VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

Response to Public Comments

for

The Draft Prevention of Significant Deterioration of Air Quality Permit

Virginia City Hybrid Energy Center in Wise County, Virginia
DEQ Registration Number 11526

June 13, 2008

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Introduction

On July 7, 2006, the Department of Environmental Quality Southwest Regional Office (DEQ-SWRO) received an air quality permit application from Virginia Electric and Power Company (Dominion) for an Article 6 minor new source review and Article 8 Prevention of Significant Deterioration (PSD) air quality permit. The permit was sought for the purpose of constructing and operating an electrical power generating facility in the Virginia City area of Wise County, Virginia. The proposed power plant would utilize two circulating fluidized bed run-of-mine coal, coal waste, and biomass-fired boilers and a single power turbine, which would provide the facility with a rated gross electrical output of approximately 668 megawatts. Dominion anticipated commercial operation of the Virginia City Hybrid Energy Center (VCHEC) would commence in 2012.

Beginning in 2006 and continuing to present, DEQ-SWRO engineering and technical staff reviewed documentation, conducted research, and compiled and assessed information regarding the proposed VCHEC and its anticipated environmental performance and impact on air quality in the area and region. That work led to the preparation by staff of a January 7, 2008 Engineering Analysis document, which supports a draft permit of the same date.

The proposed project and draft permit were subject to certain public participation requirements pursuant to the provisions of Articles 6 and 8 of 9 VAC Chapter 80. On October 5, 2006, Dominion conducted a public information briefing in St. Paul, Virginia to discuss the permit application with the public. That briefing was conducted in accordance with the requirements of applicable provisions of Articles 6 and 8. Also in accordance with regulatory requirements, DEQ-SWRO personnel conducted a public briefing on December 10, 2007, in St. Paul, Virginia to discuss the Engineering Analysis and draft PSD permit.

The public comment period for the draft PSD permit for the VCHEC commenced on January 12, 2008, and ended on March 12, 2008. On January 9, 2008, advertisements were published in the Bristol Herald Courier, Kingsport Times-News, and Clinch Valley Times and on January 11, 2008, an advertisement was published in the Coalfield Progress, that announced a public comment period that would extend from January 12, 2008 to February 26, 2008, and a public hearing that would be held in St. Paul on February 11, 2008. On January 23, 2008, an advertisement was published in the Clinch Valley Times and on January 25, 2008, advertisements were published in the Bristol Herald Courier, Kingsport Times-News, and Coalfield Progress that continued the February 11, 2008 hearing in St. Paul on February 12, 2008. These advertisements extended the public comment period through February 27, 2008. On February 6, 2008, advertisements were published in the Bristol Herald Courier, Kingsport Times-News, Clinch Valley Times, and Richmond Times Dispatch and on February 8, 2008, an advertisement was published in the Coalfield Progress that announced an additional day of public hearing scheduled for February 19, 2008, in Glen Allen, Virginia and extended the public comment period through March 12, 2008.

Hearing participation

A public hearing was conducted in St. Paul, Virginia on February 11, 2008, and it was continued on February 12 in St. Paul, and on February 19 in Glen Allen, Virginia. Documented attendance and participation on the three hearing dates is as follows:

Date	Location	Non-Commenting Public Attendees	Public Commenters	Total Attendance
2/11/08	St. Paul High School	259	69	373
2/12/08	St. Paul High School	136	46	182
2/19/08	Marriott Glen Allen	141	92	247
			207	802

Note: Total attendance may not equal the sum of the number of speakers and attendees because some speakers who had signed-in to speak on 2/11/08 were not heard until 2/12/08. Additionally, for 2/11/08 and 2/19/08, some commenters who had originally signed-in to speak did not respond when their names were called and they were provided with an opportunity to speak.

In addition to the oral testimony received from 207 individuals during three hearing nights, documents were received by DEQ by e-mail, fax, regular mail, personal delivery to the Southwest Regional Office, and personal submittal at the hearings. A total of 2,352 separate documents were received and logged by DEQ between January 12, 2008 and March 12, 2008.

Comments from elected officials, boards, and governmental bodies

Oral testimony was received from eight elected officials, as listed below:

Virginia Senator Phillip Puckett – Tazewell
Virginia Senator Frank Ruff – Clarksville
Virginia Senator William Wampler – Bristol
Virginia Delegate Terry Kilgore – Gate City
Virginia Delegate Ed Scott – Culpepper
Virginia Delegate Dan Bowling – Oakwood
Council member Marty Jewell – Richmond
Former Virginia Attorney General Jerry Kilgore

Copies of the transcripts of their testimony are included with the transcript for the February 19, 2008 public hearing.

A number of resolutions from various governmental bodies were either submitted for the record or read into the record. Copies of these resolutions are in the written record and transcripts.

A copy of the statement of Gary McLaren, Deputy Director of the Virginia Economic Development Partnership is included in the record.

Comments from governmental agencies

Written comments and other documentation were received from the United States Department of the Interior – Park Service. Park Service comments are addressed in the categories outlined later in this document. There was no finding of adverse impact from any Federal Land Manager, including the Forest Service and the Park Service. There were no comments received from the United States Environmental Protection Agency.

As discussed in the DEQ Engineering Analysis, prior to commencement of the public participation period for the PSD permit, permit terms and conditions were negotiated with the Forest Service Federal Land Manager, by which potential sulfur deposition and visibility impacts in the Linville Gorge Wilderness Area would be mitigated through sulfur dioxide emissions reductions and offsets.

Comments from environmental groups

In addition to the comments of elected officials, governmental bodies, and individuals, oral and written comments were received from a number of individuals representing environmental groups. The commenting groups are listed below:

- Southern Environmental Law Center (SELC), including:
  - Appalachian Voices
  - Chesapeake Climate Action Network
  - Sierra Club
  - Southern Appalachian Mountain Stewards
- National Parks Conservation Association (NPCA)
- Save The Bay
- Virginia Forest Watch
- Clinch Coalition
- Virginia Native Plant Society
- Wild Virginia

Comments from these entities are addressed throughout various sections of this document.

Form Letters/Petitions received

Comments also were received from individuals expressing support for the project and from those expressing concerns about, and objections to, the project.

Example 1

There were a number of individual submittals that generally conformed to the format of the example below. In addition to the individual submittals of this form, a single submittal of this form with 257 endorsers names affixed to the letter also was received.

I am writing to voice my support for building the Virginia Hybrid Energy Center in Wise County. I would ask that the Department of Environmental Quality approve the air quality permit so the proposed plant can be built and begin to meet the growing energy demands of the region.

This power plant will give us the additional electricity we need and cut down significantly on pollution, while keeping electricity costs low. It will also serve to bolster the local economic development.

I understand this plant will use advanced clean coal technology that will take advantage of a wide range of fuels from the region, including coal, waste coal and biomass. This plant will be among the cleanest fossil-fuel electric generation plants in the nation.

Not only will this generating plant continue improvements in air quality that have been made over the years, it will also add jobs to the area and double the economic output of Wise County. Using the reclaimed coal mine in Wise County as the site for the plant also adds value to local natural resources.

Making use of our vast coal resources is the smart thing to do. Coal is the most affordable fuel to produce electricity that we have. It is more affordable than other fuels – about a third the cost of petroleum and natural gas – and the price is stable. Making sure clean American coal – particularly Virginia coal – continues to be part of our energy mix for the future is a big step toward making our country energy independent and secure.

Please approve Virginia Power's application for an air quality permit for the Virginia City Hybrid Energy Center.

Example 2
The following example was extracted from petition forms in support of the facility. There were a total of 3,404 signatures on petitions that had identical or similar wording to that below.

I am a resident of or work in Wise County or a neighboring county, and I fully support the construction and operation of the Dominion Power coal fired plant that is to be built in the Virginia City/St. Paul area of Wise County, Virginia. This plant represents the continuing development of clean coal technology in the electricity generating industry. We are a nation of energy consumers; plants such as this are necessary to produce the electricity that all of us use. In fact, we consistently use more electricity each year. To supply current needs and to meet future demands, we must continue to develop electricity generation capacity using clean coal technology, wind and solar power, natural gas and nuclear energy, in areas where it is convenient to employ these resources.

Wind and solar energy are not currently major sources of electricity generation, and the technology is not currently available to make these sources major contributors to our power generation. Natural gas should be used where the gas and transmission lines are available; however, the cost of electricity produced from natural gas is approximately 5 times higher than that produced from coal. Nuclear power could provide the electricity currently produced by coal, but plants would have to be constructed, and this takes at least 10 years.

At this point in time, coal is the only domestic energy source that is capable of economically supplying our nation's energy needs. Coal is abundant in southwest Virginia, and a coal burning power plant located in Wise County would be a reliable source of affordable power for our homes and would create and support much needed jobs and economic development in our community. That is why I completely support, welcome and encourage the construction and operation of this plant, as well as continued development of clean coal technology (including carbon capture) and continued research and use of alternative energy sources.

In addition to meeting the requirements of the Clean Air Act Standards, the Dominion Plant's design will also accommodate carbon capture technology when it becomes commercially available and Dominion is partnering with Virginia Tech to demonstrate carbon dioxide injection into un-minable coal seams.

My signature below indicates my agreement with and support of the above statements.

Example 3

Copies of electronic mail endorsements for 181 individuals were received that concur with the example provided below.

TO: Virginia State Air Pollution Control Board
Virginia State Corporation Commission

DATE: February 19, 2008

SUBJECT: DOMINION ENERGY'S PROPOSED COAL-FIRED POWER PLANT, WISE COUNTY, VA.

I am a resident of the United State and I see the importance of utilities looking to the future to provide their customers with clean, affordable and dependable electricity. I fully support the construction and operation of Dominion Energy's proposed coal-fired power plant to be built in the Virginia City/St. Paul area of Wise County, Virginia. This Dominion Energy plant will use Circulating Fluidized Bed (CFB) Technology, a proven clean coal technology that offers:

- Environmental performance
  - o Greatly reduced air emissions
- Fuel flexibility
  - o Capable of burning waste coal and wood wastes
- Reliability
  - o Availability is proven to be greater than 90%
- Cost
  - o Less costly than other clean coal technologies

It is my understanding this technology meets the Clean Air Act Standards established by the federal government and this power station will meet all Virginia Department of Environmental Quality air quality requirements. The project's design will also accommodate emerging carbon dioxide provisions.

Carbon Capture

- The design includes a site for installing carbon capture technology when it becomes commercially available.

Carbon Sequestration

- Dominion is partnering with the Virginia Center for Coal & Energy Research at Virginia Tech to demonstrate carbon dioxide storage into nearby un-mineable coal seams.

While energy conservation can help, plants such as this are necessary to produce the electricity needed to supply current needs and to meet future demands. Electricity demand is projected to increase by 100% in the next 25 years. We must continue to develop electricity generation capacity using clean coal technology in addition to developing wind and solar power, natural gas and nuclear energy.

Wind and solar energy will likely make greater contributions in the future, but are not currently major sources of electricity generation. Coal must remain a part of the mix.

Currently, coal is the only domestic energy source capable of economically supplying our nation's energy needs and meeting the increasing demand for electricity. In fact, nine out of every ten tons of coal mined in the United States today is used to generate power, and about 56 percent of the electricity used in the country is coal-generated electricity. Coal is abundant in southwest Virginia, and a coal burning power plant located in Wise County would provide a reliable source of affordable power for homes, manufacturing, educational, retail, and professional institutions.

Today's modern mining practices enable coal to be mined in a safe and more environmentally friendly manner.

The Wise County facility would create and support much needed jobs and economic development in the community and surrounding area. In addition, this plant is designed to burn waste coal and run-of-mine coal, which would encourage deep-mining in marginal seams and recovery and elimination of abandoned gob piles.

We, the undersigned, completely support, welcome and encourage the construction and operation of this plant, as well as continued development of clean coal technology (including carbon capture and storage) and continued research and use of alternative energy sources.

By emailing my NAME, ADDRESS, PHONE and EMAIL ADDRESS to the Eastern Coal Council (Barb@netscope.net), I hereby offer my agreement with and support of the above statements and my

Example 4

The following form represents the basic content of 1,559 e-mails, faxes, and mailed documents that were received from individuals who expressed concern about the project.

