]

In promulgating the 2005 BART guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF. There we respond:

> CALPUFF is the best modeling application available for predicting a single source's contribution to visibility impairment. It is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for some purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO2 and NOX. As explained above, simulating the effect of precursor pollutant emissions on PM2.5 concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. *We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.*

In the 2003 revisions to the Guideline on Air Quality Models, CALPUFF was added as an approved model for long –range transport of primary pollutants. At that time, we considered approving CALPUFF for assessing the impact from secondary pollutants but determined that it was not appropriate in the context of a PSD review because the impact results could be used as the sole determinant in denying a permit.[804] However, the use of CALPUFF in the context of the Regional Haze rule provides results that can be used in a relative manner and are only one factor in the overall BART determination. We determined the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[805]

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[800] 70 FR 39121

[801] "more recent series of comparisons has been completed for a new model, CALPUFF (Section A.3). Several of these field studies involved three-to-four hour releases of tracer gas sampled along arcs of receptors at distances greater than 50km downwind. In some cases, short-term concentration sampling was available, such that the transport of the tracer puff as it passed the arc could be monitored. Differences on the order of 10 to 20 degrees were found between the location of the simulated and observed center of mass of the tracer puff. Most of the simulated centerline concentration maxima along each arc were within a factor of two of those observed." 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models

[802] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.

[803] 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models

[804] 70 FR 39123

[805] 70 FR 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other

We also recognized the uncertainty in the CALPUFF modeling results when we made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[806] Examining the distribution of CALPUFF modeled visibility impacts, it can be seen that the few values at the extreme of the distribution are much higher than the rest of the values.[807] Therefore, in recognizing some of the limitations of the CALPUFF model, we determined that use of the maximum modeled impact may be overly conservative and recommended the use of the 98th percentile value.

We disagree with the commenter's general statement that there is an acknowledged over-prediction of the CALPUFF model or an acknowledged inaccuracy at low levels, and that the actual visibility impact from the BART sources are lower. The CALPUFF model can both under-predict and over-predict visibility impacts when compared to photochemical grid model. For example, the 2012 ENVIRON report on *Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other criteria pollutants and AQRVs* found that CALPUFF predicted highest 24-hr nitrate and sulfate concentrations lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[808] In a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010)[809] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model which has a much more rigorous treatment of photochemical reactions. As discussed above, model evaluations examining how the model captures the transport and diffusion of pollutants showed that the model performed in a reasonable manner for modelled distances less than 300km.[810] The selection of the 98th percentile value rather than the maximum value was made to address concerns that the maximum may be overly conservative.

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modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.'

[806] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121.

[807] See figures below for Lake Catherine and Domtar in our response to comments on the "Margin of Error" analysis

[808] Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.

[809] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder "Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements" Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11-15, 2010) can be found at http://www.cmascenter.org/conference/2010/agenda.cfm.

[810] 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models

The CALPUFF modeling following the BART guidelines and using the 98th percentile value does not lend itself to model performance evaluations of the type suggested by the commenters (see comments below concerning the "Margin of error" analysis), comparing measured visibility impairment at a specific time and place to modeled impairment at that same time and place to derive some "margin of error" in the modeled estimates. The BART modeling is a worst case assessment, utilizing maximum emissions[811], assumptions of background ammonia and ozone, and simplified chemistry, modeled over a period of three years.[812] The modeling also does not capture the effect of competition with other emission sources for the available ammonia. The goal of this modeling is to estimate the maximum anticipated impact from the source in the vicinity of a Class I area (typically an area on the order of several hundred square miles or more), and not to provide an estimate of downwind concentrations or visibility conditions for a specific place at a specific time.

CALPUFF uses a pseudo-first-order chemical reaction mechanism to model the conversion of SO2 to SO4 and NOx (NO + NO2) to NO3. We find the representation of key chemical conversions of precursors to PM2.5 in CALPUFF are appropriate for estimating a worst-case scenario for this particular source and region. We note that small changes in emission levels will not significantly perturb the available ammonia. Therefore, the relative difference between two scenarios with similar emissions will not be overly influenced by assumptions of background concentrations of ammonia.

The utility of the model used must be judged based on the available data, the known limitations or simplifications inherent to the model, and the purpose of the modeling or manner in which the model results are used in informing decisions. The use of the 98th percentile value and considering a minimum of three years of meteorological data within CALPUFF provides a snapshot of the worst case visibility impacts, simulating impacts (based on maximum emissions and assumed ammonia concentrations) on a day when modeled meteorological conditions are most conducive to formation and transport of visibility impairing pollutants to a receptor within a Class I area. While there is some uncertainty in the absolute visibility impacts and benefits due to the model and some of the simplifications and assumptions used in the BART guideline modeling approach, the relative level of impact is a reliable assessment of the degree of visibility impacts and benefit from controls. Any uncertainties in meteorological conditions that govern the transport and diffusion of pollutants are less important in comparing impacts between two control scenarios, since the same effects will be included in both the base and the control scenario model simulations. CALPUFF modeling will be better at predicting changes in visibility impairment due to the application of controls than at predicting the absolute visibility impacts. BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Modeling of control scenarios is used to estimate the amount that this visibility impact can be

[811] Page 39129 of BART Rule, "We believe the maximum 24hour modeled impact can be an appropriate measure in determining the degree of visibility improvement expected from BART reductions (or for BART applicability)"

[812] Pages 39107-3918 of BART Rule. For assessing the fifth factor, the degree of improvement in visibility from various BART control options, the States may run CALPUFF or another appropriate dispersion model to predict visibility impacts. Scenarios would be run for the pre-controlled and post-controlled emission rates for each of the BART control options under review. The maximum 24-hour emission rates would be modeled for a period of three or five years of meteorological data.

reduced due to a reduction in emissions. The modeling of these control scenarios is done in a manner that holds all variables constant except for the emissions of the pollutant of interest. A relative reduction in visibility impact due to a change in emissions is an indication that visibility benefits are reasonably anticipated to occur. The modeled magnitude of the visibility improvement is not a determinative factor in the BART determination, but only one factor and is considered on a relative basis to the baseline impact and the benefits of other controls. The relative visibility benefit of all controls is weighed along with the absolute and relative costs of controls, energy and non-air environmental impacts, any existing controls, and the remaining useful life of the source. As stated above, we are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.

CALPUFF visibility modeling, performed using the regulatory CALPUFF model version and following all applicable guidance and EPA/FLM recommendations, provides a consistent tool for comparison with the 0.5 dv subject-to-BART threshold. The CALPUFF model, as recommended in the BART guidelines, has been used for almost every single-source BART analysis in the country and has provided a consistent basis for assessing the degree of visibility benefit anticipated from controls as one of the factors under consideration in a five-factor BART analysis. Since almost all states have completed their BART analyses and have either approved SIPs or FIPs in place, there is a large set of available data on modeled visibility impacts and benefits, and how those model results were utilized to screen out sources and as part of the five-factor analysis in making BART control determinations for comparison with.

The commenter states that the largest visibility benefit from controlling a single EGU is 0.813 dv, an imperceptible amount. We address this comment elsewhere where we discuss that perceptibility is not a threshold criterion for considering improvements in visibility to be meaningful.

Comment: [Domtar Supplemental Comments (0170) p. 1] The Domtar Ashdown Mill stated that it is submitting supplemental comments on the EPA's proposed BART rules for the Ashdown Mill. The Ashdown Mill appreciates the EPA's willingness to reopen the comment period on the proposed BART requirements to allow the Ashdown Mill to complete its very detailed and comprehensive analysis of CALPUFF's model's "margin of error." Based on the report, the Ashdown Mill's proposed BART requirements will not result in any reasonably anticipated improvements in visibility and should be withdrawn. Without waiving any of our supplemental comments, should EPA proceed to finalize the proposed Ashdown Mill BART, we incorporate by reference the prior comments submitted on July 15, 2015, including the comments justifying an extension of the compliance period for five years.

In these supplemental comments, the Domtar Ashdown Mill is providing the following additional information:

(1) Margin of Error Analysis for the Ashdown Mill;
(2) reasonable progress; and
(3) other considerations.

Response: We acknowledge Domtar's supplemental comments. We address Domtar's July 15, 2015 comments elsewhere throughout this RTC document. We address the specific comments provided in Domtar's supplemental comments in the sections of the RTC document where we discuss modeling, cost, and reasonable progress analysis issues. The "margin of analysis" evaluation submitted by Domtar is addressed in response to comments below.

Comment: EPA improperly uses CALPUFF to justify emission reduction measures when the visibility improvements predicted by the CALPUFF model are within CALPUFF's margin of error. [The Associations (0165) p. 9-10] The Associations stated that in at least two instances, the proposed Arkansas federal implementation plan FIP imposes emission reduction measures through BART on the grounds that CALPUFF modeling showed that those measures would reduce visibility impairments, yet those improvements are within CALPUFF's margin of error. This means that EPA has no credible demonstration that there would be *any* visibility improvements attributable to those determinations.

BART requires that states (or EPA in the case of a federal implementation plan) consider "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). The Ninth Circuit, in *National Parks Conservation Association v. EPA*, Case No. 12-73710, 2015 WL 3559149 at *8 (9th Cir. June 9, 2015), held that an estimated visibility improvement of 0.085 deciviews was less than CALPUFF's margin of error, and thus, EPA had no basis to believe that BART controls in that case could "reasonably be anticipated" to improve visibility. In the proposed rule, EPA imposes emission reduction requirements under BART in situations where CALPUFF predicted very small visibility improvements without completing any site specific analyses to determine if these visibility improvements are within the margin of error. For example, EPA would require the installation of low NOX burners and overfire air at Flint Creek Unit 1 even though the *highest* modeled visibility improvement was 0.081 dv. Based on the site specific analysis that was completed for Montana in the Ninth Circuit decision for *National Parks and Conservation Association*, this very small visibility improvement may be less than the margin of error. EPA needs to justify that the small visibility improvement is "reasonably anticipated". The Clean Air Act does not require visibility improvements that cannot be reasonable anticipated. Visibility improvements that are less than the margin of error are not "reasonably anticipated" and found to be invalid by the Ninth Circuit in *National Parks Conservation Association*. 80 Fed. Reg. at 18,968. Visibility improvements at other Class I areas were a fraction of this: 0.026 deciviews at Upper Buffalo, 0.024 deciviews at Hercules-Glades, and 0.014 deciviews at Mingo.

Further, EPA's own guidelines establish that a threshold of 1.0 deciviews for when a stationary source "causes" visibility impairments at a Class I area and 0.5 deciview threshold of when a stationary source "contributes" to visibility impairments. 70 Fed. Reg. 39,161 (July 6, 2005). In other words, EPA is imposing costly emission reduction requirements on sources that, even if their emissions were much higher, would not even rise to the level of "contributing to" visibility impairments at the Arkansas Class I areas. EPA cannot rationally hold that emission reductions at these stationary sources would be "reasonably anticipated" to improve visibility at Class I areas when EPA's own modeling shows that they do not even contribute to visibility impairments.

Sensing that infinitesimal visibility improvements (tiny fractions of what the human eye may perceive) cannot justify the imposition of new emission controls, EPA adds these supposed improvements through a "Cumulative Visibility Improvement" metric. In this case, the purported visibility improvements are 0.145 deciviews – just over 1/10th of what a person may perceive. Justifying emission reductions on *cumulative* visibility improvements is arbitrary and capricious, even if the modeled visibility improvements could be believed. In this case, however, where each constituent modeled visibility improvement is below CALPUFF's margin of error, EPA can have no confidence that visibility will improve at any individual Class I area through new reduction measures. By adding modeled visibility improvements that should individually be treated as zero, EPA arbitrarily attempts to create something out of nothing (and even here the "something" is far below human perception). EPA should abide by the Ninth Circuit's decision and avoid basing BART determinations on modeled visibility improvements that are within the margin of error. This includes its attempt in this case to avoid the decision's holding by adding low confidence modeling results in order to artificially exaggerate the impact of emission reduction measures.

Response: The commenter is mistaken regarding the Ninth Circuit decision including the "margin of error" of the model. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF or the "margin of error". Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law. We respond to comments concerning the calculated "margin of error" of CALPUFF modeling in a separate response.

The BART guidelines establish that a visibility impacts from a stationary source of 1.0 deciviews or greater are considered "causing" visibility impairments at a Class I area and a 0.5 deciview impact as "contributing" to visibility impairments.[813] The commenter confuses visibility *impacts* with potential unit-level visibility *improvements* from controls. Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews, it would be inconsistent to automatically rule out additional controls where the improvement in visibility may be less than 1.0 deciview or even 0.5 deciviews. A visibility improvement greater than 0.5 dv, as the commenter suggests, is not a requirement of the BART determination because visibility improvements less than 0.5 dv may still be determined to be significant. Similarly, as discussed in depth in a separate response to comment above, we have not considered perceptibility as a threshold criterion for considering improvements in visibility.

We address comments concerning the use of cumulative visibility in a separate response to comment above.

Comment: Visibility improvement from controls on Lake Catherine Unit 4 cannot be reasonably anticipated due to the margin of error in the CALPUFF model. [Entergy Arkansas Inc. (0166) p.52-53] Entergy Arkansas Inc. stated that EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of

[813] 70 Fed. Reg. 39161

the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.
- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.
- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by

CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NO_X BART controls on Lake Catherine Unit 4.

[Exhibit H to EAI Comments, p. 6-1] Based on the analysis completed for the Entergy Lake Catherine Plant, the minimum calculated margin of error for CALPUFF for the Lake Catherine Plant is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART for Lake Catherine at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART cannot be reasonably anticipated, as is required by the Clean Air Act. (42 U.S.C. 7491(g)(2).

Comment: Domtar's Margin of Error Analysis demonstrates that the predicted visibility improvement from EPA's proposed BART controls for Power Boiler 2 fall within the CALPUFF model's margin of error. [Domtar Supplemental Comments (0170) p. 1-2] Domtar stated that as demonstrated in the Trinity Consultants report enclosed with Domtar's comments, the predicted visibility improvements associated with the imposition of the proposed BART requirements for Power Boiler 2 at the Ashdown Mill fall within the CALPUFF model's margin of error. The CALPUFF model's predicted visibility gains are mere artifacts of the model and do not show that any real world improvements in visibility will occur. Since these visibility improvements cannot be "reasonably anticipated," the proposed BART requirements for Power Boiler #2 should be withdrawn. *See Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002).

As highlighted in *Nat'l Parks Conservation Ass'n v. EPA*, No. 12-73710, 2015 WL 3559149 (9th Cir. June 9, 2015), it is essential that EPA demonstrate that any BART requirements result in visibility improvements that can be reasonably anticipated. *See* 42 U.S.C. § 7491(g)(2). This showing is even more important in situations, such as the proposed BART requirements for the Ashdown Mill, where the annual cost of meeting the proposed rule is projected to be in the millions and threatens the competitive position of the Ashdown Mill. The enclosed report by Trinity Consultants demonstrates that EPA cannot show any "reasonably anticipated" improvements in visibility will result, and as such, this fundamental predicate to the imposition of BART on the Ashdown Mill is lacking. [See "Evaluation of the CALPUFF Modeling System Margin of Error For a BART Analysis- Domtar A.W. LLC, Ashdown Mill," prepared by Trinity Consultants, dated August 2015.]

[Domtar Supplemental Comments, Attachment p. 7-1] Based on the analysis completed for the Domtar Ashdown Mill, the minimum calculated margin of error for CALPUFF for the Ashdown Mill is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for the Ashdown Mill Power Boiler No. 2 at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these

Class I areas associated with the proposed BART requirements cannot be reasonably anticipated, as is required by the Clean Air Act.27 As such, it is not appropriate for EPA to require controls on the unit based on the CALPUFF model's predicted visibility impacts.

Response: The commenters mischaracterize the Ninth Circuit decision regarding the "margin of error" of the model. The commenter suggests that the Court agreed that the anticipated visibility benefits in that case were within the margin of error of the model. This is incorrect. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF. Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law.[814] Here and elsewhere in our response to comments we address a very similar comment with respect to CALPUFF modeling for Arkansas sources, as well as the commenter's analysis claiming to estimate the "margin of error".

The Trinity analysis[815] purports to calculate a "margin of error" of the CALPUFF modeling for Lake Catherine. In general, the commenter's analysis adds CALPUFF model results for a specific source or sources with CAMx model results and compares this value to visibility conditions derived from monitored data at each Class I area. This analysis is flawed for many reasons as discussed in detail below and fails to provide any assessment of the ability of the CALPUFF model to evaluate the "degree of visibility improvement that may be expected from available control technology" to inform BART and reasonable progress evaluations. We note that the commenter did not provide any spreadsheets or detailed calculations to support this analysis, therefore we were unable to fully review and respond to the individual calculations or specific methodology underlying the presented values in the commenter's summary report. We therefore focus our comments on the general methodology described in the report.

CALPUFF modeling following the BART Guideline approach is used to provide estimates of the maximum visibility impacts from a source based on maximum emissions and simplified chemistry, irrespective of the relationship to the 20% worst days. The CALPUFF visibility analysis performed for each of the sources in this action modeled a period of three years and utilized a constant emission rate (equal to the maximum 24-hr emissions for baseline and estimated control-level emissions), assumptions of constant background ammonia, and simplified, limited chemistry. Modeling of a three year period allows for consideration of climatological worst case conditions. The goal of this modeling is to estimate the maximum anticipated impact from the source, and not to provide an estimate of downwind concentrations or visibility conditions for a specific place at a specific time.

In promulgating the BART guidelines we made the decision in the final BART Guideline to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value as proposed. We made the decision to consider the less

[814] "Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances." Nat'l Parks Conservation Ass'n vs. EPA

[815] Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. – Lake Catherine Plant, available as Exhibit H to comments submitted by Entergy Arkansas, Inc.

conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[816] As a starting point, a BART-eligible source is identified as subject-to-BART and subjected to a five-factor BART analysis only if it may reasonably be anticipated to cause or contribute to any impairment of visibility based on the baseline CALPUFF modeling following the protocol and using the inputs discussed above. The assessment of anticipated visibility benefits due to controls is then done in a relative sense following the same modeling procedure and comparing the modeled impact from baseline emissions to the reduced modeled impact of the various control scenarios. This visibility analysis is only one factor of the BART determination and is used to weigh the visibility benefits of controls in consideration of costs and incremental costs of controls, other environmental impacts of controls, remaining useful life of the source, and the existing control equipment at the source.

Our CALPUFF visibility modeling, performed using the regulatory CALPUFF model version and following all applicable guidance and EPA/FLM recommendations, showed significant visibility impacts due to the source and benefits from controls. The CALPUFF model, as recommended in the BART guidelines, has been used in almost every single-source BART visibility impact analysis in the country and has provided a consistent basis for determining if a source is anticipated to "cause" or "contribute" to visibility impairment at a Class I area and in assessing the degree of visibility benefit anticipated from controls as one of the factors under consideration in a 5-factor BART analysis. CALPUFF modeling, following the BART modeling protocol, has also been used to evaluate the visibility benefit of controls in a number of reasonable progress analyses.

Inappropriately combines model results from two different models

The commenter's analysis asserts that adding a "background" light extinction value derived from the 2002 CENRAP CAMx photochemical model results for the 20% worst days to the CALPUFF model results accounts for the impact of all other emissions sources and allows for a "like-kind comparison" with the monitored values. The commenter is incorrect because the CALPUFF modeling following the BART guidelines is designed to provide a maximum, worst case value. The CALPUFF modeling utilized a constant emission rate based on the maximum actual 24-hr emissions during the baseline period. In addition, the CALPUFF modeling used a constant background ammonia value of 3 ppb, and a limited, simplified chemistry mechanism. Meteorological data is based on an initial wind field based on prognostic data from the MM5 model which is then adjusted based on terrain and land use data and then further adjusted based on observational data. A model such as CALPUFF essentially holds constant a number of factors in order to isolate the impacts of a single source. It is extremely difficult in observational analyses to sufficiently control for all factors, including emissions from other sources, to be able to isolate the impacts of a single facility.

[816] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121.

Simply adding a background value does not address many of the issues that cause the comparison to not be a "like-kind" comparison. We discuss below why the CAMx "background" value does not properly represent the impact from all other emission sources for the purposes of the commenters comparison. In addition, the use of this "background" value does not address or adjust for the maximum constant emissions and background ammonia assumptions used in the CALPUFF model, nor does it address the issue of considering the competition for available ammonia that other emission sources represent. As discussed by the commenter, CALPUFF is a "clean background analysis" because it only models emissions from one source. Therefore all of the ammonia present in the model is available to react to the emissions from this one source. In a "dirty background analysis" emissions from all sources interact and compete for available ammonia in forming particulate matter. This limits the amount of ammonia available to react with the emissions from the source of interest to form visibility impairing particulate matter.

CAMx photochemical modeling using actual or typical emissions (which includes all emissions sources and has a more realistic representation of formation, transport, and removal processes of particulate matter that causes visibility degradation) provides an estimate of downwind concentrations paired in space and time. The CENRAP 2002 CAMx modeling utilized actual available emissions data, including hourly measured emissions data from EGUs and prognostic meteorological data from the MM5 model that went through extensive meteorological model performance analysis.[817] Ammonia concentrations are calculated based on emissions, transport, deposition, and chemistry. It is not appropriate to simply add predicted concentrations or visibility impacts from two very different models that rely on different model inputs (emissions and meteorological data), utilize different chemistry, and are used for different purposes. Furthermore, because the CENRAP CAMx modeling already contains emissions from the BART sources, simply adding the two model estimates results in a double counting of the impact from these sources. As we discuss in more detail below, it is unclear if or how there was an attempt to adjust this "background" value to avoid double counting in this manner.

Fails to consider uncertainty in "background" value

The commenter's analysis fails to consider any uncertainty in the CAMx derived "background" value that is added to the CALPUFF modeled visibility impact. As demonstrated below, the "margin of error" calculated by the commenter is dominated by the under-prediction in the CAMx derived "background" value. The CENRAP 2002 CAMx model results the commenter uses to estimate the "background" were compared to monitored values and a thorough model performance analysis was performed by CENRAP to assess the model's ability to estimate visibility conditions at the Class I areas.[818] In reviewing the 2008 Arkansas Regional Haze SIP, we reviewed the CENRAP model selection and performance of the CAMx and CMAQ modeling performed.[819] In that review we summarized the CENRAP model performance evaluation the

[817] See CENRAP TSD at section 1.3.9 and Appendix A
[818] See the CENRAP TSD
[819] See Appendix A to the TSD, Review of Modeling and Emission Inventory Development for the Regional Haze Implementation Plan for the State of Arkansas available at: http://www.regulations.gov/#!documentDetail;D=EPA-R06-OAR-2008-0727-0013

2002 CENRAP modeling for Caney Creek and Upper Buffalo on the days that comprise the 20% worst days as defined by the monitor:

> On most of the worst 20 % days at Caney Creek, total extinction is dominated by sulfate extinction with some extinction due to OMC. On four of the worst 20% days, extinction is dominated by nitrate. Sulfate is underestimated and results in an under-prediction (-33% bias) on total extinction. There is an overestimate of extinction (+44% bias) on the 20% best days due to an over-prediction of NO3. For Upper Buffalo, the worst 20% days are dominated by sulfate extinction, however two of these worst days are dominated by nitrate. Sulfate and OMC under-prediction results in an under-prediction (-40%) on total extinction. Overall performance is good on the 20% best days at Upper Buffalo, however there are large over-predictions of nitrate on some days.

The model performance evaluation performed by CENRAP found that total extinction at both Arkansas Class I areas was under-predicted by the model. Therefore, the "background" value added by the commenter has uncertainty associated with it that it alone can explain any difference between modeled and measured values evaluated by the commenter. In other words, it is impossible to discern from the commenter's evaluation whether any of the difference calculated between monitored and measured values are due to over or under performance of the CALPUFF modeled values.

As we noted earlier, the commenter did not provide any supporting spreadsheets or datasets, so we are unable to review the individual calculations or specific methodology underlying the presented values in the commenter's summary report. The commenter did not provide the "background" values that were added as part of the analysis. From the submitted reports, it is unclear for Lake Catherine if any adjustment was made to address double counting from the BART source(s). The Domtar analysis discusses subtracting out impacts from the BART sources, but does not discuss how this was done or provide any additional information to determine the values that were used. The CENRAP CAMx source apportionment modeling does not provide any source-specific impact information that could be subtracted from the CENRAP modeling.

For the Lake Catherine analysis, the report states the following concerning background value used:

> In order to obtain an estimate of the impact of other emission sources (i.e., point, non-point, mobile, biogenic, etc.), Entergy obtained a background value from CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.[820] The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenarios and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

[820] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool - CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

For the Domtar analysis, the report states the following concerning background value used:

> In order to estimate the impact of other emission sources (i.e., point, non-point, mobile, etc.), Domtar obtained a background value from the CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.15 The CENRAP PSAT tool is determined by subtracting contribution of all BART source (for scenario 1) or contribution of the Ashdown Mill (for scenario 2 and 3) from the total CENRAP predicted concentrations. The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenario runs performed using 2002 meteorological data and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

The Domtar analysis provided CALPUFF modeled and observed data points for the Pre-BART scenario[821] in some of the figures included in that report. We reviewed the 2002 Lake Catherine baseline modeling that was prepared for the BART analysis and downloaded the observed data for 2002 for Caney Creek and Upper Buffalo.[822] From this data we attempted to back calculate the "background" values used by the commenter in their analysis.[823] We estimate that the "background" values that were added to the CALPPUFF model results are approximately 133.9 Mm-1 for Caney Creek and 124.7 Mm-1 for Upper Buffalo. We compared these to the 2002 CAMx model results from the CAMx PSAT tool. The value used for Caney Creek appears consistent with the projected 20% worst days value of 133.93 Mm-1, but the value used for Upper Buffalo is not consistent with the projected 20% worst days value of 131.79 Mm-1 from the CENRAP CAMx modeling. From the available data, we are unable to determine from where the value used for the Upper Buffalo "background" was derived. As best we can conclude, the "background" values represent the 2002 CAMx projections of the total visibility impairment from all sources. Any adjustments to those values were not documented in the submitted comments.

This "background" value derived from the CENRAP CAMx photochemical modeling constitutes the majority of the modeled value (CALPUFF modeled impact plus "background") that is being compared to the monitored value. For example, the table below summarizes the modeled and observed values that were used in the Domtar analysis for Caney Creek. The calculated "margin of error" is dominated by the difference between the observed values and the CAMx modeled visibility impairment due to all sources. As discussed above, the model performance of the CENRAP 2002 CAMx modeling is well understood and it was demonstrated that this CAMx model scenario underestimates visibility impairment by 30-40% at these two Class I areas. The commenter's analysis shows this under-prediction.

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[821] See Figures 5-1 through 5-6, "Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Domtar A. W. LLC, Ashdown Mill" Prepared by Trinity Consultants, August 2015

[822] 2002 monitor data was obtained from the WRAP Technical Support System website at: http://vista.cira.colostate.edu/tss/

[823] See "EPA calcs RTC margin of error.xlsx" in the docket for this action

Following the commenter's methodology, even if the CALPUFF modeled values were increased by a factor of ten, the commenter's estimated "margin of error" of the model would not change significantly. The table below summarizes the change in margin of error due to a ten-fold increase in the CALPUFF modeled values. For example, for the "modeled vs. measured" scenario the margin of error changes by only 4% due to a ten-fold increase in the CALPUFF modeled values. This clearly demonstrates the disconnect between the commenter's estimated "margin of error" and any assessment of the CALPUFF model's ability to estimate visibility impairment from a source. Furthermore, because of the under-prediction in the "background" value, increasing the CALPUFF modeled value tenfold actually results in a slight improvement in what the commenters asserts is an indication of model performance by decreasing the calculated "margin of error" for two of the comparisons. For the "modeled vs. measured" scenario the margin of error decreases from -29.02 Mm-1 to 27.9 Mm-1 when the CALPUFF modeled values are increased by a factor of ten. We explain further below the over-prediction seen on the measured vs. modeled comparison.

Domtar impacts on Caney Creek. Modeled and observed values and estimated "margin of error"

Domtar Pre-BART Scenario	Observed	CALPUFF modeled	CAMx derived "background"	"Margin of Error"		
				Modeled minus Observed	10xCALPUFF Modeled minus Observed	Change in Margin of error due to ten-fold increase in CALPUFF results
Modeled vs. Measured	163.05	0.124	133.9	-29.02	-27.9	-4%
Measured vs. Modeled	70.23	1.137	133.9	64.81	75.05	16%
Modeled & Measured	163.05	1.137	133.9	-28.01	-17.77	-37%

Considered Scenarios

The commenter's comparison includes consideration of three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Because the commenters did not submit any spreadsheets or supporting data, it is not clear how CALPUFF results for all BART sources were combined for the first scenario. It is unclear how

the inclusion of all BART sources would provide useful information on the uncertainty of modeling the impact from a single source. The second scenario still suffers from all the issues discussed above concerning the uncertainty in the selected "background" concentration and the combining of CAMx and CALPUFF results. The third scenario, modeling post-control emissions, attempts to compare monitored visibility conditions in 2002 to a future scenario that would only result from the installation of additional controls. As such this scenario would not provide any useful information on the ability of the model to reproduce past visibility conditions. The commenter provides no explanation to support the selection of these scenarios or why analysis of any one scenario would be preferable to the other.

Flaws with the Modeled Versus Measured Visibility comparison

The commenter calculates the difference between the modeled values (the commenter calculated average CALPUFF impact summed with the CAMx derived "background" concentration for the 20% worst days) and the monitored values during 2002 at Caney Creek and Upper Buffalo for the three scenarios described above. Specifically, the commenter made the following comparisons:

- Modeled vs Measured W20 Days: The 20% Worst days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.
- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.
- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

We note that for all comparisons and calculated difference between modeled and monitored values, as discussed above, the 2002 CENRAP CAMx modeled concentrations for the 20% worst days were added to the CALPUFF model results before comparison to the monitored values. The observational data used in the comparison is from the IMPROVE network monitors at the Class I areas. These monitors only take measurements every third day, so the data set is limited to approximately 120 days of measurements over 2002. We also note that the strength of the CALPUFF model for BART and RP analysis is to predict the highest values (8th High value) that would occur sometime during a 3 year period at a Class I area and not to model specific values tied to specific time and location.

The first comparison looks at the 20% worst days (24 highest days) measured at the monitor and the corresponding CALPUFF modeled impact on that day. We discuss above the goal of the CALPUFF modeling for the BART analysis is to estimate the maximum anticipated impact from the source (based on constant maximum emissions, constant background ammonia, and simplified chemistry) at a Class I area that is typically at least several hundred square miles, and not to provide an estimate of downwind concentrations or visibility conditions for a specific place and at a specific time. Nevertheless, the commenter attempts to do just that by examining

the specific modeled values on those days with measured high visibility impairment during 2002. As can be seen by the CALPUFF model results used for this comparison,[824] the Domtar and Lake Catherine facilities do not have large modeled impacts during the 20% worst days at the monitor. In fact for many of these days, there is no visibility impairment due to these sources as the transport patterns on these days do not carry emissions from these sources to the Class I area. As discussed elsewhere, the days that CALPUFF model maximum or 98th percentile value impacts of the facility occur may not coincide with any of the days that make up the days in the worst 20% days at the Class I area. As such, this comparison provides little value in assessing the CALPUFF model's ability to estimate the maximum visibility impairment or assessing the benefit of controls in reducing this impact.

The second comparison looks at the 20% highest modeled days, only looking at the subset of days with corresponding measurements. While the monitored data corresponds to the days with the highest CALPUFF modeled values, the "background" value derived from the CAMx modeling corresponds to the 20% worst days as defined by the monitor. This "background" value represents the average visibility impairment over the worst 20% days (as defined by the monitor) due to the visibility impact from all sources. This mismatch between the set of days in the observations and the set of days estimated in the photochemical modeling "background" results in a "background" value that is much higher than the observational data set, and an overall over-prediction in the comparison. As can be seen in the table above, the "background" value is almost twice the observed visibility impairment and results in a large calculated difference in modeled versus observed values in the commenter's analysis.

The third comparison looks to compare the set of days with the highest monitored visibility impairment with the set of days with the highest modeled visibility impairment. As discussed above, in general, the visibility impairment on the highest (worst) monitored days is due to sources other than the Domtar or Lake Catherine facilities. Those days with high CALPUFF modeled impacts are a different set of days that have different meteorological/transport conditions that are conducive to the chemistry and transport needed to cause visibility impacts from Domtar or Lake Catherine to occur at the Class I area. Therefore, in addition to the problems discussed throughout this response, this comparisons does not provide for a "like-kind" comparison as it attempts to compare observations that occur under one set of meteorological conditions to a set of days with completely different overall meteorological conditions.

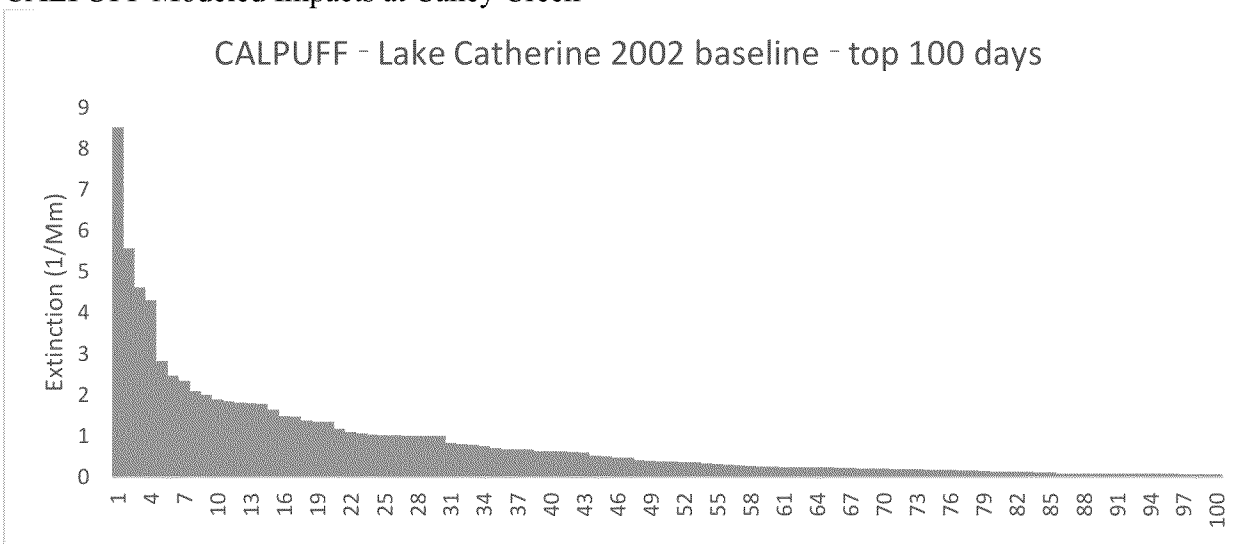
Gives undue weight to values at extreme tail of distribution of CALPUFF model results

As discussed above, the BART guidelines recommend the use of the 98th percentile value as to not give undue weight to the extreme tail of the distribution of modeled values. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile. The commenter's analysis utilizes those values at the extreme end of the distribution that can significantly impact their calculated average of the 20% worst days, despite EPA guidance recommending not to use those extreme values because they may be overly conservative (high). For example, the 100 highest modeled days for 2002 baseline visibility impacts at Caney Creek from Lake Catherine and Domtar Power

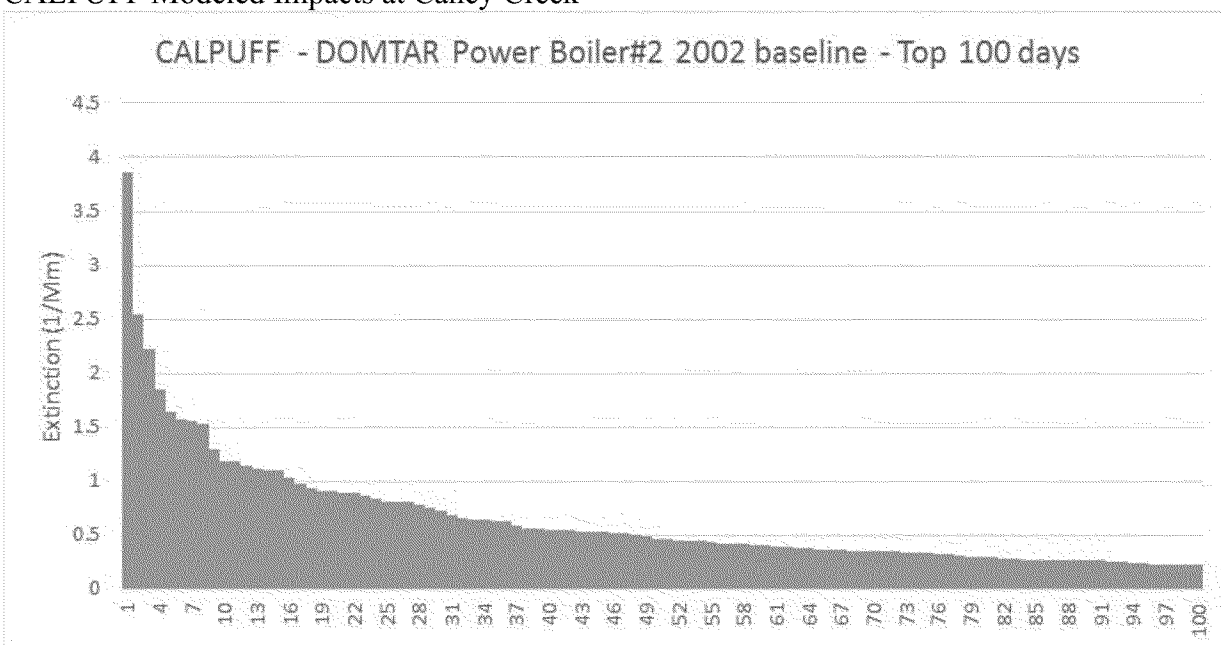
[824] See Figures 4-1 and 4-4 of the Margin of Error Analysis for Lake Catherine and Figures 5-1 and 5-4 of the Margin of Error Analysis for Domtar.

Boiler #2 are shown in the figures below. It can be seen that the few values at the extreme of the distribution are much higher than the rest of the values. Any averaging across a set of days of CALPUFF values, whether averaging the 20% worst days as defined by the monitor or by the model, that includes some of the values at the extreme end of the distribution (within the top 7 days) would be shifted towards possibly being overly conservative. For example, one of the comparisons made by the commenter included the average over the 24 highest CALPUFF modeled impacts. This average value included values for the seven highest modeled impacts in the average despite EPA recommendations to avoid these values at the extreme end of the distribution because they may be overly conservative.

CALPUFF Modeled Impacts at Caney Creek



CALPUFF Modeled Impacts at Caney Creek



Model Performance Evaluation

Finally, even if the commenter's comparison of observed versus modeled values were appropriate and free from all of the flaws detailed above, the analysis performed does not constitute a proper model performance evaluation. Visibility impairment is calculated based on the summation of extinction due to each visibility impairing pollutant. The concentration of each visibility impairing pollutant is either measured or obtained from the model estimates. These concentrations are then used to calculate the total visibility impairment based on the light absorbing or scattering characteristic of each pollutant specie and adjustment for relative humidity. As we discuss in our modeling guidance, the individual components of the total visibility impairing particulate matter should be evaluated individually. Good performance for total visibility impairment does not indicate if the model performed well for "the right reasons" or the right mix of components.[825,826] This type of evaluation should be comprised of statistical assessments of modeled versus observed data. Model performance can best be assessed using extensive data bases, such as those obtained in major field studies with many monitors and more intensive monitoring. In the commenter's analysis, the comparisons are limited to only 24 data points. Limitations in the available monitored data (observational data is only available for every third day at one monitor) further limits the amount of available data used in the commenter's analysis for certain comparisons. Section 3.2.1 of the draft modeling guidance[827] provides a description of recommended metrics to be used in this type of evaluation. As we discuss in this guidance, it is important to include multiple statistical measures in any operational evaluation to fully characterize model performance. At a minimum, we recommend evaluating: Mean obs, Mean Model, Mean Bias, Mean Error and/or Root Mean Square Error, Normalized Mean Bias and/or Fractional Bias, Normalized Mean Error and/or Fractional Error, and the correlation coefficient. In addition to these metrics, graphical displays of data allow for a fuller characterization of model performance. Therefore, plots play a key role in any model performance evaluation. Our guidance details a number of different plots that should be evaluated including scatter plots, bugle plots, and soccer plots. The commenter's analysis does not provide an adequate analysis of the available data and improperly focuses on the total visibility impairment rather than the individual visibility impairing components.