> *I am writing to share my serious concerns about the environmental impacts of the Wise County Power Plant. In addition, I strongly request that the State Air Pollution Control Board make the final determination on any permit for Dominion's proposed Wise County coal plant by vote of the Board members at a publicly noticed meeting. The authority to make the decision on this major coal-fired power plant should not be delegated to anyone other than the Board. I also encourage the Department of Environmental Quality to extend the public comment period. The public deserves a fair and full opportunity to respond to Dominion's controversial proposal.*
>
> *I am greatly concerned about the harmful air pollutants this plant would emit and urge you to show the leadership on clean energy that Virginians are demanding.*
>
> - *Sulfur dioxide, nitrogen oxides, and fine particulate matter would worsen smog, haze, and acid rain in our national parks and wilderness areas. Soot from the power plant would increase rates of heart attacks, strokes, cancer, asthma, and even cause premature death.*
>
> - *The Department of Health has imposed mercury-related fish advisories on hundreds of miles of waterways within Virginia. Several studies have linked this mercury contamination to coal-fired power plants like the one proposed for Wise County.*
>
> - *The plant would also worsen Virginia's contribution to climate change, spewing more than 5.3 million tons of carbon dioxide into our air each year. Dominion currently has no plan to control these dangerous global warming emissions.*
>
> *Given these serious concerns, I urge you to reject Dominion's permit as written. And, given the heightened public interest in the matter, I again urge the Department of Environmental Quality to extend the public comment period. Finally, I encourage the State Air Pollution Control Board to make the final determination on any permit for Dominion's proposed Wise County coal plant itself.*
>
> *Thank you for your consideration and for showing the leadership on clean energy that Virginia so desperately needs.*

Comments from these individuals are addressed below.

DEQ's Response to Comments

General objections and general support

A number of written and oral comments were received in which the commenters stated their general objection to the plant and/or requested permit denial and a number of comments were received in which individuals expressed general support of the plant and requested permit approval. There were a few comments received in which the commenter did not clearly state their position on either side of the issue, but appeared to be neutral. All such comments are acknowledged, but no technical or administrative response to these comments is provided.

In the matter of general comments received, a number of commenters were concerned about the sign-up procedures used by DEQ at public hearings. Specifically, some commenters stated they believed because approximately the first two hours of hearing testimony was from proponents of the project, there may have been a coordinated effort to restrict opportunities to speak at the hearing by those who were opponents or had concerns to express. It is DEQ's procedure to arrive sufficiently early on the date of hearings to allow anticipated attendees to sign-in and enter the hearing room in advance of the posted hearing start time. On all hearing nights for the draft PSD permit, DEQ personnel arrived at the hearing location at least two hours before the hearing start time and began signing in individuals immediately upon completion of facility setup and administrative preparation. Individuals were able to sign-in to speak in the order they arrived at the sign-in station.

Water quality issues

Although outside the purview of the air quality permitting process, a number of commenters were concerned about the impact the effluent from the proposed plant would have on the water quality and temperature of the Clinch River. There appeared to be a misunderstanding on the part of some commenters regarding the plant's usage (withdrawal and discharge) of water. The facility will be designed and built to cool the system with air-cooled "condensers" and obtain system water from the local, municipal water supply. Approximately one million gallons of water will be acquired from the municipal system each day. In contrast to the VCHEC, a similarly sized plant using water-cooled technology could require in excess of ten million gallons of water per day, which would have to be acquired directly from surface waters and discharged back to these waters, because of economic and availability constraints. Any discharge of water from this facility (with the exception of industrial stormwater runoff) will likewise be to the municipal collection and treatment system. There will be no direct withdrawal of water from or discharge of water to the Clinch River. Therefore, the impact of the plant's discharge on water quality and the ecosystem and habitats of the Clinch River will be minimal, since municipally discharged water will be closely monitored by the municipality and DEQ and must meet Virginia and federal standards.

Some commenters expressed concern about deposition of air pollutants onto land and water, particularly nitrogen, sulfur, and mercury. Potentially acidifying pollutants such as sulfur dioxide and nitrogen oxides are limited in the permit based on Best Available Control Technology (BACT) in accordance with Virginia air quality regulations. Additionally, emissions of these potentially acidifying pollutants and mercury are addressed by appropriate Virginia and federal permit programs, including Title IV of the 1990 Clean Air Act Amendments, Phase II Acid Rain, NO_X SIP Call, Clean Air Interstate Rule, and Case-By-Case Maximum Achievable Control Technology standard requirements. Waters of the Clinch River are not currently classified as impaired by mercury, sulfates, or nitrates and based on applicable statutory and regulatory requirements and proposed air quality permit limits, it is not anticipated that there will be any adverse impact to the waters of the Clinch River as a result of deposition from operation of the plant. Further discussion of mercury deposition onto land and water appears later in this response document.

Dominion has applied for a permit under the Virginia Water Protection (VWP) permit program for the solid waste management facility (landfill), which will serve the VCHEC. The construction of the landfill will require impacts to approximately 0.42 acres of emergent wetland and will require the placement of fill material upon approximately 3,880 linear feet of stream channel in a tributary to Meade Creek known as Curley Hollow. The DEQ water quality permitting staff has drafted a proposed permit to authorize the activity.

The VWP permit will require on-site compensation for the proposed impacts to wetlands and stream channels. Compensation for the wetland impacts associated with this proposed permit will occur by enhancing and protecting in perpetuity at least two acres of wetlands along Meade Creek. Compensation for the stream channel impacts associated with this proposed permit will be provided by restoration and preservation of approximately 1,580 linear feet of Meade Creek, using a design that mimics natural stream channel pattern and profile. Compensation for the losses will also require permanent preservation of the entire watershed along 6,100 feet of intermittent stream channel in the adjacent Maize Hollow.

Commenters were concerned about the potential for toxic spills and the effect on the mussel habitat of the Clinch River. The control of accidental spills would be addressed in the facility’s emergency preparedness and spill prevention and management plans, which are administered by other governmental agencies. Guidelines and authorities overseeing such events would be in place to ensure effective management of the incidence and outcome of such accidental releases. When appropriately implemented, these plans would mitigate impacts on water and land resources.

Solid and hazardous waste

The plant will generate waste in the form of bottom ash and fly ash. The air quality aspects of handling these materials are dealt with in the air quality permit, where appropriate restrictions and Best Available Control Technology requirements have been established.

The company proposes to utilize an onsite solid waste landfill for disposal of fly ash and bottom ash. In September 2007, the company submitted their Part A solid waste permit application, which deals with siting of the landfill. Part B, which deals with design and operation was submitted in April 2008. The landfill will comprise about 300 acres and will have a volume of about 35 million cubic yards. Analysis of the Part A solid waste permit application is ongoing at the time of this writing, however, appropriate handling, disposal, and stabilization procedures will be required by any resultant permits consistent with applicable laws and regulations. Additionally, the company is investigating by-product uses for the fly ash, which if implemented, would have to comply with all applicable waste utilization, handling, management, and disposal regulations.

A number of commenters were concerned about the toxic or hazardous constituents of fly ash. Of particular concern to some individuals was the prospect of elevated concentrations of mercury in the ash, as a result of removing it from the coal and "concentrating" it in the waste materials. While mercury removal from the flue gas is a co-benefit of the baghouse and flue gas desulfurization system, its occurrence in the solid waste must be dealt with in accordance with all Virginia and federal permits and regulations. No material that can be classified as a hazardous waste will be allowed in the solid waste landfill the facility will construct. In addition to mercury, other constituents of the solid waste stream must be monitored and dealt with in accordance with all applicable solid waste requirements. For further discussion of this issue, see the section regarding mercury, that appears later in this document.

Energy conservation and alternative electricity generating technologies

Comments were heard from individuals who advocated use of natural gas, wind, solar, and geothermal as alternatives to the proposed circulating fluidized bed systems. Some alternatives mentioned by commenters included Integrated Gasification Combined Cycle (IGCC), pulverized coal, supercritical CFB, and supercritical PC, which are discussed in greater detail below. A few commenters advocated use of nuclear energy as an alternative to the proposed facility. Several commenters suggested that increasing electricity demand could be best handled through conservation measures. Commenters also suggested DEQ assert a leadership role in the area of clean energy.

DEQ recognizes the air quality benefits of wind, solar and geothermal energy, but DEQ does not have the legal authority to require an applicant to consider or utilize these technologies. Indeed it is unclear that such facilities could be a substitute for the proposed plant which will be designed to operate continuously (i.e. 24 hours/day, 7 days/week). Similarly, DEQ does not have the authority to require a permit applicant to utilize natural gas or nuclear technology for generating electricity. Further, although DEQ recognizes the importance of energy conservation measures, such energy conservation measures are typically addressed as a matter of public or corporate policy and are beyond the scope of the evaluation of a PSD air quality permit application. In Virginia, the Energy Division of the Department of Mines, Minerals and Energy works to foster and encourage energy conservation within the Commonwealth. Similarly, the State Corporation Commission is tasked with promoting effective conservation and use of energy by public utilities rendering utility services. In this regard, Dominion has implemented a program directed at public awareness, education, and outreach in the area of alternative energy, renewables, and energy conservation. Dominion's stated purpose in forming a new energy conservation group was to encourage interest in energy efficiency and explore new technologies that could reduce electricity demand.

Several individuals commented that any type of coal combustion for generating electricity was outdated, dirty, or otherwise inappropriate and some commenters specifically identified circulating fluidized bed technology as outdated. Some comments indicated the alternative coal technology of IGCC should be considered. Some commenters advocated considering IGCC as BACT for the Virginia City project. Comments regarding IGCC as BACT are addressed elsewhere in this document. Some commenters also called into question the designation of this circulating fluidized bed (CFB) technology as U.S. Department of Energy (DOE) clean coal technology. This designation has been applied to such technology by the U.S. DOE and this designation was used by Dominion in their description of the technology in their application and DEQ documents utilized the same terminology.

Some commenters suggested IGCC technology as an alternative to the CFB units proposed for VCHEC for generating electricity. As part of its permit application, Dominion provided an analysis of IGCC as an alternative technology. Dominion indicated they specifically chose circulating fluidized bed coal combustion technology for a variety of reasons including the available fuel types and Virginia legislation that encourages and provides incentives for the development of an electric generating facility in the Virginia coalfields. Information available to DEQ indicates that application of IGCC technology is neither technologically nor economically feasible in situations where considerable fuel flexibility is necessary. Such is the case with the Virginia Hybrid Energy Center, where they will seek to remediate coal waste piles, utilize readily available run-of-mine coal, and use a considerable amount of biomass. Indeed, one premise for the facility is the reduction of piles of waste coal in the region. Precipitation falling on these piles of waste coal generate leachate having suspended solids, which results in them being major contributors to degradation of area streams by water pollution. Such low quality fuels in terms of heat and ash content have not been tested with IGCC processes. See Response to Comments on Draft PSD Permit for Deseret Power Electric Cooperative, U.S. EPA Region 8 at 16-18 (Aug. 30, 2007). Additionally, DEQ believes that data and information reviewed for operating IGCC facilities indicates the technology is not adequately developed to the point that IGCC would be immediately suitable for reliable baseload electricity generation.

Commenters also suggested pulverized coal (PC) combustion as another alternative type of coal-fired electricity generating technology. Pulverized coal boilers are generally believed to be less flexible with regard to fuels than are circulating fluidized bed combustors. In fact, use of waste coal and run-of-mine coal would be impossible, without extraordinary coal cleaning measures, which would result in the generation of more waste coal piles and additional emissions from the cleaning and transportation processes and possible greater demand for process water for system operation and environmental controls. The circulating fluidized bed technology chosen for the Virginia City Hybrid Energy Center is a good technological fit, considering the types of available fuels (run-of-mine coal, coal refuse, and biomass) and other resource availability.

At the time of this writing, there were no known demonstrated supercritical CFB installations in operation. Therefore, supercritical CFB technology was eliminated as an alternative for consideration. The application of supercritical PC boiler technology to the VCHEC project was considered, but determined to be inappropriate due to the intended use of locally available fuels. The DEQ cannot require or dictate to any applicant what type of source to construct. It is the role of DEQ to determine if the proposed source will meet all applicable rules and regulations. This approach is consistent with DEQ's historical interpretation of BACT and EPA guidance, which makes clear that the BACT analysis is to consider the facility proposed and to not redefine the source proposed.

Climate change and issues related to carbon dioxide

There were many oral and written comments received that were related to the issues of climate change, global warming, greenhouse gases, carbon dioxide emissions, carbon dioxide control, carbon dioxide sequestration, and suitability of the Virginia City plant for future retrofitting with carbon capture and sequestration technology. The hourly estimates of emissions of carbon dioxide in the company's permit application were extrapolated to an annual emissions rate which was then described by commenters as impacting climate. A few comments were received regarding carbon emissions, carbon cost, less carbon-intensive technology, cancellation of the "DOE project," and potential carbon dioxide regulations.

Comments were received which suggested that a precedent had been established in a "Kansas case" that should affect permitting for the Virginia City project. With little more information, it is assumed the commenter was referring to actions in Kansas regarding the Sunflower Electric Power project near Holcomb, Kansas. In October 2007, Secretary Bremby of the Kansas Department of Health and Environment denied an air quality permit for Sunflower's two new 700 MW coal-fired units citing their potential greenhouse gas emissions, in particular carbon dioxide, as potentially adversely impacting the public. The permitting authority in Kansas referenced the U.S. Supreme Court's ruling in *Massachusetts vs. EPA*, No. 05-1120 (Apr. 2, 2007), as one basis for not approving the permit. In that case, the U.S. Supreme Court held that carbon dioxide was a pollutant that the U.S. Environmental Protection Agency had authority to regulate with respect to emissions from motor vehicles under § 202 of the Clean Air Act if EPA determines that such emissions may reasonably be expected to endanger public health or welfare. Currently, there are no ambient air quality standards under Virginia or federal law that address ambient air concentrations, impact, or emissions of carbon dioxide (or any other greenhouse gases). Because carbon dioxide is not a regulated pollutant in Virginia – that is there are no standards by which DEQ can evaluate impacts and impose standards and conditions for carbon dioxide or other greenhouse gas emissions -- DEQ could not develop emission estimates, engineering analyses, cost estimates, regulatory reviews, and evaluation of less carbon-intensive technology. Likewise, no carbon dioxide controls were evaluated as part of the engineering analysis for the PSD permit.

One commenter made reference to the Department of Energy's canceled Future Gen project, but no further information or comments were provided about how such a statement should be germane to this evaluation.

The applicant did indicate to DEQ during the application evaluation process that the facility would be carbon capture and control compatible. Because there are no requirements associated with carbon control under current air quality regulations, further refinement and analysis regarding carbon capture compatibility were not required. The company has indicated that the Virginia legislation that is the basis for the proposed plant requires that the facility be carbon capture compatible in order to achieve the State Corporation Commission's (SCC) additional rate recovery basis point allowance. To this end, the SCC conducted hearings and received comments and testimony on the facility's carbon capture compatibility, as well as many other issues pertaining to their areas of responsibility. In early 2008, the SCC granted approval of a rate recovery percentage that excluded any provision for the carbon capture compatibility basis points. The SCC indicated they would allow additional public comment and give Dominion additional opportunities to request the carbon-related basis points. At the time of this writing, it is unknown when such requests will be heard before the SCC.

One commenter was concerned that possible future earthquakes could "dislodge" sequestered "toxic waste." As there are no indications or requests from the applicant regarding sequestration of "toxic waste" it appears that this comment is referring to the potential sequestration of carbon dioxide underground in southwest Virginia. Dominion has collaborated with a Virginia university to study the scientific and engineering feasibility of carbon dioxide sequestration in Southwest Virginia coalfield mine voids. The company has committed financial resources and technical expertise to this endeavor and they seek to ascertain the practicality of sequestering carbon dioxide underground. Fieldwork on this study may get underway in Southwest Virginia during the summer of 2008. It is expected that any future underground sequestration would be done with the oversight of appropriate state and federal authorities, in accordance with applicable laws and regulations and with full consideration given to geotechnical issues.

Although there are no carbon dioxide standards for DEQ to consider, the reduction in sulfur dioxide emissions realized from increased use of biomass will have a commensurate effect of reducing carbon dioxide emissions. For additional discussion regarding reduction in sulfur dioxide emissions, see the section later in this document that pertains to proposed permit changes.

General comments regarding Dominion

A few commenters suggested that Dominion had a history of environmental irresponsibility that should preclude them from embarking on the Virginia City project. To consider such aspects is beyond the scope of the engineering evaluation of a PSD permit application for a greenfield source that is yet neither constructed nor in operation. As with any permitted or regulated source, DEQ retains the responsibility and authority to enforce the State Air Pollution Control Board's regulations and will do so in accordance with appropriate laws, regulations, guidance, and policy.

One commenter brought up the matter of the "Mt. Storm cleanup," but no other specific comment or information was presented about that subject. Another commenter suggested, in reference to Dominion's proposal to convert their Bremo Power Station in Fluvanna County to natural gas, that Dominion clean up their older plants before building a new plant. As discussed above, consideration of these matters for the VCHEC is beyond the scope of DEQ's authority under applicable air quality permitting laws and regulations.

General environmental impact issues

Comments were received concerning the potential for general negative environmental impacts. These comments included: more pollution being introduced into the environment; dirty air; harmful air pollutants, and the variety of air pollutants emitted. There were comments concerning negative impact on national parks, wilderness areas, and forests from smog, haze, fog, and acid rain caused by sulfur dioxide, nitrogen oxides, fine particulate matter, and mercury from the facility, and the impact the facility would have on defoliation, and thinning ozone. Some comments concerning general environmental impacts referenced the Great Smoky Mountains National Park, Roan Mountain, Linville Gorge Wilderness Area, Pisgah National Forest, and High Knob in Wise County, Virginia. One commenter expressed concern for an un-named nature preserve in Meigs County, Ohio. There was a question regarding the effects on the biological communities from having two major polluters in the area, and the commenter asked if DEQ had done a risk analysis of such.

Air quality analyses were conducted in accordance with Virginia and federal PSD permitting regulations and guidance in order to assess compliance of projected emissions from the proposed facility with all applicable National Ambient Air Quality Standards (NAAQS) and PSD increments. Response to comments regarding modeling and the air quality analysis is provided elsewhere in this document.

The NAAQS were established in order to define air quality levels for sulfur dioxide, nitrogen dioxide, particulate matter, ozone, carbon monoxide, and lead that are protective of public health and welfare, with an adequate margin of safety, from any known or anticipated adverse effects including visibility impairment, damage to animals, crops, vegetation, and buildings. The air quality analyses for the VCHEC project included emissions from other facilities where applicable, including the American Electric Power Clinch River Plant. The analyses assessed impacts on local and regional areas including, but not limited to, the area of High Knob in Wise County, and six federal Class I areas within 300 kilometers (186 miles) of the proposed facility: Great Smoky Mountains National Park (NC/TN), James River Face Wilderness Area (VA), Linville Gorge Wilderness Area (NC), Shining Rock Wilderness Area (NC), Joyce Kilmer/Slickrock Wilderness Area (NC/TN) and Cohutta Wilderness Area (GA). Linville Gorge Wilderness Area, along with Roan Mountain, is located within Pisgah National Forest. These air quality analyses demonstrated that projected air emissions from the proposed facility would neither cause nor significantly contribute to a violation of any applicable NAAQS or PSD increment. Further, the facility is not expected to be a significant contributor in the production of ozone-depleting substances that can lead to the thinning of the ozone layer in the upper atmosphere. Ozone-depleting substances are contained in some pesticides, solvents, refrigerants and certain other materials. The USEPA has established regulations to phase out ozone-depleting substances.

No specific acid deposition thresholds have been established for PSD Class II areas, including the vicinity of the proposed facility. The PSD regulations, however, require an analysis of the impacts from the proposed facility on soils and vegetation. Results of the analysis identified no adverse impacts on soils or vegetation. Visibility in the immediate vicinity of the proposed facility will be protected by air pollution control requirements and stringent visible emission limits included in the air permit. Details of the soils and vegetation analysis are provided in later sections of this document.

Impacts on acid deposition and visibility from the facility were evaluated as they pertain to Federal Land Manager air quality related values (AQRV) in the affected Class I areas. As a result of the acid deposition and visibility AQRV analysis, Dominion, DEQ, and the forest supervisor for National Forest Service in North Carolina agreed to permit conditions that require reduction and/or mitigation of sulfur dioxide emissions from the facility above 1,684 tons per year to address impacts to the AQRV for visibility and sulfur deposition at Linville Gorge Wilderness Area. Details of the acid deposition and visibility AQRV analysis are provided in later sections of this document.

The permit limit for mercury, based on a Best Available Control Technology analysis, was demonstrated to be in compliance with the Significant Ambient Air Concentration (SAAC) guidelines in Virginia's State Toxics Rule, 9 VAC 5-60, Article 5, of Virginia's air pollution control regulations. These standards are designed to be protective of human health and the environment. The mercury limit in the draft permit also was demonstrated to be compliant with the mercury standard for electric steam generating units contained in 40 CFR Part 60, Subpart Da that was applicable at the time the permit was drafted. As discussed below and later in this document, the mercury standard set forth in 40 CFR Part 60, Subpart Da no longer applies as a result of the vacatur of the Clean Air Mercury Rule (CAMR). See the section in this document regarding proposed permit changes for further information about NSPS Da (40 CFR Part 60, Subpart Da) regulatory citations that appeared in the draft permit.

As a result of the recent vacatur of the Clean Air Mercury Rule (CAMR) by the United States Court of Appeals for the District of Columbia Circuit, the proposed facility is subject to a case-by-case Maximum Achievable Control Technology (MACT) determination and air quality permit in accordance with the provisions of 9 VAC 5-80, Article 7, of Virginia's air pollution control regulations also known as a Clean Air Act section 112(g) permit. The provisions of Article 7 are not applicable to the evaluation conducted for the PSD permit; however, the MACT determination and permit required by Article 7, will limit mercury emissions from the proposed facility to levels protective of the environment. The DEQ regards the Article 7 permit process a distinct but parallel process which will produce a mercury emission limit that may supplant the limitation established by the PSD permit. Once emission limits are established in the Article 7 permit, the PSD permit may be amended to reflect the more stringent limitation.

There were comments received concerning negative environmental impact of mountaintop mining, mountaintop removal, strip mining, surface mining, and mining in general, and that negative impact may be increased by the operation of the proposed facility. Regulation of coal mining techniques, including mountaintop mining, mountaintop removal, strip mining, surface mining, and underground mining is managed by the Department of Mines, Minerals and Energy, as well as other state and federal authorities. The air quality issues arising from individual mining operations and facilities are addressed on a site-by-site basis by the appropriate regulatory agencies. Consideration of such matters is beyond the scope of the evaluation for the air quality permit application for the VCHEC. Based on the additional impact analysis conducted pursuant to 9 VAC 5-80-1755 of Virginia air regulations, operation of the proposed facility is not anticipated to substantially affect the overall coal mining activity in the region because a significant quantity of coal has been historically mined from the area, and, as a result, overall emissions from support industries are not expected to increase considerably.

There were comments concerning negative environmental impacts associated with the disturbance of bituminous coal refuse (gob) piles to be used as fuel at the proposed facility. One commenter suggested the planting of beach grasses on gob piles as an apparent means of stabilizing them, in lieu of reclaiming them as a fuel source. There has been success in other states with reclaiming gob piles for fuel and neutralizing acid runoff by placing and/or mixing CFB ash with refuse piles; however, waste and water issues associated with gob piles are beyond the scope of the evaluation conducted for the air quality permit. Proper agencies and authorities are in place and will manage these aspects of the project. The air quality permit does, however, require fugitive dust and fugitive emission controls for conveying, transporting, loading, and storage of coal refuse at the facility. Limitations and air pollution control requirements have been established in the permit for fugitive emissions and fugitive dust, in accordance with the BACT analysis. There is no anticipated adverse environmental impact from the fugitive emissions expected from this source.