Conclusion

In conclusion, the commenter's assessment of the "margin of error" of the model suffers from a number of fatal flaws and does not provide any useful evaluation of CALPUFF's ability or utility in screening sources that contribute to visibility impairment and "the degree of visibility improvement that may be expected from available control technology" as part of a BART visibility analysis to inform a BART determination. Whether or not the modeled visibility impacts or benefits lie below this calculated "margin of error" is immaterial to any assessment of whether or not the visibility impairment or benefits from controls can reasonably be anticipated

[825] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze (2007)
[826] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze (2014)
[827] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze (2014)

to occur. BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Modeling of control scenarios is used to estimate the amount that this visibility impact can be reduced due to a reduction in emissions. The modeling of these control scenarios is done in a manner that holds all variables constant except for the emissions of the pollutant of interest. A relative reduction in visibility impact due to a change in emissions is an indication that visibility benefits are reasonably anticipated to occur. The modeled magnitude of the visibility improvement is not the determinative factor in the BART determination, but only one factor and is considered on a relative basis to the baseline impact and the benefits of other controls. The relative visibility benefit of all controls is weighed along with the absolute and relative costs of controls, energy and non-air environmental impacts, any existing controls, and the remaining useful life of the source. As discussed elsewhere, we are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.

Comment: Case study comparisons of CALPUFF modeled values to measured values
As part of the submitted "Margin of Error for a BART Analysis" reports prepared for the Domtar and Lake Catherine facilities,[828] the commenters include a discussion of work performed by TRC Environmental Corporation. This work includes a June 2012 paper prepared by Gale Hoffnagle that discusses several case studies that compared CALPUFF modeled values to measured values from the IMPROVE monitoring network.[829] The commenter's state that PPL Montana relied on this study in its successful challenge to the Montana FIP, for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[830] This 2012 Hoffnagle analysis is also referred to in comments from Nucor Steel-Arkansas and Nucor-Yamato Steel.

Response: We respond to comments concerning each separate case study below. As we discuss above, the commenter mischaracterizes the Court's finding in the Montana Case.

Comment: Mohave Generation Station

CALPUFF modeling completed for the Mohave Generating Station (Mohave Station) showed that the 1,590 megawatt (Mw) coal-fired power plant was causing visibility impacts of 2.31 dv at the Grand Canyon National Park. The plant was permanently shut down in 2005. A review of monitored visibility at IMPROVE stations as close as 90 km to the plant showed no change in either nitrate concentrations or visibility impacts subsequent to the closure of the plant. The measured visibility impairment at the Grand Canyon National Park during the three years prior to (2003-2005) and subsequent to the permanent shutdown (2006-2008) of the Mohave Station

[828] "Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Domtar A. W. LLC, Ashdown Mill" Prepared by Trinity Consultants, August 2015 and "Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Entergy Arkansas, Inc., Lake Catherine Plant" Prepared by Trinity Consultants, August 2015
[829] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.
[830] National Parks Conservation Ass'n v. EPA, 788 F.3d 1134, 1146-47 (9th Cir. 2015)

were analyzed.[18] Based on a review of data from three (3) IMPROVE monitoring sites, summarized in Table 5-1 below, the changes in visibility were not statistically significant.

Table 5-1. Mohave Visibility Impairment – Before and After

IMPROVE Monitor	2003-2005 (dv)	2006-2008 (dv)	Difference (dv)
Meadview	8.24	8.23	0
Indian Gardens	8.92	8.86	0.1
Hance Camp	6.54	6.61	-0.14

While the actual change at the nearest monitor between pre- and post-shutdown of the Mohave Station, Meadview, was zero dv, the CALPUFF results indicated that visibility impairment caused by the Mohave Station was twice the level detectable by the human eye.[19] The maximum CALPUFF predicted visibility impairment was 3.94 dv over 3 years, with a 98th percentile visibility impairment of 2.31 dv from the Mohave Station. Based on the IMPROVE monitoring data, CALPUFF highly overestimated the visibility impairment attributable to the Mohave Station. In reality, the Mohave Station had essentially no impact on the visibility impairment at the Grand Canyon National Park as documented by the change in monitoring values pre- and post-shutdown.

[18] Jonathan Terhorst and Mark Berkman, *Effect of Coal-fired Power Generation on Visibility in a Nearby National Park*, Atmospheric Environment 44, 2010.

[19] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012

Response: The study by Terhorst and Berkman does not convince us that use of CALPUFF modeling is inappropriate or that the modeled visibility impacts and benefits should not be considered as one of the factors in a BART analysis. The findings of Terhorst and Berkman that are summarized and cited to here have been rebutted in the same journal, disputing the author's representation of their findings.[831] In their rebuttal, the authors state that Terhorst and Berkman's data analysis actually validate EPA's interpretation of the data and clearly establish the impact of the Mohave Station emissions on visual air quality in the Grand Canyon. The authors also warn of the "sensational characterizations" of Terhorst and Berkman, and that such "careless claims invite mischievous citation in regulatory contexts." The commenter does not address or acknowledge the findings of this rebuttal.

As also noted by the authors in their rebuttal, the comparison above of CALPUFF modeled visibility impairment from the Mohave station to measured visibility impairment over time, is an improper comparison of deciview values. The CALPUFF modeled impairment is based on a natural background approach, where the measured change in deciview impairment is a change relative to the degraded or dirty background conditions. As we discuss elsewhere, the deciview

[831] White, W.H., Farber, R.J., et al. Comment on "Effect of coal-fired power generation on visibility in a nearby National Park (Terhorst and Berkman, 2010)" Atmospheric Environment 55, 2012.

is a logarithmic function of extinction and the different deciview calculations are not directly comparable. Had the CALPUFF values been adjusted to account for the degraded background conditions, the modeled impairment would be calculated as much smaller. Furthermore, the CALPUFF modeled impairment is the maximum (or 98th percentile) impairment from the source and it would be incorrect to attempt to compare that to a long-term average of observed visibility conditions. In addition, a model such as CALPUFF essentially holds constant a number of factors in order to isolate the impacts of a single source. As acknowledged by Terhorst and Berkman, it is extremely difficult in observational analyses to sufficiently control for all factors, including emissions from other sources, to be able to isolate the impacts of the closure of a facility.

Comment: Craig Station

The Craig Station is located approximately 90 km west of the Mt. Zirkel Wilderness Area (Mt. Zirkel) in northwestern Colorado. A study was completed during the development of the Colorado Regional Haze SIP to compare CALPUFF predicted impacts for the Craig Station to IMPROVE data at Mt. Zirkel.[14] Modeled impacts for the Craig Station on the highest 25 days were compared against IMPROVE data, which includes impacts from all other sources (e.g., other point sources, area sources, mobile sources, etc.). The results showed that the modeled impacts from the Craig Station exceeded the monitored values on 14 out of 19 days, and in some instances by a significant amount. Given that the IMPROVE data reflects the cumulative impact of all sources, both within Colorado and outside of the state, the magnitude of the CALPUFF model over-prediction is severe. Although there is another large power plant located between the Craig Station and Mt. Zirkel, the modeled impacts from the Craig Station alone were larger than the monitored values for all sources combined, which further highlights the degree of over prediction. The modeled values were on average ten times the IMPROVE monitored values (i.e., 9.56 Mm-1).[15]

[14] Gale Hoffnagle, Evaluation of Craig Bart Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.
[15] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

Response: As we discuss above, the CALPUFF modeling following the BART guidelines approach is used to estimate the maximum visibility impact from the source, modeling maximum emissions using simplified chemistry and an assumption of constant background ammonia over a period of three years. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative (high), EPA decided to use the less conservative 98th percentile. The goal of this modeling is to estimate the maximum anticipated impact from the source, and not to provide an estimate of downwind concentrations or visibility conditions for a specific place at a specific time.

EPA has recognized that the CALPUFF model can be conservative in estimating visibility impairment, and therefore, EPA has used the 98th percentile model results instead of the maximum modeled visibility impairment to address the possibility of model over-predictions. We have also recognized the model's sensitivity to background ammonia concentrations,

particularly in the arid regions of the Western United States where ambient ammonia concentrations can be low. In development of the Colorado BART modeling protocol[832], the Colorado Department of Public Health and Environment investigated the sensitivity of CALPUFF modeling for the northwestern portion of the state (where Craig station and Mt. Zirkel are located) and determined that "while there is a moderate drop in impacts when ammonia is dropped from 10 ppb to 1.0 ppb, the model is very sensitive to ammonia when the background ammonia level is less than 1.0 ppb."

The background ammonia concentration input into CALPUFF is constant in space and time. As discussed in the IWAQM Phase 2 Report:

> A further complication is that the formation of particulate nitrate is dependent on the ambient concentration of ammonia, which preferentially reacts with sulfate. The ambient ammonia concentration is an input to the model. Accurate specification of this parameter is critical to the accurate estimation of particulate nitrate concentrations. Based on a review of available data, Langford et al. (1992) suggest that typical (within a factor of 2) background values of ammonia are: 10 ppb for grasslands, 0.5 ppb for forest, and 1 ppb for arid lands at 20 C. Langford et al. (1992) provide strong evidence that background levels of ammonia show strong dependence with ambient temperature (variations of a factor of 3 or 4) and a strong dependence on the soil pH. However, given all the uncertainties in ammonia data, IWAQM recommends use of the background levels provided above, unless specific data are available for the modeling domain that would discredit the values cited.

Accordingly, Colorado selected a background ammonia value of 1.0 ppb based on available information and the IWAQM recommendations for their BART modeling. This represented a worst case assumption for the available ammonia in that area. We note that for CALPUFF modeling for sources in Arkansas, the selected background ammonia value utilized in our analysis and agreed upon by CENRAP in developing their BART modeling protocol is 3 ppb. For some areas of Arkansas, this may be an underrepresentation of the ammonia levels due to the numerous sources of ammonia emissions in the state, such as poultry and livestock operations. Therefore, the sensitivity of model results to the background ammonia assumption is much less for CALPUFF modeling of Arkansas sources. Estimated impacts from sulfate emissions are less impacted by the simplified chemistry and ammonia assumptions used in the BART modeling than nitrate impacts.

Comparison of observed visibility versus modeled impacts

In evaluating the total visibility impacts, Hoffnagle concludes that the results showed that the modeled impacts from the Craig Station alone exceeded the monitored values on 14 out of 19 days. However the values used in the comparison do not represent the impact from the source alone as claimed in the report and Hoffnagle's conclusion is incorrect. Hoffnagle compares the total impact, which includes an estimate of background visibility, rather than the impact from the source alone, to the measured impairment. As can be seen in the second table below, the estimated background value (input into the CALPUFF modeling to provide a background level

[832] Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling (DRAFT) April 15, 2010 (revised June 25, 2010 and August 19, 2010)

for the deciview impact calculation) adds an extinction of approximately 12.2 Mm-1 on top of the modeled visibility impact from the source. This is a significant level of extinction, particularly for a relatively clean Class I area with an average visibility condition of approximately 20 Mm-1 (average over 2001-2003). When this estimated background extinction is eliminated from the comparison, the measured visibility impairment on 15 of the 19 evaluated days is larger than the extinction from this source alone, contrary to the claims of Hoffnagle. If the analysis is limited to those specific days where appreciable visibility impairment is measured (impairment greater than the 12.2 Mm-1 natural background level) the average modeled visibility impairment is less than half the average observed impairment due to particulates. The table below shows the IMPROVE monitor data for Mt. Zirkel,[833] the model data used in Hoffnagle's analysis,[834] and our calculation of the extinction due to Craig Station when the approximate background value is subtracted.

Observed Visibility Conditions at Mt. Zirkel compared to Modeled impacts from Craig Station

day	monitor			Modeled			
	Dv	Total extinction	Particle extinction	Total impact	Total modeled extinction	Background	Estimated extinction from source
4	4.200	15.22	7.22	4.5	15.68	12.20	3.48
22	1.275	11.36	3.36	5	16.49	12.20	4.29
46	7.300	20.75	12.75	4.6	15.84	12.20	3.64
61	4.213	15.24	7.24	4.2	15.22	12.20	3.02
364	5.092	16.64	8.64	5.1	16.65	12.20	4.45
32	3.507	14.2	6.2	6.7	19.54	12.20	7.34
143	3.271	13.87	5.87	4.6	15.84	12.20	3.64
287	3.365	14	6	4.7	16.00	12.20	3.80
305	8.368	23.09	15.09	5.1	16.65	12.20	4.45
332	-0.704	9.32	1.32	5.2	16.82	12.20	4.62
335	3.228	13.81	5.81	5	16.49	12.20	4.29
341	4.656	15.93	7.93	4.8	16.16	12.20	3.96
42	2.445	12.77	4.77	4.6	15.84	12.20	3.64
57	6.355	18.88	10.88	6.7	19.54	12.20	7.34
141	5.429	17.21	9.21	4.8	16.16	12.20	3.96
177	6.549	19.25	11.25	4.6	15.84	12.20	3.64
249	6.647	19.44	11.44	4.3	15.37	12.20	3.17
345	4.543	15.75	7.75	4.5	15.68	12.20	3.48
351	0.266	10.27	2.27	4.8	16.16	12.20	3.96

Nitrate Over-prediction

[833] Data obtained from WRAP TSS website: http://vista.cira.colostate.edu/tss/

[834] Data estimated from Figure 3 and 4 of Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

We have reviewed the data presented in the 2010 and 2012 reports and have determined that the reported over-prediction of nitrate of 9.56 Mm-1 was also arrived at in error and is greatly overstated. The commenter did not provide any supporting data for these reports, but the initial comparison discussed in the 2010 report refers to the 2005 BART analysis developed by the Colorado Department of Public Health and Environment.[835] Figure 25 of this analysis lists the 25 highest days of modeled visibility impact for 2002 including the day, receptor, total deciviews, background deciviews, delta deciviews due to the source and the % Nitrate contributing to the impairment (as shown in the table below). Hoffnagle compares this data to monitored data using the same methodology as he did for the updated model data discussed later in the 2010 report and discussed in the 2012 report. Based on the modeling data from the 2005 CDPHE analysis, we have calculated the total modeled extinction due to emissions from Craig Station is approximately 5 Mm^{-1} for the highest modeled value and 3.76 Mm^{-1} for the 8th high. However, Hoofnagle calculates that the extinction from nitrate alone is between 10 Mm^{-1} and 14 Mm^{-1} over the 25 highest modeled days[836], 2 to 3 times higher than the actual maximum modeled extinction due to all pollutants. Hoffnagle incorrectly calculated the total extinction and nitrate extinction based on the delta deciview value rather than calculating the difference in extinction between the total and background extinction. As we discuss elsewhere, the deciview is a logarithmic function of extinction, therefore the change in extinction that results in a certain delta deciview is dependent on where on the deciview scale you are. A delta deciview of 2 dv in near pristine conditions would be a much smaller change in extinction than a delta deciview of 2 dv in degraded conditions. Using the correct methodology, the modeled nitrate extinction from the source on the highest modeled impact day is 4.327 Mm-1 and 3.191 on the 8th highest modeled day. While the average monitored nitrate extinction value over all monitored days during 2001-2003 is approximately 1.23 Mm^{-1}, the maximum observed nitrate extinction value does exceed 6 Mm^{-1} in 2002[837] and exceeds 3 Mm^{-1} on 18 monitored days during 2001-2003 (greater than 5% of all monitored days). Recognizing the assumptions in the modeling that result in evaluating a worst case scenario, the sensitivity to background ammonia levels, and that available monitored data is limited to one measurement every three days, we consider these results to be reasonable. If actual ammonia levels during these particular days where conditions were conducive to transporting the plume to the Class I area were lower, we would anticipate less nitrate formation than modeled using the assumed 1ppb.

[835] BART CALPUFF Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis For Tri-State Generation & Transmission Association Craig Station Units 1 and 2 (Revised) March 3, 2006

[836] See Figure 4 of EXHIBIT 7: G. Hoffnagle, TRC Environmental Corporation, Evaluation of Craig BART Modeling for Regional Haze Analysis to Tri-State Generation and Transmission Association, Inc.'s Detailed Comments to EPA Proposed Rule Published at 77 Fed. Reg. 18052 to 18098 Submitted May 25, 2012; available in the docket for this action.

[837] See Figure 4 of EXHIBIT 7: G. Hoffnagle, TRC Environmental Corporation, Evaluation of Craig BART Modeling for Regional Haze Analysis to Tri-State Generation and Transmission Association, Inc.'s Detailed Comments to EPA Proposed Rule Published at 77 Fed. Reg. 18052 to 18098 Submitted May 25, 2012; available in the docket for this action.

Modeled Total Impacts and Impacts due to nitrate from Craig Station

Year [1]	Day[1]	Receptor [1]	DV (Total) [1]	DV (BKG) [1]	Delta DV[1]	%_NO3 [1]	Total extinction [2]	BKG extinction [2]	Extinction due to source[2]	Nitrate extinction due to source[2]
2002	359	2948	5.463	1.974	3.489	85.07	17.269	12.182	5.086	4.327
2002	38	2880	5.175	1.996	3.179	84.68	16.778	12.209	4.569	3.869
2002	335	3075	4.907	1.974	2.932	89.78	16.335	12.182	4.152	3.728
2002	34	3075	4.894	1.996	2.898	84.88	16.313	12.209	4.104	3.484
2002	332	2880	4.84	1.974	2.866	86.83	16.226	12.182	4.043	3.511
2002	30	2855	4.749	1.996	2.753	85.03	16.079	12.209	3.869	3.290
2002	293	2949	4.653	1.93	2.723	79.15	15.925	12.129	3.796	3.005
2002	118	3021	4.663	1.974	2.689	84.89	15.941	12.182	3.759	3.191
2002	145	2852	4.457	1.996	2.461	83.72	15.616	12.209	3.407	2.852
2002	124	2855	4.32	1.996	2.324	87.48	15.403	12.209	3.194	2.794
2002	344	3011	4.285	1.974	2.311	89.05	15.350	12.182	3.167	2.820
2002	360	2868	4.242	1.974	2.268	87.81	15.284	12.182	3.101	2.723
2002	298	3075	4.092	1.93	2.162	86.24	15.056	12.129	2.927	2.525
2002	341	3075	4.075	1.974	2.101	89.47	15.031	12.182	2.848	2.548
2002	84	3075	4.042	1.952	2.09	86.58	14.981	12.156	2.825	2.446
2002	12	2868	4.05	1.996	2.054	87.69	14.993	12.209	2.784	2.441
2002	325	2868	4.016	1.974	2.041	87.59	14.942	12.182	2.760	2.417
2002	137	2855	4.013	1.996	2.017	86.75	14.938	12.209	2.729	2.367
2002	326	2915	3.976	1.974	2.002	89.47	14.882	12.182	2.700	2.416
2002	255	3011	3.94	1.952	1.988	87.74	14.829	12.156	2.673	2.346
2002	85	2852	3.91	1.952	1.958	84.85	14.785	12.156	2.629	2.231
2002	292	2855	3.878	1.93	1.948	77.8	14.737	12.129	2.609	2.029
2002	51	2852	3.94	1.996	1.944	89.7	14.829	12.209	2.620	2.350
2002	297	3032	3.832	1.93	1.901	83.26	14.670	12.129	2.541	2.116
2002	302	2915	3.83	1.93	1.9	85.65	14.667	12.129	2.538	2.174

[1]Data obtained from Figure 25 of BART CALPUFF Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis For Tri-State Generation & Transmission Association Craig Station Units 1 and 2 (Revised) March 3, 2006

[2]Values calculated by EPA using the relationship extinction = 10*exp(dv/10)

Additional considerations

In addition, another factor to consider in evaluating the difference between the modeled and monitored results is that the CALPUFF model estimates visibility impacts at discrete receptors located throughout the Class I area and returns the maximum modeled value for each day regardless of location while the monitor (located south of the Class I area) only measures visibility conditions at this one site. Given the North to South orientation of the Class I area, the complex terrain and that Craig Station is located to the west of the Class I area, it is likely that for many of the days analyzed the emission plume from the source was carried towards a portion of the Class I area north of the monitor's location so that the maximum modeled impact from the source could be significant, while conditions at the monitor location would be much cleaner. Hoffnagle acknowledges this possibility but does not limit his analysis to days where the modeled maximum is near the monitor location, and simply states that on some days the receptor with the maximum modeled impact is near the monitor location. As discussed elsewhere, the analysis utilizes those values at the extreme end of the distribution that can significantly impact

the analysis examining a small number of days, despite EPA guidance recommending not to use those extreme values because they may be overly conservative (high). The analysis of modeling at Craig station does not consider the impact of including these extreme values in their analysis. Furthermore, model performance compared to measurements at one fixed site under a specific set of conditions, does not invalidate the model for all applications and conditions.

Comment: North Dakota SIP

In the development of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDH) relie d on photochemical modeling conducted by the Western Regional Air Partnership (WRAP) to determine the impact of sources located outside of the state, as well as non-utility sources in North Dakota.[22] CALPUFF was utilized to determine the impacts of utility sources within the state; however, NDDH utilized alternate options in the CALPUFF model to address known areas of inaccuracy. The specific areas where they deviated from the EPA BART prescribed approach include:

- Consideration of boundary conditions based on CMAQ modeling, rather than ignoring the impact of sources outside of the domain as is done in the EPA approach;
- Puff splitting;
- Diffusion coefficients based on actual measurements of turbulence rather than the 1952 Pasquill-Gifford diffusion confidentsrequired by the EPA approach;
- Meteorological data from the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model; and
- Use of hourly average ammonia concentrations instead of an annual average value.

The resulting CALPUFF values were then compared to IMPROVE monitoring data from the South Unit at Theodore Roosevelt National Park, as summarized in Table 6-2 below.[23]

A review of extinction values showed that the average difference between measured and modeled extinction was 0.37 Mm^{-1} with a standard deviation of 12.6 Mm^{-1}.[24] EPA rejected NDDH's modeling on the basis that it included impacts from other sources rather than evaluating the impairment due to BART sources against the natural background visibility impairment ("dirty" background analysis vs. "clean" background analysis). EPA did not specifically comment on the accuracy of NDDH's CALPUFF modeling. Even with the revisions to the modeling methodology applied by NDDH, the margin of error was still 0.39 dv on average.[25]

Table 6-2. NDDH Measured versus Modeled Nitrate Concentrations

Theodore Roosevelt South Unit	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)

98th Percentile	2.03	2.06
90th Percentile	1.21	1.21
Average of 20% Worst Days	1.42	1.41
Annual Average	0.53	0.53

[20] Gale Hoffnagle, Evaluation of Craig BART Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.
[21] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.
[22] North Dakota State Implementation Plan, February 24, 2010.
[23] North Dakota State Implementation Plan, Chapter 8, February 24, 2010.
[24] These statistics are based on the exclusion of January 26, 2002 which was an outlier.
[25] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

Response: The commenter states that EPA did not comment on the accuracy of the hybrid modeling developed by North Dakota. Because the modeling approach, including impacts from other sources and consideration of visibility impacts using a degraded or "dirty" background were inconsistent with the modeling approach necessary to assess single-source visibility impacts, whether or not the model performed well in predicting the overall visibility conditions was irrelevant. We note that Appendix W outlines specific criteria for the use of alternate models and it does not appear that those criteria have been satisfied for the use of North Dakota's hybrid modeling. Summarizing model results at one Class I area is not sufficient to demonstrate model performance. Furthermore, the commenter does not include model results for the other Class I area that is included in North Dakota's modeling, Lostwood, where the hybrid modeling does not compare as favorably to the observed results or the WRAP CMAQ modeling. In conclusion, the commenter does not provide sufficient data to determine model performance of the hybrid modeling or support any of the non-default modeling options employed in CALPUFF. We discuss more specific comments concerning puff splitting in a separate response to comments.

We also disagree with the use of the Ammonia Limit Method (ALM) in North Dakota's modeling and note that it is inconsistent with the nitrate repartitioning approach that has been previously accepted by the FLMs and EPA. There is a lack of documentation, adequate technical justification, and validation for the development and use of the ALM. We and the FLMs have previously reviewed protocols proposing using ALM and we and/or the FLMs have not approved the use of the proposed ALM procedure. In general terms, one of the key issues is ALM is a method to have emissions from other sources consume ammonia, so there is less ammonia to react with the source of interest being modeled. Since ammonia levels from the local area were used by North Dakota, to do calculations in the modeling to consume ammonia from surrounding sources would unnaturally consume ammonia that was actually monitored in the North Dakota area modeled. The ALM has not been approved by EPA and the FLMs through interagency workgroups (IWAQM or FLAG) as an approved part of CALPUFF based visibility analyses. The commenter has not provided any adequate justification, documentation, or other analyses to justify the proposed use of ALM.

Comment: Colstrip

TRC (Gale Hoffnagle) conducted an analysis of measured versus modeled visibility impacts for the Colstrip Generating Station (Colstrip Station) located in eastern Montana, which is partially owned and operated by PPL Montana, LLC. TRC specifically completed comparisons for the worst 20% measured days and worst 20% modeled days (where a corresponding measurement was available). TRC found CALPUFF significantly over predicted the visibility impacts from the Colstrip Station, as impacts from this source alone were frequently higher than the monitored values, which include all other sources (e.g., point, area, mobile etc.) as well as the Colstrip Station. Modeled nitrate extinction from the Colstrip Station alone was higher than the monitored values on 11 out of 22 of the worst 20% modeled days at the Theodore Roosevelt IMPROVE monitoring site. At the UL Bend Wilderness Area IMPROVE monitor, modeled nitrate extinction from the Colstrip Station exceeded the monitored values on 11 out of 28 of the worst 20% modeled days. At the North Absaroka IMPROVE site, the impact from the Colstrip Station was over predicted on 9 out of 20 days of the worst 20% modeled days. At the Yellowstone IMPROVE site there are 10 days when the modeled extinction from the Colstrip Station exceeded the monitored values for the worst 20% modeled days.

Based on this analysis, PPL Montana, LLC, the operator and partial owner, challenged EPA's BART rules, in part, on the basis that the maximum predicted visibility improvement for Colstrip Units 1 and 2 was below the range of perceptibility and falls within the model's margin of error, "meaning that such improvement cannot be reasonably anticipated as required by the Act."[26] The U.S. Court of Appeals for the Ninth Circuit upheld PPL Montana LLC's position stating that "the issue is not the perceptibility of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye. EPA simply offered no response to this objection."

Response: As discussed elsewhere, the commenters misrepresents the Ninth Circuit decision regarding the "margin of error" of the model. The commenter suggests that the Court agreed that the anticipated visibility benefits in that case were within the margin of error of the model. This is incorrect. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF. Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law. [838]

The commenter did not provide the modeling data to allow for a complete review of this analysis. It is very likely that this analysis suffers from the same calculation errors noted above for the Craig Station/Mt. Zirkel analysis (also performed by TRC) that resulted in a calculated "modeled nitrate extinction" value much higher than the actual model estimated value. In the

[838] "Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances." Nat'l Parks Conservation Ass'n vs. EPA

case of the Craig Station analysis, the incorrectly calculated nitrate extinction was 2 to 3 times larger than the total extinction estimated by the model. The commenter's comparison between modeled and observed nitrate would be significantly impacted by this error as correcting for this error would result in much smaller modeled nitrate extinction values for comparison with the monitored values.

Furthermore, as discussed elsewhere, the analysis examining the 20% worst modeled days utilizes those values at the extreme end of the distribution that can significantly impact the analysis examining only a small number of days, despite EPA guidance recommending not to use those extreme values because they may be overly conservative (high). The analysis of modeling at Colstrip station does not consider the impact of including these extreme values in their analysis.

The CALPUFF modeling following the BART guidelines and using the 98th percentile value does not lend itself to model performance evaluations of the type suggested by the commenters, comparing measured visibility impairment at a specific time and place to modeled impairment at that same time and place (see additional discussion in response to comments on the "margin of error" analysis submitted by commenters). The BART modeling is a worst case assessment, utilizing maximum emissions[839], assumptions of background ammonia and ozone, and simplified chemistry, modeled over a period of three years.[840] The modeling also does not capture the effect of competition with other emission sources for the available ammonia. The goal of this modeling is to estimate the maximum anticipated impact from the source in the vicinity of a Class I area (typically an area on the order of several hundred square miles or more), and not to provide an estimate of downwind concentrations or visibility conditions for a specific place at a specific time. BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Modeling of control scenarios is used to estimate the amount that this visibility impact can be reduced due to a reduction in emissions. The modeling of these control scenarios is done in a manner that holds all variables constant except for the emissions of the pollutant of interest. A relative reduction in visibility impact due to a change in emissions is an indication that visibility benefits are reasonably anticipated to occur.

Comment:

In 1998, the Interagency Workgroup on Air Quality Modeling (IWAQM) conducted a study using tracers to test the ability of CALPUFF to match measured concentrations.[9] The study specifically involved non-reacting tracers and focused on the model's ability to predict plume location and concentration rather than accuracy of the model chemistry. Table 3-1 below summarizes the results of the IWAQM study.

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[839] Page 39129 of BART Rule, "We believe the maximum 24hour modeled impact can be an appropriate measure in determining the degree of visibility improvement expected from BART reductions (or for BART applicability)"

[840] Pages 39107-3918 of BART Rule. For assessing the fifth factor, the degree of improvement in visibility from various BART control options, the States may run CALPUFF or another appropriate dispersion model to predict visibility impacts. Scenarios would be run for the pre-controlled and post-controlled emission rates for each of the BART control options under review. The maximum 24-hour emission rates would be modeled for a period of three or five years of meteorological data.

Experiment	Distance (km)	Error in Model Results	
		Angle of Error (degrees)	Concentration Error
Savannah River	~100	25	140%
Idaho Falls	48	40	200%
	90	40	200%
Great Plains	100	5-20	250%
	600	25	-300%

Based on the results shown above, IWAQM concluded that CALPUFF could be used to predict concentrations at distances of "200 kilometers or less" from the source and that "transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved."[10] Despite this, EPA's BART guidelines fails to address the uncertainties in the modeling predictions at greater than 200 km and requires sources to add on expensive controls based on small impacts predicted by CALPUFF at distances in excess of 200 km. The Ashdown Mill is located approximately 250 km from Upper Buffalo. Due to the large distance from the source, the predicted visibility improvements at Upper Buffalo for the proposed BART controls on Power Boiler No. 2 should be used with caution since EPA did not consider the uncertainties in the modeling predictions.

[9] EPA-454/R-98-019, December 1998

[10] EPA-454/R-98-019, December 1998

Response: The commenter claims that our action requires controls based on small impacts predicted by CALPUFF at distances in excess of 200 km. We disagree with the commenter. EPA concluded from the evaluation of the IWAQM phase 2 report case studies that the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300km.[841],[842] Domtar Ashdown Mills is within 300km of Upper Buffalo. Our BART determination was based on consideration of the five-factors, including the anticipated visibility benefit due to controls at all impacted Class I areas. The BART visibility analysis for Domtar includes assessment of visibility impacts and benefits at Caney Creek as well, which is less than 100 km from the source. Visibility impacts and anticipated benefits from controls are much larger at this nearby class I area than at Upper Buffalo.

7.e. Reasonable Progress Analysis for Entergy Independence

[841] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.

[842] 68 FR 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models

Comment: Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc, Independence Plant [Exhibit C to EAI Comments]. Entergy contracted with Trinity Consultants to perform regional haze modeling using CAMx and PSAT based on the modeling originally developed for CENRAP. This modeling was performed to assess the proposed control options for Independence units 1 and 2, as well as White Bluff units 1 and 2. In addition to the baseline scenario modeling, the FIP scenario (proposed controls in EPA's FIP) and Entergy's proposed control approach consisting of installed LNB/SOFA on Independence, and the cessation of coal combustion at White Bluff were modeled. The CENRAP 2018 emission inventory as developed for the Texas and Oklahoma regional haze FIP was utilized. 2002 NEI data was substituted for the BART units, with the exception of the Entergy units that were revised based on information from Entergy (see table below).

Unit	Uncontrolled Baseline (tpy)		Entergy's Proposal		Arkansas FIP	
	NOx	SO2	NOx	SO2	NOx	SO2
IND E 1	6313	14258	3150	12154	3619	1357
IND E 2	6516	15407	3347	13162	3167	1521
WB 1	7580	15939	---	---	4145	1453
WB 2	8145	16034	---	---	4060	1476
LC 4	1228	3.26	564	3.26	564	3.26

Source apportionment was used on the baseline modeling scenario to assess the individual source contributions to visibility impairment.

Response: Results from Entergy's CAMx modeling analysis are discussed below in response to more specific comments.

We note that it is unclear how the above modeled baseline emissions for the Entergy units were derived. The table below shows recent actual annual emission levels and emissions during the baseline period of 2000-2004. Baseline modeled impacts for the subject to BART White Bluff facility would be larger had the modeling utilized historic baseline emissions rather than emissions closer to the more recent actual emissions. We also note that the commenter mentions additional adjustments to stack locations and stack parameters in the modeling inputs but did not provide any documentation on these adjustments in their modeling report.

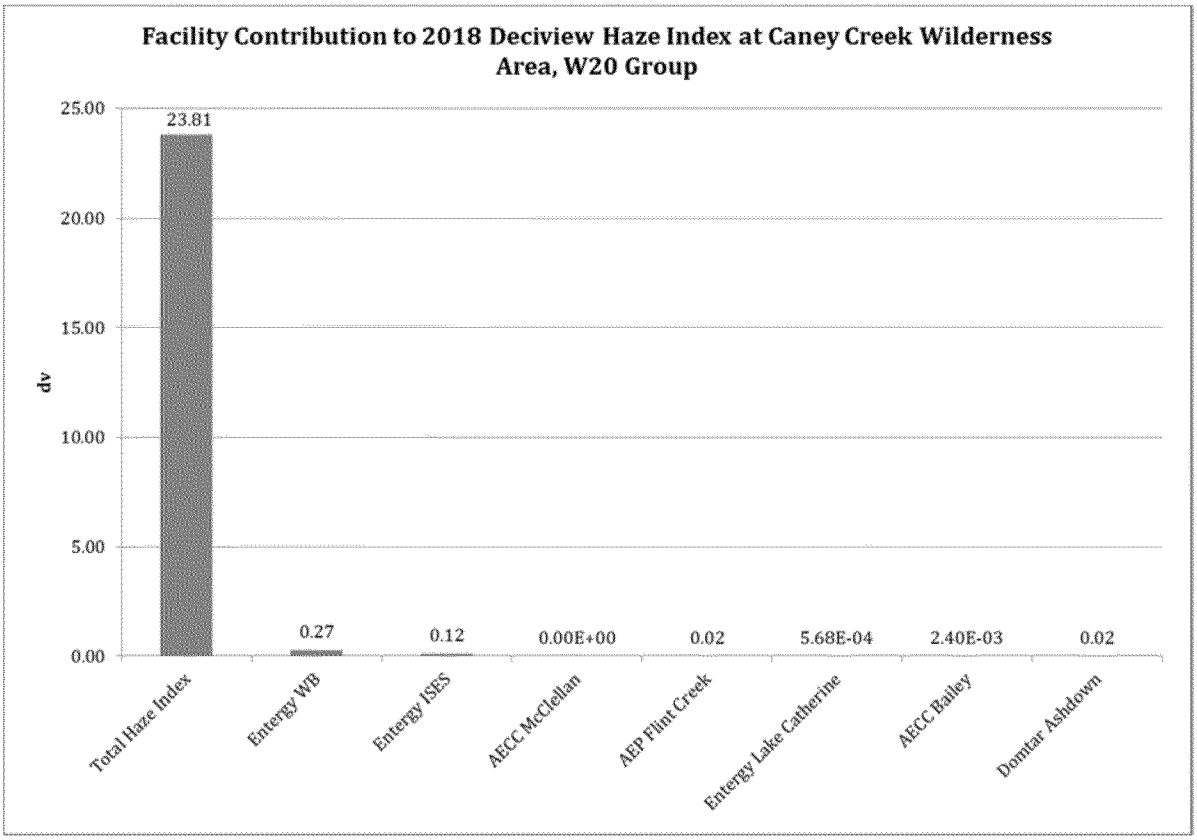
Unit	Average annual emissions 2010-2014 (tpy)		Average annual emissions 2010-2014 excluding max and min (tpy)		Average emissions 2000-2004 (tpy)	
	NO_x	SO_2	NO_x	SO_2	NO_x	SO_2
IND E 1	6181	14785	6109	15037	7385	11225
IND E 2	6242	15401	6243	15502	8974	11819
WB 1	8134	16183	8147	16132	10509	20069
WB 2	8267	15868	8396	16614	8812	18519
LC 4	441	1.04	378	0.90	1165	2.94

Comment: Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis visibility benefit toward reasonable progress. [Entergy Arkansas Inc. (0166) p. 32-34] Entergy Arkansas Inc. stated that EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id.* The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id.* The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

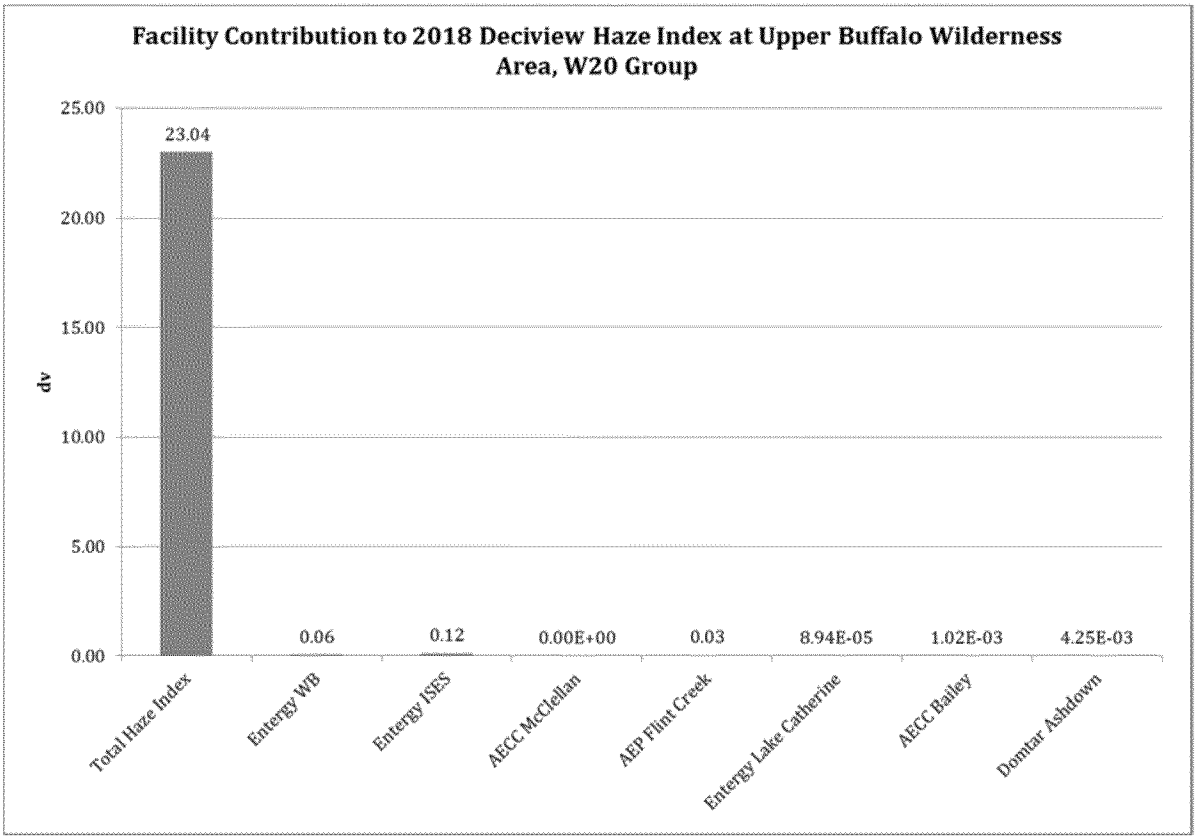
Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures below for Caney Creek and Upper Buffalo.[843] This reflects only one half of one percent of the

[843] Figures assume no FIP controls on any of the Arkansas sources. Also, the total haze index values

visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO2 and NOx controls at Independence are warranted.



presented in the figures are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days.