General health impact issues

Comments were received concerning general negative impact on human health. These comments included: assertions that air pollution contributes to a weakened immune system, cancer, asthma attacks, cancer rates, pregnancy problems, birth defects, and premature death; concern for children's health; concerns that Dominion has not assessed health effects of toxic air pollutants; assertions that Southwest Virginia has the highest asthma rate in the state, high above the national average; concerns that air pollution from the plant will have greater negative health impacts on a medically underserved and health disadvantaged region; emissions from the proposed facility added to emissions from the American Electric Power Clinch River Plant will further exacerbate the region's already high rate of illnesses such as asthma, coronary disease, and emphysema, and increase cancer rates. A cancer center in Norton, Virginia was referenced to illustrate the point of the area's high cancer rate.

Some comments referenced specific pollutants in conjunction with negative health effects. These comments included: assertions that soot increase will have detrimental health effects; concerns of health impacts from mercury exposure such as birth defects, developmental disorders, disfluency, attention deficit disorder, Aspergers Syndrome, autism, language deficits, impaired memory, impaired visual and motor functions; concerns regarding health effects from fine particulate matter including asthma, heart disease, lung health problems, premature birth, and sudden infant death; and potential health risks from inhalation of particulate matter and fugitive dust from blasting and mining operations.

Air quality analyses were conducted in accordance with Virginia and federal PSD permitting regulations and guidelines in order to assess compliance of projected emissions from the proposed facility with all applicable National Ambient Air Quality Standards (NAAQS) and PSD increments. Response to comments regarding modeling and the air quality analysis is provided elsewhere in this report.

Air pollutants with a NAAQS may contribute to negative impact on human health, when present in concentrations above those specified in law and regulations. The primary standards of the NAAQS are established in order to define air quality levels for sulfur dioxide, nitrogen dioxide, particulate matter, ozone, carbon monoxide, and lead that are protective of public health with an adequate margin of safety, including the health of sensitive populations such as asthmatics, children, and the elderly. The air quality analyses conducted for the VCHEC included emissions from other facilities where applicable, including the American Electric Power Clinch River Plant. These air quality analyses demonstrated that projected air emissions from the proposed facility would neither cause nor significantly contribute to a violation of any applicable NAAQS or PSD increment, therefore, there is no anticipated adverse health impact from these regulated pollutants. The PSD increments were established to ensure that areas that meet the NAAQS are protected from any significant deterioration of air quality.

The permit limits for mercury, hydrogen fluoride, and hydrogen chloride were based on a Best Available Control Technology (BACT) analysis for each of those pollutants. Further, an analysis of projected emissions of these and other regulated toxic air pollutants from the facility, demonstrates compliance with the Significant Ambient Air Concentration (SAAC) guidelines in Virginia's State Toxics Rule, 9 VAC 5-60, Article 5, of Virginia's air pollution control regulations. Title 9 of VAC 5-60-330 of Virginia's State Toxics Rule indicates the SAAC for each regulated toxic air pollutant is based on a fraction of the Threshold Limit Value (TLV) for that pollutant. The TLV® is defined as the maximum airborne concentration of a substance to which the American Conference of Governmental Industrial Hygienists believes that nearly all workers may be repeatedly exposed day after day without adverse effects.

As a result of the recent vacatur of the Clean Air Mercury Rule (CAMR) by the United States Court of Appeals for the District of Columbia Circuit, the proposed facility is subject to a case-by-case Maximum Achievable Control Technology (MACT) determination and air quality permit in accordance with the provisions of 9 VAC 5-80, Article 7, of Virginia's air pollution control regulations, also known as a Clean Air Act section 112(g) permit. The provisions of Article 7 are not applicable to the evaluation conducted for the PSD permit; however, the MACT determination and permit required by Article 7, will limit emissions of affected hazardous air pollutants, including mercury, to levels that are protective of human health. DEQ regards the Article 7 permit process a distinct but parallel process which will produce a mercury emission limit that may supplant the limitation established by the PSD permit. Once emission limits are established in the Article 7 permit, the PSD permit may be amended to harmonize with the more stringent limitation.

Regulation of coal mining, including mountaintop mining, mountaintop removal, strip mining, surface mining, and underground mining is managed by the Department of Mines, Minerals and Energy, as well as other state and federal mining authorities. The air quality issues arising from individual mining operations and facilities are addressed on a site-by-site basis by the appropriate regulatory agencies. Limitations and air pollution control requirements have been established in the air quality permit for fugitive dust and particulate matter emissions to the atmosphere from the proposed facility in accordance with the BACT analysis. There is no anticipated adverse health impact from any fugitive dust or particulate matter emissions from the proposed facility.

One comment referenced concern for non-inhalation health risks such as ingestion of toxins emitted by the facility through soil, drinking water, and food. An additional analysis assessing impacts of the proposed facility on soils and vegetation was conducted. Results of the impact analysis did not identify any adverse impacts on soils or vegetation. Drinking water issues are beyond the scope of the evaluation conducted for the air quality permit, however, issues regarding potential deposition of pollutants on soil and water bodies has already been discussed and is discussed further later in this document. Proper agencies and authorities are in place and will manage the other environmental aspects of the project in accordance with applicable laws and regulations. As previously discussed, impacts may be considered negligible because there will be no direct water withdrawals or water discharges from this facility. All water utilized by this plant will be obtained from the municipal water supply and effluent will be discharged to an approved, municipal treatment system.

In questioning the effect of increased air pollution on people who already have a respiratory or cardiovascular disease, one comment stated that DEQ has declared that the proposed facility would be among the top ten emitters in the entire United States.

The DEQ has never made such a declaration concerning the proposed facility. In reference to air pollution, a review of projected emissions in comparison to historical actual emissions indicates the facility would not be among the top ten emitters in Virginia or the United States.

One commenter questioned whether there has been a cost-benefit analysis of a child's cognitive ability in consideration of mercury health impacts. A cost-benefit analysis considering estimated benefits of a source and costs associated with its negative impacts is not part of the air quality permitting process for a proposed source. Potential negative air quality impacts are considered, however, when establishing emission limitations, standards and other requirements applicable to a source to minimize any negative air quality impact and to demonstrate compliance with air quality standards protective of human health and welfare.

One commenter wondered what coal dust could do in Virginia City, Virginia if sugar dust caused such a tragedy in Port Wentworth, Georgia. This comment appears to be in reference to a reported explosion at a sugar refinery in Port Wentworth, Georgia. Limitations and air pollution control requirements have been established in the PSD air quality permit for fugitive emissions, fugitive dust, and stack emissions to the atmosphere from conveying, transporting, loading, storage, and processing of coal and coal refuse at the facility in accordance with the BACT analysis. There is no anticipated adverse health impact from any fugitive emissions, fugitive dust, or point source emissions from the proposed facility. Regulation of occupational exposure and safety issues at the proposed facility would be managed by the Virginia Department of Labor and Industry and the United States Occupational Safety and Health Administration.

There were references made by one commenter to the "circle of death" and this project's relationship to such. It is unclear what the commenter was referring to with regard to the "circle of death." The implication from such a statement is that adverse health impacts could occur within a certain area surrounding the source. As discussed elsewhere in this report, dispersion modeling and the air quality analysis were conducted and the results indicate this facility will not cause or significantly contribute to predicted ambient air concentrations at any location that are in excess of the health-based NAAQS standards.

Request for more hearings, comment period extensions, Board involvement

Virginia air quality regulations at 9 VAC 5-80-1775 F.4. require that DEQ provide notice of the draft PSD permit and opportunity for public comment on the VCHEC draft permit. These regulations only require a 30-day comment period prior to the hearing, a single hearing event, and fifteen additional days of public comment after the hearing. As discussed below, DEQ followed and went beyond regulatory requirements in extending the public comment period and providing hearing continuations. Numerous requests for additional hearings and comment period extensions were received from the public during the public comment period. As discussed in the "Introduction" to this document, in addition to the opportunities for public participation required by the regulations, DEQ acted early in the public comment period to provide for additional public hearings by extending the February 11, 2008 hearing to include public hearings on February 12 and February 19. In addition, the public comment period was extended until March 12, 2008, providing for a total of 60 days for public comment on the draft permit. The additional hearings and extended public comment period allowed for more comments to be submitted and provided extra time during which commenters could evaluate the project and draft permit and prepare their comments. The wide range of subjects discussed in the numerous written and oral comments, as well as in the various submitted documents show that there is considerable public interest in the project. Therefore, DEQ's decision to hold hearings in both the local Wise County area as well as in Richmond, in addition to extending the public comment period, served this public interest by providing more opportunity for public input.

<u>State Air Pollution Control Board actions</u>

The State Air Pollution Control Board has delegated authority to issue all air quality permits to the DEQ Director. The Board can reserve for itself the ability to review draft permits, conduct hearings, and issue final permits on a case-by-case basis. On March 20, 2008, the Board voted to assume all authority for the draft PSD and draft Article 7 (or MACT) permits for the proposed VCHEC.

On April 16, 2008, a public comment period was announced for receiving comments on documents containing questions and information prepared and submitted by three Board members: Vivian Thompson, Bruce Buckheit, and Hullihen Moore. The documents were posted on the DEQ website and comments were received through May 16, 2008. Dominion and others responded to these documents.

Air quality modeling/analysis issues

PM-2.5 Air Quality Analysis
Commenters stated the following with respect to the PM-2.5 air quality analysis:

1. Using PM-10 as a surrogate for PM-2.5 shows the modeled concentration is in violation of the 24-hour and annual PM-2.5 NAAQS.

2. Virginia's PM-2.5 monitoring data added to PM-10 modeled concentrations demonstrates that the PM-2.5 NAAQS is exceeded.

3. The assessment did not address impacts on PM-2.5 non-attainment areas, including neighboring States.

4. The analysis failed to evaluate the ambient air quality impact from PM-2.5 precursor emissions.

5. Many States now require an analysis of PM-2.5 be included in the permits for new sources using an appropriate modeling analysis.

6. Other States in the country, for example Connecticut, now require that an analysis of the fine particle impacts be included in permits for new sources through an appropriate modeling analysis.

DEQ disagrees with the commenters that the applicant is required to conduct a PM-2.5 air quality analysis in support of this permit action.

On May 16, 2008, EPA published in the Federal Register its final rule governing the implementation of the NSR program for particulate matter less than 2.5 micrometers in diameter (PM-2.5) (see Attachment 1). PM-2.5 also is known as fine particles. A related rule, proposed by EPA on September 21, 2007, would complete the PM-2.5 preconstruction review program framework by establishing increments, significant impact levels (SILs), and significant monitoring concentrations (SMCs) for PSD that are needed to conduct an air quality analysis (see Attachment 2).

EPA has established an interim period that allows a State with a SIP-approved PSD program (e.g., Virginia) time to incorporate these final NSR rule changes in its SIP. During this SIP development period, the PM-2.5 NAAQS must still be protected under the PSD program in such States. EPA proposes to accomplish this by allowing the continued implementation of the PM-10 program as a surrogate to meet the PSD program requirements for PM-2.5 during the transition period. EPA requires that States with SIP-approved PSD programs submit a revised PSD program for PM-2.5 within 3 years from the effective date of its rulemaking or by July 15, 2011.

EPA's May 16, 2008 rulemaking specifically states the following with respect to its PM-10 surrogate policy and the requirement for PM-2.5 air quality modeling:

> *"We (EPA) have dropped the requirement for demonstrating compliance with the PM-2.5 NAAQS in order to maintain consistency in the application of the existing surrogate policy across the PSD program during the interim period. Since in the final rule we are otherwise allowing SIP-approved States to continue with the existing PM-10 surrogate policy to meet the PSD requirements for PM-2.5, partially implementing the PM-10 surrogate policy in this manner would be confusing and difficult to administer. Thus, to ensure consistent administration during the transition period, we have elected to maintain our existing PM-10 surrogate policy which only recommends as an interim measure that sources and reviewing authorities conduct the modeling necessary to show that PM-10 emissions will not cause a violation of the PM-10 NAAQS as a surrogate for demonstrating compliance with the PM-2.5 NAAQS."*

EPA's recent rulemaking reiterates support for its guidance on the interim implementation of NSR requirements for PM-2.5 contained in the following documents:

- "Interim Implementation of New Source Review Requirements for PM-2.5," John Seitz (EPA), October 23, 1997.
- "Implementation of New Source Review Requirements in PM-2.5 Non-attainment Areas," Steve Page (EPA), April 5, 2005.

The current DEQ interim policy (see Attachment 3) for the implementation of PM-2.5 under NSR is based on these two EPA memorandums. The current NSR policy dictates that DEQ will use PM-10 as a surrogate for PM-2.5 until such time as:

- DEQ establishes a more appropriate implementation methodology; or
- EPA promulgates revised implementation guidance or policy; or
- EPA promulgates final regulations

Using PM-10 as a surrogate for PM-2.5, as applied in Virginia and throughout EPA Region III, compares the PM-10 modeling results to the PM-10 NAAQS. The VCHEC modeling analysis demonstrates compliance with the PM-10 NAAQS as a surrogate for PM-2.5.

There are several examples of the PM-10 NSR surrogate approach that have been approved by States and EPA. In all of these recent NSR coal-fired power plant cases in EPA Region III, the facilities modeled PM-10 and compared the impacts to the PM-10 NAAQS as the method for addressing PM-2.5:

- Western Greenbrier (WV)
- Greene Energy (PA)
- Robinson Power (PA)
- Longview Power (WV)

There are also numerous examples nationwide that use this approach.

The use of the surrogate approach is supported by DEQ as an interim solution for the following reasons:

- The method avoids setting a precedent that may be inconsistent with forthcoming EPA guidance, particularly with respect to emission factor calculations (i.e., filterable versus condensable emissions), stack test methods and modeling.

- Adoption of overly conservative modeling techniques, such as those contained in the interim methodologies developed by a few States, may create fictitious modeled NAAQS violations and the use of these results may unjustifiably preclude the construction and operation of facilities throughout Virginia, regardless of the level of control. Additionally, results using these modeling approaches have been shown to be inconsistent with observed air quality.

The proposed permit contains a provision that requires an ambient air quality analysis for the emissions of PM-2.5 from the facility based on a schedule and protocol to be established by DEQ after EPA promulgates final rules for PM-2.5 analysis, EPA promulgates revised implementation guidance or policy for PM-2.5 analysis, or DEQ establishes a more appropriate implementation methodology for PM-2.5.

Although there is no requirement to conduct a PM-2.5 analysis, the applicant submitted an assessment to DEQ (see Attachment 4) that demonstrates compliance with the PM-2.5 NAAQS. Specifically, the projected design values in the immediate vicinity of the plant are 27 $\mu g/m^3$ (24-hour, NAAQS = 35 $\mu g/m^3$) and 13.0 $\mu g/m^3$ (annual, NAAQS = 15.0 $\mu g/m^3$).

Furthermore, DEQ requested that the proposed plant be included in the latest regional modeling analysis conducted by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS). The analysis indicates that the plant will not have a significant impact on PM-2.5 design value concentrations locally or in neighboring States. For instance, the projected design values in 2018 at nearby Bristol City, Virginia are 24 $\mu g/m^3$ (24-hour) and 12.0 $\mu g/m^3$ (annual), well below the NAAQS.

Additional information on this topic also is provided in The Air Quality Planning Process and Regional Modeling for Visibility, Ozone & PM-2.5.

Meteorological Data

Commenters stated the following with respect to meteorological data:

1. The meteorological data used in the Class I and Class II modeling was inappropriate.

2. The VISTAS 4-kilometer horizontal grid resolution generated by CALMET from MM5 and used in the Class I modeling analyses is too coarse to accurately simulate dispersion in the southwest Virginia region. Furthermore, these meteorological data have not been evaluated.

3. The MM5 runs performed in the VCHEC Class II application used different model options than the VISTAS MM5 runs. The differences need to be investigated before the MM5 runs can be used for modeling in the Class II areas.

4. A quantitative evaluation of the CALMET-generated meteorological inputs for the Class II analyses should be performed against actual measurements to evaluate their validity and accuracy.

DEQ disagrees with the commenters that the meteorological data used in the Class I and Class II modeling were inappropriate.

As background, CALMET is a diagnostic meteorological model that is used to drive the CALPUFF dispersion model. It produces three-dimensional fields of wind and temperature, two-dimensional fields of mixing heights and other meteorological data. It contains slope flow effects, terrain channeling, and kinematic effects of terrain. CALMET can use meteorological observational data and/or three-dimensional output from prognostic numerical meteorological models such as MM5 in the development of its fine-scale meteorological fields.

The horizontal grid resolution of the modeling domains is different for the Class I and Class II modeling analyses; therefore, each is discussed separately below.

Class II Modeling

The Class II modeling analysis utilized an MM5 fine grid resolution of 1.33 kilometers in the near-field. As described in Volume II of the applicant's air permit application, MM5 was used to develop high-resolution three-dimensional meteorological fields to serve as initial inputs for the CALMET diagnostic meteorological model. The simulations involved running MM5 for a three-year period (2001-2003) and then nudging the model solutions (i.e., predictions) toward a gridded analysis at regular intervals. This gridded analysis places a constraint on the model predictions so that the resulting meteorological fields will be consistent with the analysis field for a given time interval and at the same time are dynamically balanced. This gridded analysis was developed using surface and upper air observations and satellite data over the MM5 modeling domain.

The CALMET Class II domain covered a region extending at least 30 kilometers from the project site. The size of the fine scale CALMET domain was determined based on preliminary screening modeling of the site to estimate the likely Class II Significant Impact Area (SIA) for each pollutant. Based on the size of the largest SIA, the bounds of the CALMET domain were determined. This domain is designated as Domain 1 since it was anticipated that background emission sources would also need to be modeled and a larger CALMET domain would be needed to accommodate the more distant sources.

There are clearly significant terrain features that need to be properly resolved by the CALMET grid resolution in order to adequately characterize the local air flows. A grid resolution of 200 meters was used for the fine-scale near-field CALMET simulations. This high resolution allows the terrain to be adequately resolved and allows for detailed characterization of the local air flows and spatial changes to the air flow fields.

It is important to note that available observational data within and immediately surrounding the CALMET domains were utilized. There were four surface stations located in the near-field CALMET domain (Lonesome Pine, Abingdon, Richlands, and Consol) that were incorporated in the analysis.

In developing the Step 1 wind field, CALMET adjusts the initial inputs to reflect effects of the terrain, including slope flows and blocking effects. Slope flows are a function of the local slope and altitude of the nearest crest. The crest is defined as the highest peak within a radius (TERRAD) around each grid point. The value of TERRAD is determined based on an analysis of the scale of the terrain. For this application, an appropriate value of 15.0 kilometers is chosen for CALMET Domains 1 and 2. This value is based on the characteristic length scale of the surrounding terrain. The Step 1 field produces a flow field consistent with the fine-scale CALMET terrain resolution (200 meters).

In Step 2, observations are incorporated into the Step 1 wind field to produce a final wind field. Each observation site influences the final wind field within a radius of influence (parameters RMAX1 at the surface and RMAX2 aloft). Observations and the Step 1 wind field are weighted by means of parameters R1 at the surface and R2 aloft: at a distance R1 from an observation site, the Step 1 wind field and the surface observations are weighted equally. For this application, because the observations are not well located to characterize the local terrain flows, relatively small values of the R1 and R2 parameters were used. Both R1 and R2 were chosen to be 10 kilometers while RMAX1 and RMAX2 were chosen to be 15 kilometers. These values have been deemed appropriate for this application and give more weight to the highly resolved MM5 winds as adjusted by the CALMET diagnostic wind field module in the complex terrain valleys where the proposed facility would be located. The time period modeled with CALMET corresponds to the modeled period with MM5, which are the years 2001 through 2003.

The applicant also properly evaluated model performance for the Class II MM5 and CALMET files. Specifically, an operational evaluation of the wind, temperature, and specific humidity fields used to drive the CALMET/CALPUFF simulations was conducted. As previously discussed, the CALMET fields are based on simulations made with the MM5 model. The meteorological model performance is acceptable. Examination of the statistical metrics confirms the absence of significant performance problems, building confidence in the CALMET/CALPUFF modeling system for this project. It is also important to note that model performance evaluation (MPE) goals and criteria are not regarded as a pass/fail test, but rather as a basis of comparing model performance across studies, sensitivity tests, and models. The MPE is listed in the Supporting Reference Documents (see Attachments 9 and 10).

Class I Modeling
VISTAS distributed 4-kilometer CALMET data for five 4-kilometer grid sub-domains covering the VISTAS States and VISTAS Class I areas. To create the CALMET input files, TRC Solutions (formerly Earth Tech) used the MM5 databases developed by EPA for 2001, VISTAS for 2002 and Midwest Regional Planning Organization (RPO) for 2003. An extensive MPE was conducted for all three of these MM5 data sets that were used as input to the CALMET model. The MPE is listed in the Supporting Reference Documents (see Attachments 5, 6, 7 and 8).

For finer resolution sub-domains (4 km grid or less), available surface and upper air observations were used in addition to MM5 meteorological model outputs. The specific model settings have been reviewed and approved by EPA, DEQ and the Federal Land Managers (FLMs) responsible for assessing impacts on the Class I areas.

The CALMET fine grid resolution in the sub-regional modeling domains used for finer grid modeling depends on the terrain, land use, location of the source, distance of the source from Class I areas and total size of the sub-regional modeling domain. There is not a single distance at which a particular grid size is appropriate. It depends on factors such as the complexity of the terrain, the source-receptor distances involved, the location of the source relative to the terrain features, the physical stack parameters (e.g., a tall stack in complex terrain may be unaffected by the terrain forced air flow) and other factors including availability of representative observational data.

In this particular case, the 4-kilometer horizontal grid resolution CALMET simulations were run in hybrid mode, using both MM5 data to define the initial inputs and meteorological observational data in the Step 2 CALMET calculations. Over water (buoy) data were provided in addition to the hourly surface meteorological observations, precipitation observations and twice-daily upper air sounding data.

A domain-specific set of modeling parameters were defined and approved by EPA, DEQ, and the FLMs for each sub-regional domain. The proper selection of the CALMET diagnostic wind field parameters that are used to blend observations with the Step 1 CALMET wind field depends on factors such as the locations of the meteorological stations relative to terrain and coastal features (which affects the representativeness of the observational data), the terrain length scale, and the quality (resolution) of the MM5 data used to define the initial inputs and the ability to properly resolve wind flows on the fine-scale CALMET domain. The definition of the proper CALMET parameters is done as part of sensitivity testing where model performance is evaluated against available observations and expected terrain effects, such as channeling of flows within a valley.

Some commenters asserted that the same model options should be used for each MM5 run. The VISTAS MM5 runs used for Class I modeling were conducted at a horizontal spatial resolution of 12 kilometers for 2001 and 2002 and 36 kilometers for 2003. The MM5 runs for the Class II analyses used an inner domain with a horizontal spatial resolution of 1.33 kilometers. There is no reason to use the same options for all MM5 runs primarily due to the differences in the spatial resolution between data sets.

In summary, DEQ accepts the processed CALMET meteorological data used for the Class I and Class II analyses as valid inputs to CALPUFF. VISTAS and its member States, including Virginia, decided that the 4-kilometer resolution was adequate for assessing Class I impacts.

<u>Air Quality Model</u>
Commenters stated the following with respect to the CALPUFF model:

1. The applicant used unapproved models.

2. CALPUFF must fulfill the five requirements set forth in the EPA Modeling Guideline in order to be used as an alternative model for the Class II application and must be shown to be equivalent to the preferred model AERMOD.

3. The Class II CALPUFF model used the non-default option that computes the dispersion coefficients from turbulence parameters rather the using the Pasquill-Gifford default option. Additionally, the model used the non-default options that use the slug approach for near-field dispersion and the PDF approach for convective dispersion instead of their respective technical option. The use of non-default options can cause CALPUFF to underestimate impacts.

DEQ disagrees with the commenters that the CALPUFF model is an unapproved model for assessing Class I and Class II air quality impacts for this particular application. According to Appendix W to 40 CFR Part 51 (Guideline on Air Quality Models (GAQM)) (see Attachment 11), CALPUFF may be applied on a case-by-case basis for air quality estimates in situations were there are “inhomogeneous local winds” (GAQM Section 7.2.8 (Complex Winds)). With respect to the proposed location of the VCHEC, the “design concentrations” are significantly affected by the presence of mountain and valley wind patterns. As a result, both DEQ and EPA have determined that getting the trajectory correct is an important consideration in this analysis. The purpose of choosing a modeling system like CALPUFF is to fully treat the time and space variations of meteorology effects on transport and dispersion.