Response: We disagree with the commenter's assertion that the contribution to visibility impairment from Entergy Independence is "insignificant" or "minimal." For example, as the commenter states, the CENRAP source apportionment data shows that sulfate from Arkansas point sources are projected to be responsible for 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo in 2018. As we discuss in our proposal, based on 2011 NEI data the Entergy Independence Plant is the second largest source of both SO_2 and NOx point source emissions in Arkansas, accounting for approximately 36% of the SO_2 point-source emissions and 21% of the point source NOx emissions in the State.[844] Therefore, a significant portion of the total visibility impairment on the 20% worst days, on the order of 1% or more, can be expected to be attributable to SO_2 emissions from a single facility, the Independence facility. As we discuss in more detail elsewhere, given their contribution to visibility impairment on the 20% worst days, we consider both SO_2 and NO_X to be key pollutants contributing to visibility impairment at Arkansas' Class I areas. Our CALPUFF modeling evaluating the baseline 98th percentile impacts confirmed that the Independence facility was estimated to impact visibility at levels much larger than the level considered to "cause" visibility impairment (greater than 1 dv) at nearby Class I areas, ranging from 2.512 dv at Caney Creek, to 1.859 dv at Mingo. CALPUFF modeling also showed that anticipated visibility benefits from SO_2 and NO_X controls at the facility exceeded 1 dv at each of the four impacted Class I areas. Although we recognize that Independence is not a subject to BART source, for comparison purposes we note that the

[844] 80 FR 18991

threshold used for visibility impacts to determine whether facilities are subject to BART is 0.5 dv.[845]

We disagree with the commenter that the CAMx modeling submitted by the commenter confirms that contributions to visibility impairment from the Independence facility are insignificant. When properly assessed, as detailed below, the commenter's CAMx modeling supports and reinforces our finding that visibility impairment from Entergy Independence is significant and emission reductions will result in meaningful visibility benefits towards the goal of natural visibility conditions. Entergy's CAMx modeling shows a visibility impact of 0.12 dv at both Caney Creek and Upper Buffalo when compared to 2018 "dirty" or "degraded" background conditions. The commenter then calculates that this 0.12 dv impact is 0.5% of the total 23 dv visibility impairment. As discussed below, the deciview scale is a logarithmic function of extinction, and therefore the calculations by the commenter are incorrect because they are based on deciview values and must be performed based on light extinction to properly calculate the percent contribution to visibility impairment. Spreadsheets submitted by the commenter presents the light extinction attributable to each source (in inverse megameters) based on the results of their CAMx source apportionment modeling and calculates the percent contribution to total visibility impairment at each Class I area.[846] The table below summarizes these results for Entergy White Bluff and Independence.

Entergy Arkansas' 2018 CAMx Modeling Percent Contribution to Total Visibility Impairment on the 20% worst days (calculated using Mm^{-1})

Unit	Caney Creek	Upper Buffalo
Independence Unit 1	0.611%	0.618%
Independence Unit 2	0.706%	0.687%
White Bluff Unit 1	1.489%	0.327%
White Bluff Unit 2	1.455%	0.302%

As can be seen in the table above, the commenter is incorrect in their statement that the impact from the Independence facility is one half of one percent and is in fact, based on their own modeling and calculation, approximately 1.3% of the total visibility impairment at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion

[845] "As a general matter, any threshold that you use for determining whether a source ''contributes'' to visibility impairment should not be higher than 0.5 deciviews." BART Guidelines, App. Y to 40 CFR 51

[846] See "Entergy Scenario 01 Contribution 2015-1124_FINAL.xlsx", "Avg_Impacts" tab, column "AA" for Caney Creek and Upper Buffalo Class I areas.

(approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. The CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined.

Furthermore, the deciview visibility impacts for individual sources should be assessed based on natural "clean" background visibility conditions. The deciview improvement based on the 2018 background conditions provides an estimate of the amount of benefit that can be anticipated in 2018 and the impact a control/emission reduction may have on the established RPG for 2018. However, this estimate based on degraded or "dirty" background conditions underestimates the visibility improvement that would be realized for the control options under consideration.

The source impacts and the potential benefits of controls must be considered relative to a light extinction level that represents a clean/natural background, rather than the current visibility conditions or projected visibility conditions at the end of the planning period.[847]

The need for consideration of visibility impacts and benefits relative to clean/natural conditions was explained in the preamble to the final BART Guidelines:[848]

> Using existing conditions as the baseline for single source visibility impact determinations would create the following paradox: the dirtier the existing air, the less likely it would be that any control is required. This is true because of the nonlinear nature of visibility impairment. In other words, as a Class I area becomes more polluted, any individual source's contribution to changes in impairment becomes geometrically less. Therefore the more polluted the Class I area would become, the less control would seem to be needed from an individual source. … Such a reading would render the visibility provisions meaningless, as EPA and the States would be prevented from assuring "reasonable progress" and fulfilling the statutorily-defined goals of the visibility program. Conversely, measuring improvement against clean conditions would ensure reasonable progress toward those clean conditions.

The same logic applies to the evaluation of visibility impacts and benefits for sources examined for controls for reasonable progress. Accordingly, the EPA has used clean background conditions in evaluating the benefits of controls on individual reasonable progress sources and has

[847] This recommended approach to the treatment of background air quality when quantifying source impacts and potential benefits from additional measures is different than the approach to background air quality when projecting how all emission reductions measures combined will determine visibility conditions at the end of the implementation period, i.e., how background assumptions relate to the RPGs. It is not appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall deciview index value as of the end of the implementation period, i.e., the degree by which the RPGs would differ with and without the control being included in the LTS. The RPGs are values that will be compared in a progress report to actual visibility conditions, and accordingly must represent the expected actual overall visibility conditions. Estimates of source impacts and measure benefits have a different purpose, which is to help guide decisions on the control of individual sources.

[848] 70 FR 39124, July 6, 2005

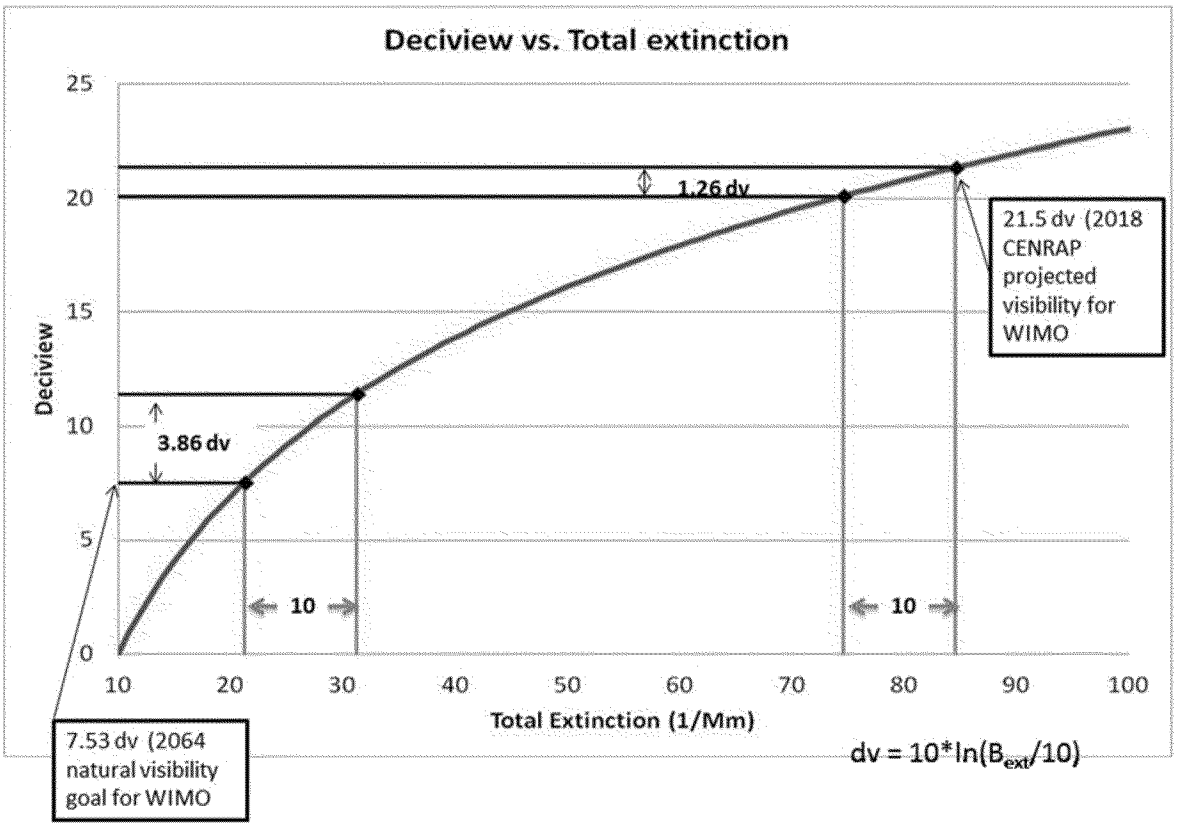
disapproved reasonable progress decisions by states that relied on modeling employing dirty background conditions.[849] This approach has been upheld by the Eighth Circuit.[850]

Because of the logarithmic deciview scale, the use of dirty background conditions will result in much lower values for deciview impacts than when using natural background. The figure below shows that an increment in light extinction of 10 MM^{-1} causes a deciview scale increment of only 1.26 dv when the light extinction increment is assumed to be a "on top of" a degraded extinction level of 75 MM^{-1} from all other sources. However, if the same light extinction increment is assumed to be "on top of" the natural light extinction value for this Class I area, the deciview scale increment is 3.86 dv. In this example, the 'clean background' situation yields a del-dv improvement 3 times greater than the 'dirty background' for the same level of extinction improvement.

[849] The EPA has followed this logic in the ND (77 FR 20894, April 6, 2012), MT (77 FR 57864, September 18, 2012), AZ (79 FR 52420, September 3, 2014), and TX (81 FR 296, January 5, 2016) FIPs and partial disapprovals of ND (77 FR 20894, April 6, 2012) and TX (81 FR 296, January 5, 2016).

[850] North Dakota v. EPA, 730 F.3d 750, 764-766 (8th Cir. 2013). "Although the State was free to employ its own visibility model and to consider visibility improvement in its reasonable progress determinations, it was not free to do so in a manner that was inconsistent with the CAA. Because the goal of § 169A is to attain natural visibility conditions in mandatory Class I Federal areas, see 42 U.S.C. § 7491(a)(1), and EPA has demonstrated that the visibility model used by the State would serve instead to maintain current degraded conditions, we cannot say that EPA acted in a manner that was arbitrary, capricious, or an abuse of discretion by disapproving the State's reasonable progress determination based upon its cumulative source visibility modeling."

Illustration of the different "delta deciview" values, depending on whether projected conditions or natural background conditions are used as the starting point. ("WIMO" means the Wichita Mountains Class I area. "Mm" means megameters.)



Because of the non-linear nature of the deciview metric, as a Class I area becomes more polluted the visibility impairment from an individual source in terms of deciviews becomes geometrically less. Results based solely on a degraded background, will rarely if ever demonstrate an appreciable effect on incremental visibility improvement in a given area. Rather than providing for incremental improvements towards the goal of natural visibility, degraded background results will serve to instead maintain those current degraded conditions. Therefore, the visibility benefit estimated based on natural or "clean" conditions is needed to assess the full benefit from potential controls. We note that while CALPUFF results are not directly comparable to CAMx model results due to differences in metrics, models and model inputs[851], CALPUFF visibility impacts are also calculated based on natural or "clean" background conditions.

We recalculated the average modeled visibility impact for the 20% worst days based on the commenter's CAMx modeled average visibility impact for the 20% worst days using a clean

[851] Some of the major differences are: (1) CALPUFF uses maximum 24-hour emission rates, while CAMx uses annual average emission rates; (2) CALPUFF focuses on the day with the 98th percentile highest visibility impact from the source being evaluated, whereas CAMx focuses on the average visibility impacts across the 20% worst days regardless of whether the impacts from a specific facility are large or small; and (3) CAMx models all sources of emissions in the modeling domain, which includes all of the continental U.S., whereas CALPUFF only models the impact of emissions from one facility without explicit chemical interaction with other sources' emissions.

background approach (using annual average natural conditions background).[852] The results are shown in the table below.[853]

Entergy Arkansas 2018 CAMX Modeling - Average Deciview Impacts on the 20% Worst days

Unit	Caney Creek		Upper Buffalo	
	"dirty" background	"clean" background	"dirty" background	"clean" background
Independence Unit 1	0.05	0.27	0.06	0.26
Independence Unit 2	0.06	0.32	0.06	0.28
White Bluff Unit 1	0.13	0.65	0.03	0.14
White Bluff Unit 2	0.13	0.64	0.03	0.13

We note that the Independence facility (units 1 and 2 combined) has impacts greater than 0.5 dv at both Caney Creek and Upper Buffalo on average across the 20% worst days on a "clean" background basis based on CAMx modeling submitted by the commenter. These CAMx model results for the average across the 20% worst days show that the Independence facility contributes significantly to visibility impairment on the 20% worst days and controls will result in meaningful visibility benefit towards the goal of natural visibility conditions. Furthermore, the maximum visibility impact on an individual day within the subset of days that make up the 20% worst days are much larger. The table below summarizes the maximum impacts as modeled by Entergy using CAMx. Facility-wide visibility impacts from Independence exceed 1 dv at each Class I area. We note that in some situations, the days that CALPUFF model maximum or 98th percentile value impacts of the facility occur may not coincide with any of the days that make up the days in the worst 20% days at the Class I area and the visibility impacts modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days.

Entergy Arkansas 2018 CAMX Modeling- Maximum Deciview Impacts ("clean" background) on an individual day within the 20% Worst days

Unit	**Caney Creek (dv)**	**Upper Buffalo (dv)**
Independence Unit 1	0.76	0.75

[852] Deciview impacts are calculated using the following equation: $\Delta dv = 10 \ln((b_{background} + b_{source}) / b_{background})$, where b is extinction (Mm-1) and Δdv is the delta-deciview visibility impact.
[853] See " Entergy Arkansas CAMx - EPA calcs max and clean background.xlsx" available in the docket for this action

Independence Unit 2	0.88	0.83
White Bluff Unit 1	1.77	0.40
White Bluff Unit 2	1.73	0.37

Comment: The level of improvement expected from EPA's proposed controls for Independence is virtually insignificant and does not justify the costs of controls. [AEP-SWEPCO July 15, 2015 comments (00164), p. 5-6, and August 7, 2015 comments (0167), p. 6-7] AEP-SWEPCO stated that EPA's evaluation of the impact of emissions on visibility notes that their BART-type evaluation for NOx for the Independence Power Plant Units 1 and 2 would result in visibility improvements ranging from 0.148 to 0.459 dv with a cumulative improvement of 0.978 dv.[854] EPA recognized that these improvements were relatively small and proposed an option (Option 2) that did not include the LNB/SOFA NOx controls for Units 1 and 2.[855] EPA, however, did not recognize that the Independence facility is subject to CSAPR and that NOx reductions "better than BART" would already be achieved by participation in that program without specifically requiring the LNB/SOFA in the FIP.

For SO_2 emissions for Independence Units 1 and 2, EPA estimated improvements with dry FGD ranging from 1.045 to 1.178 dv with a cumulative benefit of 4.375 dv. Three of the four class I areas would realize visibility improvements barely discernible to the human eye (< 1.1 dv). The best improvement is for Upper Buffalo and is only 1.178 dv. It is not appropriate to use the cumulative values as a representation of the visibility benefit of adding controls since only the improvement at each particular Class I area could actually be recognized. This level of visibility improvement is virtually insignificant and does not justify the costs associated with adding a dry FGD and, therefore, does not meet the statutory RPG requirement for proper consideration of the cost of controls and so is not "reasonable."

Response: We disagree with the commenter and do not believe that visibility improvements from NOx controls ranging from 0.128 to 0.459 dv are relatively small. Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews, it would be inconsistent to consider an improvement in visibility of nearly 0.5 dv to be insignificant or small for reasonable progress. In our proposed action, we noted that "The single source CALPUFF modeling shows that sizeable reductions to the maximum 98th percentile visibility impact from the Independence facility may be achieved through NOX controls." [856] Furthermore, total modeled extinction at Caney Creek is dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, and a significant portion of the total extinction at Upper Buffalo on 2 of

[854] 80 Fed. Reg. At 24873, supplemental modeling values
[855] 80 Fed. Reg. at 18995 and 18997.
[856] 80 FR at 18995.

the days that comprise the 20% worst days in 2002 is due to nitrate.[857] Both NOx and SO2 are key pollutants that contribute to visibility impairment at the Arkansas Class I areas. Because we have identified these two pollutants as key, we are obligated to determine which sources or source categories are responsible for emitting these pollutants and evaluate them for reasonable progress. Independence is the second largest point source of both SO2 and NOx in the State.[858] Therefore, we evaluated it for reasonable progress controls for both pollutants. We recognized, however, that at this time, even though NOx emissions are a key pollutant, point source NOx emissions are not the main contributors to visibility impairment on the average of the 20% worst days at Arkansas' Class I areas in 2018, as projected by CAMx source apportionment modeling."[859] Even though we recognized that NOx emissions are a key pollutant to reaching the regional haze goals, and that the visibility benefits from NOx controls were sizeable, we took comment on two options because the visibility impairment due to Arkansas point source emissions on the average of the 20% worst days were primarily due to sulfate emissions. We also found that significant reductions could be achieved very cost effectively through the implementation of low NOx burners. In our final action, we have determined that it is appropriate to require the NOx controls as proposed under Option 1 because the goal of the long-term strategy and reasonable progress requirements is to improve visibility and make progress towards natural conditions and NOx is a key pollutant impacting visibility at the Arkansas Class I areas. We used a shorthand term, driver, in our proposal discussing SO2, and did not mean to imply that NOx was not also a key pollutant. While point source NOx emissions are not the primary contributor to impairment on most of the 20% worst days, NOx is a key contributor to visibility on other days of the year and on some days that make up the 20% worst days (in 2002, IMPROVE monitor data shows that two days that make up the 20% worst days at Upper Buffalo and three days at Caney Creek are more significantly impacted by nitrate than sulfate). So in considering reasonable progress factors, we have determined that because NOx and SO2 are both key visibility impairing pollutants, for Independence there are technically feasible and cost effective controls available for both SO2 and NOx, and those controls will provide significant visibility improvement. Therefore, both SO2 and NOx controls are reasonable and necessary to eventually achieve the national goal. We have determined that it is appropriate to reduce NOx emissions and finalize Option 1. As to the comment that we did not recognize "better than BART" coverage due to CSAPR, we address this comment elsewhere in a separate response to comment.

With respect to the anticipated visibility improvement due to SO2 controls, we consider visibility benefits ranging from 1.045 to 1.178 dv at each Class I area to be significant. We note that, the Regional Haze Rule provides that sources with a 0.5 dv impact at a Class I area "contribute" to visibility impairment and must be analyzed for BART controls, and that source with a 1.0 dv impact at a Class I area to "cause" visibility impairment. Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews and visibility impacts greater than 1.0 deciview are considered a level to be "causing" visibility impairment, it would

[857] See Arkansas RH SIP, Appendix 8.1- "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans," section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas RH SIP.
[858] See Table 59 80 FR 18991
[859] 80 FR 18995

be inconsistent to consider a potential improvement in visibility of greater than twice the BART threshold to be insignificant.

Furthermore, as discussed elsewhere, results of Entergy Arkansas' CAMx modeling with source apportionment provide additional support that the Independence facility has significant impacts on visibility at nearby Class I areas on the 20% worst days and that controlling these units would result in significant visibility benefits towards the goal of natural visibility conditions.

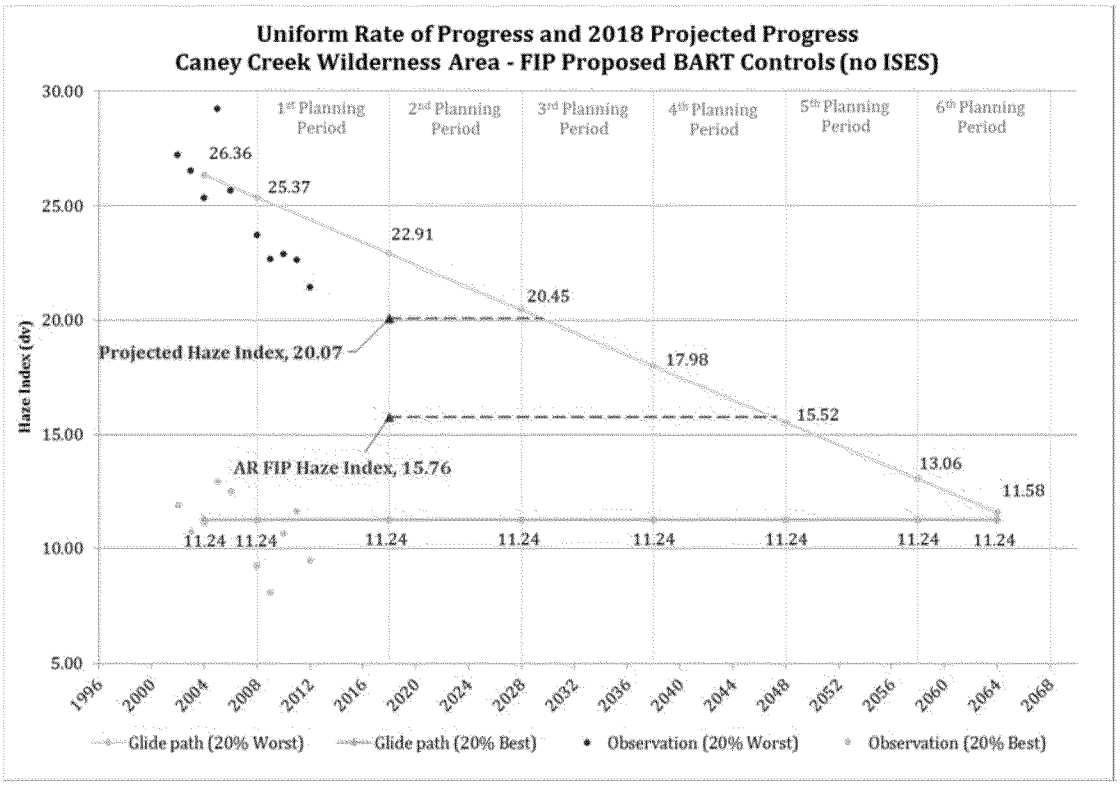
We address comments concerning the consideration of cumulative visibility benefits and imperceptible visibility benefits elsewhere.

Comment: The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

[Entergy Arkansas Inc. (0166) p.37-4; Entergy Mississippi Inc. (0168) p. 8-10; Conway Corporation et. al. (0172) p. 8-9; and EEAA (0173) p. 14-15] Entergy Arkansas Inc., Entergy Mississippi Inc., Conway Corporation et. al., and EEAA stated that EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.81 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id.* At 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NO_X limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

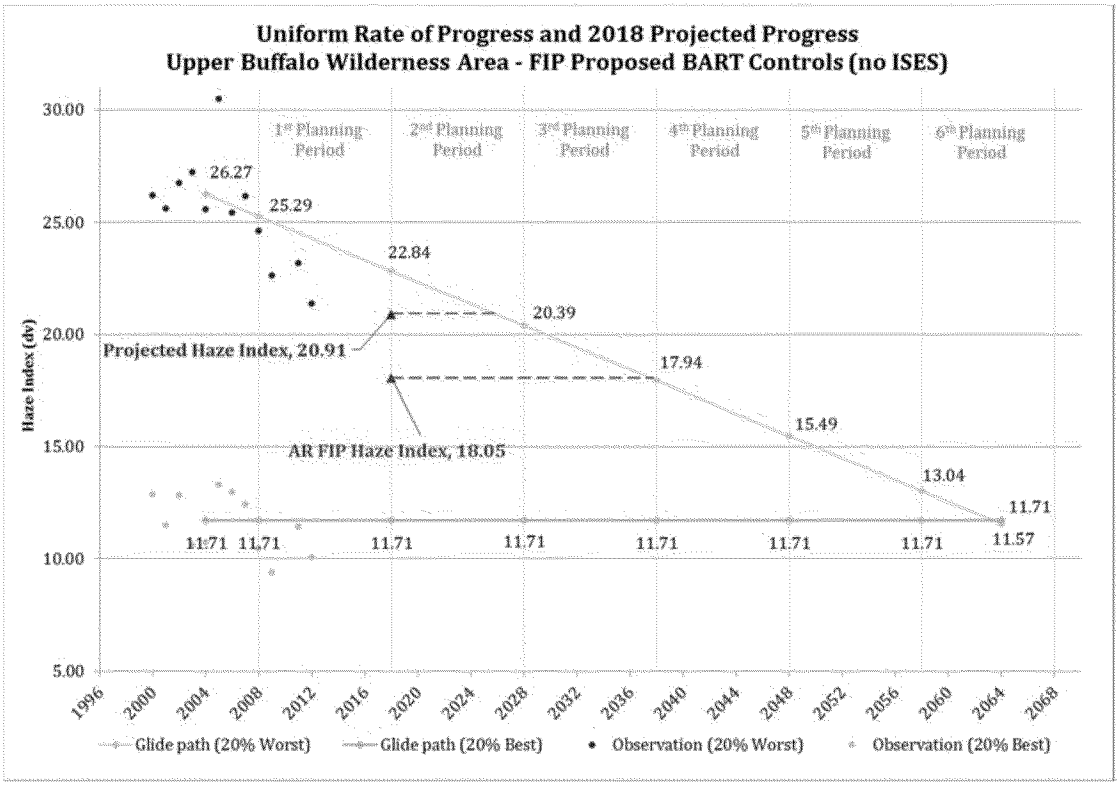
[Entergy Arkansas Inc. (0166) p.37-41] Entergy Arkansas Inc. stated that another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in

projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[860] *See first figure* below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 of EAI's comments), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP would not reach that haze level until approximately 2048.[861] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.



[860] Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.

[861] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See second figure below.*



If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

Response: As more fully explained above, the commenter's analysis fails to account for the fact that deciviews are a logarithmic function of extinction, that CALPUFF results are for the maximum impact (98th percentile impact from each source) in contrast to the CENRAP projected visibility conditions that are for the average visibility over the 20% worst days, and also fails to differentiate between deciview values calculated based on natural background conditions (as the CALPUFF results are) and the deciview values relative to a degraded or dirty background.

First, the commenter incorrectly estimates that the impact from sulfate point source emissions in Arkansas is 0.81-0.86 dv. Because the deciview metric is a logarithmic function of extinction, the percent extinction cannot be directly applied to the total deciview impairment. On the 20% worst days in 2018, sulfate from Arkansas point sources is projected to contribute 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo, and nitrate from Arkansas point sources is projected to contribute 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. 3.58% of the total extinction in 2018 at Caney Creek is 3.073 Mm-1. Converting to deciviews, yields approximately 0.32 dv based on a "dirty" background 2018 projected visibility conditions and 0.92 dv based on a natural background approach.

Second, 0.92 dv represents the estimated deciview improvement from eliminating sulfate emissions at all point sources in Arkansas (based on typical or average emissions) on average across the 20% worst days, as defined by the 20% worst days of monitored visibility at Caney Creek. This CAMx derived value is not directly comparable to the CALPUFF modeled 1.952 dv improvement from controls on both units at Independence, due to differences in models, model inputs and metrics. CALPUFF modeling following the BART guidelines and recommended protocol, provides an estimate of the maximum (98th percentile) visibility benefit based on 24-hr maximum actual emissions modeled over a period of three years. The CAMx modeling results presented by the commenter represent the average visibility impacts over the 20% worst days (as defined by monitored data) based on modeling actual emissions levels. In addition, CALPUFF uses an estimated constant background ammonia level and does not account for the competition for ammonia due to emissions from other sources. A maximum value of 1.952 dv for visibility benefits of controlling Independence based on CALPUFF modeling is not inconsistent with an estimated 0.92 dv impact from all sulfate point source emissions averaged over the 20% worst days. In general, the maximum value could be several times larger than the average over the 20% worst days (representing the average visibility over the 73 days, or 24 monitored days with the worst visibility). Furthermore, the maximum value as modeled by CALPUFF is based on maximum 24-hr emissions which may be much higher than the average emissions. As discussed in a separate response to comment above, CAMx modeling using source apportionment provided by the commenter (Entergy) modeled a facility-wide impact from Entergy Independence of 1.64 dv on the maximum day within the subset of days that make up the 20% worst days. The maximum modeled impact across the full 365 days modeled could be much larger. Furthermore, this modeling is based on actual emissions and not maximum 24-hr emissions as modeled by CALPUFF. Therefore, the 1.952 dv visibility benefit estimated by CALPUFF is not "impossible" and is in fact in line with the visibility impacts estimated using the CAMx model as supplied by the commenter.

Third, the commenter is incorrect in estimating a 4.3 dv improvement from all BART controls and using this value to adjust projected visibility conditions in 2018 on the 20% worst days in the above figures. The cumulative visibility impacts cited to by the commenter (e.g., 4.3 dv improvement at Caney Creek due to all BART controls) combines the maximum visibility improvements from each facility that would result from required NOx or SO2 controls without any consideration of the location of the source or if the impacts and benefits would occur on the same day. The commenter's approach overstates the combined impact at a given Class I area and does not contemplate if sources are located near each other and would likely impact a Class I area at the same time. Contrary to the commenter's description of the methodology used to estimate the total visibility benefits of BART controls,[862] the commenter simply added the CALPUFF modeled deciview visibility benefits for each control. These benefits represent the maximum (98th percentile) visibility benefits at each source based on reductions to the maximum 24-hr emissions modeled over a period of three years. The maximum benefits from controlling one source cannot be added to the maximum benefits of controlling another source as these

[862] Commenter states: "Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling."

benefits are not likely to occur on the same day since the sources are not collocated. In addition, the maximum benefits from NOx controls and SO2 controls at the same facility cannot be added as they may not occur on the same day. Furthermore, these values represent the benefit on an individual day and not the average visibility benefit on the 20% worst days so it is not appropriate to adjust the visibility conditions on the 20% worst days by this amount as the commenter does in the above figures. In some situations, the days that CALPUFF model maximum or 98th percentile value impacts of the facility occur may not coincide with any of the days that make up the days in the worst 20% days at the Class I area and the visibility benefits modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days from those specific controls. Furthermore, as discussed elsewhere, because deciviews are a logarithmic function of extinction, they cannot be added as the commenter does here. The CALPUFF modeled visibility benefits represent the visibility benefits of controls based on a clean background approach, and not the amount of benefit that would occur from degraded conditions, which would be needed to estimate the improvement in overall visibility conditions in 2018. We estimated the amount of visibility benefit anticipated from all controls against 2018 visibility conditions in estimating the proposed RPGs for 2018. In this calculation we estimated the benefit from all required controls to be 0.21 dv at Caney Creek and 0.19 dv at Upper Buffalo.

Comment: CALPUFF overstates the visibility improvement expected from EPA's proposed controls on Independence. [Entergy Arkansas Inc. (0166) p.41-42] Entergy Arkansas Inc. stated that EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence (as discussed elsewhere in Entergy's comments) and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id.* At 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo).[863] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19

[863] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.

dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[864] Requiring imperceptible visibility improvements is simply unreasonable. The CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

Response: We address comments concerning perceptibility of visibility improvements elsewhere in this document. There we explain that in our visibility improvement analysis, we have not considered perceptibility as a threshold criterion for considering improvements in visibility to be meaningful.

As we discuss in depth elsewhere, visibility improvements from controls must be evaluated on a "clean" background basis to fully assess the benefits from controls. It is not appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall deciview index value as of the end of the implementation period, i.e., the degree by which the RPGs would differ with and without the control being included in the LTS, as the commenter does here. We also discuss elsewhere that the deciview scale is a logarithmic function of extinction and calculations to determine benefits or amount of contribution to visibility impairment must be based on extinction and then converted into deciviews. Nevertheless, the commenter's estimated visibility benefits of 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo on average across the 20% worst days are approximately a reduction in extinction of 0.8 Mm^{-1} at Caney Creek and 0.7 Mm^{-1} at Upper Buffalo, which is 0.37 dv and 0.32 dv based on a clean background approach for the 20% worst days. In our response to a separate comment above, we discuss that due to the differences in models, model inputs, and metrics, the estimated visibility benefits estimated from CAMx modeling cannot be directly compared to CALPUFF modeled visibility benefits. For one, CALPUFF modeling is used to estimate the maximum visibility benefit based on maximum emissions whereas the CAMx modeling estimates the average visibility benefit over the 20% worst days (as defined by the monitored data) using actual or typical emission levels. As we also discuss above in a separate response to comment, CAMx visibility modeling with source apportionment submitted by Entergy estimates a maximum visibility impact (limited to only the days comprising the 20% worst days) of over 1.5 dv from the Independence facility at both Caney Creek and Upper Buffalo. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the Worst 20% monitored days at the Class I area, therefore the maximum impact based on CAMx modeling could be even higher.

[864] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id.* at 1242, Figure 2

With regard to the quote the commenter reproduced from the Eighth Circuit Court's decision in North Dakota v. EPA[865], several environmental groups challenged a portion of our final action on North Dakota's regional haze SIP that ultimately approved North Dakota's reasonable progress determination for NOx controls for the Coyote Station.[866] The environmental groups objected to North Dakota's decision to reject a control it had evaluated, after having applied the four reasonable progress factors, and subsequently approving another NOx control as reasonable progress.

We interpret the Court's statement as meaning broadly that just because a more stringent level of control could be technically feasible in a particular instance, it does not mean it necessarily must be required under reasonable progress. We see no conflict with this determination and our proposed Arkansas FIP and requiring controls that may not result in perceptible visibility improvements. In North Dakota's case, we noted technical flaws in North Dakota's analysis, and we noted that we could have reached a different conclusion had we conducted the analysis ourselves, but we ultimately determined these issues did not prevent us from accepting North Dakota's reasonable progress determination. The Court did not find that our conclusions on the issue were arbitrary, stating in part that, "[e]ven if [the control in question] were perhaps the most reasonable technology available, the CAA requires only that a state establish reasonable progress, not the most reasonable progress. In contrast, and as explained in greater detail elsewhere, in our 2012 rulemaking,[867] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. Our proposed rulemaking completed the reasonable progress analysis and established revised RPGs, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved. We determined that cost effective controls were in fact available that would have very significant visibility benefits.

Comment: [UARG (0176) p. 16-18] UARG stated that certain elements of EPA's assessment demonstrate that the Independence Power Plant's emissions have, and will continue to have, very little effect on visibility in any Class I area. EPA's reasonable progress analysis shows that "[o]n the 20% worst days in 2002, sulfate from Arkansas point sources contributed 2.20% of the total light extinction at Caney Creek and 1.99% at Upper Buffalo, and nitrate from Arkansas point sources contributed 0.27% of the total light extinction at Caney Creek and 0.14% at Upper Buffalo." 80 Fed. Reg. at 18,989 (footnote omitted). According to EPA, these very small percentages reflect contributions from *all* "Arkansas point sources," not for the Independence Power Plant alone, whose emissions of course contribute only a fraction of these small amounts.

Response: We disagree with the commenter's assertion that the contribution to visibility impairment from Independence is "insignificant" or "minimal". As the commenter states, the CENRAP source apportionment data shows that sulfate from Arkansas point sources contributed 2.20% of the total light extinction at Caney Creek and 1.99% at Upper Buffalo in 2002. The

[865] The commenter states that requiring imperceptible visibility improvements is simply unreasonable and refers to the 8th circuit decision that the CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013)

[866] See EPA's final rule at 77 FR 20,894-945 (April 6, 2012)

[867] 64 FR 35732

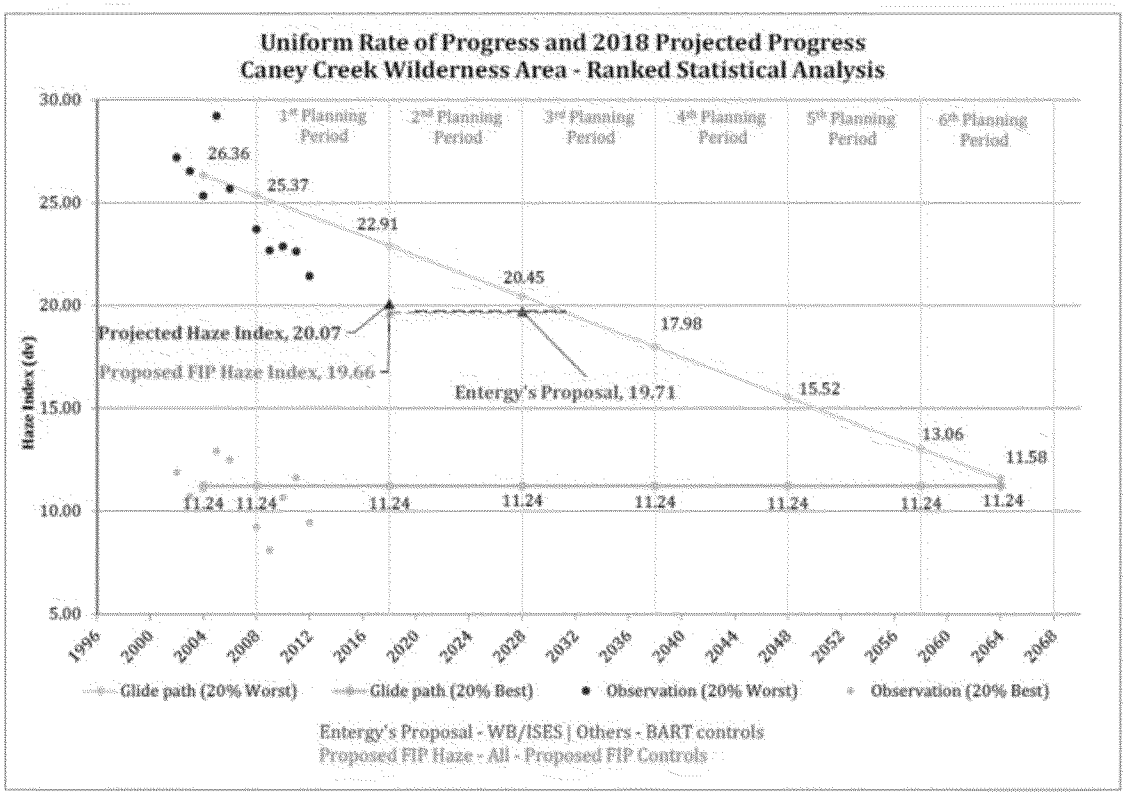
CENRAP modeling also projects that Arkansas point sources will be responsible for 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo in 2018. As we discuss in our proposal, based on 2011 NEI data the Entergy Independence Plant is the second largest source of both SO_2 and NOx point source emissions in Arkansas, accounting for approximately 36% of the SO_2 point-source emissions and 21% of point-source NO_X emissions in the State.[868] Therefore, a significant portion of the total projected visibility impairment on the 20% worst days, on the order of 1% or more, can be expected to be attributable to SO2 emissions from a single facility, the Independence facility, based on the CERNAP modeling. We discuss in a separate response to comment that results of our CALPUFF modeling, as well as the results of additional CAMx modeling submitted by Entergy, confirm and support that the visibility impairment due to the Independence facility is significant and that emission reductions will result in meaningful visibility benefits towards natural visibility conditions. We address comments concerning the magnitude of the projected benefits from controls for the projected 2018 visibility conditions, as well as the perceptibility of those benefits in a separate response to comment elsewhere in this document.

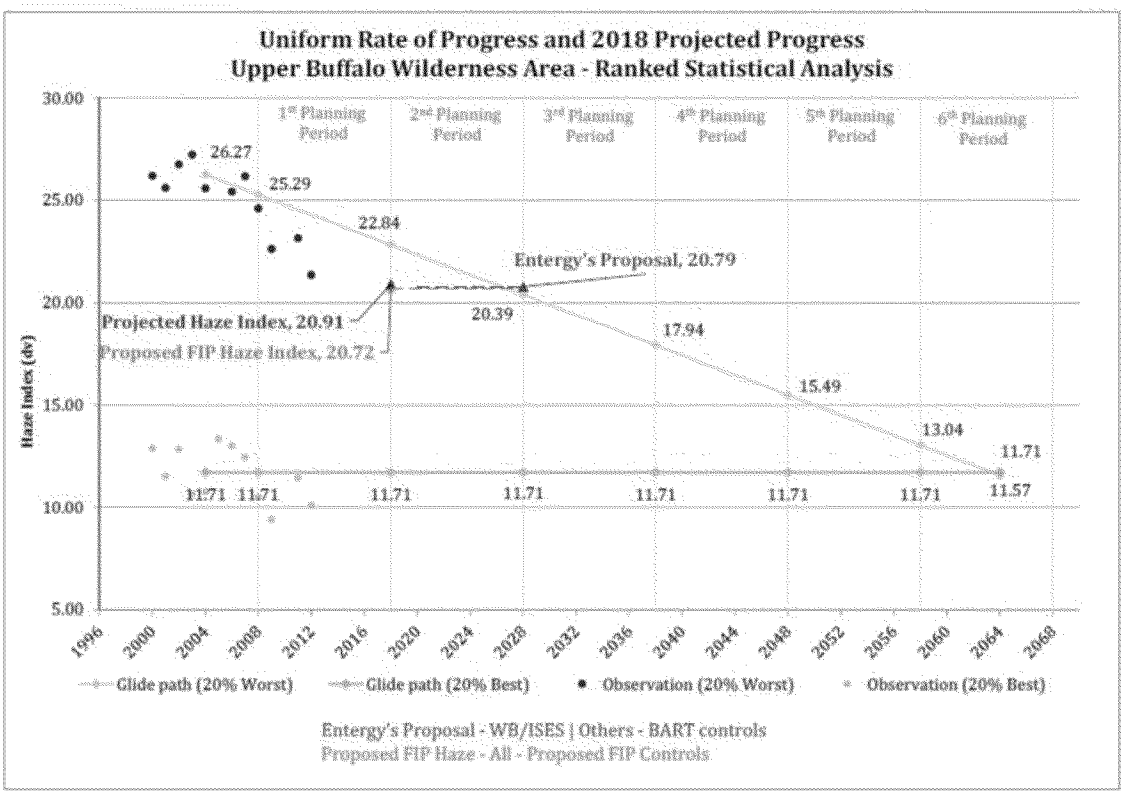
7.f. Visibility Benefit of Entergy Arkansas Proposal

Comment: Entergy's proposed combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal.[869] *See* Figures below, which compare the projected 2018 haze index at each Arkansas Class I area based on a Ranked Statistical Analysis, to the deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of EPA's proposed FIP controls at all BART sources and Independence. Based on Entergy's CAMx modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 dv at Upper Buffalo.

[868] 80 FR 18991

[869] Entergy Arkansas Inc. stated that it is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy is proposing to meet lower SO_2 emission rates at White Bluff Units 1 and 2 and Independence Units 1 and 2 by 2018, and is willing to install LNB/SOFA at all four units and meet a 30-day rolling average NO_X emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP as part of its multi-unit approach [Entergy's comments with regard to the proposed NO_X rate is included as a separate comment in this RTC document].


Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
Entergy's Proposal, 20.79
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Response: We discuss the "ranked statistical analysis" submitted by the commenter in the response to comments below in this section. We disagree with the commenter that the Entergy proposed control scenario achieves "virtually" the same visibility benefits as does the controls required in this FIP. The table below summarizes the estimated visibility benefits of the FIP and Entergy's proposal from the commenter's CAMx photochemical modeling. We note that both scenarios include benefits from all required BART controls at all subject-to-BART facilities with the exception of White Bluff. The modeled FIP scenario also includes SO_2 and NOx controls at both Independence and White Bluff. The modeled Entergy proposal scenario includes the elimination of emissions from White Bluff, an approximate 15% reduction in SO_2 emissions from Independence and roughly similar NOx reductions at Independence as required in the FIP.

Entergy Arkansas CAMx model results average 20% worst days

Modeled Scenario	Caney Creek		Upper Buffalo	
	Change in Light extinction from 2018 baseline (Mm-1)[870]	Delta-dv (clean background)	Change in Light extinction from 2018 baseline (Mm-1)[871]	Delta-dv (clean background)
FIP	2.95	1.29	1.54	0.70
Entergy Proposal	2.66	1.17	0.97	0.45
Difference	0.29	0.12	0.57	0.35

Entergy's proposal achieves less visibility benefit than the FIP controls at Arkansas' Class I areas, most significantly at Upper Buffalo where the benefit from Entergy's proposal is approximately only 63% of the benefit from the FIP (1.54 Mm^{-1} from the FIP compared to 0.97 Mm^{-1} from Entergy's Proposal). CAMx source apportionment modeling submitted by Entergy shows that Entergy Independence has significant visibility impacts at both Arkansas Class I areas. At Upper Buffalo, the Independence facility contributes more to visibility impairment than all the subject-to-BART sources addressed in this action combined. Additional reductions from the elimination of emissions from the White Bluff facility under Entergy's proposal are much too small to compensate for the lack of significant SO2 reductions at Independence. Visibility impacts due to emissions from Independence at nearby Class I areas in Missouri (not shown in the table) are also larger than the combined impacts from all subject-to-BART sources. Furthermore, Entergy's proposal does not achieve these benefits until 2028, seven years after the full benefits from the FIP would be realized. We discuss other aspects of Entergy's proposal, including uncertainty in emissions at White Bluff after the cessation of coal-burning, and issues concerning the BART requirements for White Bluff in separate responses to comment elsewhere in this document.

[870]See "Entergy CAMx Results 2015-1124_FINAL.xls" submitted with comments from Entergy Arkansas, Inc. and available in the docket for this action

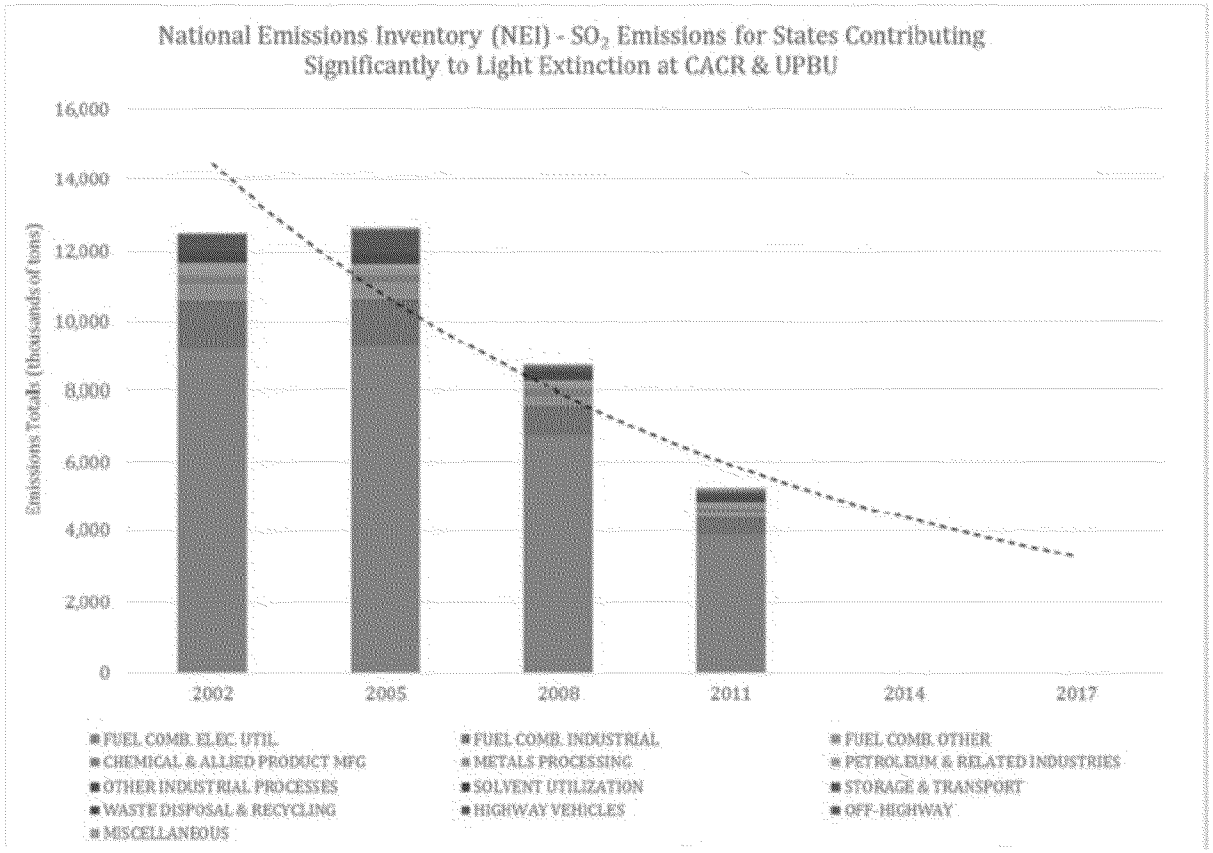
[871]See "Entergy CAMx Results 2015-1124_FINAL.xls" submitted with comments from Entergy Arkansas, Inc. and available in the docket for this action.

We also disagree with the commenter's use of the results of their ranked statistical analysis (the "projected haze index" shown in the figures above, Entergy Arkansas Inc.'s submitted comments in figures 13 and 14) as the starting point for calculating the overall visibility benefits from the FIP or the commenter's proposed alternative. As discussed elsewhere, the ranked statistical analysis is simply a projection of future visibility conditions based on past improvement and is not directly tied to any additional required emission reductions in the next few years that would result in this future visibility improvement from current conditions to this projected value in 2018.

7.g. Observed Visibility Improvements

Comment: Trinity Consultants Inc. (Trinity) was tasked by Entergy Arkansas with conducting a statistical analysis of observed visibility data gathered through the Interagency Monitoring of Protected Visual Environment (IMPROVE) program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.

For Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations (see URP and projected visibility figures below). This downward trend is consistent with the historical (2002 – 2011) trend in decreasing sulfur dioxide (SO2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas. Figure 2-3 of the submitted comments presents the National Emissions Inventory (NEI) SO2 emissions from 2002, 2005, 2008, and 2011. Pursuant to the NEI emissions data, the SO2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

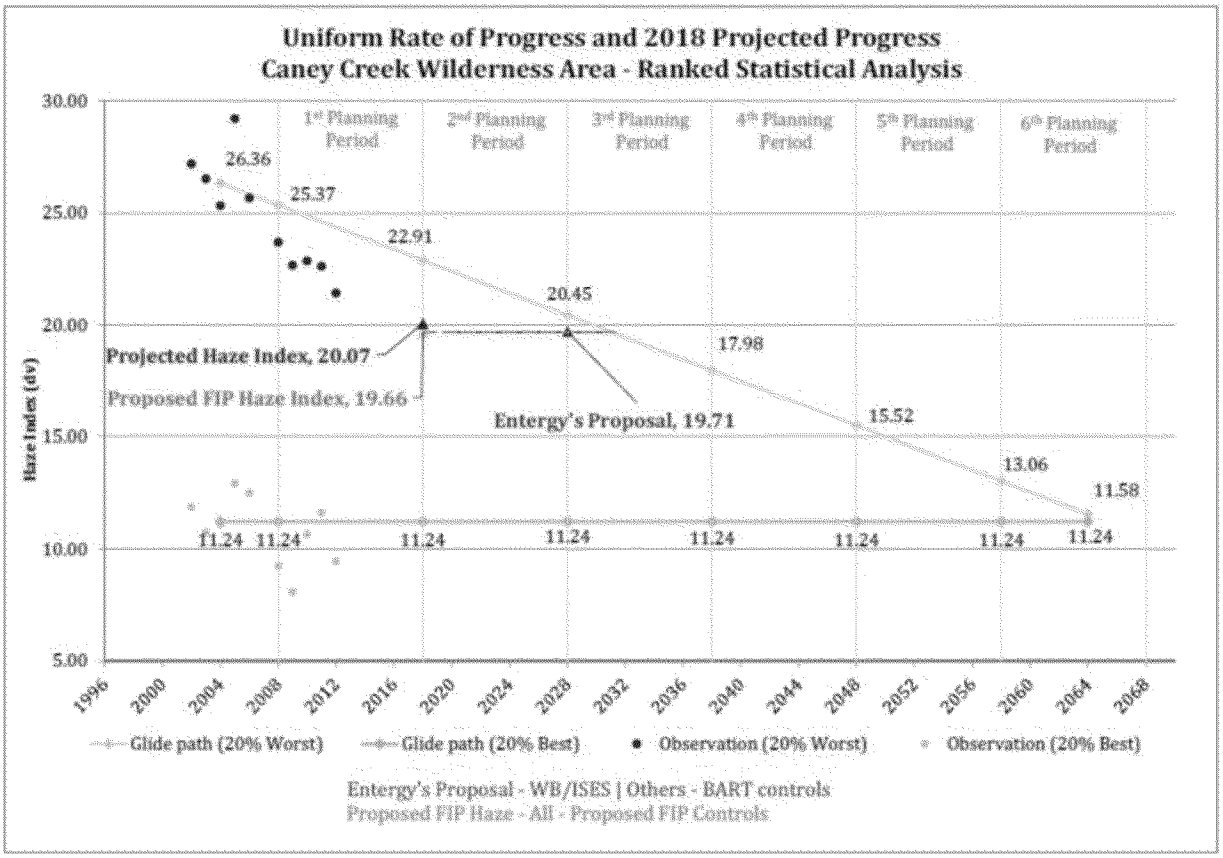


Based on the above, when looking at the observed values, the CENRAP model predicted regional haze value for 2018 is overly conservative and over predicting the future haze index. Although the predicted 2018 haze index values are good conservative estimates for attainment demonstrations, the values are misleading when assessing the effect of proposed controls on single sources. Additionally, the CENRAP CAMx model predicted haze index does not account for the observed values and the trend predicted if an assessment occurred evaluating the observed values. Therefore, instead of using the CENRAP CAMx predicted 2018 haze index to understand the effect of the control options, a statistically derived projected haze index must be used.

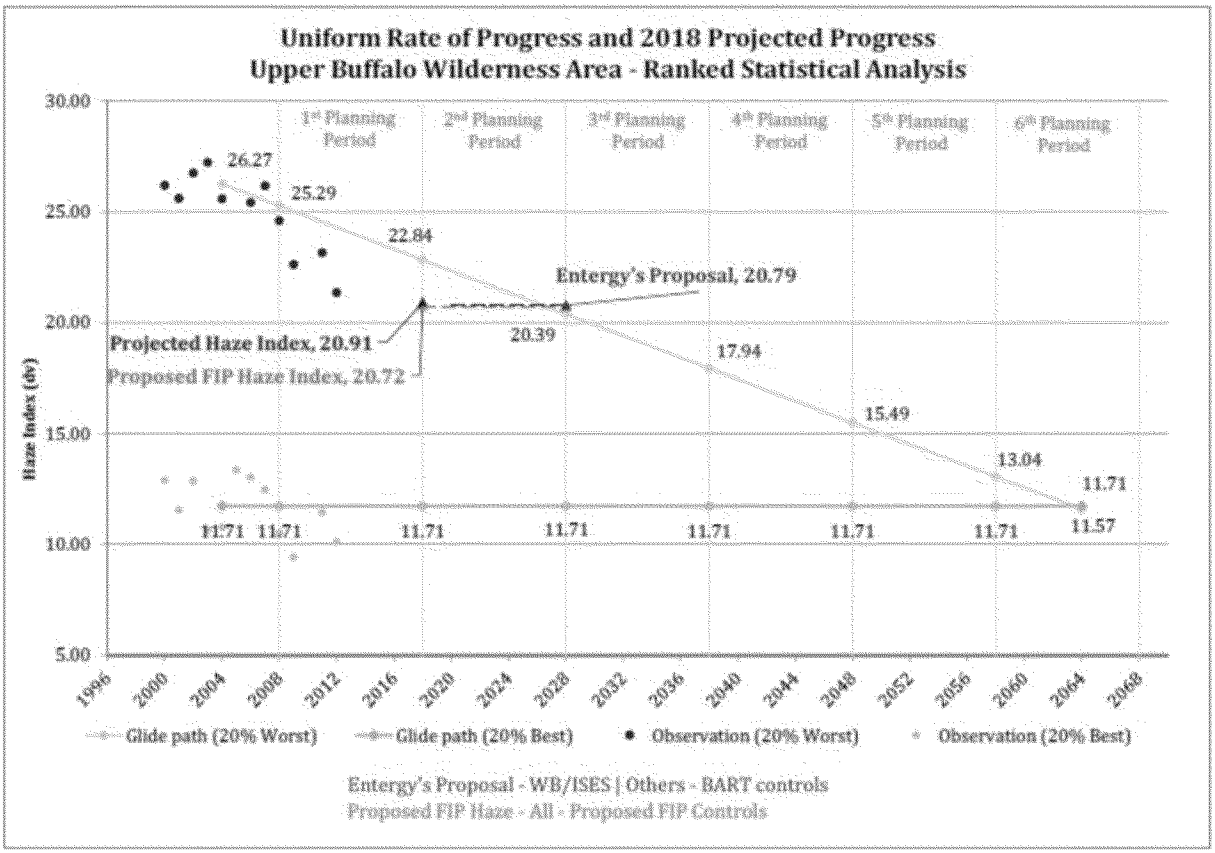
In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data: Trend Analysis, and Ranked Statistical Analysis.[872] The results of the ranked statistical analysis are summarized in the following figures and display the predicted 2018 values in relation to the URP curves for each Class I Area and the estimated proposed FIP haze index and the haze index based on Entergy's proposed controls based on CAMx modeling performed by Trinity for Entergy Arkansas. The 2018 average of the 20% worst days for visibility was

[872] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

calculated to be 20.07 dv for Caney Creek and 20.91 dv for Upper Buffalo.[873] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path.



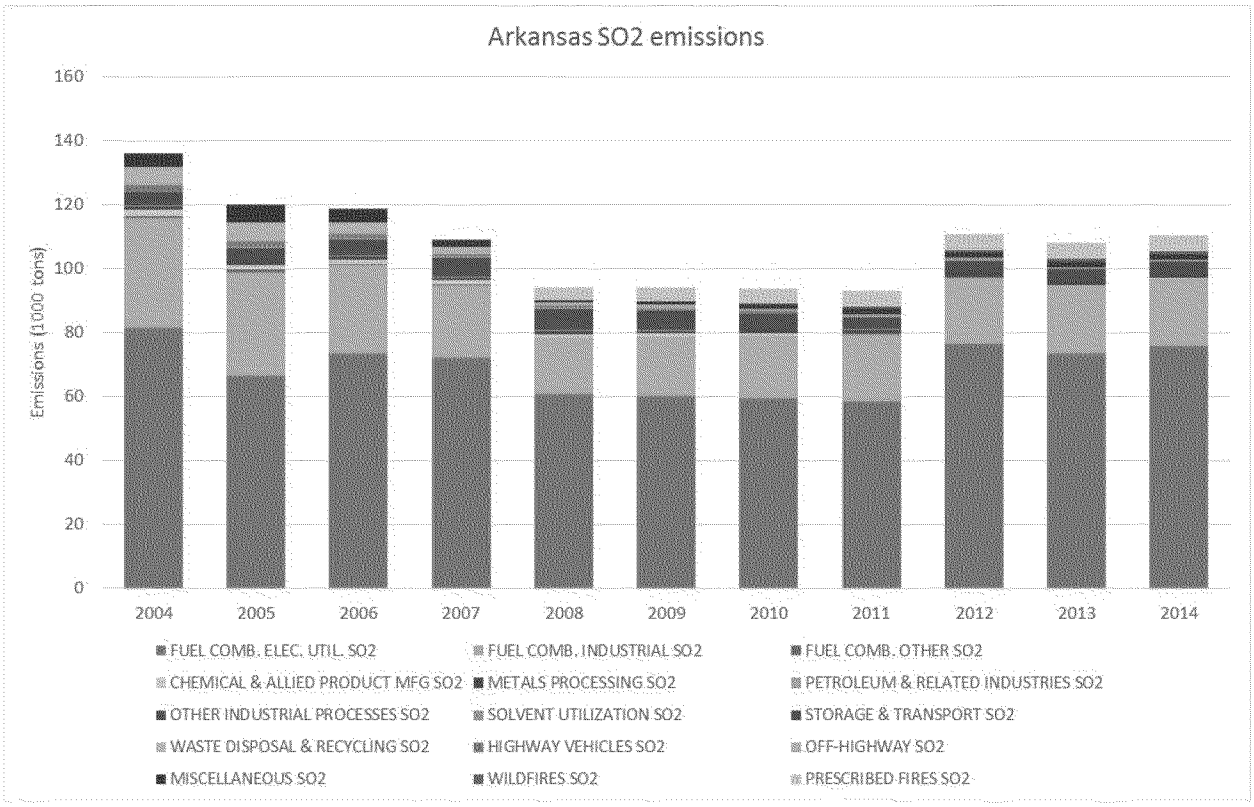
[873] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy stated it is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.



Response: As we discuss elsewhere in this document and in section V.C of the final rule, being projected to be on or below the URP glidepath in 2018 (or even beyond) does not automatically mean that no controls or evaluation under reasonable progress is needed in this planning period. The commenter presents SO_2 emissions data from 2002, 2005, 2008, and 2011 for states identified by the commenter as impacting visibility at the Arkansas Class I areas. This data shows significant emissions reductions over this time period and is consistent with observed visibility improvement at the Arkansas Class I areas. However, most of the visibility improvement currently observed in Arkansas appears to be due to emissions reductions that have taken place outside the state. Arkansas emissions do not exhibit the same downward trend as presented for the other states that impact visibility at the Arkansas Class I areas. The figure below shows Arkansas SO_2 emissions from all source categories for 2004-2014.[874] More recent annual emissions from 2012-2014 are actually higher than emissions from the 2008-2011 period and there is no downward trend in emissions from those point sources with the largest visibility impacts, those from fuel combustion at electric utilities. To the extent that the commenters are suggesting that Arkansas should be relieved of its regional haze obligations because other states' emission reduction efforts have already resulted in significant visibility improvement at Arkansas' Class I areas, this is incorrect. Rather Arkansas, and EPA in standing is Arkansas's

[874] Data available from EPA air pollutant emission trend data: https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

shoes, must consider the statutory factors in addressing the long term strategy and reasonable progress requirements.



The commenter asserts that the CENRAP CAMx predicted 2018 haze index is overly conservative and that to understand the effect of the control options, a statistically derived projected haze index must be used. We disagree with the commenter. The comments indicate a lack of understanding of how reasonable progress goals are established, as well as the imports of the goals as opposed to the measures adopted to ensure reasonable progress. As we state in the Regional Haze Rule, the reasonable progress goal(s) set by the state, or EPA when promulgating a FIP, are not enforceable. The reasonable progress goals are an analytical tool used by EPA and the states to estimate future visibility conditions and track progress towards the goal of natural visibility conditions. Accordingly, the RPGs must represent an estimate of the degree of visibility improvement that will result in a future year from changes in emissions inventories, changes driven by the particular set of control measures adopted in the regional haze SIP or FIP to address visibility, as well as all other enforceable measures expected to reduce emissions.[875] Given the forward-looking nature of reasonable progress goals and the range of assumptions that must be made as to emissions in the future, we expect there to be some uncertainty in the estimates of future visibility.

The statistical analyses provided by the commenter are simply extrapolations of future visibility conditions based on observed reductions in visibility impairment in the past. Future visibility projections must be directly tied to projections of future emissions, and anticipated reductions

[875] 64 FR 35733

due to federal and state requirements. Current 5-yr average (2010-2014) observed visibility conditions are 21.8 dv at Caney Creek and 21.6 dv at Upper Buffalo.[876] Any future improvements in overall visibility conditions at the Arkansas Class I areas between now and 2018 will be due to future emission reductions during that time period. Commenters have not provided any specific information suggesting anticipated enforceable emission reductions from those Arkansas point sources with significant visibility impacts or other sources that would result in the almost 2 dv visibility improvement by 2018 projected by the commenter at Caney Creek in their statistical analysis. Furthermore, as discussed above, any anticipated emission reductions from sources in other states does not relieve Arkansas of its regional haze obligations. The BART requirements under section 51.308(e) must be met for those specific sources that meet the BART criteria and contribute to visibility impairment. The determination of whether an RPG and the emission limitations and other control measures upon which it is based constitute reasonable progress is made by conducting certain analyses and meeting the requirements under section 51.308(d)(1).

As discussed in depth elsewhere in a separate response to comment, it is necessary to assess the visibility benefit of individual controls compared to natural or "clean" background conditions. It is not appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall deciview index value as of the end of the implementation period, i.e., the degree by which the RPGs would differ with and without the control being included in the LTS, as the commenter does here. The RPGs are an analytical tool the state and we use to evaluate whether the measures in the implementation plan are sufficient to achieve reasonable progress.[877] Instead, what is enforceable under the RH rule are the emission limitations and other control measures that apply to specific sources, and upon which the RPGs are based. Since the emission limitations we are requiring in our FIP for specific Arkansas sources (which is what our revised RPGs are based upon) are not currently being achieved, we disagree that visibility at the Class I areas has already improved beyond what we would require in our FIP and that our FIP is therefore unjustified and unwarranted. The emission reductions required in this action will result in significant visibility improvements at the Class I areas beyond what is currently being achieved or observed. As discussed elsewhere, the commenter's photochemical modeling analysis provides an additional demonstration that the controls required in this action result in visibility benefits beyond current observed visibility conditions and serve to accelerate progress towards natural visibility conditions.

7.h. Reasonable Progress Goals

Comment: [ADEQ (0160) p. 15-16] EPA's proposed RPGs are more stringent than Arkansas's proposed RPGs in its 2008 Regional Haze State Implementation Plan, which would have ensured that Arkansas is on track to achieve natural visibility conditions by 2064. Arkansas is reducing regional haze in its Class I areas at a higher rate than both the URP, which was approved by EPA, and Arkansas's initial proposed RPGs.[878] EPA's RPGs in the Proposed FIP are only about

[876] IMPROVE monitoring data obtained from: http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx
[877] See 51.308(d)(1)(v).
[878] *See* Exhibit 1 to ADEQ's comments.

0.2 deciviews lower than those developed by Arkansas.[879] Even if EPA's RPGs were the result of proper analysis and modeling, the difference between the State-established and EPA-proposed RPGs is insignificant and below the range of human perceptibility. As indicated by the URP, Arkansas is well on track to reaching natural visibility conditions by 2064 and more stringent RPGs than those in Arkansas's 2008 Regional Haze State Implementation Plan are not necessary. EPA should withdraw the Proposed FIP and ensure that revised RPGs in any subsequent plan are within the scope of EPA's authority to address impairment of visibility.

Comment: [UARG (0176) p. 16-18] The differences in projected 2018 visibility conditions at Caney Creek and Upper Buffalo that are attributable to *all* of the proposed FIP controls – including both FIP BART and FIP reasonable progress requirements – will be imperceptibly small (*i.e.*, improvements of, at most, 0.21 dv and 0.19 dv, respectively, at Caney Creek and Upper Buffalo). *Id.* at 18,997-98 & Table 67. Yet the minimal visibility improvements that EPA's proposed reasonable progress emission control requirements would produce would come at exorbitant cost – nearly $64 million *per year* for SO2 controls and almost $2.5 million annually for NOx controls, according to EPA. *See id.* at 18,993 Table 60, 18,996 Table 65.

Response: As we discuss in more detail elsewhere in response to comments, we agree that Arkansas proposed RPGs in its 2008 regional haze SIP that fell below the URP. However, in our 2012 rulemaking,[880] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. In our proposed rulemaking, we completed the reasonable progress analysis and established revised RPGs, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved. As discussed in our proposal and elsewhere in this response to comments document, we focused our reasonable progress analysis on the Entergy Independence facility because of its significant emissions of NOx and SO_2 and its large potential to impact visibility at nearby Class I areas. We determined that cost-effective controls were available for units at this facility and that they would result in significant visibility benefits. We respond to specific comments concerning the visibility benefits from controls on the Independence facility in separate responses to comments. We also completed five-factor BART analyses and determinations for subject-to-BART facilities where we had previously disapproved the BART determination in the 2008 Arkansas regional haze SIP. Our proposed RPGs reflected the visibility benefits anticipated from the implementation of controls across the subject-to-BART facilities and the Independence facility required in this action. As we discuss in our proposal and in response to comments, we have determined that these controls are cost-effective and result in significant visibility benefits that provide for progress towards the goal of natural visibility conditions. As we discuss below in a separate response to comment, after considering comments received, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. We are finalizing RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018.

[879] 77 FR 14604 at 18998, Table 67.
[880] 64 FR 35732

We disagree with the commenter that the amount of visibility improvement due to our proposed FIP is "insignificant." We address comments concerning the perceptibility of visibility improvements in response to comments above. The required controls are estimated to improve overall visibility benefits compared to the CENRAP projected visibility conditions for 2018 by approximately 0.2 deciviews, a reduction in light extinction of about 2 Mm-1 at Caney Creek and 1.8 Mm-1 at Upper Buffalo. Once fully implemented, the required controls to meet the BART requirements, as well as required controls on the Independence facility result in an approximate 2% improvement in overall visibility conditions projected by CENRAP at both Caney Creek and Upper Buffalo on the 20% worst days. Our technical record demonstrates that the required controls reduce impacts from these sources and result in meaningful visibility benefits towards the goal of natural visibility conditions. The required controls reduce the projected visibility impairment due to all Arkansas point sources by 50% at Caney Creek and 50% at Upper Buffalo. We note that the required controls actually result in larger visibility improvements than calculated here because the CENRAP projections already included an assumption of large emission reductions due to SO_2 BART at Flint Creek, as well as NO_X controls at White Bluff and Flint Creek.[881]

Comment: The RPGs chosen by EPA are based on admittedly flawed methods that reject the refined modeling approach used by EPA in other states. [ADEQ (0160) p. 13-15] ADEQ stated that not only did EPA improperly perform the reasonable progress analysis necessary to establish RPGs, but EPA also used an admittedly inferior method to model Arkansas's RPGs. In supporting the RPGs in the Proposed FIP, EPA substituted a method that relies on "a scaling of visibility extinction components in proportion to emission changes."[882] In support of this method, EPA cites to its use in developing RPGs for Hawaii and Arizona.[883] EPA offers little in the way of positive support for its choice in the Proposed FIP. Rather, EPA chose a method of determining RPGs that is admittedly inferior and less sophisticated than the alternative approach, which EPA rejected in Arkansas but used in Texas: CAMx photochemical modeling.

EPA admits that it has not performed its own modeling in a manner adequate to develop "refined numerical RPGs."[884] EPA seems to acknowledge the infirmity in its modeling by explaining its methodology as follows: "Development of refined numerical RPGs for Arkansas's Class I areas would require photochemical grid modeling of a multistate area, involving thousands of emission sources, unlike the comparatively simple single-source CALPUFF modeling used for individual BART assessments."[885] EPA further explains that "[d]eveloping all of the necessary input files, running the photochemical model, and post-processing the model outputs would take several months at a minimum."[886] EPA cites additional reasons for rejecting the approach using photochemical grid modeling such as the part that it is requiring an "update of the emission inventory for Arkansas and surrounding states," which would include the effects of all EPA and

[881] 2002 CENRAP modeled SO_2 emissions for Flint Creek were 11,165 tpy and 2018 CENRAP modeled SO_2 emissions were 2,896 tpy, an assumed 75% reduction in emissions.
[882] 80 FR 18944 at 18997.
[883] Id.
[884] Id.
[885] *Id.*
[886] *Id.*

state regulatory actions on point, area, and mobile sources.[887] EPA states this approach would require "specialized and extensive computing hardware and expertise."[888]

Despite the additional complexity and time needed, EPA chose to use the more refined CAMx photochemical model in the Texas-Oklahoma FIP.[889] As evidenced by EPA's actions in the Texas-Oklahoma FIP, EPA certainly possesses the "specialized and extensive computing hardware and expertise" needed to perform modeling using the CAMx photochemical model. EPA fails to justify this disparate treatment in Arkansas's Proposed FIP. Instead, EPA arbitrarily used an alternative algorithm to develop RPGs that resulted in admittedly inferior numerical goals.

In fact, the only modelling EPA performed for the Proposed FIP was "comparatively simple single-source CALPUFF modeling used for individual BART assessments."[890] EPA used this modeling only to justify additional emissions controls on Entergy's Independence Plant outlined in the reasonable progress analysis and not in support of the proposed state-wide RPGs.

Given the substantial impact on Arkansas businesses and rate-payers that the potential differences in RPGs would make, ADEQ is troubled by EPA's decision to forego methods that would ensure the same degree of accuracy for RPGs in Arkansas's Proposed FIP as in the Texas-Oklahoma FIP. EPA should withdraw the Proposed FIP, and any subsequent plan should include a method of analysis sufficient to establish "refined numerical RPGs."

Response: We discuss our selection of the CALPUFF model for evaluating single-source visibility impacts in a separate response to comment above. In the response, we also explain the model selection for our Texas action and refer the reader to our detailed explanation in the RTC that accompanies that action.[891] Commenters are incorrect in their comparison of approaches for establishing new RPGs between this action for Arkansas and our previous action in Texas. For both Texas and Arkansas, we utilized the CENRAP 2018 CAMx modeling that estimated the 2018 RPGs and then adjusted those RPGs to account for estimated visibility improvement due to required controls. In neither case did we perform a full photochemical modeling analysis to model all the required controls and project the future visibility conditions. In both cases, the 2018 RPGs were adjusted based on a scaling of the source apportionment model results and emission inventory changes.

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[887] 80 FR 18944 at 18997.

[888] *Id.*

[889] Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation
Plans; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility, 79 FR 74818.

[890] 80 FR 18944 at 18997.

[891] See "Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze," December 9, 2015. Available at www.regulations.gov, Document ID: EPA-R06-OAR-2014-0754-0087

The primary difference between the two actions was that in evaluating the visibility impacts and benefits of potential controls at individual sources we relied on CAMx modeling for Texas sources and CALPUFF modeling for Arkansas sources. Among the key differences that resulted in the selection of different models was the number of sources that needed to be analyzed (38 facilities in Texas compared to 1 facility in Arkansas) and the distances from the sources to the impacted Class I areas (distances in many cases ranging from 300 to 1000 km or more for Texas sources compared to four impacted Class I areas less than 300km from the source in Arkansas).

Furthermore, as we noted in our proposal[892], "RPGs, unlike the emission limits that apply to specific RP sources, are not directly enforceable. Rather, they are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to achieve reasonable progress. Arkansas may choose to use these RPGs for purposes of its progress report, or may develop new RPGs for approval by us along with its progress report, based on new modeling or other appropriate techniques, in accordance with the requirements of 40 CFR 51.308(d)(1)."

Comment: [Entergy Arkansas Inc. (0166) p.41-42] Entergy Arkansas Inc. stated
The demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[893] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NO_X molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NO_X emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NO_X molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NO_X will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

Comment: [EarthJustice/ Dr. Gray] In Texas, the model results were used to demonstrate that the overall change in species concentrations was very nearly linearly proportional to the change in emission levels for an individual source (with very high linear correlation coefficients near 1.0). This strongly supports their use of the emission scaling approach for Arkansas. If the CAMx model were used to determine the impact of emission controls on a single source in Arkansas (such as
Independence), it is therefore expected that the modeled reductions in sulfate and nitrate concentrations at each of the Class I areas will be very nearly proportional to the SO2 and NOX

[892] 80 FR 18997-18998
[893] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

concentration reductions. In other words, the emission scaling approach has been shown to be mathematically sound and quite appropriate, especially considering the resources that would be required to exercise CAMx separately for each control measure at each evaluated source.

Response: We disagree with the comments that the methodology used to estimate overall visibility benefits from all required controls control level emissions was unreasonable or unscientific. We agree with comments that the approach we followed is reasonable and based on a scaling of visibility extinction components due to Arkansas point sources in proportion to emission changes from the required controls at Arkansas point sources. The commenter is incorrect in suggesting that we developed a linear relationship between emissions and deciviews and then commenting that this "fractioning or scaling of deciviews" is flawed because the relationship between light extinction and deciviews is exponential. We properly developed a linear relationship between emissions and light extinction (inverse Megameters), not deciviews.

We agree with the commenters, that in general, the relationship between downwind concentrations and emissions can be complicated and non-linear due to complex chemistry, including the fact that reductions in sulfur emissions can result in an increase in ammonium nitrate. For estimating the total visibility benefit from all controls and estimating a new reasonable progress goal that reflects those controls, we relied on the CENRAP's 2018 CAMx modeling results, including source apportionment results, and the projected emission inventories, and scaled the results as described in the TSD, similar to what was done in our previous action in Arizona and Texas. While we acknowledge that this approach is not as refined an estimate as would be attained in performing a new photochemical modeling run, it is based on scaling to adjust earlier photochemical modeling results that took into account the complex chemistry that impacts the overall visibility. The uncertainty in the visibility benefit from these controls introduced by the linear extrapolation does not impact the overall conclusions. Furthermore, in our technical analysis developed to support our action on Texas regional haze, we observed that for each facility and Class I area, the available modeled visibility impact was linear with respect to emissions with high correlation.[894] Following this approach we estimated that when fully implemented, the required controls would result in a reduction in light extinction of about 2 Mm^{-1} at Caney Creek and 1.8 Mm^{-1} at Upper Buffalo on the 20% worst days. As discussed elsewhere, Entergy Arkansas submitted additional CAMx modeling with their comments. This photochemical modeling projects a 2.95 Mm^{-1} reduction at Caney Creek and 1.54 Mm^{-1} reduction at Upper Buffalo when compared to the Entergy's base case modeling for 2018 for the 20% worst days.[895]

Comment: [UARG (0176) p. 16-18] Even the negligible changes in visibility represented by EPA's proposed revised RPGs are greatly overstated: Even though, as EPA observes, "some FIP controls will not be in place by 2018," *id.* at 18,997 – an observation that is indisputably correct with respect to the FIP's SO2 control requirements that have compliance deadlines that are five years after the final EPA rule's effective date – EPA counterfactually calculates its proposed 2018 RPGs assuming that *all* of the proposed FIP's BART and reasonable progress emission

[894] See 81 FR 335 and the FIP TSD that accompanies that action (Available at www.regulations.gov, document ID: EPA-R06-OAR-2014-0754-0007)

[895] See Entergy CAMx Results 2015-1124_FINAL.xls

limits are in place by 2018, *see id.* (stating that although "[w]e note that some [of the proposed] FIP controls will not be in place by 2018, … for the purpose of this calculation, we included reductions from all FIP controls"). Because the bulk of the EPA-projected visibility improvements are due to proposed SO2 emission limits for BART and reasonable progress that have a five-year compliance deadline and thus will not become operative until at least 2020, no sound basis exists for the projections of visibility improvements by 2018 that EPA sets out in the proposed rule. Those EPA projections are not merely, as EPA concedes, "not refined," *id.*; they are flatly inaccurate and unsupportable.

In this regard, EPA fails to explain why (a) the Agency may permissibly use a concededly oversimplified and inaccurate shortcut methodology for calculating RPGs in its FIP, on the grounds that EPA otherwise would have to conduct time-consuming and complicated modeling, *see id.*, but (b) Arkansas and other states apparently are held to a much higher standard for *their* RPG analyses, *see id.* In proposing and promulgating a FIP for Arkansas, EPA merely stands in the state's shoes. Accordingly, if EPA may lawfully comply with the CAA and the regional haze rules by conducting and relying on this sort of analysis that is "not refined" but (purportedly) sufficient to support its FIP's RPGs, then states also may do so to support their SIPs' RPGs. On the other hand, to the extent EPA does not believe that RPGs based on such an abbreviated analysis would be approvable if submitted by a state in a SIP, EPA cannot lawfully promulgate the RPGs that it proposes based on the analysis presented in its proposed rule.

Response: We proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo of 22.27 dv and 22.33 dv, respectively that reflected the anticipated visibility conditions resulting from the combination of control measures from the approved portion of the 2008 Arkansas Regional Haze SIP and our FIP proposal. After considering these comments, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. This approach is consistent with the purpose of RPGs and the direction provided in our 2007 Reasonable Progress Guidance.

Section 169B(e)(1) of the CAA directed the Administrator to promulgate regulations that "include[e] criteria for measuring 'reasonable progress' toward the national goal." Consequently, we promulgated 40 CFR 51.308(d)(1) as part of the Regional Haze Rule. This provision directs states to develop RPGs for the most and least impaired days to "measure" the progress that will be achieved by the control measures in the state's long-term strategy "over the period of the implementation plan."[896] The current implementation period ends in 2018. RPGs "are not directly enforceable" like the emission limitations in the long-term strategy.[897] Rather, they fulfill two key purposes: (1) allowing for comparisons between the progress that will be achieved by the state's long-term strategy and the URP,[898] and (2) providing a benchmark for assessing the adequacy of a state's SIP in 5-year periodic reports.[899] Consequently, in our 2007 Reasonable Progress Guidance, we indicated that states could consider the "time necessary for compliance" factor by "adjust[ing] the RPG to reflect the degree of improvement in visibility achievable

[896] 40 CFR 51.308(d)(1).
[897] 40 CFR 51.308(d)(1)(iv).
[898] 40 CFR 51.308(d)(1)(ii).
[899] 40 CFR 51.308(g)-(h).

within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018."[900] In other words, RPGs need not reflect the visibility improvement anticipated from all of the control measures deemed necessary to make reasonable progress (as a result of the four-factor analysis) and included in the long-term strategy.