The applicant has provided the necessary supporting documentation as required by the GAQM. Appendix A to the GAQM (Summaries of Preferred Air Quality Models) also states that CALPUFF may be used on a case-by-case basis if it can be demonstrated using the following criteria:

1. The model has received a scientific peer review;
2. The model can be demonstrated to be applicable to the problem on a theoretical basis;
3. The data bases which are necessary to perform the analysis are available and adequate;
4. Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates; and
5. A protocol on methods and procedures to be followed has been established.

EPA and DEQ have determined that the applicant has fulfilled these criteria based in part on a review of the applicant's document "Use of CALPUFF for Near-Field Class II Air Quality Modeling of Proposed Coal-Fired Power Plant in Southwest Virginia, TRC Environmental Corporation," June 27, 2007 (see Attachment 12).

In summary, the setup and application of CALPUFF (Version 5.8) has been conducted in consultation with the appropriate reviewing authority (DEQ) and has been accepted for both the Class I and Class II modeling in this application. EPA's concurrence is documented in its letter to DEQ on December 6, 2007 (see Attachment 15).

DEQ disagrees with the commenters that the use of the turbulence-based dispersion coefficients for Class II modeling for this facility is unapproved or would result in an underestimate of air quality impacts. This was a consideration in the approval of CALPUFF as an alternative model for the Class II application. Evaluations of the CALPUFF model demonstrate improved performance in predicting concentrations when using turbulence-based dispersion. In fact, use of turbulence-based dispersion generally produces higher predicted ground-level concentrations and better performance than the use of Pasquill-Gifford coefficients. In summary, information submitted by the applicant supports the use of turbulence-based dispersion coefficients for this application.

DEQ disagrees with the commenters that the use of the slug approach to model near-field air quality impacts from certain area sources (i.e., material handling operations) is incorrect or would result in an underestimate of air quality impacts. CALPUFF is equipped with a set of puff sampling routines that are designed to evaluate near-field low-level sources during rapidly-varying meteorological conditions. It is important to note that the slug approach produces identical results as the integrated puff approach under steady state conditions. The slug approach also reduces puff overlap problems associated with the circular integrated puff approach in the near-field.

NAAQS and PSD Increment Analyses

Commenters stated the following with respect to the NAAQS and PSD increment analyses:

1. VCHEC's emissions will exacerbate air pollution impacts from American Electric Power's Clinch River Plant (AEP - Clinch River) located in Carbo, Russell County, Virginia.

2. The cumulative effect of the AEP - Clinch River pollution with the VCHEC predicted pollution impacts is alarming.

3. Class II SILs were incorrectly used in showing that VCHEC contributions to a predicted NAAQS violations were insignificant.

4. The permit cannot be issued because there is a violation of the 24-hour SO_2 Class I increment.

5. VCHEC's contribution to exceedances of the Class I PSD increment in the Great Smoky Mountains National Park was initially discounted by claiming the contribution was below the proposed EPA Class I Significant Impact Levels (SILs). This approach cannot be used because there are no promulgated SILs to determine whether a source contributes to a PSD increment violation. Specifically, the Class I modeling report contends incorrectly that the PSD SIL of 0.2 $\mu g/m^3$ for the 24-hour averaging period can be used to demonstrate that the contribution to a Class I exceedance by a source is insignificant.

6. The applicant has underestimated the pollution impacts.

DEQ disagrees with the comment that the applicant has underestimated the pollution impacts. All air quality modeling analyses conducted conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models. Additionally, it is important to understand that there are several levels of conservatism built into the PSD modeling methodology. Worse-case conditions for load, meteorology, background air quality, and interacting sources would all have to occur simultaneously on both a spatial and temporal scale to produce the modeled results used to determine compliance for the VCHEC.

Class II NAAQS Modeling
DEQ disagrees with the commenters' assertions that the VCHEC's emissions will exacerbate air pollution impacts from the AEP - Clinch River facility. The commenters correctly point out that there were model-predicted concentrations that exceeded the NAAQS for sulfur dioxide (SO_2). A review of the modeling results indicated that the proposed facility did not make a significant contribution to any of these modeled violations.

DEQ does not agree with the claim that the Class II SILs cannot be used as a basis to establish a significant contribution to a NAAQS violation. Pursuant to 9 VAC 5-80-1180 (Standards and conditions for granting permits), no permit shall be granted unless it is shown that the source will "be designed, built and equipped to operate without preventing or interfering with the attainment or maintenance of any applicable ambient air quality standard and without causing or exacerbating a violation of any applicable ambient air quality standard." There is sufficient precedent that allows a State to use the Class II SILs as a basis for determining a significant contribution (i.e., exacerbation) to a modeled NAAQS violation. For example, EPA Region IV ruled in 1984 that the Class II SILs can apply to all sources causing or contributing to a violation of a standard, under the criteria used by Section III.A of 40 CFR Part 51, Appendix S (see Attachment 17).

A significant NAAQS contribution is defined as a concentration equal to or greater than the Class II SIL at that receptor and time. The receptors and times of every predicted exceedance of the NAAQS for SO_2 were compared to the locations and times of the proposed facility's contributions equal to or greater than the SILs and there were no events that occurred at the same time.

The modeled NAAQS exceedance events were evaluated to determine individual source contributions. It was determined that the AEP - Clinch River facility, one of the background sources included in the analyses, was the primary contributor to the modeled SO_2 NAAQS exceedances. DEQ has been working to further define the extent of these impacts and to develop a compliance demonstration and strategy to assure compliance with the NAAQS as expeditiously as possible.

It also is important to note that a federal consent decree between AEP and EPA was signed in 2007. The consent decree requires the company to comply with a number of specific items including emission caps for sulfur dioxide for facilities in the AEP Eastern System. The consent decree also specifically addresses the units located at the AEP - Clinch River facility. Beginning on January 1, 2010, the Clinch River Plant will have a plant-wide annual rolling tonnage limitation for SO_2 of 21,700 tons per year. Annual SO_2 emissions will be capped at 16,300 tons per year beginning January 1, 2015. These reductions will be integrated into the overall SO_2 NAAQS compliance strategy for the AEP - Clinch River facility.

Class I Increment Modeling
DEQ disagrees with commenters that a violation of the 24-hour SO_2 Class I increment exists in the Great Smoky Mountains National Park (GRSM). The PSD Class I increment analysis included emissions from the proposed source and emissions from increment-consuming sources from Virginia and neighboring States. The results of the multi-source PSD increment analysis for the GRSM are presented below. Compliance with the PSD Class I increments has been demonstrated.

PSD Class I SO_2 Increment Modeling Results for the GRSM ($\mu g/m^3$)

Averaging Period	3-hour			3-hour Maximum	24-hour			24-hour Maximum
Year	2001	2002	2003		2001	2002	2003	
Great Smoky Mountains National Park	12.46	11.60	14.00	14.00	4.01	4.58	3.17	4.58
Class I PSD Increment	**25**	**25**	**25**	**25**	**5**	**5**	**5**	**5**

Although there are no modeled Class I PSD increment violations, commenters questioned the use of the EPA proposed Class I SILs as a means to discount the VCHEC contribution to any potential exceedances. DEQ agrees with the commenters that there are no promulgated Class I SILs; however, DEQ disagrees with the assertion that the State does not have the authority to establish a threshold (i.e., 0.2 $\mu g/m^3$ for the 24-hour averaging period) as a method to demonstrate that a facility's contribution to an exceedance is insignificant.

In the case of the *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360–61 (D.C. Cir. 1979), the court ruled that administrative agencies may exempt ''truly de minimis'' situations from a statutory command ''when the burdens of regulation yield a gain of trivial or no value.'' In 1996, EPA proposed to add SILs for the Class I increments (see Attachment 18). Although EPA's rule was never finalized, States have the authority to establish a de minimis impact resulting from the emissions from a proposed source that would serve as the basis for a determination that such emissions will not contribute to a violation of the applicable Class I increments.

DEQ agrees with EPA's statement in its proposed regulation that "the use of Class I SILs is not intended to serve as thresholds for determining the need for an AQRV analysis or whether an adverse impact on AQRV will occur. An adverse impact on AQRV in a Class I area depends upon the sensitivity of the particular AQRV and involves an assessment of potential harm. An ambient pollutant concentration that is deemed to be of relatively insignificant consequence for purposes of increment consumption should not automatically be considered inconsequential relative to the inherently fact-specific demonstration upon which an adverse impact on AQRV is to be based" (see Attachment 18).

In summary, the use of the Class I SILs in this instance is unnecessary because there are no modeled Class I PSD increment violations. However, in the event that such violations existed, DEQ would have the authority to establish Class I SILs (i.e., de minimis levels).

NAAQS and PSD Increment Emissions Inventory
Commenters stated the following with respect to the emissions inventory:

1. Not all sources were included in the modeling - the auxiliary boilers and other low-level sources, such as the diesel emergency generators and firewater pumps were not modeled in the Class I analyses.

2. The applicant used incorrect or misleading information in conducting its increment modeling using the full range of operating conditions (i.e., multiple load analysis).

3. The startup scenarios should have included the more realistic case of one boiler in startup mode while the other is operating at full load. This would lead to larger impacts.

4. The cumulative modeling for PSD Class I increment analysis and NAAQS compliance has used annual averaged pollutant emissions. Maximum allowable short-term emissions should have been used.

5. The Class I PSD increment analysis should use the maximum actual or allowable emission rate for each emissions unit for the averaging time being modeled.

6. The cumulative modeling for the PSD Class II increment analysis and NAAQS compliance used annual averaged emissions. Maximum allowable short-term emissions should have been used.

7. The Class I increment modeling removed "non-PSD sources" of Eastman Chemical Company without evidence that it was appropriate.

8. The Class I PSD cumulative source inventory is incomplete because it does not include increment consumption from emission increases after the minor source baseline date (MiSBD) has been triggered in an area.

9. The MiSBDs were not identified for any of the Class I areas at which pollutant impacts were evaluated.

10. Several power plants were not included in the list of increment-affecting sources. These include John Sevier, Kingston, Bull Run, Duke Cliffside and Clinch River.

11. It is unclear how emissions for sources included in the cumulative source inventory were determined as of the MiSBD.

12. It is unclear how current emissions for sources included in the cumulative source inventory were determined.

13. The cumulative source inventory has not been provided in an Excel-compatible format as requested.

Modeled Emission Units, Load Scenarios and Startup Conditions
The auxiliary boiler and the CFB boilers were included in the Class I modeling. Several minor sources, such as the emergency diesel generator and emergency diesel fire pump were not included since they: (1) do not run for 24 hours;, (2) emit only a small fraction of the total facility SO_2 and NO_X emissions; and (3) will only make significant contributions to locations immediately adjacent to VCHEC because of their short stacks.

DEQ disagrees with the comments suggesting that the full range of load conditions was not sufficiently conservative and representative of potential air quality impacts, including startup conditions. The modeling analysis for the VCHEC encompassed the full range of operating scenarios from 25% load through 100% load. These analyses demonstrated compliance with applicable air quality standards. The applicant used vendor data to characterize the multiple load operating conditions of the CFB boilers.

The use of regulatory models to characterize startup conditions is a challenging task. These models have difficulty in accurately assessing the transient conditions that exist during startup because they are designed to analyze steady-state conditions. During startup, stack mass emission rates, exit velocities and exit temperatures are continuously varying. Regulatory models assume these stack parameters remain constant for each time-step of the model. As a result, there are inherent difficulties and uncertainties in accurately defining the exhaust parameters and emission rates at specific time periods. Due to these limitations, many regulatory agencies have historically not required compliance demonstrations for these conditions. It is generally accepted that demonstrating compliance for the full range of load conditions is sufficiently conservative and representative of potential impacts during startup conditions.