In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due.[901] As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021. Because RPGs are only unenforceable analytical benchmarks, we think that it is appropriate to follow the recommendation in our 2007 Reasonable Progress Guidance and finalize RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018. These RPGs are listed in the table below:[902]

Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I area	2018 RPG 20% Worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

We note that the RPGs we are finalizing are very similar to the ones that we disapproved in the Arkansas Regional Haze SIP. [903] The reason for this is that Arkansas' RPGs were calculated using the 2018 CENRAP CAMx modeling completed in 2006/2007, which assumed that Flint Creek would install scrubbers to meet the presumptive SO_2 BART limit of 0.15 lb/MMBtu, that Flint Creek and White Bluff would install low NO_X burners to satisfy NO_X BART, and that AECC Bailey and Entergy Lake Catherine would be shut down by 2018. In contrast, our RPGs reflect a more stringent SO_2 emission limit of 0.06 lb/MMBtu at Flint Creek and the installation of low NO_X burners at Independence in addition to Flint Creek and White Bluff, but also the continued operation of AECC Bailey and Entergy Lake Catherine. In other words, our RPGs reflect additional emission reductions from Flint Creek and Independence, but more emissions from AECC Bailey and Entergy Lake Catherine.

The fact that the RPGs we have calculated are very close to those originally submitted by Arkansas does not undermine the reasonableness of our action. We disapproved Arkansas' RPGs because Arkansas failed to conduct a four-factor analysis, as required by the CAA and the Regional Haze Rule. Without a four-factor analysis, Arkansas was unable to determine whether control measures were necessary to make reasonable progress—the core requirement of the CAA's visibility program.[904] After conducting a full four-factor analysis, we have determined

[900] 2007 Reasonable Progress Guidance at 5-2.
[901] We discuss in section II.A of the final rule the history of the state's submittals and our actions.
[902] These RPGs are calculated using the same methodology described in our proposal and TSD.
See "CACR UPBU RPG analysis 2018.xlsx" for additional information on the calculation of the RPGs.
[903] 77 FR 14604.
[904] CAA section 169A(b)(1) and (g)(1).

that controls at the Independence plant are cost-effective and reasonable and therefore necessary to make reasonable progress. The visibility benefits of the SO_2 controls at Independence, along with benefits of the SO_2 BART controls at White Bluff, and additional BART controls at AECC Bailey, AECC McClellan, Entergy Lake Catherine, and the Domtar Ashdown Mill will be fully realized in 2021, and we expect Arkansas to properly take these benefits into account when developing RPGs for 2028.[905]

We disagree with the commenter that the proposed RPGs overstated the visibility benefit of controls or that they are inaccurate. In our proposal, we acknowledged that the methodology we utilized to estimate the RPGs is not as refined as developing an updated model projection. However, it allows us to translate the emission reductions contained in the proposed FIP into quantitative RPGs, based on modeling previously performed by the CENRAP.[906] The proposed RPGs provided an estimate of the visibility benefit of all the required controls compared to the 2018 visibility conditions projected by the state and established in their SIP that would result without the required controls. Our final RPGs, calculated using the same methodology, reflect the anticipated visibility conditions at the end of the implementation period in 2018 and the visibility benefit from those controls required to be implemented by the end of 2018. RPGs, unlike the emission limits that apply to specific reasonable progress and BART sources, are not directly enforceable.[907] Rather, the RPGs are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to achieve reasonable progress.[908] Our FIP imposes emissions limitations that we conclude to be necessary under the CAA for the first planning period. Ideally, these controls would be installed and the emission limitations achieved, so the visibility improvements can be realized and built on in a subsequent comprehensive periodic SIP revision (see 40 C.F.R. 51.308(f)). Arkansas may choose to use these RPGs for purposes of its progress report (along with a consideration for what controls had already been implemented and what controls would be implemented in the near future), or may develop new RPGs for approval by us along with its progress report, based on new modeling or other appropriate techniques, in accordance with the requirements of 40 CFR 51.308(d)(1) in evaluating the adequacy of their SIP (or this FIP) to meet the established RPGs.

We disagree that Arkansas would be held to a higher standard or that the methodology utilized by EPA to adjust the RPGs would not be approvable if submitted by a state. The approach followed by EPA in this action, using scaling to adjust the modeled RPGs based on photochemical source apportionment model results is reasonable and meets the requirements of the Regional Haze Rule. In our 2012 rulemaking,[909] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. In our proposed

[905] The RPGs we are finalizing today for Caney Creek and Upper Buffalo are a logical outgrowth of our proposed RPGs based on comments we received, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union,UMW*, 407 F.3d at 1259; *Fertilizer Inst.,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n* v. *Block,* 755 F.2d 1098.

[906] 80 FR 18998

[907] 40 CFR 51.308(d)(1)(v).

[908] 64 FR 35733 and 40 CFR 51.308(d)(1)(v).

[909] 64 FR 35732

rulemaking, we completed the reasonable progress analysis and established revised RPGs using the methodology described above, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved.

Comment: EPA did not appropriately develop the revised RPGs for Caney Creek and Upper Buffalo. [AECC (0169) p. 3-4] AECC stated that EPA explains how to appropriately develop RPGs for Class I areas in the proposed Rule, but EPA states that it did not use this approach in developing RPGs for the proposed Rule.[910] AECC stated that EPA explains that to develop an appropriate RPG analysis there should be:

- Use of a photochemical grid model for a multi-state area;
- An update of the emissions inventory for Arkansas and the surrounding states; and
- Specialized and extensive computing hardware and expertise to develop input files, run the models, and post-process the model outputs.[911]

AECC stated that EPA explains that this process was not used to develop RPGs for Caney Creek and Upper Buffalo because it would take several months.[912]

AECC stated that EPA used CALPUFF, which is not a photochemical grid model, to develop a "quick-and-dirty" RPG analysis in proposed Rule. CALPUFF is a single-source model used for individual BART assessments. A photochemical grid model would use data from thousands of emission sources to determine the impact on a given Class I area.

Based on the information above, AECC believes that EPA used an inappropriate process to develop RPGs for the Arkansas Class I areas. EPA is using the results of this inappropriate analysis to subject the Independence plant to installation of controls. AECC believes that this is arbitrary on the part of EPA and the Independence units should be removed from the scope of this proposed Rule.

Response: The commenter is incorrect and confuses the single-source visibility analysis used to evaluate the visibility benefit of controls on a specific source with the assessment of overall visibility conditions. We did not use the CALPUFF modeling to develop the new reasonable progress goals we establish in this rulemaking. The RPGs are based on adjusting the CENRAP 2018 CAMx photochemical modeling based on source apportionment modeling results and emission inventory data. As we stated in the proposed rulemaking, we did not perform additional photochemical modeling to directly model the new projected visibility goals due to the time and resource demands associated with photochemical modeling.

7.i. Additional Modeling Comments

Comment: EPA should have used realistic data for its visibility analysis [Nucor Steel-Arkansas and Nucor-Yamato Steel (0163) p.38-40] Nucor stated that according to EPA's BART

[910] *80 FR* 18997.
[911] *Id.*
[912] *Id.*

Guidance "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 40 CFR Part 51, Appendix Y, Section IV.D.4.c. However, EPA's BART and Reasonable Progress determinations do not comply with this requirement. First, EPA's use of the maximum 24-hour recorded emissions extrapolated across the three year analysis period significantly overestimates the visibility impacts from a facility. For example, from 2001 to 2003, Entergy Independence reported maximum 24-hour SO_2 emission rates of 5,463 lb/hr and 6,337 lb/hr from Unit 1 and Unit 2, respectively. However, the average daily emission rate over that same three year period (with downtime omitted) for Unit 1 and Unit 2 is 2,927 lb/hr and 3,088 lb/hr, respectively. Actual average emissions from the facility are half of what is represented in the modeling analysis.

Additionally, EPA admits in the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations that modeled impacts are overstated. Specifically, EPA states that "there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source." 70 Fed.Reg. 39104, 39121 (July 6, 2005). This led the EPA to its decision to use the 98th percentile of modeled visibility values, which eliminates roughly 7 days per year from the analysis. However, this approach has no rational or generally accepted scientific basis as a way to "normalize" the emissions data. Using the same example for Entergy Independence, if the maximum 7 days of each year from 2001 to 2003 is eliminated for each unit, the maximum 24-hour emissions rates across that timeframe become 4,768 lb/hr and 5,357 lb/hr at Unit 1 and Unit 2, respectively. This is still far above the actual average daily emission rate and continues to severely overestimate the reasonable amount of emissions that would occur over an extended period of time at the facility.[913]

In addition, EPA failed to use the most recent SO_2 emissions data for the White Bluff and Flint Creek BART determinations, relying instead on continuous emissions data from 2001-2003 to establish baseline visibility impacts. EPA should have used 2009-2011 emissions data, which Entergy specifically proposed for its White Bluff BART Five Factor Analysis, and which reflects a significant decrease in SO_2 emissions.[914] Because use of low-sulfur coal is an acceptable pollution control technology, it was wrong for EPA not to accept the emissions data from 2009-2011 just because use of low-sulfur coal was not required by a permit condition. North Dakota v. EPA, 730 F.3d 750, 764 (8th Cir. 2013).

Response: The portion of the BART Guidelines cited by the commenter (40 CFR Part 51, Appendix Y, Section IV.D.4.c.) refers to the section that discusses how to estimate cost-effectiveness of controls using annualized costs and annual emission reductions. Our cost-effectiveness analysis for the BART units (developed by the facilities) and our cost analysis for Independence, under reasonable progress, follows this guidance and utilizes average emissions from the baseline period. Elsewhere in the guidance, for visibility analyses, the BART

[913] EPA's 98th percentile approach also does not suffice to "normalize" the maximum visibility impacts, since there is no demonstrated relationship between the modeled highest visibility impacts and the highest observed visibility impacts.

[914] See Exhibits 15A and 15B to Nucor's comments, demonstrating the reduction in SO_2 emissions and coal sulfur concentrations for White Bluff in 2009-2011, compared to 2001-2003.

guidelines state:[915] "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the precontrol scenario)."

With respect to our analysis of controls under reasonable progress, we rely on our reasonable progress Guidance.[916] Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in Section 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. Also, similar to a BART analysis, we are also considering the projected visibility benefit in our analysis following the BART guidelines.[917] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

Therefore, our analysis for the Independence facility followed the BART guidance and was consistent with the BART analyses done for all subject-to-BART facilities. Consistent with this guidance, we utilized the 24-hr maximum emission rate from the 2001-2003 baseline period and modeled using 2001-2003 meteorological data. The BART Guidelines also state that the emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction. In addition, the monthly average relative humidity is used, rather than the daily average humidity—an approach that effectively lowers the peak values in daily model averages.[918] As discussed elsewhere in this document, the BART guidelines also recommend the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value as proposed. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[919] Therefore, our modeling approach is consistent with the guidance and focuses on estimating the maximum potential visibility impacts that correspond to periods of high utilization and not the average emission rate over the baseline period.

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[915] 40 CFR Part 51, Appendix Y, Section IV.D.5

[916] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007

[917] As we explain in our proposed action (80 FR 18993): "While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress". See 79 FR at 74838, 74840, and 74874.

[918] 40 CFR Part 51, Appendix Y, Section III

[919] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution."
70 FR 39104, 39121.

The commenter does not provide the full context from the preamble to the final Regional Haze Rule[920] discussing the use of the 98th percentile value. The full text states:

"…there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution. The use of the 98th percentile of modeled visibility values would appear to exclude roughly 7 days per year from consideration. In our judgment, this approach will effectively capture the sources that contribute to visibility impairment in a Class I area, while minimizing the likelihood that the highest modeled visibility impacts might be caused by unusual meteorology or conservative assumptions in the model."

As we discuss above in a separate response to comment, the extreme tail of the distribution of modeled results are typically much higher than the remainder of the modeled values and can be an overly conservative estimate of the maximum impact. The commenter confuses eliminating the highest modeled impacts (that may reflect unusual meteorology or conservative model assumptions) with eliminating the highest emission rates and using the 8th highest emission rate. The commenter claims that the use of the 98th percentile is an attempt to "normalize" the emissions data, but this is not correct. As we discuss above, the modeling approach is to estimate the impact from the highest emission days (using actual emission data), not the average or a "normalized" emission rate.

The commenter also states that we should have utilized emissions data from 2009-2011 rather than the 2001-2003 baseline emissions for the evaluation of controls at White Bluff and Flint Creek. As stated above, consistent with the BART guidance, we utilized the 24-hr maximum emission rate from the 2001-2003 baseline period and modeled using 2001-2003 meteorological data. The commenter provides emissions data for the White Bluff units for 2001-2012, but this data only shows average monthly emissions and monthly sulfur content of coal and does not provide any information on shorter term emission rates or the maximum 24-hr emission rates during those years. This data also shows an upward trend in monthly SO2 emissions, particularly at Unit 1 from 2010 through the end of the data in 2012. Similar to the information we presented in Appendix C of the TSD for the Independence units, the table below shows the maximum 24-hr emission rate for each year for the White Bluff units. As can be seen in the table below, more recent data shows high variability in maximum emissions with 2014 maximum emissions higher than emissions in 2009-2011. Furthermore, the recent utilization of lower-sulfur coal does not provide any assurance that the suggested 2009-2011 baseline would be representative of future emissions because there is no requirement or physical control technology in place to reasonably prevent emissions from increasing in the future, emission rates in 2013 and 2014 are higher than the 2009-2011 period,[921] and it is possible that the addition of potential control equipment would allow for the utilization of cheaper, higher-sulfur coal. Consistent with the BART analysis prepared by Flint Creek, we utilized emissions from the

[920] 70 FR 39104, 39121

[921] See "whitebluff unit1 and 2 EI.xlsx" in the docket for this action for additional emission inventory data for thiese units

2001-2003 baseline. In the case of NOx emissions, in 2006 Entergy completed the addition of a neural network system and conducted extensive boiler tuning that substantially reduced NOx emissions, resulting in an actual change in operations and emissions between the original baseline period (2001–2003) and current operations. For NOx, we did utilize more recent emissions data from the 2009-2011 period because this data reflected the installation of controls, a change in operations and emissions, and any additional NOx controls would be applied in combination with these existing controls.

Year	SO2	
	24-hr Max (lb/hr)	
	unit 1	unit 2
2000	7214	8212
2001	6983	6858
2002	6986	6635
2003	7764	7825
2004	7944	7801
2005	7123	6772
2006	7628	7948
2007	6664	7685
2008	6975	7121
2009	6772	6622
2010	5833	5598
2011	6485	6435
2012	5532	6131
2013	5999	6133
2014	7251	6852
2001-2003	7764	7825
2009-2011	6772	6622
2012-2014	7251	6852

Comment: [UARG (0176) p. 15-16] UARG stated that EPA proposes reasonable progress requirements for the Independence Power Plant, which is not subject to BART. EPA attempts to support its proposed reasonable progress determination for Independence with supplemental visibility modeling that EPA conducted after learning of an error in the Agency's previous modeling. *See* Summary of Additional Modeling for Entergy Independence, Docket ID No. EPA- R06-OAR-2015-0189-0147, at 3 (Apr. 20, 2015). In conducting this supplemental modeling, EPA evaluated projected visibility improvements using different baselines. For SO2, EPA evaluated visibility improvements against a 2001-2003 baseline period ("BASE") and against an alternative baseline that included 2001 2003 SO2 emissions and updated NOx emissions using 2011-2013 data ("BASE2"). *See id.* at 5 6. For NOx, EPA only evaluated visibility improvements against the BASE2 (*i.e.*, the 2011-2013) scenario. *See id.* at 6-7.

Modeled visibility impacts for SO2 depend on whether EPA used the BASE period or the BASE2 period, with impacts varying by as much as 0.461 dv. *See id.* at 5-6; *compare id.* at 5 Table 2 (projected visibility improvement of 1.056 dv with dry FGD at Hercules-Glade using BASE) *with id.* at 6 Table 3 (projected visibility improvement of 0.595 dv with dry FGD at Hercules-Glade with BASE2). In the Federal Register notice announcing the availability of EPA's supplemental modeling, EPA presented only the SO2 modeling results using BASE and the NOx modeling results using BASE2, thereby suggesting that those values are the ones on which EPA proposes to rely in this rulemaking. 80 Fed. Reg. 24,872, 24,873 (May 1, 2015). EPA did not, however, provide any rationale for using an updated, 2011-2013 baseline for NOx modeling while retaining the 2001-2003 baseline for evaluating visibility impacts of SO2 and SO2 reductions. If EPA intends to proceed to promulgate a final FIP based on this proposed rule and the Agency's additional modeling, it must first publish a supplemental notice of proposed rulemaking with an adequate explanation of its reasons, together with any supporting information, for its decisions on this matter and must allow a reasonable opportunity for public comment on that explanation and information.

Response: We disagree with the commenter's characterization of our action. For our visibility impact analysis of the Independence facility, we modeled using both the baseline period of 2001-2003 as well as the updated baseline period for NOx in order to consider the currently existing NOx controls. As we explained in the TSD, modeled visibility benefits from the use of DFGD using the updated NOx emissions baseline from 2011-2013 are similar to those modeled with the 2001-2003 baseline NOx emissions values.[922] We also noted that had we modeled a more recent baseline for SO2 emissions, the baseline visibility impact would be greater and the visibility benefits modeled from the control scenarios would also be greater. In Appendix C of the TSD we explain the baseline emissions we identified for our analysis, using an updated baseline to evaluate NOx controls due to changes in operation between the baseline period and when the modeling was performed. We noted that this was similar to the adjustment made to the White Bluff NOx emissions discussed in the response to comment above. As can be seen in Table 3-1 of Appendix C of the TSD, the NOx emission levels, particularly for unit 2 are much lower for the 2011-2013 time period than the 2001-2003 baseline, reflecting a change in operation and emissions.

Our Federal Register notice on May 1, 2015, provided notice of supplemental modeling available in the docket and provided a summary of the model results. The supplemental modeling corrected an error in the modeled location of the facility due to a typographical error. All other model inputs and model scenarios were identical to the previous modeling described in Appendix C of the TSD. A summary of all the results of the supplemental modeling was made available in the docket, including results using both NOx baseline emission levels.[923] The commenter incorrectly calculates the difference between modeled visibility impacts for SO2 control scenarios between the BASE and BASE2 modeled scenarios. The projected visibility improvement at Hercules-Glade using BASE is 1.056 dv compared to a projected visibility

[922] Appendix C to the TSD, Section 3.1, available in the docket for this action

[923] Summary of Additional Modeling for Entergy Independence, available in the docket for this action

improvement at Hercules-Glade using BASE2 of 1.139 dv, a difference of 0.083 dv.[924] We noted that these results are similar and that either modeled scenario supports our conclusion that visibility impacts from these units are large and that controls will result in meaningful visibility benefits towards the goal of natural visibility conditions. We disagree with the commenter and have provided opportunity for comment on all aspects of the modeling that we conducted including our additional modeling for the Independence facility.

Comment: EPA's NO_X BART analysis for Lake Catherine Unit 4 did not adequately consider the visibility improvements from potential NO_X controls, along with other statutory BART factors, and is therefore legally flawed. [Sierra Club et. al. (0171) p. 27-28] The Sierra Club et. al. stated that EPA must base BART determinations on an analysis of the five statutory BART factors: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) existing pollution controls in use at the source, (4) the remaining useful life of the source, and (5) the degree of visibility improvement. 42 U.S.C. §7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). The Lake Catherine Unit 4 BART analysis fails to accurately consider the visibility improvement from NO_X controls, along with compliance costs and the non-environmental impacts of controls. [The Sierra Club's detailed comments regarding consideration of compliance costs and non-environmental impacts of controls are found in the sections of this RTC document where we discuss cost and other BART issues.] EPA incorrectly analyzed the visibility improvements from potential controls in several ways. EPA failed to provide sufficient documentation for the proposed achievable NO_x limit of BOOS and, as a result, EPA likely overstated the visibility benefits of this control scenario. In 2007, ENSR Consulting found that BOOS could achieve an emission rate of 0.280 lb/MMBtu. Stamper Report at 53. Sargent & Lundy found, based on BOOS testing, that an emission rate of 0.24 was achievable. *Id.* Sargent & Lundy, however, also found that Entergy would need to increase natural gas firing by 25% to operate the unit at the same capacity factor. *Id.* at 53-54. Sargent & Lundy never calculated what emission rate was achievable with this additional natural gas usage. *Id.* Then in 2015, EPA proposed an emission limit of 0.22 lb/MMBtu on a 30 boiler operating day rolling average based on the installation and operation of BOOS. 80 Fed. Reg. at 18,978. Neither EPA nor Entergy explained or documented why the new rate is achievable despite these past findings. *Id.* As the Stamper Report explained, Entergy appeared to rely on the long averaging time and the fact that this facility is a peaking unit, to find that this emission rate is achievable. If EPA or Entergy used averaging times to find this lower emission rate achievable than it is likely that Entergy did not properly model short term NO_x emissions for Lake Catherine. Stamper Report at 54.

In addition, EPA overestimated the visibility benefits of BOOS because it did not analyze whether NO_x emissions under this scenario would be higher than the assumed baseline due to additional natural gas usage. *Id.* Finally, EPA overestimated the visibility benefits of each control scenario as it relied on Entergy's flawed maximum daily average NO_x emission rate. As described in Ms. Stamper's report, Entergy incorrectly determined the maximum daily rates for each control scenario, which resulted in applying a percent reduction that was higher than

[924] Summary of Additional Modeling for Entergy Independence, available in the docket for this action. See Table 2 for visibility improvement over baseline using BASE and Table 3 for visibility improvement over baseline using BASE2

required by the proposed NO_x rates for each control scenario. *Id.* at 55-57. As a result, Entergy understated the maximum daily NO_x emission rates under each control scenario. This in turn overstated the visibility benefit from each control scenario.

Comments [Sierra Club Stamper Report]: Typically, the determination of the maximum 24-hour emission rate for a control scenario is determined through the following steps: 1) Determine the 24-hour period of maximum daily emissions during the baseline period. 2) Determine the NOx rate in lb/MMBtu that the unit achieved during the baseline period over a long term average. Usually, the annual average NOx rate over the baseline is determined, although sometimes the maximum 30-day average NOx rate during the baseline period is evaluated. 3) Determine the percent reduction from the annual average or from the 30-day average NOx emission rate during the baseline period needed to achieve the proposed 30-day averaging limit for the proposed control scheme. 4) Apply that percent reduction to the maximum daily NOx rate over the baseline period to predict maximum daily NOx emissions under the control scheme being evaluated to meet BART.

Entergy correctly determined the baseline NOx emission rate for Lake Catherine Unit 4 during the 2001-2003 baseline period as the maximum daily emissions during the baseline period, divided by 24 hours per day to lb/hr rate of 2,456.4 lb/hr.[208] Entergy also assumed a maximum emission rate of 0.4825 lb/MMBtu for Lake Catherine Unit 4 during the baseline period.[209] To project maximum daily rates under the various control scenarios, Entergy determined the percent NOx reduction from 0.4825 lb/MMBtu to the proposed 30-day average NOx emission rate for each control scenario, and applied that to the 2001-2003 maximum daily rate of 2,564.4 lb/hr to estimate maximum daily NOx emissions under each control scenario.[210] However, the 0.4825 lb/MMBtu baseline emission rate was not a long term average NOx rate at Lake Catherine Unit 4: instead, it was the maximum 24-hour average NOx emission rate at Lake Catherine Unit 4 during the 2001-2003 baseline period.[211] By using a maximum daily NOx rate during the baseline period and comparing it to proposed 30-day average emission rates for each control scenario to determine the percent removal, Entergy has greatly understated the maximum daily NOx emission rates under each control scenario (because Entergy's approach overstates the percent reduction from each control evaluated). As a result, Entergy's modeling overstates the visibility benefits with each control scheme evaluated.

As stated above, the commonly applied approach for determining emission rates to model for BART visibility analyses is to determine the annual average NOx rate or, at most, the maximum 30-day average NOx rate during the baseline period, and then to evaluate the percent reduction from that annual or 30-day average rate to achieve the 30-day average emission rate assumed for each control scenario. The 2001-2003 annual average NOx rate for Lake Catherine Unit 4 was 0.18 lb/MMBtu[212], which is lower than the NOx rate assumed for BOOS and low NOx burners/OFA (meaning BOOS would provide no NOx reductions from an annual average baseline). The maximum 30-day average NOx rate at Lake Catherine Unit 4 during the 2001-2003 baseline period was 0.27 lb/MMBtu.[213] Entergy should not have assumed a baseline NOx rate any higher than 0.27 lb/MMBtu in projecting emissions rates under each control scenario.

In Table 15 below, I recalculate the projected maximum daily emission rates based on a 0.27 lb/MMBtu baseline and the 30-day average NOx rates assumed by Entergy in its BART analysis.

[208] *See* Entergy Revised BART Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014 at 4-1.
[209] *Id.* at 6-5; Appendix D at 17 -18.
[210] *Id.*
[211] *Id.*, App. D at 18 (Note 1).
[212] *See* spreadsheet with Lake Catherine Unit 4 annual emissions CAMD data for 2001 to 2003 (Ex. 92).
[213] *See* spreadsheet with Lake Catherine Unit 4 daily emissions CAMD data for 2001 to 2003 (Ex. 93).

Table 15. Maximum Daily NOx Emission Rates for Various NOx Controls Evaluated for Lake Catherine Unit 4 Based on Percent NOx Reduction from 30-Day Average NOx Baseline Rate, Rather than Entergy's Maximum Daily NOx Baseline Rate

NOx Control Scenario	30-Day Average NOx Rate, lb/MMBtu	Max Daily NOx Emissions, lb/hr	Max Daily NOx Emissions Modeled by Entergy, lb/hr[214]
Baseline	0.27	2,456.4	
BOOS	0.22	1,999.5	1,287.0
LNB/SOFA	0.19	1,726.8	1,111.5
LNB/SOFA Plus SNCR	0.14	1,272.4	819.0
LNB/SOFA Plus SCR	0.03	272.7	175.5

As Table 15 demonstrates, the use of the commonly-applied methodology for estimating maximum daily NOx emissions under each control scenario predicts significantly higher maximum NOx emission rates for each control scenario, which means that Entergy's modeling overstates the visibility benefits for all controls evaluated.

For BOOS, it may not even be appropriate to assume an 18.5% reduction in daily NOx emissions.[215] As discussed above, it is not clear what the maximum short term NOx rate would be with BOOS at Lake Catherine Unit 4, because the fuel firing rate will need to be increased by 25% to achieve maximum generation capacity with BOOS.[216] Sargent & Lundy predicted a 0.24 lb/MMBtu emission rate with BOOS at Lake Catherine Unit 4.[217] Entergy has assumed it could meet a lower 0.22 lb/MMBtu NOx limit with BOOS on a 30-day averaging basis based on the exp ected utilization rate of Unit 4.[218] It appears Entergy was assuming it could average in peak NOx rates with lower NOx rates to achieve a 30-day average rate of 0.22 lb/MMBtu. That may be acceptable for demonstrating compliance with a 30-day average BART limit, but modeling a lower NOx limit would overstate the visibility benefits of BOOS at Lake Catherine Unit 4 by failing to reflect the max daily NOx rate that would be emitted at Unit 4 with BOOS.

EPA should carefully estimate the maximum daily emissions expected from the operation of BOOS (along with the increased firing rate) at Lake Catherine Unit 4 to ensure it is basing its BART determination on an accurate prediction of the visibility benefits of BOOS.

[214] See Entergy Revised BART Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014 at 4-1 and 6-10.

[215] This is the percent reduction from the 0.27 lb/MMBtu 30-Day Average NOx baseline rate and the proposed NOx limit with BOOS of 0.22 lb/MMBtu.
[216] See Id. at 6-2, 6-4, Appendix D at 15-16.
[217] Id.
[218] Id. at 6-2.

Response: See our response to the issue of whether Entergy can achieve the NOx emission limit of 0.22 lbs/MMBtu due to the installation of BOOS in the Cost section of our Response to Comments Document.

The commenter states that we overestimated the visibility benefits from controls because we used a maximum daily NOx rate during the baseline period and compared it to proposed 30-day average emission rates for each control scenario to determine the percent removal.

The BART guidelines recommend the following approach in developing the modeled scenarios:

> For each source, run the model, at precontrol and post-control emission rates according to the accepted methodology in the protocol. Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the precontrol scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of precontrol emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO2, then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.[925]

As discussed in detail previously, we rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

This is the general approach followed by us and the BART analysis prepared by the facility for the Lake Catherine analysis. The baseline emission rate was based on maximum actual 24-hr emission rate during the baseline period of 0.4825 lb/MMBtu. The modeled controlled emission rates were then estimated based on a percentage reduction anticipated by each control technology, as identified in the Sargeant and Lundy report[926], from this maximum emissions rate, as shown in the table below. The commenter is incorrect in their assertion that all the modeled emission rates represent 30-day average emission rates. We disagree that it is necessary to remodel the baseline and control scenarios utilizing a long-term emission rate.

Control	% reduction from baseline	NOx emission rate (lb/MMBtu)	NOx emission rate (lb/hr)[1]
Baseline	---	0.4825	2456.4[2]

[925] 40 CFR 51 Appendix Y IV.D.5
[926] NOx Control Technology Cost and Performance Study Entergy Services, Inc. White Bluff & Lake Catherine, May 16, 2013 (Appendix D to the Entergy Revised BART Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014)

BOOS	50%	0.24 (0.22)[3]	1404.0 (1287.0)
LNB/SOFA	60%	0.19	1111.5
LNB/SOFA + SNCR	70%	0.14	819.0
LNB/SOFA + SCR	94%	0.03	175.5

[1]lb/hr emission rate for control scenarios based on percent reduction applied to 0.4825 lb/MMBtu rate and maximum heat input rate of 5850 MMBtu/hr
[2]Baseline lb/hr rate based on actual emissions from highest emitting day during baseline period
[3] Entergy Lake Catherine final analysis utilized 0.22 lb/MMBtu, previous analyses used 0.24 lb/MMBtu

The commenter is correct that the final BART analysis[927] prepared by the facility utilized a 0.22 lb/MMBtu emission rate for the BOOS control scenario, which represents the 30-day average emission rate rather than the 0.24 lb/MMBtu estimated short term emission rate estimated as a 50% reduction from the baseline maximum short term rate of 0.4825 lb/MMBtu. The previous BART analysis[928] prepared by the facility utilized the 0.24 lb/MMbtu emission rate for modeling the BOOS control scenario. We evaluated the difference between these modeled scenarios and summarize the results below for most impacted Class I area, Caney Creek.

Control	**Visibility impact**	**Visibility improvement from baseline**	**Incremental improvement over BOOS**	
			0.22 lb/MMBtu	**0.24 lb/MMBtu**
Baseline	1.371			
BOOS (0.22lb/MMBtu)	0.775	0.596		
BOOS (0.24lb/MMBtu)	0.835	0.536		
LNB/SOFA	0.683	0.688	0.092	0.152
LNB/SOFA + SNCR	0.529	0.842	0.246	0.306
LNB/SOFA + SCR	0.163	1.208	0.612	0.672

We note that the BART determination is based on consideration of five factors, including the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The visibility modeling is intended to give a reasonable best estimate of the visibility impacts from an evaluation of emission reductions. The visibility analysis is only one of the factors in a BART determination. In this final action, we are setting a NOx limit of 0.22 lb/MMBtu to be calculated on a 30-day rolling average Boiler Operating Day. We modeled the

[927] Entergy Revised BART Five Factor Analysis, Lake Catherine Steam Electric Station, May 2014
[928] BART Five Factor Analysis, Lake Catherine Steam Electric Station, March 2013

0.22 lb/MMBtu in our proposal, because we have determined this emission rate to be achievable based on information supplied by the facility. In response to comments, we have also examined that visibility impacts and benefits based on the shorter-term emission rate of 0.24 lb/MMBtu from the previous analysis available in the record. We find that consideration of the visibility impacts and benefits at the higher, short-term rate does not change our determination that BOOS is BART for this source. While the incremental visibility benefits over BOOS are larger by 0.06 dv, the total visibility benefit of higher control levels is unchanged. As we discuss in the proposal[929], the incremental costs for more effective controls above BOOS remain high. BOOS was estimated to cost $138/ton compared to $1,450/ton for LNB/SOFA (an incremental cost of more than $14,000/ton). Furthermore, while the visibility benefits from SCR are not insignificant, we do not consider the cost per ton removed ($5,614/ton) and the incremental costs of SCR to be cost-effective.

Comment: EPA should revise its NO_X BART analysis for Lake Catherine Unit 4 and in doing so should give due consideration to SCR's superior visibility benefits. [Sierra Club et. al. (0171) p. 28] The Sierra Club et. al. stated that EPA's Lake Catherine Unit 4 NO_X BART analysis fails to accurately consider the degree of visibility improvement of controls, as well as the compliance costs and non-environmental impacts. Therefore, EPA's analysis is legally flawed. [The Sierra Club et. al.'s detailed comments regarding consideration of the degree of visibility improvement of controls, as well as the compliance costs and non-environmental impacts in the NOX BART analysis for Lake Catherine Unit 4 are found throughout different sections of this RTC document.] EPA must conduct a new NO_x BART analysis that corrects these flaws and considers whether SCR represents the best system of continuous emission reduction for NO_x at Lake Catherine Unit 4. In doing so, we urge EPA to give due consideration to the superior visibility benefits of control scenarios that include SCRs and to not place inappropriate weight on the incremental cost-benefit analysis in its revised BART analysis. When EPA corrects its BART analysis to address the flaws that Ms. Stamper identified, the agency will likely find that control scenarios that include SCR are more cost-effective than EPA originally calculated and will provide for the greatest visibility benefits at Caney Creek and the other Class I areas. [Our responses to comments regarding the cost-effectiveness and incremental cost-effectiveness of NO_X controls for Lake Catherine Unit 4 are found in the section of this RTC document where we discuss cost issues.] While EPA overestimated the visibility improvements from the use of SCR by relying on Entergy's flawed maximum daily average NO_x emission rate, its modeling of the SNCR control scenario does provide an approximation of SCR's likely visibility benefits under correct modeling, as discussed in Ms. Stamper's report. Stamper Report at 59. This means that the 98_{th} percentile visibility improvement at Caney Creek would be at least 0.842 dv and the cumulative benefit across all four Class I areas would be at least 1.702 dvs. *Id.*; *see also* Table 42 at 80 Fed. Reg. 18,978. No other suite of NO_x controls would come close to providing as much visibility improvement as the SCR control scenario at Lake Catherine Unit 4. We thus urge EPA to give due consideration to these significant and superior visibility benefits in its revised Lake Catherine NO_x BART analysis.

Response: We disagree with the commenter that we overestimated visibility benefits from SCR. We address comments concerning the estimated visibility improvements from controls at Lake Catherine in the response to comments above. The BART determination is based on

[929] 80 FR 18978

consideration of five factors, including the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The visibility modeling is intended to give a reasonable best estimate of the visibility impacts from an evaluation of emission reductions. The visibility analysis is only one of the factors in a BART determination. In the visibility analysis, we modeled the 24-hr maximum emission rate and percent reductions anticipated from available control technologies, following the BART guidelines, as discussed above. As we discuss in the proposal[930], the incremental costs for more effective controls above BOOS, such as SCR remain high. BOOS provides for very inexpensive emission reductions and significant visibility improvement. While the visibility benefits from SCR are not insignificant, we do not consider the cost per ton removed and the incremental costs of SCR to be cost-effective. If the commenter were correct that we over-estimated the visibility benefits of SCR this would serve only to only reinforce our determination that the visibility benefits, while not insignificant, do not justify the costs of SCR in this case.

Comment: [Dr. Gray]: EPA compared the visibility outcomes from the revised modeling for the various control scenarios to the baseline emission scenarios to determine the benefits associated with each of the potential control measures. The baseline emission scenarios (BASE and BASE2) represent emission levels during two previous time intervals (2001-2003 and 2011-2013) and do not necessarily reflect future emission levels (without controls). EPA should have used projected future year emissions with controls (baseline) and then compared that to a control scenario with commensurate emission reductions as this would be a more-appropriate comparison.

EPA's BASE2 scenario consists of actual SO2 emission levels from 2001-2003 and NOx levels from 2011-2013. The SO2 emission levels are not representative of recent (or projected) emission levels for Independence. As EPA states (in their additional modeling report): "We note that had we modeled a more recent baseline for SO2 emissions, the baseline visibility impacts would be greater and the visibility benefits modeled from the control scenarios would also be greater."

EPA thus underestimated the differences between baseline (using either BASE or BASE2) and the various control scenarios ("visibility improvement over baseline"). Ultimately, a more logical approach is for EPA to simply compare the visibility impacts between the different control scenarios.

Examination of the modeling results shows that the peak days are typically caused by a combination of high sulfate and high nitrate concentration impacts, although high sulfate impacts dominate the highest visibility impact days under the baseline emission scenarios. When significant SO2 emission reductions are applied however (such as through the application of DFGD), the remaining peak days are dominated by high nitrate events, which require NOX reductions to mitigate. Although DFGD controls at Independence achieve a significant reduction in the visibility impact, the modeling shows that the peak impact is still over 1 delta dV at Caney Creek.

[930] 80 FR 18978

The combined control strategy consisting of LNB and DFGD results in the largest visibility improvement of EPA's modeled scenarios. The modeled peak delta dV impact is less than 0.6 at all affected Class I areas. The combined LNB and DFGD scenario is the only control strategy for which the peak delta dV impact would be less than 1.0 at all Class I areas. When the modeled control scenarios for Independence (WFGD, DFGD, LNB, etc.) are compared, it is apparent that the combined SO2 and NOX control scenario consisting of both LNB and DFGD achieves the best visibility outcomes in the four modeled Class I areas of the scenarios considered.

Response: We agree with the commenter that we likely underestimated visibility benefits of controls at the Independence facility using the 2001-2003 emissions baseline because recent SO2 emissions (and possibly projected future emissions) are higher than the modeled baseline emissions from the 2001-2003 time frame. We acknowledged this in our analysis stating: "We note that had we modeled a more recent baseline for SO2 emissions, the baseline visibility impacts would be greater and the visibility benefits modeled from the control scenarios would also be greater." In our analysis, as documented in our proposed rulemaking, we determined that modeled visibility impacts were large, visibility benefits from reductions in SO2 emissions from controls were significant, and controls (DFGD) were reasonable in consideration of the cost of the controls. Using a higher SO2 emission baseline in our analysis would result in even larger visibility benefits from proposed installation of controls and would have reaffirmed this determination. We agree with the commenter that after significant projected SO2 emission reductions, the remaining visibility impact from the source is still significant (> 1 dv at Caney Creek). This remaining visibility impact was shown to be reduced by highly cost-effective NOx reductions from the use of LNB. The combined use of LNB and DFGD does provide for the largest reduction in visibility impairment from the source among the options evaluated. As we discuss in our proposal, we also found these reductions from LNB and DFGD to be cost-effective.

Comment: [Dr. Gray/EarthJustice]: Consideration of SCR for Independence Units 1 and 2 and Reconsideration of SCRs for White Bluff Units 1 and 2.

EPA did not evaluate SCR on the two Independence power plant units using the CALPUFF modeling system. Instead EPA claimed that SCR at White Bluff would not achieve a large enough visibility improvement and therefore EPA need not consider SCR for Independence either.

CALPUFF modeling following the EPA's protocol and model inputs, was used to evaluate SCR at an emission rate of 0.055 lb/MMBtu. The emission rate for SO_2 was assumed to be the 0.06 lb/MMBtu . The modeled emission rates for the SCR_DFGD scenario are shown in Table 2.

Table 2. Modeled Emission Rates for Independence Power Plant for SCR.

Modeled Emission Rate (lb/hr)

Scenario	Source	SO2	SO4	NOX	PMC	PMF	EC	SOA
SCR_DFGD	Unit 1	537.00	0.05	492.25	11.10	10.70	0.40	16.60
	Unit 2	537.00	0.05	492.25	11.10	10.70	0.40	16.60
	Total Facility	1,074.00	0.10	984.50	22.20	21.40	0.80	33.20

The modeled visibility impacts for each Class I area are shown below in Table 3, and in Figure 2 (not reproduced here).