Despite these facts, DEQ requested that the applicant conduct a specific startup modeling analysis which utilized vendor data. Modeling was conducted to assess the impact on short-term pollutant concentrations of startup of the two CFB boilers. The startup process takes 12 hours to reach full load. Although the emissions are generally less during startup, the plume rise is lower which may result in greater impacts from emissions. The startup modeling parameters for the two CFB boilers were for a scenario with both boilers starting up at the same time. It was assumed that startup occurred every day of the year from midnight to noon followed by a full load operation from noon to midnight. This is a conservative assumption, since, for example, if startup occurred at 0600 local time, the six hours from midnight until startup began would have zero emissions. Instead, there are no hours with zero emissions and 12 hours of full load operation are included in the calculation of 24-hour averaged concentrations.

Lastly, it is expected that the CFB boilers of the type proposed at the VCHEC will be started a limited number of times per year and the receptors in the vicinity of the proposed plant experience very small changes in impacts between startup and 100% load conditions.

Background Source Emissions Inventory Development
DEQ disagrees with the comments asserting that the full cumulative NAAQS and PSD increment background source inventories were not sufficiently conservative and representative of potential air quality impacts. The inventories were developed in accordance with EPA's 1990 draft "New Source Review Workshop Manual" (NSR Manual) (see Attachment 25) based on input from Virginia and neighboring States.

A key element to understanding increment and increment consumption is baseline dates. These dates are trigger dates for determining what emissions are required to be examined for increment consumption. Increment is consumed when emission increases contribute to ambient air concentrations after the baseline date. Baseline dates are established on a county/city specific basis in Virginia as described in the NSR Manual and implemented in the vast majority of States.

There are many conservative assumptions that were implemented in the development of the inventory. In some instances, allowable, permitted or potential-to-emit emissions were identified. If more than one emission rate was provided, the largest emission rate was used in the modeling. If it was not known whether a particular source was a PSD source, it was assumed to be a PSD source. Also, if a facility was identified as PSD, but the specific units at that facility were not identified as PSD units, all the units in the facility were modeled as PSD emitting units. Another conservatism element of both the NAAQS and PSD increment inventories was that a Significant Impact Area (SIA) of 35 kilometers was assumed for all pollutants even though the actual SIAs for SO_2, PM-10, and nitrogen dioxide (NO_2) are all less than 35 km. This resulted in the inclusion of more sources than are specifically required in order to ensure that the full cumulative impact was appropriately assessed. It is also important to note that PSD increment analyses are based on actual emissions as opposed to the NAAQS analyses, which are based on allowable or potential-to-emit emissions.

In response to comments on the cumulative Class I PSD increment analysis, an alternative modeling assessment using preferred FLM methodology was provided to DEQ by the applicant (see Attachments 19 and 20). Specifically, the preferred FLM methodology uses a MiSBD for each Class I area and evaluates emissions sources within 300 km of each Class I area. This analysis includes supplementary sources, primarily electric generating units (EGUs) that have either increased or decreased emissions since the MiSBD was set in the Class I areas. These EGUs, which are often the largest emitters of sulfur dioxide, had reported data on 3-hour and 24-hour emission rates. The MiSBDs have been set in Monroe County, Tennessee for Joyce Kilmer Wilderness Area (set on January 17, 1979) and Cocke County, Tennessee for Great Smoky Mountains National Park (set on May 6, 1982). The MiSBD has not been triggered yet for Linville Gorge. The supplemental inventory added 229 sources that were modeled for Great Smoky Mountains National Park, 206 sources that were added for Joyce Kilmer Wilderness Area, and 104 sources for Linville Gorge Wilderness Area. For conservatism, the supplementary inventory was modeled for all three Class I areas, which were the only Class I areas that required a multi-source modeling analysis for SO_2.

Commenters referenced several specific facilities in their comments. For example, commenters made specific reference to the exclusion of emissions units from the Eastman Chemical Company facility. As a result of information obtained from the Tennessee Air Pollution Control Division (see Attachment 21), it was determined that only coal-fired boilers 30 and 31 at the Eastman Chemical Company facility consumed SO_2 PSD increment. It is also important to note that on November 8, 2007, it was announced that Eastman Chemical Company would be installing emission controls to reduce SO_2 emissions at the plant (see Attachment 22). These controls will expand the available PSD increment but were not factored into the analysis. Additionally, the follow-up cumulative Class I increment analysis assessed changes in the emission rates for several sources since the Class I MiSBD. The John Sevier, Kingston, Bull Run, and Duke Cliffside power plants had emission decreases since the MiSBD was set and resulted in increment expansions. The AEP - Clinch River plant was modeled as an increment consuming source even though the recent EPA consent decree will result in future substantial emission reductions.

The alternative PSD Class I increment analysis results are provided below:

Alternative PSD Class I SO_2 Increment Modeling Results Using FLM Methodology ($\mu g/m^3$)[1]

Averaging Period	3-hour			3-hour Maximum	24-hour			24-hour Maximum
Year	2001	2002	2003		2001	2002	2003	
Cohutta	N/A[2]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Great Smoky Mountains National Park	18.70	18.58	16.80	18.70	3.03	2.84	3.50	3.50
James River Face	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Joyce Kilmer	N/A	N/A	N/A	N/A	N/A	N/A	3.90	3.90
Linville Gorge	11.74	10.94	11.28	11.74	3.56	2.97	3.00	3.56
Shining Rock	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Class I PSD Increment	**25**	**25**	**25**	**25**	**5**	**5**	**5**	**5**

1 Matrix of Highest-Second-High cumulative predicted PSD SO_2 Concentrations (3-hr and 24-hr) when the SILs were exceeded for project source alone by year and Class I Area (project source + all relevant background sources (The inventory includes original inventory and supplemental inventory).

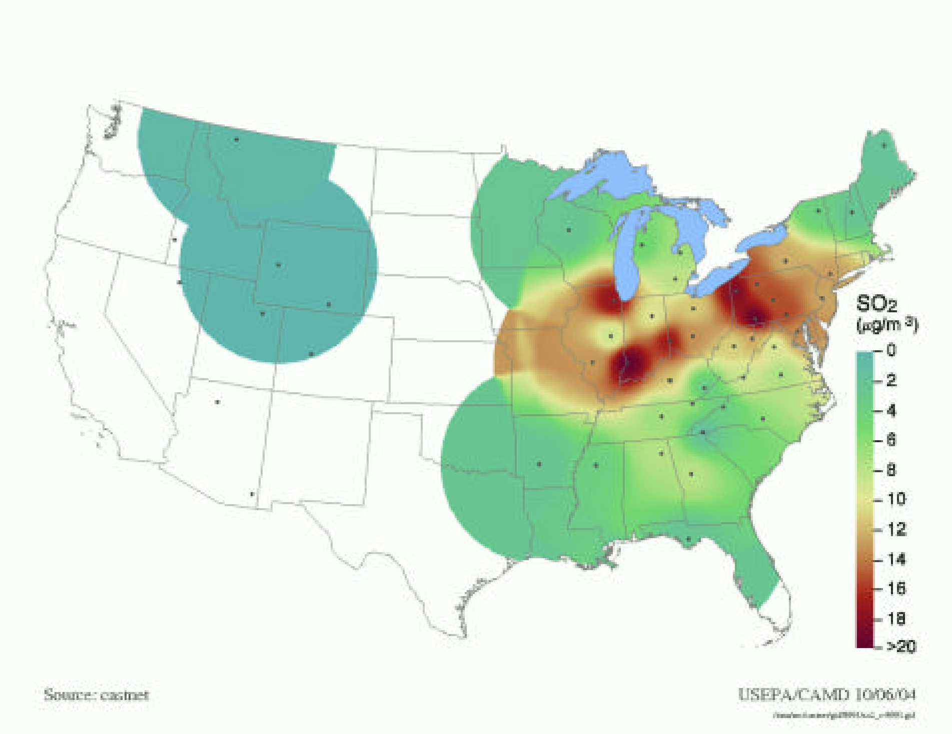
2 N/A means a multi-source modeling analysis for the Class I area was not required because the impact from the proposed facility was less than the SIL.

These results confirm that the proposed facility does not cause or contribute to any exceedances of the Class I PSD Increment

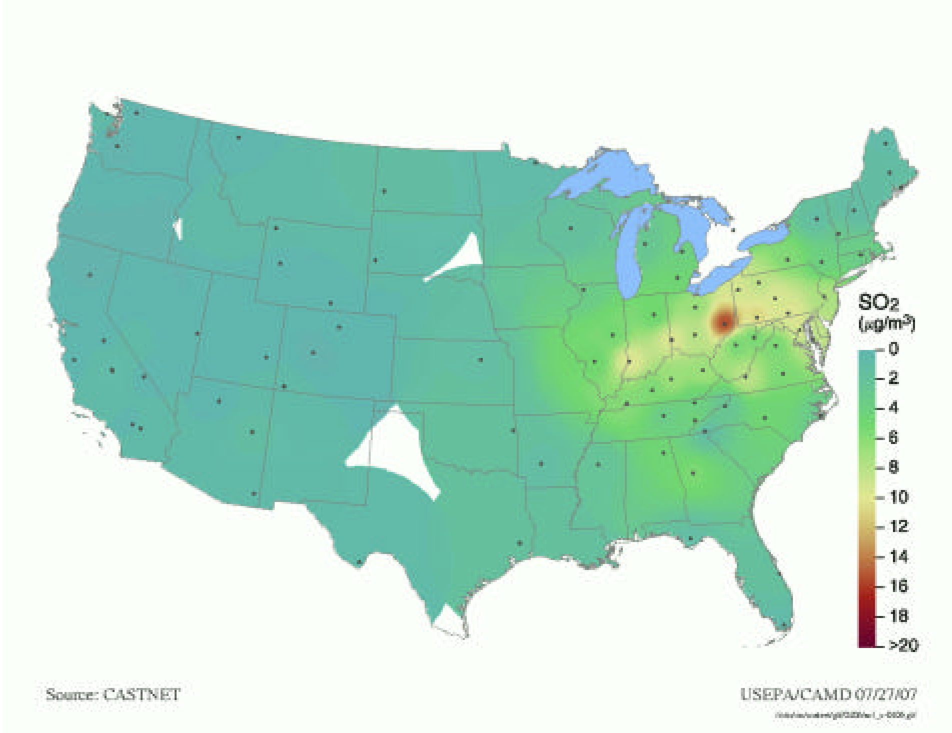
It is also important to put into context the air quality trends in the Appalachian Class I areas and whether the "weight of evidence" would lead one to conclude that a SO_2 Class I increment violation actually exists. It is clear that air quality trends are improving and are expected to improve for deposition and visibility within areas such as Linville Gorge, as recognized by the FLM in its December 14, 2007 letter to DEQ (see Attachment 24). In fact, the FLM for Linville Gorge Wilderness Area acknowledges in its submittal to DEQ that neither the 3-hour nor 24-hour Class I increments have been consumed for the Forest Service Class I areas in North Carolina. These trends are expected to continue as a result of the Clean Air Interstate Rule (CAIR) reductions, Virginia's regional haze State Implementation Plan (SIP) and the EPA consent decree with AEP.

An examination of the Clean Air Status and Trends Network (CASTNET) data supports the FLM statements that air quality trends continue to improve. CASTNET data is used in conjunction with other national monitoring networks to provide information for evaluating the effectiveness of national emission control strategies and consists of over 80 sites across the eastern and western United States and is cooperatively operated and funded with the National Park Service (NPS). Below are two charts that show the trend in SO_2 concentrations. There is a similar trend in sulfate deposition. The range of years in each chart represents 3-year averages. For example, 1989-1991 is the average concentration of 1989, 1990 and 1991.

1989-1991 3-Year Average SO_2 Concentration (µg/m^3)



2004-2006 3-Year Average SO_2 Concentration ($\mu g/m^3$)



EPA clearly recognizes the need for clarification and improved procedures for Class I increment inventory development and modeling. On June 6, 2007, EPA proposed to refine several aspects of the method that may be used to calculate how air emissions from a new or modified industrial facility might impact an area (see Attachment 23). EPA's rule, when promulgated, will hopefully clarify how States and regulated sources may calculate increases in concentrations for the purposes of determining compliance with the PSD increment.