Table 3. Modeled Maximum 98th percentile delta dV for the SCR_DFGD scenario

	CACR	HERC	MING	UPBU	TOTAL
2001	0.303	0.187	0.196	0.186	
2002	0.193	0.207	0.142	0.239	
2003	0.246	0.207	0.165	0.262	
3-yr max	0.303	0.207	0.196	0.262	**0.968**
Improvement over LNB_DFGD	0.257	0.124	0.142	0.220	**0.743**

The cumulative delta dV (sum of all four Class I areas) for each of the modeled emission scenarios (see Figures 1 and 2) is summarized below (total facility impact):

Cumulative delta dV, Independence:

Baseline (BASE2):	7.526
LNB:	6.548
DFGD:	3.067
LNB_DFGD:	1.711
SCR_DFGD:	0.968

From these model results, it can be seen that the application of NOX emission reductions using LNB (LNB_DFGD) would achieve a cumulative delta dV improvement of 1.356 over the DFGD-only scenario. If SCR were applied, the improvement to the cumulative 98th percentile delta dV would be 2.099 (relative to DFGD-only).

The cumulative visibility (delta dV) improvement for SCR at Independence relative to LNB was modeled to be 0.743. SCR at White Bluff resulted in a cumulative delta dV improvement of about 0.43 (relative to LNB/SOFA) – which EPA did not consider sufficient to recommend SCR over LNB/SOFA. The current modeling shows that SCR at Independence would achieve a much larger incremental visibility improvement relative to LNB (0.74 dV) than SCR would achieve at White Bluff relative to LNB (0.43 dV).

If LNB and DFGD were first applied at Independence, then the addition of SCR would remove over 40 percent of the remaining visibility impact from this source, leaving only a small remaining cumulative impact (less than 1 delta dV). If one were then to consider LNB in place of SCR, it would approximately double the visibility impact (to 1.71).

EPA used the modeling results for SCR at White Bluff to discount the consideration of SCR at Independence. EPA's White Bluffmodel results are shown below:

Cumulative delta dV, White Bluff:

Baseline:	9.540
DFGD:	3.902
LNB/SOFA:	8.457
LNB/SOFA_SNCR:	8.313
LNB/SOFA_SCR	8.025

Relative to LNB, SCR at White Bluff achieves a small additional visibility improvement (the cumulative delta dV is reduced by 0.29). EPA observed that the largest incremental visibility improvement over LNB/SOFA was 0.069 at Caney Creek. However, this was for a single unit and also relative to SNCR, which was not proposed; the impact for the total facility (both units) at Caney Creek relative to LNB was 0.21.

EPA understated the benefits of SCR relative to LNB at White Bluff. The cumulative visibility benefit at the four modeled Class I areas was modeled to be 0.43 (delta dV) for SCR relative to LNB at White Bluff[9], much larger than the 0.069 delta dV (for one unit at one Class I area, relative to SNCR) that EPA apparently used to dismiss SCR at White Bluff.

The current modeling shows that SCR at Independence would achieve a much larger cumulative visibility improvement at the modeled Class I areas than SCR at White Bluff. SCR controls should therefore be considered for both the White Bluff and Independence power plants. The current modeling shows that SCRs at Independence provide significant visibility benefit, including significant incremental visibility benefit relative to less stringent controls, such as LNB. The cumulative visibility improvement for SCR at Independence relative to LNB is 0.743 deciview ("dV"), which is larger than EPA assumed in failing to review this technology.

Moreover, EPA significantly undervalued the incremental visibility improvement between LNB and SCRs at White Bluff. The cumulative visibility benefit at the four modeled Class I areas for SCRs at White Bluff relative to LNB is 0.43 (delta dV),[10] which is much larger than the 0.069 delta dV (for one unit at one Class I area, relative to SNCR) than EPA assumed. EPA should consider requiring this technology in its Final Rule for both White Bluff and Independence.

Response: We disagree with the commenter that we undervalued the incremental visibility benefit for SCRs at White Bluff. In evaluating the visibility benefit from controls we considered

the total and incremental visibility benefit at each impacted Class I area as well as the cumulative visibility benefits.[931] For the White Bluff facility, we found that LNB/SOFA and SNCR had a cost-effectiveness of a factor of 4 to 5 times larger than that of LNB/SOFA in terms of $/ton and SCR had a cost-effectiveness approximately 8 to 10 times larger than LNB/SOFA. Based on our cost estimates of controls, we estimate the incremental cost of SCR over LNB/SOFA for unit 1 to be $7,338/ton and $6,611/ton for unit 2. The incremental visibility benefit of SCR over LNB is summarized below. We continue to find that incremental visibility benefits ranging from 0.032 to 0.103 dv on a unit-basis at an individual Class I area and incremental cumulative visibility benefits of 0.216 dv per unit across all 4 impacted Class I areas are not large enough to justify the additional cost of SCR for this planning period.

Class I Area	**White Bluff modeled visibility benefit over baseline (dv)**					
	LNB		SCR		Incremental benefit of SCR over LNB/SOFA	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Caney Creek	0.166	0.225	0.269	0.327	0.103	0.102
Upper Buffalo	0.101	0.139	0.149	0.188	0.048	0.049
Hercules-Glades	0.176	0.190	0.209	0.222	0.033	0.032
Mingo	0.038	0.047	0.07	0.08	0.032	0.033
Sum	0.481	0.601	0.697	0.817	0.216	0.216

In considering NOx controls at Independence we determined that the visibility improvement due to the installation of LNB/SOFA at the Independence facility is of a similar magnitude to that of the White Bluff facility. As explained in our proposed rule, we applied the total annualized LNB/SOFA cost developed by Entergy for White Bluff Units 1 and 2, with one line item revision made by us, to Independence Units 1 and 2. However, we adjusted the cost-effectiveness ($/ton) due to the differing NOx emissions from the units. We reasoned that because (1) the Independence and White Bluff facilities were sister facilities and very similar, and (2) we found that the costs of SNCR and SCR for White Bluff were not worth the resulting visibility improvement, we had no reason not to conclude the same for the Independence facility. The additional visibility benefit from SNCR and SCR did not justify the additional cost of controls at White Bluff for this planning period. Therefore, our evaluation of NOx controls for Independence Units 1 and 2 focused on LNB/SOFA.

We disagree with how the commenters assessed and compared the modeled visibility benefits of SCR. The commenters modeled the combined visibility benefit of SCR controls and dry FGD at Independence (on a facility wide basis), but based on the information provided it does not appear that they modeled or considered the visibility improvement of SCR controls alone, as was done

[931] 80 FR 18974

for White Bluff. The commenter's comparison of visibility benefit from SCR at White Bluff to visibility benefits at Independence is incorrect because the visibility benefits due to SCR at White Bluff were modeled using baseline SO2 emission levels, while the commenter's modeled benefits of SCR at White Bluff are modeled using controlled SO2 emission levels. If the modeling had been performed on a consistent basis allowing for a direct comparison, the visibility benefits from SCR at the two facilities would be similar, as demonstrated by the modeled visibility benefits for LNB/SOFA shown in the table below. Furthermore, the commenter does not provide any modeling for LNB/SOFA and SNCR, so we are unable to assess the incremental visibility benefits of SCR over SNCR as we did for White Bluff. Despite these differences, we have determined that the additional visibility modeling submitted by the commenter does not demonstrate that the visibility benefits due to SCR at Independence are larger than that at White Bluff or are large enough to justify the additional cost of controls.

Class I Area	**Visibility improvement of LNB/SOFA at Independence over baseline (deciviews)**	**Visibility improvement of LNB/SOFA at White Bluff over baseline (deciviews)**
Caney Creek	0.459	0.391
Upper Buffalo	0.198	0.240
Hercules-Glades	0.173	0.366
Mingo	0.148	0.085
Cumulative	0.978	1.082

The commenter's modeling analysis estimates the benefits of SCR at Independence and compares this to the modeled visibility benefits of LNB/SOFA. The table below summarizes the results of our modeling for LNB/SOFA and the commenter's modeling of SCR. As we discuss above, the modeling submitted by the commenters utilized the DFGD controlled emission rate for SO2 rather than the baseline SO2 emission rate so these numbers are not directly comparable to the visibility benefits for White Bluff summarized above.

Class I Area	Independence Modeled visibility benefit over BASE2_DFGD		
	LNB/SOFA	SCR[1]	Incremental benefit of SCR over LNB/SOFA
Caney Creek	0.485	0.742	0.257
Upper Buffalo	0.337	0.557	0.22
Hercules-Glades	0.264	0.388	0.124

Mingo	0.27	0.412	0.142
Sum	1.356	2.099	0.743

[1]SCR model results submitted by commenter

As shown in the table above, the largest incremental visibility benefit of SCR on both units over LNB/SOFA (using the reduced SO2 emission rate) is 0.257 dv at Caney Creek and 0.22 dv at Upper Buffalo. We do not believe this amount of incremental visibility benefit justifies the incremental cost of SCR, estimated to be approximately $6,600/ ton and $7,300/ton based on the White Bluff cost-estimate, at this time. We address comments concerning the commenter's cost-estimates for SCR at Independence and White Bluff in separate responses to comment.

Comment: EPA Used a Few Non-Default CALPUFF Modeling Options That, When Returned to the Default, Had No Material Impact on the Analysis.

Examination of EPA's modeling files for Independence[11] revealed that the agency used a few non-default options. I reviewed these and found that, when returned to the default, the use of these options did not materially impact EPA's analysis. The two parameters evaluated were minimum vertical divergence criteria ("CDIV") and the dispersion parameter ("XSAMLEN").

The commenter states that the vertical divergence (dw/dz) is a measure of the change in the vertical wind speed (w) per meter of depth (the units of dw/dz are 1/s). In the CALPUFF input control file, the user must set a minimum divergence criterion ("CDIV") for dw/dz that is used to initiate an adjustment to the vertical mixing parameter (sigma-z) for modeled puffs. The vertical mixing is adjusted (sigma-z is increased) whenever the vertically averaged dw/dz across the height of the puff exceeds CDIV (and then the increase in sigma-z is proportional to the value of dw/dz). Increasing sigma-z shifts a larger portion of each puff upward and downward from its center point height.

The default value for CDIV of 0.0 (for which sigma-z will always be adjusted) was used for all BART modeling. For the Independence modeling only, EPA used a value of CDIV = 0.01 (equivalent to a change of 1 m/s per 100 m of depth). The result is that for a large number of puffs (whenever the averaged dw/dz is less than 0.01), a larger portion of the puff will be closer to the puff's center height. Shifting a larger portion of the puff closer to the center height will mean that the wind data (which are used for transporting the center of the puff horizontally) may be collected from fewer vertical levels, potentially resulting in somewhat different wind speeds (and directions).

The commenter modeled both values for CDIV and compared the results for 2001. The commenter noted that some days are higher and some are lower, however overall it balances out such that the 98th percentile days (8th highest) were not significantly affected at the four modeled Class I areas (see Table 5). At Upper Buffalo, the use of CDIV=0.01 increased the 98th percentile delta dV by 11 percent. The cumulative delta dV (for 2001) increased by only about 2 percent (from 7.66 to 7.84).

XSAMLEN is a dispersion parameter that is input by the user in the CALPUFF control file. XSAMLEM is the maximum travel distance of a puff/slug (in grid units) allowed during one sampling step. The commenter states that the default value of XSAMLEN is 1.0 but EPA used XSAMLEN=10.0 for all modeled sources. By allowing the value of XSAMLEN to be greater than 1.0, faster moving puffs may stretch over multiple horizontal grid cells. The meteorological parameters affecting the movement of each modeled puff are obtained from the center point of each puff. Using a lower value for XSAMLEN forces the CALPUFF model to release more puffs per time step, so that each individual puff can be adequately represented by the meteorological parameters at its center point.

Setting XSAMLEN=10 will cause fewer puffs to be modeled which will speed up the time of model run slightly. However, the horizontal motion of each puff will be determined by the parameters at its center point location which may not adequately represent the motion of a large puff that is stretched out over multiple meteorological grid cells. Using the meteorology at a single location to represent the entire puff will increase the uncertainty of the location of a portion of the puff's mass. The differences in wind speeds from one grid cell to the next are randomly distributed (with a mean of zero), so the overall effect on a large collection of modeled puffs that have each travelled over numerous time steps will likely be minimal (and unbiased).

The commenter evaluated CALPUFF results with both settings for XSAMLEN for 2001. The model results (see Table 6) indicate that the peak daily delta dV at Upper Buffalo changed by 5 percent or more on eight of the top twenty impact days by using XSAMLEN=10 instead of the default value. Nonetheless, the unbiased nature of the increase in uncertainty of the modeled puffs' locations associated with the larger XSAMLEN model option resulted in a small overall effect on the 98th percentile delta dV at each of the four modeled Class I areas (see Table 7). Using XSAMLEN=10 instead of the default value resulted in a decrease in the modeled cumulative visibility impact of less than 1 percent.

Table 7. 98th Percentile Delta dV (2001)

98th Percentile delta dV (2001)

	XSAMLEN = 1	XSAMLEN = 10
Caney Creek	2.471	2.484
Hercules-Glades	1.758	1.760
Ming Junction	1.867	1.827
Upper Buffalo	1.563	1.532
Total	7.659	7.603

Although the use of the CDIV=0.01 and XSAMLEN=10 options lead to small (and largely unbiased) errors in the modeling results, and these non-default options are not recommended, the overall effect on the modeled 98th percentile delta dV impacts at the four Class I areas is small. Furthermore, it is expected that the differences in model results would be similar for each of the modeled emission scenarios, so that the conclusions drawn when using the model results to compare various emission control strategies would not be changed at all.

Response: We appreciate the sensitivity analysis provided by the commenter. The selection of CDIV = 0.01 and XSAMLEN =10 in the modeling performed by EPA for the Independence facility was consistent with the CENRAP's BART modeling protocol[932] developed by CENRAP with input from the EPA and FLMs. The BART modeling performed by the facilities deviated from these settings in selecting CDIV = 0 rather than CDIV =0.01. We agree with the commenter that the differences in these settings would not significantly change the estimated 98th percentile visibility impacts and visibility benefits of controls and would not have impacted our control determinations based on consideration of all the relevant factors.

8. Legal

8.a. Controls will not be in place within the first planning period

Comment: EPA has offered no justification for requiring controls under Reasonable Progress when controls will not be installed until the next planning period [Entergy Arkansas Inc. (0166) p.42-43] Entergy Arkansas Inc. stated that EPA exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[933] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[934]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

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[932] See CENRAP BART Modeling Guidelines, Appendix B. Available in the docket for this action under document ID: EPA-R06-OAR-2015-0189-0095.

[933] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[934] The Proposed FIP provides for NO_X emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

Response: We disagree with this comment. The Clean Air Act clearly establishes our authority and responsibility to promulgate a FIP that addresses the requirements of the Regional Haze Program where a State's SIP submission fails to meet the program requirements. We disapproved Arkansas' regional haze SIP in 2012. Under these circumstances, the Clean Air Act requires EPA to promulgate a FIP within two years unless the State has corrected the deficiency by submitting a SIP revision and EPA has approved that revision. As Arkansas has not submitted a SIP revision to address the deficiencies in its regional haze SIP, we must promulgate a FIP addressing the applicable requirements.

The first planning period, ending in 2018, includes reasonable progress goals (RPGs) specific to that planning period that reflect the rate of progress for remedying visibility impairment that is reasonable, taking into consideration certain factors set out in the CAA. Although States are required to establish RPGs for 2018 to provide transparency regarding the degree of improvement predicted to result as of that date from the suite of controls in the SIP, there is no limitation in the CAA or the Regional Haze Rule that controls to improve visibility contained in a SIP must be fully implemented by the end of the planning period. In particular, as discussed below, there is no requirement that long-term strategy and BART requirements be fully implemented by 2018. As these major components of the Regional Haze program may extend beyond the first planning period, it follows that EPA has FIP authority fill in "gaps" or "inadequacies" related to those components irrespective of whether such controls can be put into place by 2018.

Congress declared that the "national goal" of the Regional Haze program is "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."[935] To meet this goal, Congress ordered us to issue regulations requiring States to implement SIPs "to contain such emission, limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal[,]" and the SIPs must include, among other requirements, "a long-term (ten to fifteen years) strategy for making reasonable progress toward meeting the national goal[.]"[936] Congress stated that "in determining reasonable progress there shall be taken into account […] the time necessary for compliance[.]"[937] Thus, the Clean Air Act does not restrain EPA from requiring sources to install controls outside of the initial planning period in the long-term strategy, but rather, it requires us to consider the time necessary for compliance when determining what constitutes "reasonable progress" toward the national goal.[938]

We issued regulations including, in addition to BART requirements, four "core requirements" including reasonable progress goals, calculations of baseline and natural visibility conditions, a long-term strategy and a monitoring strategy and other implementation plan requirements.[939] As part of these SIP requirements, a State must "consider […] the time necessary for compliance"

[935] 42 U.S.C. § 7491(a)(1).
[936] Id. at 7491(b)(2).
[937] Id. at 7491(g)(1).
[938] While the CAA does provide the statutory factors, including "time necessary for compliance," we note that it does not delineate 10 year planning periods. These are specified by the RHR.
[939] 40 C.F.R. § 51.308(d).

when establishing RPGs.[940] The long-term strategy component "must include enforceable emission limitations, compliance schedules, and other measures necessary to achieve the [RPGs]" however, this "must include" language does not limit the long-term strategy to only those measures to achieve RPGs.[941] Rather, it mandates inclusion of certain requirements to meet the RPGs without limiting planning authority to include other requirements to meet the national goal. Thus, there is no explicit statutory or regulatory requirement to limit control options to the first planning period.

Further, EPA's long-standing interpretation of the Clean Air Act and its regulations explicitly provide for the type of post-planning period controls to which Commenter objects. In issuing the Regional Haze rule and consistent with 42 U.S.C. 7491(b)(2)(B), we interpreted "long-term strategy" as the "control measures that are needed to ensure reasonable progress, together with a demonstration that those measures will provide for reasonable progress during the 10 to 15 year period."[942] Again, the reference to "reasonable progress," as opposed to RPG, refers to the national goal, and as noted above, the regulation provides for flexibility to achieve the national goal. In issuing its guidance on RPGs, the very situation to which Commenter objects is laid clear:

> The second factor is the "time necessary for compliance." It may be appropriate for you to use this factor to adjust the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018. For example, if you anticipate that constraints on the availability of construction labor will preclude the installation of controls at all sources of a particular category by 2018, the visibility improvement anticipated from installation of controls at the percentage of sources that could be controlled within the strategy period should be considered in setting the RPG and in establishing the SIP requirements to meet the RPG.[943]

In this passage, the intention in saying that "the percentage of sources that could be controlled within the strategy period should be considered …in establishing the SIP requirements to meet the RPG" is that the SIP deadline for compliance by the remaining sources should be set after the end of the implementation period, not that the SIP should contain no emission limits for the remaining sources. By noting that scrubber retrofits may take up to five years to install, yet also noting that scrubber upgrades may be installed within three years, we proposed RPGs for our FIP for Texas that only account for the visibility benefits associated with scrubber upgrades.[944] In doing so, we considered the time necessary for compliance in establishing RPGs, yet exercised our authority to propose a long-term plan including emission limits that likely require controls that may not be operational during the planning period.

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[940] Id. at 51.308(d)(1).
[941] Id. at 51.308(d)(3).
[942] 64 Fed. Reg. 35714, 35734.
[943] OAQPS, EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007), 5–2.
[944] 79 Fed. Reg. 74818, 74874.

We also note that, due to sequencing of the SIP process, including submission, review, revisions, re-review, and FIP preparation, public notice and promulgation, the CAA anticipates a substantial period of time between SIP submission and the promulgation of a FIP, as may ultimately be essential for carrying out CAA requirements. Those sources that should be subject to new controls under the CAA may take certain advantages from delays in having those control requirements imposed, but they do not have the benefit of an exclusion from CAA requirements. Instead, any emission limitations that prove to be required by the CAA for the first planning period need to be achieved at their soonest opportunity, not delayed, deferred or avoided for later planning periods at those times when other sources should be the focus of potential additional controls. Accordingly, we do not think the comment takes proper account of the time engagement required to promulgate a FIP within a planning period (if a FIP proves needed) or the significance of the CAA's contemplated ten- to fifteen-year long-term strategy, which could not be included in a FIP absent some degree of flexibility to extend FIP requirements beyond the date set for the end of the first planning period.[945]

Finally, we note that we have proposed controls outside of the planning period in other FIPs, including our proposed FIP for Arkansas and the FIP for Wyoming and Texas. Additionally, the Oklahoma FIP was stayed during litigation, resulting in a revised compliance date beyond 2018.

Comment: [Edison Electric Institute (0174) p. 5-6, 9-10] EEI stated that EPA has provided no rationale for regulating the Independence units. Further, even if EPA could articulate a need to regulate these units on reasonable progress grounds, the efficacy of doing so is thrown into further question by the timing of the proposed emission control requirements and the structure of the RHR. As noted, the regional haze program contemplates gradual visibility improvements along a "glide path" that considers the 2064 goal, and does not require immediate reductions that exceed making "reasonable progress." *See* 64 *Fed. Reg.* at 35,721. Here, the proposed FIP is attempting to require controls for Independence units that EPA knows cannot be in place or effective within the first planning period, i.e., prior to 2018. *See* 80 *Fed. Reg.* at 19,004. Given that the regional haze program's target extends to 2064, EPA's insistence that sources install extensive control equipment that technically will not be in place or effective to meet a 2018 milestone is unreasonable and unjustified, especially considering that impacted Class I areas are on track to meet upcoming reasonable progress goals for visibility. Instead, these controls, if they will be necessary at all, should only be considered by Arkansas during the next planning period, which runs between 2019 and 2028.

Response: Please see the above response explaining why we are imposing emission limits requiring installation of control equipment for this planning period, even though such control equipment will not be installed until after 2018.

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[945] Additionally, the State's responsibility for its SIP, or EPA's authority when needing to promulgate a FIP, is not shown to be discontinuous or intermittent because of the requirement to conduct comprehensive periodic plan revisions. Instead, there is ongoing authority to ensure reasonable progress from sources within the State. As demonstrated by the progress report requirements of the RHR, the regional haze program expressly contemplates that a State may determine the need for "further revision of the existing implementation plan" because the existing plan" is or may be inadequate"; in such situations, the rule sets out, deficiencies are to be addressed promptly ("within one year"), not deferred to the next comprehensive periodic plan revision, as the comment thinks to be necessary. See 40 CFR 51.308(h).

In addition to the question of timing, we disagree with the commenter's suggestion that visibility improvements beyond that associated with the glidepath exceed "reasonable progress." Assessing the measures necessary to achieve visibility improvement commensurate with the glidepath, as required by the Regional Haze Rule, ensures that States consider a relatively stringent suite of control measures in determining the appropriate measures to include in their regional haze SIPs. The glidepath, however, is an analytical requirement, and as explained in our prior disapproval of Arkansas' regional haze SIP, "being on the 'glidepath' does not mean that a state is allowed to forego an evaluation of the four statutory factors," as Arkansas did in its SIP.[946] In other words, a prediction that a Class I area will be "on the glidepath" is not enough to conclude that no further analysis of reasonable progress measures can or should be done.

We explained in our proposed rule that we focused on the Entergy Independence Power Plant in our analysis of reasonable progress measures "because it is one of most significant sources of SO_2 and NOx, as it is the second largest point source for both SO_2 and NOx point source emissions in the State."[947] (The largest point source of SO_2 and NOx, the Entergy White Bluff Plant, is subject to the BART requirements). Given that it is our obligation to ensure that reasonable progress is made toward meeting the national goal, it "would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions."[948]

We agree with EEI that the regional haze program contemplates gradual visibility improvements over time. The measures in our FIP, as well as the other CAA programs, will provide improvements in visibility after 2018 and help to ensure that Class I areas continue to make reasonable progress in the second planning period. We do not consider the emission limits that can be achieved by installation of scrubbers and combustion controls we have proposed and those we finalize in this action as being extensive or frontloading but instead represent a level of control consistent with the reasonable application of the four reasonable progress factors. As we have outlined in our proposal and our final rulemaking, Arkansas failed to comply with certain aspects of the Regional Haze Rule and thus portions of its regional haze plan were not approvable, triggering the requirement for EPA to implement a FIP.

8.b. Four unit approach for White Bluff and Independence

Comment: EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress. [Entergy Arkansas Inc. (0166) p. 45] Entergy Arkansas Inc. stated that EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the

[946] 77 FR at 14629
[947] 80 FR 18944, 18992 (April 8, 2015).
[948] *Id.*

four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.

Response: White Bluff Units 1 and 2 are BART-eligible sources that reasonably may be anticipated to cause or contribute to any impairment of visibility in any class I area and must undergo a BART evaluation under Section 51.308(e). Under 51.308(e) of the RHR, a state must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART "unless the state demonstrates that an emissions trading program or other alternative will achieve greater reasonable towards natural conditions." In several cases, after EPA has proposed or finalized a BART determination in a FIP, a source has requested that EPA instead adopt an alternative to BART under these provisions. We requested comment on alternative measures to determine whether the Entergy would be interested in an alternative path.

Entergy did provide comments tentatively suggesting a possible multi-unit alternative to the proposed FIP that would have included emission reductions at both White Bluff and Independence.[949] EPA could not complete an evaluation of an alternative proposal (as described more fully in another section of our response to comments) for White Bluff and Independence because EPA did not have, and Entergy did not provide in its comments, all the technical information required in which to perform the evaluation required under 51.308(d)(1) and51.308(e).

EPA agrees that the regional haze rule does not provide a floor for reasonable progress much in the same way that it does not provide a ceiling. Instead, states must determine appropriate measures for making reasonable progress based on consideration of the relevant factors and establish RPGs reflecting these and other measures likely to reduce emission over the planning

[949] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, EPA's understanding is that under Entergy's four-unit approach, the NO_X control measures and lower SO_2 emission rate proposed for White Bluff would be considered to constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence combined with the cessation of coal combustion at White Bluff would be considered to be more than sufficient for reasonable progress purposes for this planning period.

period. It is helpful to consider the language from the preamble to the RHR quoted by the commenter ("States may conclude that…") in context, however. In the RHR, EPA determined that it was likely that all states -- including those without Class I areas -- contain sources whose emissions are reasonably anticipated to contribute to regional haze in a Class I area. In addition, the preventative component of the national goal requires states to have a framework in place to address emissions growth. For these reasons, EPA concluded that all states must therefore submit regional haze SIPs. In explaining why it did not consider it appropriate to establish criteria for excluding states from the regional haze program, we explained that EPA is not specifying what control measures a state must implement in its regional haze SIP. As more fully explained in the preamble, we noted:

> That determination can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress … EPA recommends that these analyses and the determination of the extent of emissions reductions needed from individual States be developed and refined through multistate planning efforts using the best available technical tools, such as regional-scale modeling. The EPA also recommends the coordination of resulting strategies for regional haze with strategies needed to attain the PM2.5 NAAQS. The EPA anticipates that as a result of the more refined analyses required by this rule, some States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals. The EPA is requiring States to document their analyses, including any consultations with other States in support of their conclusions that further controls are not needed at this time. The EPA believes that there is more than enough evidence to support our conclusion that emissions from each of the 48 contiguous States may be reasonably anticipated to cause or contribute to visibility impairment in a Class I area.[950]

As the full quote makes clear, the determination that no control strategies specifically are needed to protect visibility depends on a thorough technical analysis.

EPA previously determined that Arkansas failed to reasonably address certain of the BART and reasonable progress requirements in its SIP, as explained in the final action partially disapproving Arkansas' regional haze plan.[951] We are not reopening that determination in this rulemaking.

8.c. Requirements for Reasonable Progress and Long Term Strategy

Comment: [UARG (0176) p. 11-14] UARG stated that EPA proposes reasonable progress emission limits as part of the FIP. The proposed reasonable progress emission limits are not justified under EPA's visibility rules and the Reasonable Progress Guidance and rest on an

[950] 64 Fed. Reg. at 35721.
[951] 76 Fed, Reg. 64186 (Oct. 17, 2011) (proposed rule); 77 Fed. Reg. 14604 (March 12, 2012) (final rule).

incorrect legal premise. EPA therefore should not promulgate the proposed reasonable progress emission limits.

EPA's decision to conduct a reasonable progress analysis in this rulemaking is not adequately justified. EPA explains that it disapproved Arkansas's RPGs for Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo") because, in EPA's view, Arkansas "believed, incorrectly, that no additional analysis of potential reasonable progress measures was necessary because visibility projections for the Class I areas indicated improvements in visibility consistent with the URP." *Id.* at 18,989. EPA does not dispute Arkansas's conclusion that the projected emission levels resulting from the emission controls that Arkansas's SIP would have required would have more than met the URPs for Caney Creek and Upper Buffalo.

Rather, EPA's view is that even if those controls (including BART) are projected to produce a rate of progress on visibility improvement that equals or exceeds the URP for the Class I area in question, a full reasonable progress analysis is required to permit a determination of whether additional emission reduction requirements are warranted and, if they are, the nature and the degree of stringency of the required emission reductions. Along these lines, EPA asserts that "[t]he preamble to the Regional Haze Rule … states that the URP does not establish a 'safe harbor'" in the establishment of RPGs. *Id.* at 18,992 (citing 64 Fed. Reg. 35,714, 35,732).

EPA fails to reconcile its stated position with the language of the preamble to the 1999 regional haze rule on which the Agency here relies. In that preamble, at 64 Fed. Reg. at 35,732 (the same page that EPA's proposed rule cites, *see* 80 Fed. Reg. at 18,992 n.117), EPA explains that the URP is the starting point for analysis and that the rule does not require assessing the reasonable progress criteria with respect to a potentially faster rate of progress if the rate of progress represented by the URP is deemed to be reasonable. A reasonable progress assessment for a rate that is more stringent than the URP is required only if a state chooses to make a determination "that additional progress beyond this [URP] amount is also reasonable":

> If the State determines that the amount of progress identified through the analysis is reasonable based upon the statutory factors, *the State should identify this amount of progress as its reasonable progress goal* for the first long-term strategy, *unless* it determines that additional progress beyond this amount is *also* reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy. 64 Fed. Reg. at 35,732 (emphases added).

Thus, only if a state were to "determine [] that additional progress [beyond the URP] is reasonable" would consideration of an RPG that is more accelerated than the URP – together with assessment of the additional emission control measures that would be needed to achieve that more accelerated RPG – be warranted. *Id.*

Moreover, the regional haze rule preamble explains why states, or at least states that are located in the eastern half of the country (as Arkansas is), ordinarily – and properly – would decline to consider and adopt rates of progress that are more accelerated than the URP, particularly for the first planning period. EPA explained that it selected the 2064 "goal" year in light of its projection that a 60-year period would provide time to "reach the national [visibility] goal … given that this rate of [visibility] improvement is expected to be achieved due to emissions [reductions] under [existing] CAA programs." *Id.* at 35,731-32. In promulgating the rule, EPA stated its "understanding" that "in the eastern United States … the [emission] reductions from measures implementing the CAA requirements will provide the visibility improvement and emissions [reductions] needed for reasonable progress during the first regional haze implementation plan." *Id.* at 35,733; *see also id.* at 35,737 ("It is expected that for some areas of the country, such as parts of the eastern United States, emissions [reductions] achieved for the [CAA] acid rain program and for meeting the PM2.5 NAAQS, will lead to substantial improvements in visibility as well. …. We [*i.e.*, EPA] expect that some States may be able to demonstrate reasonable progress based on these emissions [reductions] alone, particularly for the first 10-year [planning] period.").

Similarly, EPA states in the Reasonable Progress Guidance that "[g]iven the significant emissions reductions that we anticipate to result from BART, the [Clean Air Interstate Rule], and the implementation of other CAA programs, including the ozone and PM2.5 NAAQS, for many States this … may be all that is necessary to achieve reasonable progress in the first planning period." Reasonable Progress Guidance at 4-1; *see id.* at 5-1 (same). More broadly, the Reasonable Progress Guidance states that "[i]n deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade [visibility] impairment encompasses several planning periods. It is reasonable … to defer [emission] reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." *Id.* at 1-4.

Accordingly, as the 1999 rule preamble and the Reasonable Progress Guidance indicate, no requirement exists to consider or adopt reasonable progress requirements that go beyond what is needed to meet the URP if the state (or EPA) decides to rely on consistency with the URP. Because it appears from the proposed rule that EPA fails to understand the breadth of discretion under the regional haze rule to rely on consistency with the URP, this aspect of EPA's proposed rule is arbitrary, capricious, and unlawful and should be withdrawn. *Cf. Prill v. Nat'l Labor Relations Bd.*, 755 F.2d 941, 942 (D.C. Cir. 1985) (stating that "judicial deference is not accorded a decision of [an agency] when the [agency] acts pursuant to an erroneous view of law and, as a consequence, fails to exercise the discretion delegated to it by Congress").

Response: In 2012, EPA disapproved Arkansas' reasonable progress determination and long-term strategy as submitted in their RH SIP as well as other elements related to BART.[952] We are not reopening our partial disapproval of Arkansas' SIP in this action. As explained in our prior action, Arkansas did not conduct a four factor analysis as is required under 51.3018(d)(i). Our decision to disapprove Arkansas reasonable progress determination was not challenged.

[952] See Proposed Rule: 76 FR 64186 (Oct. 17, 2011); Final Rule: 77 FR 14604 (March 12, 2012).

As EPA is issuing a FIP, the relevant question is not whether EPA overstepped its authority in partially disapproving Arkansas' regional haze SIP; the question is whether anything in the CAA or the 1999 Regional Haze Rule limits EPA's authority to require additional controls beyond those needed to achieve the URP if such controls are considered reasonable based on a four factor analysis. See 51.308(d)(i)(A). As commenter notes, the preamble to the RHR makes clear that "if the State [or EPA] determines that additional progress is reasonable based on the statutory factors, the State [or EPA] should adopt that amount of progress as its goal for the first long-term strategy."[953]

We disagree with the commenter's general characterization of the URP (or "glidepath") or the conclusion that EPA anticipated that emissions reductions from other CAA programs could be relied on without further analysis to ensure reasonable progress. With respect to the URP, it is clear that this is an *analytical requirement* adopted by EPA to ensure that states carefully and transparently consider the reasonableness of the suite of controls needed to achieve that rate of progress in each Class I area. EPA developed this requirement in large part in response to concerns that our proposed presumptive rate of progress of 1 dv per 10 years that for some Class I areas would result in reaching the national goal in 200 years should not be considered reasonable. The rate of progress reflected in the URP is based on EPA's conclusion that the emission reductions achieved by the CAA from the mid-1990s to about 2005 would result, on average, to improvements in visibility that, if sustained, would lead to attainment of the national goal in 60 years. EPA "concluded that it would be reasonable to establish an analytical requirement based on this rate of progress given that this rate of improvement is expected to be achieved due to emissions under CAA programs."[954] As the full quote makes clear, the URP is only an analytical requirement, not as suggested by the commenter, a safe harbor for states in developing their SIPs.

The basis for commenter's suggestion that this language in the preamble explains why Arkansas would not adopt a more aggressive RPG than the URP is unclear. EPA's statement regarding emission reductions from other CAA programs in this context is a description of the emission reductions occurring between the mid-1990s and 2005 that *if sustained* would result in attainment of the national goal in 60 years, based on the average degree of impairment across all Class I areas. EPA was not suggesting that states could therefore delay the adoption of reasonable measures to avoid reaching the national goal more quickly. Nothing in the record for the regional haze rule supports a conclusion that attaining natural conditions before 2064 would be *un*reasonable. The commenter also cites to language indicating EPA's belief that future emission reductions resulting from the strategies to ensure compliance with the NAAQS and other CAA programs might constitute reasonable progress in some states. We note that in considering the appropriate reasonable progress measures for Arkansas, EPA has taken into account the extent to which CAA programs have reduced emissions from the largest point sources of SO2 and NOx emissions in Arkansas; as explained in the preamble to our proposed rule, three sources in Arkansas – White Bluff, Independence, and Flint Creek - make up a large majority of the SO2 point source emissions (84%) and a large proportion of the NOx point source emissions (55%). Unlike in some states, where other programs under the CAA have resulted in significant emission reductions, emissions from these three sources have not

[953] 64 FR at 35732.
[954] 64 Fed. Reg. at 35,732.

substantively changed since the baseline date of the SIP. Thus, EPA's general predictions that some states may be able to rely on measures to comply with CAA programs to make reasonable progress does not support a conclusion that the reasonable progress measures in our FIP are either unnecessary or unreasonable.

As EPA has concluded that additional controls are reasonable, we are including these measures in our FIP. EPA's reasonable progress analysis is explained more fully in the reasonable progress section of the RTC.

Comment: Two separate legal authorities require that EPA determine that scrubber installation at Independence Units 1 and 2 is necessary to meet the regional haze requirements. [Sierra Club et. al. (0171) p. 31, 33-34] Sierra Club et. al. stated that the final rule should find that reasonable progress requires the Entergy Independence plant to meet an SO_2 emission limit of 0.04 based on the use of a scrubber. Two separate legal authorities require this conclusion, and thus EPA has two independent grounds for requiring the Independence plant to install and operate a scrubber under the reasonable progress provisions.

First, EPA should require a scrubber under the reasonable progress analysis required to set the reasonable progress goals for Caney Creek and Upper Buffalo. *See* 42 U.S.C. § 7491(g)(1), 40 C.F.R. § 51.308(d)(1).

Second, EPA should require a scrubber as part of the long-term strategy that must include the emissions reductions necessary to meet the reasonable progress goals for Class I areas in other states affected by the Independence plant's emissions, namely, Hercules-Glades and Mingo in Missouri. *See* 40 C.F.R. § 51.308(d)(3). Each state's plan "must include enforceable emissions limitations . . . and other measures as necessary to achieve the reasonable progress goals established by states having mandatory Class I areas." *Id.* Similarly, each state must demonstrate that its plan contains the measures "necessary to obtain its share of the emission reductions needed to meet the progress goal for the area." *Id.* § 51.308(d)(3)(ii). EPA interprets these provisions as requiring a state to include the emissions reductions necessary to meet the approved or approvable reasonable progress goals for out-of-state Class I areas. 79 Fed. Reg. at 74,828-30. Arkansas was obligated to consult meaningfully with Missouri, *id.* § 51.308(d)(3)(i), which includes providing Missouri with the technical information necessary to determine whether the implementation of reasonable control measures in Arkansas would improve visibility in Missouri's Class I areas.

Arkansas and Missouri consulted during the development of their respective plans. However, Arkansas neither considered nor proposed reasonable progress controls for the Independence plant. As a result, Arkansas did not provide Missouri with information on available future controls at Independence Units 1 and 2. EPA disapproved Arkansas's reasonable progress analysis because it did not comply with applicable requirements.

The regulations required Arkansas to "document the technical basis . . . on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects." 40 C.F.R. 51.308(d)(3)(iii). "This documentation is necessary so that the interstate consultation process can

proceed on an informed basis." 80 Fed. Reg. at 74,829. Here, Arkansas failed to properly document its portion of reductions necessary to achieve reasonable progress in Missouri's Class I areas because Arkansas never properly developed this information in the first place—as evidenced by EPA's disapproval of Arkansas's analysis of reasonable progress. Thus, Missouri developed its reasonable progress goals for Hercules-Glades and Mingo based on Arkansas's reasonable progress analysis that was so deficient that EPA disapproved it.

EPA addressed a similar situation in the proposed Texas plan, noting that there may be situations where "the [reasonable progress] goal itself is flawed precisely because the upwind state never proposed sufficient control measures to ensure reasonable progress in the first place." 80 Fed. Reg. at 74,829. After acknowledging the problem, EPA proposed a solution: "where a RPG in a downwind state's SIP does not account for adequate visibility improvement from an upwind state for this reason, we must disapprove both the downwind state's goal and the upwind state's long-term strategy." *Id.*

EPA should remedy the deficiency in Missouri's reasonable progress goals, which resulted from a consultation in which Arkansas failed to provide Missouri with a proper analysis of available future controls on Arkansas sources that impact Missouri's Class I areas. The Independence plant has large baseline impacts at the Hercules-Glades Wilderness Area and Mingo National Wildlife Refuge in Missouri. Installing and operating a scrubber at the Independence plant would improve visibility by 1.056 deciviews at Hercules-Glades and 0.871 deciviews at Mingo, 80 Fed. Reg. at 18,994, at a reasonable cost of less than $3,000 per ton of SO2 removed. *Id.* at 18,993; *see also* Stamper Report at 63. Given that a scrubber meets all of the four reasonable progress factors, the reasonable progress goals for Hercules-Glades and Mingo must reflect operation of a scrubber at the Independence plant. Reasonable progress goals for Hercules-Glades and Mingo that do not reflect the reductions from a scrubber at Independence are not approvable;[955] for the same reason, an Arkansas plan that does not require a scrubber at Independence is not approvable under 40 C.F.R. § 51.308(d)(3).

In sum, EPA has two separate legal bases for requiring Independence Units 1 and 2 to install and operate a scrubber to achieve a SO2 emission limit of 0.04 lb/MMBtu. First, consideration of the reasonable progress factors indicates that a scrubber is a reasonable control measure at Independence Units 1 and 2 and thus the reasonable progress goals for Caney Creek and Upper Buffalo should reflect operation of scrubbers at Independence. The long-term strategy for Arkansas must require operation of a scrubber at Independence Units 1 and 2 in order to meet the reasonable progress goals for Caney Creek and Upper Buffalo. Second, the reasonable progress goals for Hercules-Glades and Mingo must reflect operation of a scrubber at both Independence units, and therefore Arkansas's long-term strategy must require scrubbers in order to achieve the reasonable progress goals for Hercules and Mingo.

[955] While EPA has already approved the reasonable progress goal that Missouri developed for Hercules-Glades and Mingo, it did so prior to proposing a FIP for Arkansas. Thus, when EPA acted on Missouri's SIP, the agency did not have before it a proper and approvable analysis of achievable emissions reductions at Arkansas sources that impact Missouri Class I areas. EPA should ensure that the Missouri RPGs are revised to remedy the deficiencies in the consultation process and in Arkansas's long-term strategy. *See* 40 C.F.R. § 51.308(d)(3)(i)(iii).

Response: We take no position on the legal rationale that commenter cites. Our legal and technical rationale for requiring controls under reasonable progress for the Independence facility at Units 1 and 2 is discussed in the reasonable progress section of the response to comments.

8.d. States have a leading role and discretion under the Regional Haze cooperative federalism

Comment: The Regional Haze program is built on principles of cooperative federalism that require EPA to defer to states in developing SIPs. [Nucor Steel-Arkansas and Nucor-Yamato Steel (0163) p. 5-6, 9-12; and Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 3-5]

AEEC/AGC stated that Congress amended the Clean Air Act ("CAA") in 1977 to include the national goal of remedying any impairment of visibility at mandatory Class I Federal areas ("Class I areas"). Two of these Class I areas are located in Arkansas: the Upper Buffalo and Caney Creek Wilderness Areas. In 1999, when it promulgated the Regional Haze Rule, the EPA established regulations to eliminate man-made visibility impairment in these Class I areas by 2064. On September 23, 2008, the ADEQ submitted the Arkansas Regional Haze State Implementation Plan ("Arkansas SIP") to the EPA. Over three years later, on March 12, 2012, the EPA partially approved and partially disapproved the Arkansas SIP.[956] Despite the EPA's partial disapproval of the Arkansas SIP in 2012, ADEQ recently submitted a Five-Year Regional Haze Progress Report to the EPA, to fulfill the requirement in 40 C.F.R. § 51.308(g) that Arkansas provide periodic reports to the EPA evaluating its progress towards the Reasonable Progress Goals ("RPGs"). The EPA promulgated the Proposed FIP on April 8, 2015.[957]

Nucor and AEEC/AGC stated that EPA's disapproval of the Arkansas Regional Haze SIP together with its decision to initiate this rule-making and impose the proposed FIP far exceeds EPA's legal authority under the Clean Air Act. EPA's actions improperly transform the structure of the regional haze program from a state-driven program grounded in cooperative federalism to a centrally controlled, federally managed program with no meaningful role for the states, regulated entities, or in the case of electric public utilities, the end users and consumers who ultimately will bear the brunt of and have to pay for EPA's determinations. Nothing in the Clean Air Act or the administrative record supports EPA's determination that mandates the installation of over $2 billion in new emission controls on public utility electric generation resources that have significant social and economic value in and to the State of Arkansas.

Nucor and AEEC/AGC stated that the Clean Air Act, including the regional haze program, is built on principles of cooperative federalism that require EPA to defer to states in developing implementation plans so long as necessary statutory requirements are met, and it sets forth specific time limits for action by both the States and EPA. EPA v. EME Homer City Generation, L.P., 134 S.Ct. 1584, 1600 (2014). EPA's Proposed FIP ignores those limits and timelines and would impose a plan that ignores the primary implementation role given to Arkansas. Not only is

[956] 77 Fed. Reg. 14604.
[957] 80 Fed. Reg. 18944.

EPA's approach inconsistent with the Clean Air Act, it gives EPA power to arbitrarily substitute its own judgment for that of a state at virtually any stage of the implementation process.

As courts have recognized, the Clean Air Act was intended by Congress to be "a model of cooperative federalism." Sierra Club v. Korleski, 681 F.3d 342, 343 (6th Cir. 2012); Michigan v. EPA, 268 F.3d 1075, 1083 (D.C. Cir. 2001); Florida Power & Light Co. v. Costle, 650 F.2d 579, 581 (5th Cir. 1981). Under this structure, Congress specifically found that "air pollution prevention ... is the primary responsibility of States and local governments." 42 U.S.C. §7401(a)(3). The Eighth Circuit recently noted that "the [Clean Air Act] grants states the primary role in determining the appropriate pollution controls within their borders." North Dakota v. EPA, 730 F.3d at 760-61. Thus, "states have broad authority to determine the methods and particular control strategies they will use to achieve the statutory requirements." BCCA Appeal Group v. EPA, 355 F.3d 817, 822 (5th Cir. 2003). Specifically, the states have "broad authority over BART determinations." American Corn Growers v. EPA, 291 F.3d 1, 8(D.C.Cir. 2002).

EPA's role is limited to ensuring that the States' implementation is consistent with the CAA. Florida Power & Light, 650 F.2d at 587 ("The great flexibility accorded the states under the Clean Air Act is ... illustrated by the sharply contrasting, narrow role to be played by EPA.").

Nucor stated that rather than establishing strict implementation requirements, EPA's rule "requires States to determine the rate of progress for remedying existing impairment that is reasonable, taking into consideration the statutory factors, and the informed input from all stakeholders." 64 Fed. Reg. at 35,731; see also 40 C.F.R. § 51.308(d)(1)(i)(A). In its guidance to States, EPA emphasized that the regional haze rule "gives States wide latitude to determine additional control requirements" and, in applying the required statutory factors, the states "have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant." USEPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 1, 2007, p. 4-2, 5-1 [emphasis supplied]. Thus, EPA has explained that "[a]s long as this evaluation is done adequately and the States provide a reasoned basis for their decision, EPA will defer to the state." 77 Fed. Reg. 40,150, 40,156 (July 6, 2012).

Nucor and AEEC/AGC stated that in the Proposed FIP, EPA ignores these well-established principles of cooperative federalism, disregards the right of the State of Arkansas to make BART and Reasonable Progress decisions, and imposes a radically different implementation plan based on its own independent analysis. This over-reaching is contrary to the Clean Air Act and is unlawful. This hijacking of Arkansas' primary authority to implement the regional haze program exceeds the EPA's authority under the CAA.

Nucor stated that even in its over-reaching, the EPA is held to the same standards as state agencies to not act arbitrarily and capriciously, to make decisions based on sound reasoning, to take into account important and relevant factors, and to act within the scope of statutory authority, which includes demonstrating that EPA's determinations are "necessary" to achieve the requirements of 42 U.S.C. §7491. EPA has not done so.

Response: As noted above, we previously determined that portions of the Arkansas SIP do not meet certain elements of the Federal regional haze requirements, and we identify and discuss those portions in our final action on the Arkansas RH SIP.[958] We are not reopening our partial disapproval of the Arkansas regional haze SIP.

We do not agree with the commenter's characterization of our action. Our action does accord with the CAA. Congress crafted the CAA to provide for States to take the lead in developing implementation plans, but also required EPA to review SIPs for compliance with statutory and regulatory requirements. We recognize that States have the primary responsibility of drafting an implementation plan to address the requirements of the regional haze program. We also recognize that we have the responsibility of ensuring that the State plans, including Regional Haze SIPs, conform to the CAA requirements. We do not agree with the commenter that EPA is ignoring the principles of cooperative federalism. The Clean Air Act provides that if a state plan is disapproved, EPA is required, within two years of the effective date of the final federal register notice disapproving the state plan, to approve a state SIP revision submittal that corrects the deficiency or promulgate a FIP. During this two-year time frame, states have the opportunity to submit a corrected SIP for review and approval by EPA. However, the Clean Air Act creates an end point in a state meeting the requirements of the CAA through an approved plan, by creating a mandatory duty for EPA to either approve the state SIP submissions or issue a FIP.

That is what has happened for the Arkansas RH and Visibility IT SIP. Here, Arkansas submitted to EPA for approval a SIP revision to address the requirements of RH and Visibility IT. As explained in an earlier response to comments, in 2012, EPA, after notice and comment, finalized rulemaking partially approving and disapproving the Arkansas RH and Visibility IT SIP. While we did receive adverse comments on the rulemaking, no party, including the state, filed a lawsuit challenging our partial approval and disapproval. After our disapproval, EPA worked with Arkansas to develop a revised SIP to address the elements we disapproved. Two years elapsed and EPA was sued for failing to either approve or issue a FIP to address the elements we disapproved on the submitted Arkansas regional haze SIP. With Arkansas as a party, a district court judge ordered EPA to either approve a revised SIP submittal from Arkansas or finalize a FIP for the elements we disapproved by August 31, 2016. That order is included in the docket to this rulemaking action. To date, EPA has not received a revised SIP for RH.[959]

Comment: The Associations provide a summary of the Regional Haze program and state that EPA should respect the primacy role Congress assigned to states in determining the best path of reasonable progress. [The Associations (0165) p. 3-5] The Associations stated that in recognition of diminished visibility at national parks and other scenic areas, Congress enacted the Clean Air Act's regional haze provisions with a long-term goal of improving the state of visibility. Regional haze is the "impairment of visual range or coloration caused by emissions of air pollution produced by numerous sources and activities, located across a broad regional area."

[958] 77 FR 14604.

[959] EPA also partially disapproved Arkansas' visibility transport SIP addressing the requirements of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and PM2.5 NAAQS in the same action in which we acted on Arkansas' regional haze SIP. We are also addressing our obligation to address the deficiencies identified in the transport SIP in today's action.

77 Fed. Reg. 30,248, 30,249 (May 22, 2012). Congress first adopted regional haze provisions in 1977 to address haze issues in national parks and other federal "Class I areas" by adding Section 169A to the Clean Air Act. *See* 42 U.S.C. § 7491.

At the same time, however, Congress realized such changes could not be fully realized rapidly and adopted an approach by which States would make incremental improvements over time. Section 169A requires EPA to "promulgate regulations to assure … reasonable progress toward meeting the national goal" of visibility. 42 U.S.C. § 7491(a)(4). EPA has established three primary components for a State's regional haze implementation plan: (1) reasonable progress goals ("RPGs") for Class I areas in the State; (2) a long-term strategy; and (3) implementation of BART for certain stationary sources. Through this program, each state charts a "Glidepath" towards natural visibility at the Class I areas within their borders by 2064. States then are provided significant flexibility in crafting the emission reductions necessary for meeting that Glidepath by assessing reasonable progress goals at regular planning period intervals. Reasonable progress goals are therefore "interim goals that represent incremental visibility improvement over time." EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) ("RPG Guidance") at 1-2.

Due to the array of options to meet these goals, and the co-benefits of reducing visibility impairments through other Clean Air Act programs, Congress intended states to have extraordinary flexibility in determining how they meet reasonable progress goals. *See North Dakota v. EPA*, 730 F.3d 750, 768 (8th Cir. 2013) (the Regional Haze program "requires only that a state establish reasonable progress, not the most reasonable progress."). Reasonable progress goals for Class I areas are based on four factors: (1) "costs of compliance;" (2) "the time necessary for compliance;" (3) "the energy and nonair quality environmental impacts of compliance;" and (4) "the remaining useful life of any potentially affected sources." 42 U.S.C. § 7491(g)(1). States are not obliged to reduce emissions from any type of source in particular and EPA acknowledges that states may not need *any* additional emission reductions for some planning periods. *See* EPA, *Additional Regional Haze Questions*, at 9 (Sept. 26, 2009) ("Reasonable progress is not required to be demonstrated on a source-by-source basis."); RPG Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States."). Through the state's consideration of these factors, each Class I area need only make incremental progress through reasonable, cost-effective means.

Perhaps more than any other program under the Clean Air Act, the Regional Haze program provides states with the leading role in exercising their discretion regarding how they meet reasonable progress goals for the Class I areas within their borders. Despite Congress' intention for states to have primary responsibility in implementing the program within their borders, EPA arbitrarily disapproved Arkansas' Regional Haze State Implementation Plan in 2012, 77 Fed. Reg. 14,604 (Mar. 12, 2012), and issued the proposed rule as a federal regional haze implemental plan in its place.

Beyond the strict violations of the Clean Air Act in EPA's approach described below, the Associations are concerned this is a further instance in a disturbing trend of EPA disregarding

the considerable discretion Congress assigned to states in the Clean Air Act and inappropriately substituting its own judgment in areas that are local in nature, state-specific, and incredibly complex. EPA justifies many of these disapprovals by amorphous demands for "additional analysis," disagreements over modeling details, minor divergences in cost considerations, or simply EPA's opinion that it believes states should have done more than what the Regional Haze program requires. This is not only inconsistent with the specific Clean Air Act provisions, but violates the prominent role Congress assigned to states in the system of cooperative federalism throughout the Act.

Ultimately, states are in the best position to make these determinations, as Congress recognized. Each state invests significant time and resources working with its neighboring states to understand out-of-state influences on visibility impairment and managing its own federal and state programs to enact a careful balancing act. This balancing act carefully considers the expected emission reductions from existing programs, emission reductions through BART, and several other emission reduction options to find the most efficient and affordable means of meeting federal requirements. As EPA has recognized, at least at the outset of the Regional Haze program, Congress intended to "provide States considerable discretion in establishing reasonable progress goals for improving visibility in Class I areas." EPA, *Response to Petition for Reconsideration of Regional Haze Rule* 11 (Jan. 10, 2001); RPG Guidance at 4-2 (states have "wide latitude to determine additional control requirements"); *id.* at 5-1 (states "have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant"). EPA has acknowledged that, so long as states consider the statutory factors required by the Regional Haze program and "provide a reasoned basis for their decision, EPA will defer to the state" with respect to reasonable progress determinations. 77 Fed. Reg. 40,150, 40,156 (July 6, 2012). Yet, as is becoming increasingly common and problematic, EPA is ignoring this deference under the Regional Haze program.

Fulfilling the role intended by Congress, states have a successful and demonstrated track record in creating the real-world, measured visibility improvements Congress envisioned under the Regional Haze program. It is increasingly troubling that EPA appears eager to disapprove state implementation plans in order to substitute its own judgment on matters affecting not just technical details, but state regulatory and economic concerns. EPA's intrusion into these areas has frequently led to costly and unnecessary burdens on state industries while failing to deliver any demonstrable visibility improvements to Class I areas over what states would have achieved. In most instances, EPA's stated rationale for imposing millions (or billions) of dollars in additional costs yield visibility improvements that cannot be perceived by the human eye. EPA's pattern of second-guessing the reasoned decisions of expert state agencies is not only economically wasteful, but it contravenes the state primacy that is the Regional Haze program's core characteristic.

For these reasons, the Associations urge EPA to reset its approach to Regional Haze and respect the primacy role that Congress assigned to the states in determining the best path of reasonable progress taking into account unique local circumstances to realize visibility improvements. EPA has failed to demonstrate any rational grounds to supplant its own judgment for Arkansas' and, as described below, lacks the legal authority to impose the proposed controls here.

Response: Please see our above responses which address EPA's authority and obligation to promulgate a FIP that satisfies the requirements of the Regional Haze Program when a state fails to submit a plan which meets the program's requirements. In addition, EPA's action today finalizing the proposed rule to address the submitted Arkansas regional haze SIP (and visibility transport SIP we disapproved in 2012) is in keeping with Congressional intent on the roles prescribed for states and EPA under the Clean Air Act. As explained earlier, EPA reviewed Arkansas' submitted regional haze and visibility Interstate Transport SIP and partially approved and disapproved through notice and comment rulemaking. EPA received comments on that action and we addressed them in our final rulemaking in 2012. No party challenged us in court on the rulemaking within 60 days of publication and the effective date of the final federal register notice disapproving the state action started the two year clock by which EPA is required to act under the Clean Air Act to either approve a revised SIP from Arkansas that corrects the deficiencies or promulgate a FIP. During the two-year period, EPA met with Arkansas on revising the SIP. After the two years elapsed, EPA was sued by Sierra Club for failure to meet our mandatory duty to act to address the disapproved elements of RH and Visibility IT by either approving a SIP or promulgating a FIP. In that mandatory duty suit, the state of Arkansas intervened and participated in the judicial proceedings whereby the judge ordered EPA to either approve a SIP or promulgate a FIP by August 31, 2016. To date, we have not received a revised SIP to address the disapproved elements for RH and Visibility IT. We have undergone notice and comment rulemaking in order to meet our August 31, 2016 court ordered rulemaking deadline.

Comment: [Edison Electric Institute (0174) p. 2, 6] EEI stated that delaying consideration of additional controls for the Independence units also is justified by the statutory context of the regional haze program, which is designed to respect the cooperative federalism principles embedded in the CAA. These principles gives states, and not EPA, the primary role in determining how best to regulate emissions sources within their borders. Arkansas has determined that controls for these units are not needed to achieve the URP goals for this first period. Arkansas's SIP works: the URP goals are being met for this first period.

EPA claims the authority to require more than reasonable progress under the guise that the RHR does not provide a "safe harbor" for units. *See* 80 *Fed. Reg.* at 18,992. This is misleading. Not regulating the Independence units during the first period does not insulate them from consideration by the state as it moves forward with its next SIP, covering the second planning period. Further, it is a weak justification for setting the concerning precedent that EPA can override reasonable state SIPs, in contravention of the cooperative federalism embodied in the Clean Air Act and the RHR.

Response: Our legal and technical rationale for requiring controls under reasonable progress for the Independence facility at Units 1 and 2 in the first planning period is discussed in the reasonable progress section of this RTC document. See our above responses concerning the roles of states and EPA and the role of the URP. Our proposed and final rules assessing the Arkansas regional haze SIP provide additional background information regarding our prior partial disapproval of sections of Arkansas' SIP addressing reasonable progress in which Arkansas did not conduct a four factor analysis as required under the RHR, 51.308(d)(1).76 FR 64186 (Oct. 17, 2011)(proposed rule); 77 FR 14604 (March 12,2012) (final rule).That action

underwent notice and comment pursuant to the Administrative Procedures Act and no party challenged the rulemaking within the required 60 days after the publication date of the final federal register notice. To address reasonable progress, EPA did the four-factor analysis for Arkansas two class I areas as required under the RHR. It is speculative and not germane as to whether Arkansas would have the same RPG if they conducted a four factor RPG analysis in accordance with 51.308(d)(1). EPA is undergoing notice and rulemaking for Arkansas' two Class I areas RPGs simply because we are under a court order deadline to either approve a state revised SIP or promulgate a FIP. Since we do not have a SIP before us, we are undergoing notice and comment rulemaking in order to comply with a court ordered deadline.

As discussed in the preamble to our proposed FIP, the URP does not establish a "safe harbor" *for the state in setting its reasonable progress goals.*[960] Rather, regardless of the amount of the visibility improvement anticipated from the implementation of other CAA programs, BART, or forecasted levels of economic activity, a state (or EPA) must provide a reasoned analysis to support its determination as to appropriate reasonable progress measures for its regional haze SIP. As explained elsewhere in this document, we have concluded that control measures for Independence --the second largest source in Arkansas of SO2 and NOx –should be included in our FIP. We agree with the commenter that sources not controlled for reasonable progress in implementation plans for this first planning period may be controlled in later planning periods. The conclusion that measures might be adopted at some point in the future, however, does not by itself support a decision to put off measures to some future planning period. As EPA is issuing a FIP, we have considered the appropriateness of additional measures on Arkansas sources to ensure reasonable progress, and as explained elsewhere, reached the conclusion that SO_2 and NO_X control measures for Independence should be included in the FIP for this planning period.

8.e. EPA does not have authority to finalize the FIP at this time

Comment: [Nucor Steel-Arkansas and Nucor-Yamato Steel (0163) p. 13-16; Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 5-7] Nucor and AEEC/AGC both stated that Section 110(c)(1) of the CAA (42 U.S.C. §7410(c)(1)) states:

> The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator —
>
> (A) Finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under section 110(k)(1)(A), or
>
> (B) Disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision before the Administrator promulgates such Federal implementation plan. [Emphasis supplied].

[960] 80 Fed. Reg. at 18992.

EPA partially disapproved the Arkansas Regional Haze SIP on March 12, 2012 (77 Fed.Reg. 14604); however, EPA did not take any action to issue a FIP during the two year period after that disapproval. Not until April 8, 2015, more than three years after EPA's disapproval of the Arkansas SIP, did EPA even publish notice of its Proposed FIP in the Federal Register (80 Fed.Reg. 18944).

The plain language of §110(c)(1) limits EPA to a two year time-limit to issue a FIP.[961] By initiating this rule-making and issuing its Proposed FIP after that time, EPA impermissibly ignores and does not give effect to the words "within 2 years." Statutes must be construed in a manner that gives effect to every word.

In EPA v. EME Homer City Generation, L.P., 572 U.S., 134 S.Ct. 1584 (2014), the Court examined section 110(c)(1), and held that because the clear language of that section allowed EPA to file a FIP "at any time" within the two year FIP deadline, EPA did not have to first allow states to issue SIPs under the Cross-State Air Pollution Rule ("CSAPR"). The lower court had held that the CAA required EPA to give states a reasonable period of time to comply with the reductions under the CSAPR rule, but the Supreme Court reversed. The Court stated:

> [T]he CAA sets a series of precise deadlines to which the States and EPA must adhere… If EPA determines a SIP to be inadequate, the Agency's mandate to replace it with a FIP is no less absolute…. In other words, once EPA has found a SIP inadequate, the Agency has a statutory duty to issue a FIP "at any time" within two years… The D.C. Circuit, however, found an unwritten exception to this strict time prescription for SIPs aimed at implementing the Good Neighbor Provision…. However sensible (or not) the Court of Appeals position a reviewing court's "task is to apply the text [of the statute], not to improve upon it…. The Act empowers the Agency to promulgate a FIP "at any time" within the two-year limit…. Carving out an exception to the Act's precise deadlines, as the D.C. Circuit did, "rewrites a decades-old statute whose plain text and structure establish a clear chronology of federal and State responsibilities." The practical difficulties cited by the Court of Appeals do not justify departure from the Act's plain text… We "must presume that a legislature says in a statute what it means and means in a statute what it says there." EME Homer, 134 S.Ct. at 1600-1601 (internal citations omitted).

Congress clearly intended to give the states the primary authority to make BART and Reasonable Progress decisions. American Corn Growers v. EPA, 291 F.3d 1(D.C.Cir. 2002); North Dakota v. EPA, 730 F.3d 750 (8th Cir. 2013). In implementing SIPs, States cannot wait indefinitely for EPA to act on State submissions or to belatedly issue FIPs; consequently, in section 7410(c)(1) Congress set a two year limit on EPA's ability to issue a FIP after a SIP disapproval. The State of Arkansas has given EPA assurances that it will continue to work to address the concerns raised

[961] EPA has previously recognized this limitation. See, 79 Fed.Reg. 29354, 29356 (May 22, 2014) ("CAA section 110(c) provides that EPA can promulgate a FIP immediately after making the finding of failure to submit a required SIP, as late as two years after making the finding, or any time in between." [emphasis supplied]) Furthermore, EPA's Region 6 office also recognized that the two year deadline for an Arkansas RHR FIP had passed. See, internal EPA email dated May 9, 2014, attached as Exhibit 4 to Nucor's comments.

by EPA in its March 12, 2012 disapproval.[962] EPA's Proposed FIP should be withdrawn so that the State of Arkansas can revise its RH SIP in accordance with the requirements of the CAA.

Response: Section 110(c)(1) of the Clean Air Act does not release EPA from its statutory mandate to promulgate a FIP or approve a state SIP after the elapse of two years. *Oklahoma v. EPA*, 723 F.3d 1201 (10th Cir. 2013), *cert. denied* (U.S. May 27, 2014)(EPA's authority to promulgate a FIP is not subject to a two year time limit). The appropriate remedy for EPA's failure to act within two year is to seek an order compelling agency action. The Eastern District of Arkansas agreed and ordered EPA to promulgate a FIP or approve a SIP submittal addressing the disapproved portions of the Arkansas' regional haze and visibility transport SIP by August 31, 2016.

8.f. EPA must address E.O. 12866 and 13211

Comment: EPA must address the requirements of Executive Orders 12866 and 13211. [Entergy Arkansas Inc. (0166) p. 55-56] Entergy Arkansas Inc. stated that EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

[962] See Exhibit 3 to Nucor's comments, Arkansas RHR Five Year Progress Report, transmittal letter to Hon. Ron Curry, EPA, Region VI Regional Administrator.

Response: We disagree with the commenter's interpretation of Executive Orders ("E.O.") 12866 and 13211. E.O. 12866 defines "regulations" or "rules," as "an agency statement of general applicability and future effect." An "agency statement of general applicability" refers to statements that apply to groups or classes of entities, as opposed to a regulation or rule which applies only to named entities. Our FIP is not, therefore, a rule of general applicability because its requirements apply and are specifically tailored to six individually identified facilities. Thus, it is not a "rule" or "regulation" within the meaning of E.O. 12866 and this action is not a "regulatory action" subject to 12866. As E.O. 13211 applies only to "significant regulatory actions" under E.O. 12866, this action is not subject to review under E.O. 13211.[963] Evaluation of the proposal under E.O. 13211's criteria is therefore not required. It should be noted that the agency action which was at the center of the Supreme Court's opinion in *Michigan v. EPA*, was a regulatory action within the meaning of E.O. 12866. The action was applicable to all EGUs meeting certain requirements, as opposed to specifically identified entities.

We note that because the commenter provided only conclusory speculations concerning energy impacts and grid reliability concerns with no data, we cannot speculate on how our rulemaking will affect the distribution of electricity or electric rates.

Comment: EPA has failed to comply with the requirements under Executive Order 12866 and 13211. [ADEQ (0160) p. 24-28] ADEQ stated that EPA asserts that its Proposed FIP is not a "significant regulatory action" within the meaning of Executive Order 12866 ("E.O. 12866").[964] However, the proposed FIP would result in substantial and material costs being transferred onto Arkansas communities through increased electricity rates due to the installation of costly control equipment at affected EGUs. This is a material adverse effect, which renders the Proposed FIP subject to the requirements of E.O. 12866. EPA has not complied with the requirements of E.O. 12866, and the Proposed FIP should be withdrawn until such time as requirements of this executive order have been met.

Under E.O. 12866, a "significant regulatory action" is subject to certain review requirements by the Office of Information and Regulatory Affairs ("OIRA"), which is a subdivision the Office of Management & Budget ("OMB").[965] For each significant regulatory action under E.O. 12866, OIRA must be provided with a copy of the draft regulation, together with a reasonably detailed description of the need for the regulatory action, and an explanation of how that action will meet that need.[966] In addition, the relevant agency must provide OIRA with an assessment of the costs and benefits of the regulatory action as well as the costs and benefits of reasonably feasible alternatives for each significant regulatory action.[967] By issuance of E.O. 13563 on January 18, 2011, the sitting President reaffirmed "the principles, structures, and definitions governing contemporary regulatory review that were established in Executive Order 12866 of September 30, 1993, were re-affirmed.[968]

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[963] 79 FR 74890.
[964] 80 FR 18944 at 19000.
[965] Exec. Order No. 12866, 58 FR 51735, (Sept. 30, 1993).
[966] *Id.* at Sec. 6(a)(1)(B)
[967] Exec. Order No. 12866, 58 FR 51735, Sec. 6(c), (Sept. 30, 1993).
[968] Exec. Order No. 13563, 76 FR 3821, (Jan. 18, 2011)

In this instance, EPA's Proposed FIP falls within the definition of significant regulatory action as set out in E.O. 12866 and reaffirmed in E.O. 13563. A "Significant regulatory action" means any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.[969]

The Proposed FIP would adversely affect in a material way Arkansas communities by causing increased electricity rates that would be passed on to Arkansas consumers. Specifically, the following facilities owned by electric utilities engaged in interstate commerce were determined to be subject-to-BART or otherwise required to install emissions controls: the Arkansas Electric Cooperative ("AECC") Carl E. Bailey Generating Station; the AECC John L. McClellan Generating Station; the American Electric Power ("AEP") Flint Creek Power Plant; the Entergy White Bluff Plant; the Entergy Lake Catherine Plant; and the Entergy Independence Plant.

These facilities are operated by public utilities with the ability to shift the costs of these controls from the utilities to the consumers of the electricity generated by these plants and generators. Under Arkansas law, a public utility such as those operating the aforementioned plants, may petition to the Arkansas Public Service Commission to recover costs for emissions control costs through a surcharge for those expenses so long as specific statutory elements have been met.[970] This statute specifically provides for the recovery of costs that "[r]elate to the protection of the public health, safety of the environment" so long as other elements have been met.[971] That surcharge would allow the affected utilities to transfer costs of compliance with the Proposed FIP onto Arkansas ratepayers. These costs would place a substantial burden on Arkansas communities. This burden constitutes a material adverse impact that renders this action subject to requirements of E.O. 12866.

In addition, a significant regulatory action under E.O. 12866 is considered a "significant energy action" and subject to yet further review by OIRA under E.O. 13211 if that action is also 'likely to have a significant adverse impact on the supply, distribution, or use of energy."[972] The Proposed FIP will likely have a significant adverse impact on use of energy through decreased use by electricity consumers responding to increased rates as a result of the emissions controls required. As a result of this adverse impact, the Proposed FIP is a "significant energy action." In order to comply with E.O. 13211, EPA is required to submit to OIRA a "Statement of Energy Effects," which describes the effects of certain regulatory actions on energy supply, distribution, or use.[973]

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[969] *Id.* at Sec.3(f).
[970] Ark. Code Ann. § 23-4-501.
[971] Ark. Code Ann. § 23-4-501(a)(1)(E).
[972] Exec. Order No. 13211, 66 FR 28355, (May 18, 2001).
[973] Id.

ADEQ disagrees with EPA that the Proposed FIP is not subject to E.O. 13211 and E.O. 12866. The impacts of the Proposed FIP render it subject to both executive orders, and ADEQ is troubled that the EPA has not provided OIRA with the statements and other information required to comply with those orders. ADEQ is greatly concerned that EPA has not provided OIRA with the cost-benefit analysis required by E.O. 12866. This is a particular concern because EPA failed to perform a proper analysis of the costs of meeting EPA's proposed RPGs.

As a result of EPA's failure to analyze the "cost of compliance" factor in relation to the RPGs,[974] EPA has not performed any analysis of the costs of the overall impact of the Proposed FIP. Without EPA complying with the required additional review by OIRA, there would be no oversight of the costs of the Proposed FIP at all. Given the recent concerns by the Supreme Court in *Michigan v. EPA* about the rationality of imposing billions of dollars in economic costs in return for a few dollars in health or environmental benefits,[975] EPA should strictly comply with E.O. 12866 and 13211 in order to properly determine the extent of the impacts of the Proposed FIP on the state of Arkansas. Since EPA has failed to do so, ADEQ requests that EPA withdraw the Proposed FIP.[976]

Response: Please see the above response in reference to E.O. 12866 and E.O. 13211.In the process of developing the FIP, we analyzed all the required factors, including the cost of compliance, at each source. Our detailed cost analysis can be found elsewhere in the proposed rulemaking and in this document.

Comment: AECC stated there should be further federal review of the cost impacts of EPA's proposed Rule. [AECC (0169) p. 6] AECC stated that EPA states that the proposed Rule is not a "significant regulatory action" as defined in Executive Order 12866.[977] AECC disagrees. A "significant regulatory action" is defined as an action that may have an annual effect on the economy of $100 million or more.[978]

The cost impacts of the proposed Rule are over $2 billion which would be spent in the five years subsequent to the effectiveness date of the final rule. This is well over the annual $100 million threshold. Therefore, the proposed Rule should have been sent to the federal Office of Management and Budget for review prior to its issuance.

Additionally, in a recent decision involving costs of MATS, the U.S. Supreme Court recognized that costs of environmental regulations should be taken into account by EPA.[979] Therefore, EPA should provide a cost-benefit analysis of the proposed Rule.

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[974] *See Supra* pp. 14-15.
[975] *Michigan v. E.P.A.,* No. 14-46, 2015 WL 2473453, at *7 (U.S. June 29, 2015) ("[o]ne would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits.").
[976] Ark. Code Ann. § 23-2-304.
[977] 80 Fed. Reg. at 18999 (April 8, 2015).
[978] Executive Order 12866 of September 30, 1993, Sec. 3(t)(l).
[979] U.S. Supreme Court decision in *Michigan v. EPA* (June 29, 2015).

Response: Please see the above responses in reference to the Executive Orders. We disagree with the commenter's overly broad characterization of the Supreme Court's decision in *Michigan v. EPA.* The Court ruled in *Michigan v. EPA* that EPA acted unreasonably when it determined that cost was irrelevant to the threshold appropriate and necessary finding under section 111 of the Clean Air Act. 135 S.Ct. 2699 (2015). The Court's holding was based on its reading of the phrase "appropriate and necessary." Even in this context, however, the Court found that "a formal cost-benefit analysis in which each advantage and disadvantage is assigned a monetary value" is not required. In our action on Arkansas, the CAA and our regulations require the state (or EPA standing in the shoes of the state) to take into account certain factors in both the BART and reasonable progress analyses. One such factor in both analyses is the "cost of compliance." We note that EPA has explicitly considered the costs (and visibility benefits) of the measures in the FIP.

8.g. EPA did not adequately consider relevant factors

Comment: EPA improperly failed to consider relevant factors in its BART and reasonable progress determinations.

[Nucor Steel-Arkansas and Nucor-Yamato Steel (0163) p. 21-28; and Arkansas Electric Energy Consumers Inc. and Arkansas Gas Consumers Inc. (0175) p. 15-16] Nucor and AEEC/AGC both stated that EPA has approved Ark. Code Ann. §8-4-312 as part of the Arkansas infrastructure SIP pursuant to 42 USC §7410. See, 40 C.F.R. §52.170(e), which certifies EPA's approval of Ark. Code Ann. §8-4-312 — "Factors in Exercise of Commission Powers" (identified as former Arkansas Statutes Annotated §82-1936). When a State Implementation Plan is approved by the EPA, its requirements become federal law and are fully enforceable in federal court. See, e.g., Safe Air for Everyone v. United States EPA, 488 F.3d 1088, 1091(9th Cir. 2007); Natural Res. Def. Council, Inc. v. S. Coast Air Quality Mgmt. Dist., 651 F.3d 1066, 1069 (9th Cir. 2011); EI Comite Para EI Bienestar De Earlimart v. Warmerdam, 539 F.3d 1062, 1066 (9th Cir. 2008); GenOn REMA, LLC v. EPA, 722 F.3d 513, 516 (3rd Cir. 2013) ("If the EPA approves the SIPs, they become enforceable as federal law."); US Magnesium, LLC v. EPA, 690 F.3d 1157, 1159 (10th Cir. 2012) ("Approved SIPs are enforceable as federal law…."). Thus, Ark. Code Ann. §8-4-312 is federal law for purposes of the Clean Air Act in Arkansas and it is as equally binding on EPA as it is on the Arkansas state environmental agencies. See, e.g., United States v. Cinergy Corp., 623 F. 3d 455 (7th Cir. 2015); Sierra Club v. Ga. Power Co., 443 F.3d 1346 (11th Cir. 2006); United States v. General Motors Corp., 702 F.Supp. 133 (D.C. Tex. 1988).

Ark. Code Ann. §8-4-312 sets out several factors that must be taken into account in decisions to regulate air quality in Arkansas, including "the economic and industrial development of the state and the social and economic value of the air contamination sources," Ark. Code Ann. §8-4 312(14). Although the Clean Air Act requires that certain factors must be "taken into consideration" in determining BART, 42 U.S.C. §7491(g)(2), and in establishing reasonable progress goals, 42 U.S.C. §7491(g)(1), the statute does not make those factors exclusive. In fact, EPA's BART guidelines indicate that "unusual circumstances…[including] the economic effects of requiring the use of a given control technology" may be considered. 40 C.F.R. Part 51, Appendix Y, IV.E.3 (70 F.R. 39,104; 39,171, July 6, 2005).

EPA's BART and Reasonable Progress determinations for Flint Creek, White Bluff and Independence will cost over $2 Billion and will result in significant increases in electric and natural gas rates over most of the State of Arkansas for residential, commercial, governmental, agricultural and industrial customers of Entergy, SWEPCO, AECC and the municipal owners of those facilities. These three sources constitute a large part of the baseload electric generation for the State of Arkansas, and an even larger proportion of the baseload generation for AECC and its member cooperatives. Nowhere in the Proposed FIP does EPA consider the social and economic value of these sources, and the economic effects of EPA's actions. Since the public utilities who will incur costs under the proposed FIP will certainly pass those costs through to ratepayers, the proposed FIP will have a profound effect on the Arkansas economy.

Nucor stated that not only does EPA's failure to consider the economic consequences of its BART and Reasonable Progress determinations violate Ark. Code Ann. §8-4-312 as part of EPA's approved infrastructure SIP for Arkansas, it also violates the spirit and purpose of EPA's own Environmental Justice (EJ) guidelines which requires EPA to "consider the impacts of our regulatory actions on populations documented as frequently bearing the greatest burdens imposed by environmental pollution." EPA, "Guidance on Considering Environmental Justice During the Development of Regulatory Actions," May 2015, at p. 2.[980] These same populations that EPA's EJ guidelines seek to protect would be adversely impacted by EPA's Proposed FIP. Arkansas is the second poorest state (49/50) with a median household income of $40,768.[981] It has the 4th highest percentage (ranked 46/50) of poverty stricken residents.[982] The areas in Arkansas that White Bluff, Independence and Flint Creek serve have an average of 19.2% of residents living below the federal poverty level. Several counties in east Arkansas that are served by these facilities have more than 30% of their residents living below the federal poverty level.[983]

Federal data illustrates that the poorer a household is, the more that higher energy rates harm the occupants.[984] In 2012, families with annual pre-tax incomes of over $50,000 spent 9% of their household budgets on energy, compared to only 5% in 2001. Those earning between $30,000 and $50,000 saw an even larger percentage of their budgets consumed by rising energy costs — 17% in 2012 compared to 10% in 2001. Most drastically, families making $10,000 to $30,000 spent 24% of their incomes on energy in 2012 compared to 14% in 2001.[985] EPA's proposed FIP will increase electric rates even more, and amplify these economic disparities and income inequality even further. The increases in electric rates that electricity providers would charge ratepayers in order to comply with EPA's proposed FIP will push more Arkansans deeper into poverty.

There is an important relationship between utility rates, poverty and poor health. One study concluded that an additional regulatory cost of $8.9 million related to electricity use causes one

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[980] Available at http://www.epa.Rov/environmentaliustice/resources/policy/considering-ei-in-rulemaking-guide-final.pdf.
[981] U.S. Census Bureau. Accessed 7/2/15. http://quickfacts.census.gov/qfd/states/05000.html
[982] Id.
[983] Information obtained by going county by county (on above website), accessed 7/2/15.
[984] http://www.forbes.com/sites/realspin/2015/06/15/epa-clean-power-plan-may-do-more-harm-than-good/ Citing: http://www.americaspower.org/sites/default/files/Energy_Cost_Impacts_2012_FINAL.pdf
[985] Id.

additional adult death, and that such impacts are highly concentrated in lower income groups and disproportionately affect certain minority groups. The study concludes that 43% of such deaths would occur in households with incomes of less than $15,000.[986] The higher energy prices resulting from EPA's Proposed FIP will force many Arkansans to spend an even higher percentage of their income on electric bills, leaving them less money for food, use of heating and air conditioning, paying health insurance premiums, buying medicine, transport to work, and to see their doctors. In forcing its proposed FIP onto Arkansas, EPA has failed to consider whether it would harm thousands of Arkansans, which likely would be the poorest Arkansans.[987]

EPA also failed to consider whether the economic impact of its proposed FIP costs would lead to closure or curtailment of White Bluff, Independence, or Flint Creek resulting in local adverse economic impacts, the impact of such closures or curtailment on electric grid reliability in the State of Arkansas, and the State of Arkansas's interest in maintaining sufficient electric generation resources within its own borders and subject to state regulation. Under EPA's BART guidance, EPA states that BART should not be so economically onerous that it brings a facility to the brink of shutdown or substantial curtailment of operations.[988] This consideration is echoed in EPA's BART Guidelines, 40 C.F.R. Part 51, Appendix Y, IV.E.3 (70 F.R. 39,104, 39,171; July 6, 2005), yet EPA did not consider whether the $2.0+ billion cost imposed by its BART and Reasonable Progress determinations would result in the shutdown or curtailment of operations at White Bluff, Flint Creek and Independence.

Under EPA's proposed Clean Power Plan, the possible impacts of the closure or curtailment of fossil-fuel electric generating units like White Bluff, Independence and Flint Creek on electric grid reliability was deemed to be an important factor, with several regional transmission organizations commenting on the adverse impacts of EPA's 111(d) plan on grid reliability.[989] Yet, EPA improperly failed to consider or take into account the impacts of its Proposed FIP on electric grid reliability, either regionally or within the State of Arkansas as a whole, or within discrete electric service territories within the State of Arkansas.[990]

Nucor and AEEC/AGC both stated that EPA did not consider whether its proposed FIP would result in economic harms and negative health impacts in Arkansas. Not only are these factors "appropriate," as indicated above they are "necessary" and required under Ark. Code Ann. §8-4-312, EPA's own BART Guidelines, and its EJ Guidelines. "No regulation is 'appropriate' if it does significantly more harm than good." Michigan v. EPA, 576 U.S. (2015). EPA should consider whether its proposed FIP "reflects the reality that too much wasteful expenditure

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[986] See Exhibit 8 to Nucor's comments, Klein, D., and Keeney, R., "Mortality Reductions from Use of Low-Cost Coal-Fueled Power: An Analytical Framework" (December 2002).

[987] See, Exhibit 23 to Nucor's comments, AECC Letter dated Sept. 26, 2014 to Hon. G. McCarthy regarding the impacts of EPA's Clean Power Plan.

[988] See Exhibit 9 to Nucor's comments, "Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plant and Other Stationary Sources, USEPA," November 1980, EPA 450/3-80-009b, section 2.6.3, p. 20.

[989] See, Exhibits 10A, 10B, and 10C to Nucor's comments, Southwest Power Pool and Midcontinent Independent System Operator comments, Docket No. EPA-HQ-OAR-2013-0602.

[990] The impact of EPA's proposed Clean Power Plan by way of closure or curtailment of operations of White Bluff, Flint Creek or Independence would also be a relevant factor in determining the costs of compliance, remaining useful life and the visibility impacts of those sources under the Regional Haze Rule statutory factors for BART and Reasonable Progress.

devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems." Michigan v. EPA, 576 U.S. (2015). Expending billions of dollars for imperceptible visibility changes under these circumstances is simply not defensible, and has not been properly justified by EPA. EPA should have considered the economic impact of the Regional Haze Rule and its BART and Reasonable Progress determinations on the ratepayers who will be paying for these expensive controls. EPA's failure to take these and other relevant factors into consideration in its BART and reasonable progress determinations is unreasonable, arbitrary, and capricious. Michigan v. EPA, 576 U.S. (June 28, 2015). Therefore, EPA should withdraw the proposed FIP.

Response: We disagree with this comment. When a State Implementation Plan is approved by EPA it is true that it "'[h]a[s] 'the force and effect of federal law.'" *Safe Air for Everyone v. U.S. EPA*, 488 F.3d 1088, 1091 (9th Cir. 2007), quoting, *Trs. for Alaska v. Fink*, 17 F.3d 1209, 1210 (9th Cir. 1994). However, we reject the assertion that EPA was required to consider the factors listed in Ark. Code Ann. §8-4-312 when promulgating a FIP to address the portions we disapproved in Arkansas' SIP.

As explained in other responses above and by the U.S. Supreme Court in *Union Electric Co. v. EPA*, 427 U.S. 246,249-50 (1976), Congress has given States the primary responsibility in preventing and controlling air pollution. States are under an obligation to submit a Regional Haze SIP to EPA which complies with federal requirements. While states have flexibility in developing a SIP, EPA must ensure that the plan meets all federal requirements. In the event that a state fails to submit a SIP that meets federal requirements, EPA must step in and create a FIP to address the portions of the disapproved the state's plan which meets all federal requirements.

Ark. Code Ann. §8-4-312 provides that "[i]n exercising their powers and responsibilities *under this chapter,* the Arkansas Department of Environmental Quality and the Arkansas Pollution Control and Ecology Commission shall take into account and give consideration to the following factors:…" (emphasis added). Arkansas has failed to develop a Regional Haze SIP which meets all applicable federal requirements. As a result, EPA is required to develop and implement a FIP. While Arkansas had the discretion to require that additional factors be considered in developing its SIP, it cannot impose that same requirement on EPA. EPA is not exercising powers granted to us by Arkansas' Air Pollution Control Act, rather we are acting under the CAA. In this situation, EPA is required to follow the requirements listed in both the CAA and our rules. It should be noted that there is a provision in Arkansas' Act which more directly targets the issue mentioned by the Commenter. That provision is not in the federally-approved SIP. Ark. Code Ann. §8-4-317 provides that "[i]n developing and implementing a state implementation plan, the Arkansas Department of Environmental Quality shall consider and take into account the factors specified in §8-4-312 and the [Arkansas] Clean Air Act…" While the CAA does not prevent states or EPA from considering other factors in its BART and reasonable progress determinations, it only mandates that the factors listed in the Act be considered. EPA considered all the factors deemed necessary to be considered by the CAA.

We disagree that our action violates the spirit and purpose of our Environmental Justice Guidelines. The full sentence from which the commenter quotes reads: "In particular, the U.S. Environmental Protection Agency has a responsibility under Executive Order 12898, Federal

Actions to Address Environmental Justice in Minority Populations and Low-Income Populations to consider the impacts of our regulatory actions on populations documented as frequently bearing the greatest burdens imposed by environmental pollution." Executive Order 12898 states that each Federal agency is required to make "achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and possessions, the District of Columbia, the Commonwealth of Puerto Rico, and the Commonwealth of the Mariana Islands." Contrary to the commenter's assertion, our action embodies the spirit in which the Executive Order was written. The reduction in air pollution that will be attributed to the controls being required in our final rule will result in improved visibility, and Arkansas residents living in the surrounding areas will reap ancillary health benefits achieved by the reduction. We do, however, note that our decision was not based on these additional health benefits. The Regional Haze Program was designed solely to improve visibility in Class I areas, it is not a health based program. Any other benefits received as a result of the Program are an added bonus.

In regards to the comments about the cost of the controls and the possible closure or curtailment of units, we note that controls achieving the level of control that we are requiring are highly cost-effective, are in wide use in the industry, and thus should not require a source to shut down to comply. During our comment period, we received no, non-speculative information to validate claims that sources would retire rather than install demonstrably cost-effective controls. Commenters who have alleged grid reliability concerns in response to our proposed controls have not provided adequate documentation for their assertions. Please see our responses to the comments regarding cost analysis that we have provided elsewhere in this document as well as out Cost TSD for a more in depth analysis.

We believe, for reasons we have outlined in our proposal and elsewhere in our response to comments, that the controls we proposed under our FIP are cost-effective and will result in significant improvements in visibility at a number of Class I areas and meet the requirements of the CAA and the RHR. We do note that we are not subject to state law requirements related to how the cost analysis must be conducted or what specific factors need to be considered. We did consider costs in great detail to ensure that the controls required by the FIP are cost-effective, worth the visibility reductions achieved, and consistent with expectations in other SIPs and FIPs. For the comments regarding costs, economics, see the previous responses.

Comment: If there is no available information showing the potential for units to close, EPA is not required to consider whether the rule may cause units to close. [Sierra Club et. al. (0171) p. 44-45] Sierra Club et. al. stated that comments submitted by other parties suggest that EPA is required to consider the potential closure of units as part of considering the cost of controls. However, there is no evidence in the record that any of the units would close since they could not afford the controls. To the contrary, EPA has proposed controls in part because they have cost-effectiveness values and absolute costs comparable to what similar sources have had to bear around the country. *See, e.g.,* pages 11-12, above. In the absence of information to the contrary, EPA can rationally conclude that when it proposes controls that have absolute costs and cost-effectiveness values similar to the costs that other utilities around the country found affordable, that the sources in Arkansas can also afford such control costs.

EPA's BART Guidelines include a provision regarding the affordability of controls. *See* 40 C.F.R. Part 51, App. Y § IV(E)(3). In the course of reviewing scores of BART determinations in haze plans across the country, EPA has relied on the affordability provision only once. 79 Fed. Reg. 33,438, 33,442-43 (June 11, 2014) (controls that would otherwise be BART are not affordable for the Intalco smelter). This is consistent with the BART Guidelines' instruction that EPA should rely upon the affordability provision only in "unusual circumstances." 40 C.F.R. pt. 51 App. Y § IV(E)(3). In this rare instance, the affected BART source took the affirmative step of providing information to EPA that allegedly indicated that the company would close the source if required to install certain BART controls. 79 Fed. Reg. at 33,439. Where a company has not substantiated the claim that otherwise cost-effective controls are not affordable, EPA has found that the controls are affordable. 76 Fed. Reg. 36,329, 36,334-36 (June 22, 2011) (rejecting claim by sugar beet processing facility in Idaho that it could not afford controls); 77 Fed. Reg. at 72,539-42 (concluding that there is no evidence that the Apache power plant in Arizona cannot afford BART controls).

It would be difficult for EPA to accurately assess the likelihood that BART controls would lead a source to close unless the source provides EPA with access to its confidential financial data. To date, no source has claimed that EPA's proposed plan would lead to plant closure due to unaffordable costs. In the absence of such claims and supporting information, EPA properly assumed that control costs which similar sources have found affordable are also affordable to Arkansas sources.

Response: EPA agrees with the commenter that the BART Guidelines include a provision allowing for the consideration of the affordability of controls. As the commenter notes, however, none of the sources subject to control measures in our FIP have claimed that the installation of the controls required by the FIP would lead to plant closures or curtailments.

8.h. Other

Comment: EPA arbitrarily chose the options for emissions control for Entergy Independence Units 1 and 2. [ADEQ (0144) p. 22-23] ADEQ stated that EPA arbitrarily chose the two options it presented for emissions controls at Entergy Independence Units One and Two as evidenced by EPA's failure to discuss a third option, which EPA presented to ADEQ for consideration prior to the promulgation of the Proposed FIP.[991] ADEQ received a technical support document dated February 11, 2015 within which EPA Region 6 presented three options for Entergy Independence: "Option 1: Propose No Additional Controls under Reasonable Progress"; "Option 2: Propose Only SO_2 Controls under Reasonable Progress"; and "Option 3: propose Both SO_2 and NO_X Controls Under Reasonable Progress."[992]

Although ADEQ received this document on February 12, 2015, EPA never included it in the Rulemaking Docket.[993] When EPA published the Proposed FIP on April 8, 2015, the option to

[991] EPA, Arkansas Regional Haze FIP Update, (February 11, 2015), see Exhibit 2 to ADEQ's comments.
[992] Id.
[993] EPA Docket Number EPA-R06-OAR-2015-0189

"Propose No Additional Controls under Reasonable Progress" had been inexplicably removed as an option from the proposed Regional Haze FIP. EPA completely excluded this option from consideration and no mention of it was made in the Proposed FIP.

While EPA has considerable discretion interpreting its own regulations, the law requires EPA to "cogently explain why it has exercised its discretion in a given manner."[994] Whether or not EPA ultimately chose to reject the option, it is legally obligated to consider and explain its decision to or not to include it. The decision to provide ADEQ with a certain set of options prior to promulgation of the Proposed FIP and simply excise one of those options from the Proposed FIP without due consideration is arbitrary and capricious. EPA should withdraw the Proposed FIP and any subsequent plan that might include emissions controls for Entergy Independence Units 1 and 2 should include a proper consideration of the available options.

Response: The document to which the commenter refers, "EPA, Arkansas Regional Haze FIP Update, (February 11, 2015)" (Exhibit 2 to ADEQ's comments), is a briefing paper based on EPA staff-level advice and recommendations. The briefing paper was provided as a courtesy to ADEQ for informational purposes and is not part of the basis for EPA's decision. For this reason, it was not included in the docket. Under Section 307(d)(3) of the Clean Air Act, the docket is required to include the factual data on which the proposed rule is based, the methodology used in obtaining the data and in analyzing the data, and the major legal interpretations and policy considerations underlying the proposed rule. The briefing paper does not fall within any of these categories. We provided the proposed factual, technical, and legal basis for requiring controls at Independence to ensure reasonable progress in our proposed rule. In doing so, we have "cogently explain[ed]" the basis for our proposed decision. In today's action, we again explain our decision to require reasonable progress measures at Independence. Although the briefing paper shared with ADEQ did not create a distinct obligation for us to propose an option of "no controls" at Independence, we have met the basic requirement that we explain our exercise of discretion in deciding to require reasonable progress measures at Independence. In explaining why we are requiring these measures, we inherently have also explained why we have not decided to not require any measures at all.

Comment: [Arkansas Attorney General (0162) p. 1-2] The Attorney General for the State of Arkansas stated that the Environmental Protection Agency ("EPA" or "Agency") has acted in an arbitrary and capricious manner by proposing a FIP to address certain regional haze and visibility transport requirements for the State of Arkansas. The proposed FIP has no basis in law or science and is a prime example of overreaching federal regulation in response to "sue and settle" litigation brought by the Sierra Club. As such, the EPA should withdraw the proposed FIP and consult with the State in developing an approvable SIP.

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[994] *Nat'l Parks Conservation Ass'n v. E.P.A.*, No. 12-73710, 2015 WL 3559149, at *3 (9th Cir. June 9, 2015); (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 48, (1983)); *Greater Yellowstone Coalition, Inc. v. Servheen*, 665 F.3d 1015, 1030 (9th Cir.2011) (requiring "a rational connection between the data before [the agency] and its conclusion"); *Nw. Envtl. Def. Ctr. v. Bonneville Power Admin.*, 477 F.3d 668, 691 (9th Cir.2007).

The Attorney General stated that there is concern with the abbreviated time frame being forced upon this review by a third party lawsuit. On February 11, 2015, the EPA lodged a proposed Consent Decree in *Sierra Club v. McCarthy*, Case No. 4:14-CV-00643-JLH, Eastern District of Arkansas ("*Sierra Club*"). The proposed Consent Decree requires EPA to issue a final regional haze FIP on or before December 15, 2015. The Attorney General submitted comments regarding the proposed Consent Decree on April 20, 2015. Contemporaneously, EPA submitted the proposed FIP for public comment on April 8, 2015 and extended that period until July 15, 2015. As I stated in my comments regarding the proposed Consent Decree in *Sierra Club*, the Attorney General does not believe that five (5) months is an adequate time period for the EPA to fully analyze and respond to the public comments. Again, the Attorney General urges the EPA to reconsider the *Sierra Club* December 15, 2015 deadline for the issuance of a final FIP. EPA must take an appropriate amount of time to address the many concerns that are being raised in the public comments. A rushed process that fails to fully review all considerations will lead to an arbitrary and capricious decision. Such a decision will most certainly lead to protracted litigation, not protection of the environment. In the light of recent case law, EPA is not likely to prevail in litigation challenging the proposed FIP.[995]

Response: Sierra Club brought suit against EPA because we have a mandatory duty under the Clean Air Act to address deficiencies in SIPs in a timely manner. Consent decrees establishing dates by which EPA must take action do not address the content of final action by the Agency. In this case, as explained in more detail earlier, after the close of the comment period, EPA concluded that it would not ask the court to enter the proposed consent decree that it had made available for public comment. Instead, the parties filed motions in the Eastern District Court of Arkansas in a case in which the state of Arkansas was a party. The court ordered EPA to promulgate a FIP or approve a state SIP by August 31, 2016, nearly 15 months after our proposed FIP. We believe this date provides adequate time for EPA to address all comments and to finalize a FIP. See Sam Coleman declaration submitted under the mandatory duty suit (provided in our docket to this rulemaking). The proposed FIP, as explained in greater detail elsewhere, addresses the portions of the Arkansas SIP we disapproved in 2012. .

Comment: EPA has broad oversight authority over the regional haze program and final say on whether state regional haze SIPs comply with the CAA and regulatory requirements. [Sierra Club et. al. (0171) p. 5-6] Sierra Club et. al. stated that the Clean Air Act's regional haze program provides states with the initial opportunity to develop regional haze SIPs that clean up the air in our nation's national parks and wilderness areas in accordance with the Regional Haze Rule and EPA guidance. *See* 42 U.S.C. § 7491(b)(2). If a state's regional haze plan fails to establish a haze program that complies with the applicable legal requirements, the Clean Air Act requires EPA to disapprove the state plan and issue a federal implementation plan ("FIP") in its place. 42 U.S.C. § 7410(c)(1); *Oklahoma v. EPA*, 723 F.3d 1201, 1207-10 (10th Cir. 2013).

Congress gave EPA the final say on whether a state's regional haze SIP complies with the Clean Air Act. 42 U.S.C. §§ 7410(c)(1), (k)(3), (l), 7491. EPA has broad oversight authority over the regional haze program and is obligated to disapprove state haze SIPs that fail to comply with the

[995] *Nat'l. Parks Conservation Ass'n. v. EPA*, -- F.3d --, 2015 WL 3559149 (9th Cir. 2015).

Act. *North Dakota v. EPA*, 730 F.3d 750, 760-62 (8th Cir. 2013); *Oklahoma v. EPA*, 723 F.3d at 1207-10. Congress gave EPA this broad oversight authority to prevent recalcitrant states from undermining the purposes of the Clean Air Act through inadequate state plans. *See, e.g.*, *Alaska Dep't of Envtl. Conservation v. EPA*, 298 F.3d 814, 819-20 (9th Cir. 2002) (Congress gave EPA oversight authority because of "disappointing state response[s] to air pollution concerns" and its recognition that "states experience[] internal industry 'pressure . . . to relax their standards'"), *aff'd*, 540 U.S. 461 (2004).

Response: We agree with the commenter that EPA is required to approve only those provisions of a SIP that comply with the Clean Air Act. When EPA disapproves a SIP in whole or part, the Clean Air Act obligates EPA to promulgate a FIP or to approve a SIP within two years of EPA's disapproval.

Comment: Since no party challenged EPA's March 12, 2012 final rule partially approving and partially approving the Arkansas Regional Haze SIP by filing a petition for review, any right to challenge EPA's final partial approval and partial disapproval of the SIP has been waived. [Sierra Club et. al. (0171) p. 6-7] Sierra Club et. al. stated that ADEQ submitted a proposed regional haze SIP to EPA on September 23, 2008 and August 3, 2010. 77 Fed. Reg. 14,603, 14,604 (Mar. 12, 2012). On September 27, 2011, ADEQ submitted supplemental information. *Id.* Less than a month later, EPA proposed to partially approve and partially disapprove Arkansas's SIP. 76 Fed. Reg. 64,185 (October 17, 2011). On March 12, 2012, EPA issued a final rule approving in part and disapproving in part Arkansas's regional haze and interstate transport SIP. 77 Fed. Reg. 14,603.

In the 2012 action, EPA approved Arkansas's identification of subject-to-BART sources, with the exception of the 6A and 9A Boilers at Georgia-Pacific Crossett Mill, which EPA found subject-to-BART. 77 Fed. Reg. 14,603. EPA approved some of Arkansas's BART determinations, and disapproved others. As most relevant to these comments, EPA disapproved these BART determinations:

- SO2 and NOx BART for AEP Flint Creek Boiler No. 1;
- SO2 and NOx BART for the bituminous and subbituminous coal firing scenarios for Entergy White Bluff Plant Units 1 and 2; and
- NOx BART for the natural gas firing scenario for Entergy Lake Catherine Unit 4; and
- SO2, NOx, and particulate matter ("PM") for the fuel oil firing scenario for Entergy Lake Catherine Unit 4.

77 Fed. Reg. at 14, 605; *see also* 80 Fed. Reg. at 18,947. EPA found that ADEQ "did not satisfy all the regulatory and statutory requirements in making [] BART determinations" for certain sources. *Id.* at 14,605.

In addition, EPA partially approved and partially disapproved Arkansas's long-term strategy because it relied on portions of the regional haze SIP that EPA disapproved, including some of the BART emissions limits. 77 Fed. Reg. at 14, 605. EPA disapproved ADEQ's reasonable progress goals ("RPGs") because Arkansas did not consider the four factors that states are

required to consider in establishing RPGs under the CAA and 40 C.F.R. § 51.308(d)(1)(A). 77 Fed. Reg. at 14, 605.

No party challenged EPA's 2012 disapproval decision by filing a petition for review in the appropriate Circuit Court of Appeals. Accordingly, any right to challenge EPA's approval or disapproval decisions in the 2012 final action has been waived. *See* 42 U.S.C. § 7607(b)(1).

Following EPA's disapproval decision, Arkansas began the process of collecting technical documentation from the companies whose BART determinations were disapproved. 80 Fed. Reg. at 18,947. Those documents were provided to EPA and form the basis of its evaluation of BART determinations in the proposed FIP. *See* 80 Fed. Reg. at 18,947.

Response: We agree with the commenter. As explained in another response, we partially approved and partially disapproved the submitted regional haze SIP of Arkansas in 2012. We received adverse comments on our proposed action; however, no party filed suit challenging our action. The proposed rulemaking before us only addresses EPA's determinations for disapproved elements that need to be addressed as required by the Clean Air Act.

Comment: EPA can satisfy the standard articulated in *NPCA vs. EPA*. [Sierra Club et. al. (0171) p. 41] The Sierra Club et. al. stated that other commenters cited *National Parks Conservation Association v. EPA* to argue that EPA has failed to rationally explain how the benefits justify the costs of the proposed controls. 788 F.3d 1134, 1138 (9th Cir. 2015). Not so. EPA can easily satisfy the standard articulated in *NPCA v. EPA* that EPA provide an explanation that is "not elaborate, but rational, and thus adequate." *Id.* at 1145. The court held that if EPA points to the costs and benefits of other control determinations it has approved, EPA satisfies the requirement to provide some metric by which it weighs costs and visibility improvement. In particular, the court stated that:

> EPA explained that it had found improvements of 0.2 deciviews at each unit of that location to be cost-justified for reasonable progress purposes when the costs of such improvement ranged from $586/ton to $661/ton. *See id.* EPA's comparison of the two sources provided NPCA with at least some broad metric for understanding which cost-per-ton ratios EPA will approve and which it will not—a rational explanation why the reasonable progress options available at Colstrip Units 3 and 4 were not feasible. *Id.* at 1149.

As we note elsewhere in our comments and as explained in the Stamper Report, EPA has approved both BART and reasonable progress determinations in which the cost-effectiveness of controls was equal to or higher than the cost-effectiveness of the Arkansas FIP controls and in which the visibility benefits were equal to or lower than the improvement expected from the Arkansas FIP controls. *See, e.g.*, pages 11-12 of Sierra Club comments; *see* Stamper Report at 12, 60-62. EPA should cite these examples in order to satisfy the concerns expressed by the court in *NPCA v. EPA*.

Response: We agree with the commenter that the cost effectiveness of the controls in our proposed FIP are comparable -- and in some cases more cost effective (i.e., lower $/ton) -- than similar controls in other regional haze actions that we have approved or promulgated. These controls are also anticipated to result in comparable or greater visibility benefits than controls in other regional haze actions. Below, we specifically point out some examples of this.

As pointed out in the Stamper Report at 12, we approved Colorado's determination that dry scrubbers on CSU Nixon Unit 1 are reasonable and cost effective controls and are required under reasonable progress.[996] In its SIP, Colorado determined that the cost effectiveness of dry scrubbers on CSU Nixon Unit 1 would be $3,744/ton SO_2 removed and that the visibility improvement (delta dv for the maximum 98th percentile impact) was projected to be 0.46 dv.

We approved Colorado's determination that dry scrubbers are BART for SO_2 for CSU Martin Drake Units 6 and 7.[997] The state determined that the cost effectiveness of dry scrubbers is $2,808/ton SO_2 removed for Unit 6 and $2,345/ton SO_2 removed for Unit 7. The state found that the visibility improvement (delta dv for the maximum 98th percentile impact) is projected to be 0.25 dv for Unit 6 and 0.40 dv for Unit 7.

We also approved Colorado's determination that BART for NO_X for Martin Drake Unit 5 is ultra LNB/OFA, which the state estimated to cost $1,342/ton removed and to result in projected visibility improvement of 0.08 dv.[998]

In our North Dakota RH FIP, we required NO_X combustion controls under the reasonable progress requirements for Antelope Valley Station Units 1 and 2 that were estimated to cost $586/ton removed at Unit 1 and $661/ton removed at Unit 2, and the anticipated visibility benefits are estimated to be 0.754 dv for the two units combined.[999]

Thus, we agree with the commenter that the cost and visibility improvement of the controls we are requiring in our Arkansas FIP are comparable and consistent with the BART and reasonable progress controls we have approved or promulgated in other regional haze actions

9. Visibility Transport

Comment: The Arkansas RH SIP satisfies the Prong 4 requirement; EPA does not have authority to require controls at these sources for purposes of "Visibility" Interstate Transport.

[Entergy Arkansas Inc. (0166) p.56] Entergy Arkansas Inc. stated it disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of

[996] 77 FR 18052 and 77 FR 76871.
[997] 77 FR 18052 and 77 FR 76871.
[998] 77 FR 18052 and 77 FR 76871.
[999] 77 FR at 20899.

Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and Entergy hereby incorporates these by reference.

Contrary to EPA's position, the Arkansas SIP submittal satisfies Prong 4, rendering the regional haze FIP unnecessary to address interference with other states' visibility SIPs. First, the SIP submittal does explain how it complies with Prong 4 by specifically identifying the state regulations that ensure emissions from Arkansas sources will not interfere with other states' regional haze SIPs. Second, while EPA has issued guidance documents stating that Prong 4 may be satisfied through the promulgation of a regional haze SIP, this is not the *only* way in which a state may meet its obligation. *See* Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and PM2.5 National Ambient Air Quality Standards, at 9-10 (Aug. 15, 2006). Indeed, EPA itself has acknowledged states may satisfy Prong 4 by something other than an EPA-approved regional haze SIP. 76 Fed. Reg. 8326, 8328 (Feb. 14, 2011) (Proposed Approval and Promulgation of State Implementation Plans; State of Colorado; Interstate Transport of Pollution Revisions for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS: "Interference With Visibility" Requirement).

Arkansas emissions cause and contribute to visibility impairment primarily in two Class I areas in Missouri, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, and potentially other Class I areas in Oklahoma, Kentucky, Illinois and Louisiana. Proposed Approval Regional Haze Interstate Transport SIP, 76 Fed. Reg. 64,186, 64,193, 64,215 (Oct. 17, 2011); Final Approval Regional Haze Interstate Transport SIP, 77 Fed. Reg. 14604, 14623 (Mar. 12, 2012). Of these states, only Missouri relied upon anticipated BART controls from sources in Arkansas when developing its regional haze SIP. *See* Missouri Regional Haze SIP. (June 25, 2009). Subsequent to EPA's partial disapproval of the Arkansas BART limits, Missouri released a 5-Year Progress Report demonstrating that Mingo and Hercules Glades are on track to meet the 2018 visibility goals. Missouri Regional Haze Plan: 5-Year Progress Report (Aug. 29, 2014). Missouri concluded that this progress was the result of emissions reductions at Missouri sources and that further reductions are not necessary. Thus, Missouri has determined that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with Missouri's reasonable progress efforts.

EPA proposes to find that the requirements of Prong 4 will be satisfied by the combination of the emission control measures in the proposed regional haze FIP, and the already approved portions of the Arkansas regional haze SIP. It is inappropriate for EPA to propose such a finding when the Agency has not yet finalized its regional haze FIP. As EPA recognizes, the Agency cannot finalize this proposal unless and until it finalizes its action on the regional haze FIP. Depending upon the comments submitted to EPA on the proposed FIP, the final regional haze FIP could be substantially different from the proposal.

It is impossible to know, during the comment period on this rulemaking, whether the final FIP will rectify these problems. Because significant changes could be made to the final FIP, because these changes are unforeseeable, and because Entergy has significant concerns that the final FIP may be legally and technically deficient, it is unreasonable to request public comment on a proposal that the final FIP will satisfy Prong 4. This is a clear violation of EPA's obligation

under the Administrative Procedure Act to provide adequate notice and opportunity to comment on a proposed rule. 5 U.S.C. § 553. EPA should defer requesting public comment on this issue until after the Arkansas regional haze FIP has been finalized.

[Nucor Steel-Arkansas and Nucor-Yamato Steel Company (0163) p. 50-53] Nucor stated the good neighbor visibility provision in 42 U.S.C. 7410(a)(2)(D)(i)(II) prohibits interference with "measures" required to be included in another State's implementation plan to protect visibility. EPA has not demonstrated that any of these sources in its Proposed FIP are interfering with any visibility control measure in any other state's SIP. Nucor disagreed with EPA's determination to disapprove the Arkansas interstate visibility transport SIP provisions submitted to EPA on April 2, 2008 based on the same reasoning.[1000] In EPA's 2011 proposed decision to disapprove that SIP submission, EPA stated that the Clean Air Act requires states to prevent "sources in the state from emitting pollutants in amounts which will interfere with efforts to protect visibility in other states." 76 Fed.Reg. 53189, 64219. In its Proposed FIP in 2015, EPA states that the Arkansas SIP did not ensure that emissions from Arkansas sources "do not interfere with other states' visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA." 80 Fed.Reg. 18998, April 8, 2015. The visibility protection requirement of §110(a)(2)(D)(i)(II) does not protect against interference with either other states "efforts" or other states "programs." Unlike the language in §110(a)(2)(D)(i)(I), which prohibits emissions that contribute significantly to nonattainment or maintenance of a NAAQS in another state, the visibility protection requirement is narrower and only protects against interference with specific measures, that is, actions included in another state's plan to achieve a visibility goal. Reasonable progress goals, projected deciview improvements from regional efforts, and the like are goals or standards; they are not "measures" taken by or enforced by a state.

There is nothing in the record demonstrating that any of the sources in the Proposed FIP interfere with any measure included in any other state's SIP for the purpose of protecting or improving visibility. To the extent that EPA's proposed interstate visibility transport FIP is not based on direct interference with a control measure in another state's regional haze SIP (in contrast to interference with a regional haze related visibility goal), EPA's interpretation is contrary to the clear and express language of Section 110. EPA's interpretation also is contrary to the Clean Air Act's clear direction that each state is to determine its own emission limits, schedules of compliance and other measures for sources in that state for purposes of visibility protection under section 169A. EPA's interpretation would impermissibly give one state the power to control another state's regional haze SIP decisions, including its BART and Reasonable Progress determinations.

Finally, even if the CAA's good neighbor visibility provision required a state SIP to contain emission limits for sources that contribute to visibility impairment at a Class I area in another state, EPA has not demonstrated that any of the controls in its Proposed FIP are "necessary" for that purpose, considering based on the uncertainty in the modeling that these controls will result in actual visibility improvements.

Response: Section 110(a)(2)(D)(i)(II) requires that each state's SIP contain adequate provisions to ensure that emissions from sources within the state do not interfere with any measures to

[1000] Exhibit 22, Nucor's Comments in Docket EPA-R06-OAR-2008-0727 (without exhibits), December 2011.

protect visibility required to be included in another state's SIP. EPA has concluded that our FIP and the elements we approved in the Regional Haze SIP on March 12, 2012, together meet these requirements.[1001]

Section 110(a)(2)(D)(i)(II) does not explicitly define what is required in SIPs to prevent the prohibited impact on visibility in other states nor does it explicitly define how to determine if a state's emissions are interfering with another state's measures to protect visibility. We have interpreted this statutory requirement as providing that a Regional Haze SIP that requires emission reductions consistent with the assumptions the relevant RPO used to model the RPGs for Class I areas in other states satisfies a state's obligation to ensure that its own emissions do not interfere with another state's visibility measures. States may rely on a fully approved Regional Haze SIP to demonstrate that a SIP for 8-hour ozone or $PM_{2.5}$ contains adequate provisions to prohibit emissions that interfere with visibility measures in other states.[1002]

Arkansas chose to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS by relying on the BART determinations it made in its 2008 Regional Haze SIP submittal. However, due to our previous partial disapproval of this submittal,[1003] the Arkansas SIP does not currently include all of the emission reductions Arkansas agreed to achieve in its RPO process. Arkansas is a member state of CENRAP, the regional planning committee on regional haze. Each CENRAP state based its regional haze plan and RPGs on the CENRAP modeling, which was based in part on the emissions reductions each state intended to achieve by 2018. Within the CENRAP process, Arkansas promised to achieve emission reductions corresponding to BART, and these emissions reductions were included in the CENRAP modeling used by the participating states to develop their RPGs and Regional Haze SIPs. However, many of the BART determinations in the SIP did not meet the CAA and Regional Haze regulations, and were disapproved by EPA; therefore, the State's SIP does not currently provide for all the emissions reductions that Arkansas itself determined to be necessary to meet the interstate visibility transport requirement. Because Arkansas has not provided any other analysis or explanation of how the Arkansas SIP fulfills the requirement of 110(a)(2)(D)(i)(II), it follows that the Arkansas SIP does not contain adequate provisions to prohibit emissions that would interfere with other states' visibility protection measures. Therefore, we disagree with the commenters' argument that the Arkansas RH SIP satisfies the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.

We disagree with Nucor's contention that our interpretation is contrary to the CAA because the Act gives clear direction that each state is to determine its own emission limits, schedules of compliance and other measures for sources in that state for purposes of visibility protection under section 169A. The commenter states that our interpretation would impermissibly give one state the power to control another state's regional haze SIP decisions. However, the commenter's

[1001] Guidance on Infrastructure State Implementation Plan (SIP) Elements Under Clean Air Act. Sections 110(a)(1) and 110(a)(2) (2013) at 33; see also 76 Fed. Reg. 491 (Jan. 5, 2011) for additional explanation of EPA's interpretation of these provisions of the Clean Air Act.
[1002] See "2006 Guidance for SIP Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and PM2.5 NAAQS" at pages 9-10.
[1003] 77 FR 14604 (Mar, 12, 2012).

interpretation is inconsistent with section 110(a)(2)(D)(i)(II)'s "good neighbor" provision, which requires states to prohibit emissions that interfere with other states' measures to protect visibility. This statutory requirement anticipates that a state may be required to adjust its own emissions based on the impacts of those emissions on other states. Our Regional Haze Rule, which was promulgated through notice-and-comment rulemaking in 1999, also requires that states develop "coordinated emission management strategies" when necessary to prevent interstate visibility impairment.[1004] Thus, while the CAA and our regulations do not allow one state to "control" another's regional haze planning, they do contemplate that a state may be required to prohibit emissions that interfere with visibility in another state's Class I areas.

As stated above, Arkansas elected to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) by relying on the BART determinations that are part of its Regional Haze SIP submittal. Arkansas could have elected to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) by other means; we have elsewhere determined that states may also be able to satisfy the requirements of CAA section 110(a)(2)(D)(i)(II) with something less than an approved Regional Haze SIP.[1005] In other words, an approved Regional Haze SIP is not the only possible means to satisfy the requirements of CAA section 110(a)(2)(D)(i)(II) with respect to visibility; however such a SIP could be sufficient.[1006] We also note that following our March 12, 2012, partial disapproval of the Arkansas RH SIP and Interstate Visibility Transport SIP, the State has not submitted a SIP revision with an analysis or explanation of how it fulfills the interstate visibility transport requirement of section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS.

The approved portion of the Arkansas Regional Haze SIP and our Regional Haze FIP together will ensure emissions reductions from Arkansas sources consistent with the assumptions used in the CENRAP modeling, and meets Arkansas's obligations to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II).

We disagree with Nucor's contention that our interpretation of section 110(a)(2)(D)(i)(II) is contrary to the CAA because reasonable progress goals are not "measures." In section 169A, the CAA gives clear direction that each state is to include in its SIP emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal. The reasonable progress goals are themselves "criteria for *measuring* 'reasonable progress' toward the national goal." [1007] The regional haze rule, in turn, requires the following:

> Each State … must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State which may be affected by emissions from the State. The long-term strategy must include

[1004] 40 CFR 51.308(d)(3)(i).
[1005] See, e.g., Colorado (76 FR 22036 (April 20, 2011)), Idaho (76 FR 36329 (June 22, 2011)), and New Mexico (76 FR 52388 (August, 22, 2011)).
[1006] We've allowed states to rely on their approved regional haze plan to meet the requirements of the visibility component of 110(a)(2)(D)(i)(II) because the regional haze plan achieved at least as much emissions reductions as projected by the RPO modeling. See 76 FR 34608, June 14, 2011 (California); 79 FR 60985, October 9, 2014 (New Mexico); 76 FR 36329, June 22, 2011 (Idaho); and 76 FR 38997, July 5, 2011 (Oregon).
[1007] See CAA section 169B(e)(1)(emphasis added).

> enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas. . .
>
> Where other States cause or contribute to impairment in a mandatory Class I Federal area, the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. If the State has participated in a regional planning process, the State must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.[1008]

We consider it reasonable to consider the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility in light of this requirement in the regional haze rule which explicitly requires that a SIP include a long-term strategy that ensures a state achieves its share of emissions reductions needed to meet the reasonable progress goals of the Class I areas both inside and outside the state.

More fundamentally, our determination is that the controls required to meet the BART and reasonable progress requirements of the regional haze program will also ensure that the visibility transport requirements of section 110(a)(2)(D)(i)(II) will be met. We have not determined that this level of control is necessary to meet the visibility transport requirements but rather that these controls (adopted for other reasons) are sufficient to ensure compliance with the CAA's visibility transport provisions (as well as the parallel regional haze requirements). Given that the level of control that we have determined must be provided by our regional haze FIP satisfies visibility transport requirements, we have not explored other approaches that would also satisfy visibility transport requirements. If our only obligation were to adopt a FIP to satisfy visibility transport requirements, we could have and would have considered such other approaches.

In arguing that the Arkansas Regional Haze SIP satisfies the interstate visibility transport requirement, one commenter says that Missouri is the only state that relied upon anticipated BART controls from Arkansas sources, and that since Missouri's 5-Year Progress Report SIP revision indicates that Missouri's Class I areas are on track to meet the 2018 RPGs, this demonstrates that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with other states' measures to protect visibility. As noted above, Arkansas promised to achieve emission reductions corresponding to BART, and these emissions reductions were included in the CENRAP modeling used by the participating CENRAP states, not just Missouri, to develop their RPGs and Regional Haze SIPs. We also noted above that following our March 12, 2012, partial disapproval of the Arkansas RH SIP and Interstate Visibility Transport SIP, the State has not submitted a SIP revision with an analysis or explanation of how it fulfills the interstate visibility transport requirement of section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS. We have an obligation to promulgate a FIP to remedy this deficiency. Further, as we explained above, we have not determined that the controls required by our FIP are *necessary* to meet the visibility transport requirements but rather that these controls (adopted for other reasons) are *sufficient* to ensure

[1008] 40 CFR 51.308(d)(3).

compliance with the CAA's visibility transport provisions (as well as the parallel regional haze requirements). As such, we disagree that the Arkansas Regional Haze SIP satisfies the interstate visibility transport requirement. For the reasons discussed elsewhere in our response, we are finalizing our determination that our Regional Haze FIP together with the approved portion of the Regional Haze SIP satisfy this requirement for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS.

We disagree that proposing our Arkansas Regional Haze FIP and Interstate Visibility Transport FIP in the same action violated the Administrative Procedures Act resulting in our not providing adequate notice and opportunity to comment on the proposed rule. Arkansas stated in its April 2, 2008 submittal that it is relying on the Arkansas Regional Haze Rule, the Arkansas Pollution Control & Ecology Commission (APC&E) Regulation 19, chapter 15 to satisfy the requirements of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. APC&E Regulation 19 provided for Arkansas BART emission limits for subject to BART sources some of which we partially disapproved in our 2012 action. Our finalized FIP addresses the emissions from those subject to BART sources we disapproved and the emission limits are as stringent as provided in the disapproved portions of the APC&E Regulation 19. Therefore, it is appropriate to finalize our finding that our FIP combined with the portions of the Arkansas Regional Haze SIP we approved meets the requirements of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility.

With regard to the comment that we cannot finalize our proposed finding that the approved portion of the Arkansas Regional Haze SIP and our Regional Haze FIP together will satisfy the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS unless and until we finalize the Regional Haze FIP, based on the proposal, commenters were on sufficient notice regarding whether section 110(a)(2)(D)(i)(II) is met. We note that we are finalizing our Regional Haze FIP in today's action and our finalized findings on emission limits for subject to BART sources follow are in keeping with what we proposed.

We address elsewhere in this document comments contending that there is uncertainty in the CALPUFF modeling and uncertainty that our proposed controls will result in actual visibility improvements.