Although there is a great deal of debate as to how to estimate actual emissions for sources that consume the PSD increment, it is clear that a promulgated EPA rule would improve implementation of the program by clarifying and codifying these principles that are currently addressed through guidance only. EPA's intent is to provide greater regulatory certainty and reduce complexity in the development of the emissions inventories without sacrificing the level of environmental protection and benefit derived from the PSD program.

Over the years, EPA has developed some recommended approaches that reviewing authorities could use to determine whether changes in emissions rates and increases in emissions associated with new construction since the baseline date have or have not increased concentrations above the increments. These recommendations have generally been described in various modeling guidance documents, while the PSD regulations in 40 CFR Parts 51.166 and 52.21 contained only a few basic requirements for the increment analysis. Although some of these guidelines such as 40 CFR Part 51,

Appendix W (Guideline on Air Quality Models (GAQM)) are incorporated by reference in the PSD regulations, EPA has continued to refer to these as ''guidelines'' and used language in the guidelines to indicate that the document does not mandate specific procedures. For example, some suggestions for the increment analysis are included in the draft NSR Manual. However, EPA makes it clear that this manual is not intended to establish binding regulatory requirements. EPA goes on to state that many people have looked to this document for guidance and have sometimes improperly construed it to contain requirements that must be followed.

The EPA's Environmental Appeals Board (EAB) has sometimes referenced the draft NSR Manual as a reflection of its thinking on certain PSD issues, but the EAB has been clear that the draft NSR Manual is not a binding Agency regulation. Two recent cases support this position and are listed below:

1. Indeck-Elwood, LLC, PSD Permit Appeal No. 03–04, slip. op. at 10 n. 13 (EAB Sept. 27, 2006);

2. Prairie State Generating Company, PSD Permit Appeal No. 05–05, slip. op. at 7 n. 7 (EAB Aug 24, 2006).

In these and other cases, the EAB also considered briefs filed on behalf of the Office of Air and Radiation that provided more current information on the thinking of the EPA headquarters program office on specific PSD issues arising in particular cases. Thus, the EAB has looked to the draft NSR Manual as one resource to consider in developing its position through case-by-case adjudications, while recognizing that the draft NSR Manual does not contain binding requirements.

In summary, DEQ disagrees with the comments suggesting that the NAAQS and PSD increment inventories were developed incorrectly. The procedures utilized were both appropriate and conservative in nature. Alternative air quality analyses using FLM methodology support the position that no Class I increment violations exist for the modeled Appalachian Class I areas. Furthermore, observed air quality data and trends do not support the position that an increment violation exists in any of the Class I areas modeled.

<u>Visibility Modeling</u>
Commenters stated the following with respect to visibility modeling:

1. PM-10 emission composition is mischaracterized in the visibility modeling.

2. There will be an adverse impact on Class I areas under appropriate modeling.

3. The applicant used visibility Method 8 which has not been approved by the National Park Service. The Park Service recommends Method 2 and Method 6, but those predict significant impacts by VCHEC on regional haze at the PSD Class I areas.

4. Class II visibility modeling should be done in addition to Class I.

5. VISCREEN runs for simulations of plume blight within 10-20 kilometers of the proposed site have not been analyzed.

6. The applicant should provide an assessment on the impact of the proposed plant on the visibility (i.e., views).

PM Speciation
DEQ disagrees with the commenters that the speciation of PM-10 emissions was performed incorrectly. The commenters appear to be comparing the emission factors by the applicant to the factors developed by the National Park Service (NPS). The difference in the composition of the PM-10 emissions is due to the fact that the applicant used site-specific emission factors whereas the NPS used generic emission factors such as those contained in EPA's emission factor database (AP-42).

For example, the AP-42 emission factor for H_2SO_4 is four times VCHEC's emission limit, which accounts for the higher inorganic PM-10 emission rate proposed by the NPS. The NPS appears to be relying upon AP-42 characterization of condensable particulate matter (CPM) emissions from circulating fluidized bed (CFB) boilers; however, AP-42's Table 1-1.5 discloses that its estimates are based upon no data whatsoever for CFB boilers and that the estimates are based upon pulverized coal (PC) boilers with particulate and flue gas desulfurization (FGD) controls. The type of FGD controls is very important because the removal efficiency of sulfuric acid mist, which makes up virtually all of the inorganic condensable particulate matter (IOR CPM) is much better with dry FGD in combination with fabric filter controls than for wet FGD controls. The proposed VCHEC project will feature dry FGD in combination with fabric filter controls. Therefore, the project's proposed H_2SO_4 emission rate is quite low, only 0.005 lbs/mmBtu. The full load emission rate of H_2SO_4 corresponds to the 3.95 grams per second IOR CPM emission rate used in the modeling analysis. The remaining condensable particulate matter is conservatively modeled as all secondary organic aerosols.

DEQ believes that the site-specific emission factors developed by the applicant are more appropriate than the NPS proposed values. It is also noteworthy that the impact on regional haze of the condensable particulate matter emissions is a small fraction of the total modeled impact (typically on the order of 10%). A change to the speciation of the CPM emissions would change this fractional impact only slightly and would not be expected to alter the overall conclusions of the modeling analysis.

Visibility Impact Calculation Techniques
DEQ disagrees with the comments suggesting that it is inappropriate to evaluate regional visibility impacts using multiple techniques. To assess the impacts on visibility, an analysis was conducted by the applicant using procedures outlined in the document Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000) and EPA's Regional Haze Rule (including Best Available Retrofit Technology (BART)).

The Federal Land Managers (FLMs) have recently pointed out that the 2000 FLAG guidance was intended to be a working document with revisions and refinements made to the techniques over time (see Attachment 26). As a result of several factors, including regulatory developments such as the BART rule and input from applicants and regulatory authorities, revisions to the FLAG procedures have been accepted by the FLMs as a matter of practice in individual applications. Attachment 26 lists modified and refined visibility procedures that are currently considered by the FLMs. These include (1) the use of Method 6 instead of Method 2, (2) use of the 98th percentile visibility impact value as recommended by the EPA for BART, and (3) use of the new IMPROVE extinction equation.

As previously stated, DEQ has also been working with Visibility Improvement States and Tribal Association of the Southeast (VISTAS) and EPA to implement the BART requirements of the Regional Haze Rule. As part of this process, the need for a methodology to post-process CALPUFF/CALPOST modeling data to implement the new IMPROVE equation was identified. The new IMPROVE equation, which is a better representation of the effects of particulate matter on light extinction than the old equation, takes into account the latest scientific understanding of several parameters.

1. The new algorithm overcomes biases of the old algorithm on the haziest days and the clearest days as demonstrated by comparing the measured light extinction from nephelometers at Class I areas to light extinction calculated using each of the equations.

2. The new algorithm recognizes spatial and temporal variation in light extinction as size distribution of the aerosol changes by increasing extinction efficiency as sulfate, nitrate, and organics concentrations increase.

3. The new algorithm incorporates a term to reflect the contribution of fine sea salt and its hygroscopic growth with increasing relative humidity recognizing research findings showing that fine sea salt can be an important contributor to light extinction in coastal areas.

4. The new algorithm reflects research finding that the mass concentration of particulate organic matter in rural areas is greater than represented by the old equation.

5. The new algorithm includes a NO_2 term to represent times when light absorption by NO_2 is a meaningful contributor to light extinction.

6. The new algorithm incorporates site-specific Rayleigh scattering values to better represent sites close to sea level or with very hot or cold climates.

With this combination of revisions to the IMPROVE equation, the resulting apportionment of extinction to various components is more accurate on the haziest and clearest days. This is important for development of emission control strategies since the benefits of control of concentrations of each species will be represented more correctly with the new algorithm.

A comparison of the old versus new IMPROVE equation and nephelometer data at several Class I areas demonstrates the old IMPROVE equation tends to show a low bias on high extinction days. The new equation shows a better match on high extinction days with a slight high bias. The correlation coefficients are often slightly lower for the new equation than the old equation because there is slightly more scatter at the low end of the equation.

In summary, the applicant's analysis uses the full array of visibility calculation techniques, including Method 2, Method 6 and Method 8. These data were provided to DEQ and the FLMs as "weight of evidence" for consideration in the evaluation of the impacts on visibility. The applicant has the prerogative to submit these data to inform the decision making process. Based on these data, the FLMs did not determine that there was an adverse impact on visibility in any Class I area as a result of the proposed facility's emissions. Lastly, the FLMs did express a concern that CALPOST Method 8 was not shown to be equivalent with the spreadsheet technique already accepted by the FLMs and EPA for BART purposes. As a result, the FLMs chose not to consider Method 8 as implemented by the applicant.

Class II Visibility Modeling
DEQ disagrees with the comments suggesting that plume blight modeling simulations are required for the area within 10-20 kilometers (Class II areas) of the proposed site. In accordance with the PSD regulations, the applicant conducted additional impact analyses to assess the impacts from the proposed facility on visibility, soils and vegetation and the potential for and impact of secondary growth. There are no sensitive Class II vistas within the Significant Impact Area (SIA) that require a specific analysis of plume blight using models such as VISCREEN or PLUVUE II. Visibility in the immediate vicinity of the proposed facility will be protected by operational requirements, such as air pollution controls and stringent limits on visible emissions that are included in the air permit. The required visibility analysis to assess the impacts on the conditions within affected Class I areas was conducted using the CALPUFF modeling system. It is important to emphasize that the FLMs did not determine that there was an adverse impact on visibility in any Class I area as a result of the proposed facility's emissions.

For additional information on the impacts of the proposed facility on visibility, see the response for air quality control programs, emissions trends and regional haze modeling results under The Air Quality Planning Process and Regional Modeling for Visibility, Ozone & PM-2.5 in this document.

Air Quality Related Values (AQRV) and Class I Area Analysis
Commenters stated the following with respect to the air quality related values and Class I areas analysis:

1. The proposed facility's AQRV impact analysis was not adequately or thoroughly conducted to assess impacts and request additional analyses.

2. The sulfur deposition from the proposed facility will exceed the FLM threshold of concern and adversely impact Class I areas.

3. Emissions from the proposed facility will increase the problems associated with acid rain.

DEQ disagrees that the applicant's AQRV impact analysis was not adequately or thoroughly conducted to assess impacts. The AQRV analysis was conducted in accordance with a protocol that was approved by EPA, DEQ, and the FLMs. The AQRV analysis conforms to the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000).

Acid Deposition
DEQ recognizes the importance of protecting resources that are susceptible to acid rain, otherwise known as acid deposition (which includes the "sulfur deposition" referred to by one commenter). The applicant conducted an analysis of the impact of the proposed emissions on acid deposition in six Class I areas within 300 kilometers of the proposed plant. The analysis was performed using the CALPUFF modeling system to predict annual sulfur and nitrogen deposition. In accordance with guidance from the FLMs, the results of the analysis were compared to the deposition analysis threshold (DAT) of 0.010 kilograms per hectare per year (kg/ha/yr) for nitrogen and sulfur for eastern Class I areas. The DAT is defined as the additional amount of nitrogen or sulfur deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The DAT is a deposition threshold, not necessarily an adverse impact threshold. If the additional amount of deposition is greater than or equal to the DAT, an additional analysis may be required. Based on results of the dispersion modeling analyses, all of the resulting maximum predicted nitrogen deposition rates for the Class I areas included in the analysis were below the DAT. The maximum predicted sulfur deposition rates for three of the Class I areas included in the analysis, two managed by the U.S. Department of Agriculture's Forest Service (Forest Service) and one by the NPS, were greater than the DAT. However, an agreement between DEQ, the Forest Service, and the applicant has resulted in the draft permit containing approaches the applicant can use to mitigate its annual sulfur dioxide

emissions above 1,684 tons per year (see Attachment 29). The Forest Service and NPS determined that the mitigation measures would be acceptable for reducing the impacts of sulfur deposition from VCHEC to a level that would not cause an adverse impact on any Class I area.

In addition, the proposed plant is also subject to acid rain permitting requirements established under Title IV of the 1990 Clean Air Act (commonly referred to as the Acid Rain Program). The acid rain permit requirements ultimately will be included in the facility's Title V operating permit.

The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X), the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention. By reducing SO_2 and NO_X, many acidified lakes and streams will significantly improve so that they can once again support fish life. Visibility will improve, allowing for increased enjoyment of scenic vistas across our country, particularly in National Parks. Stress to forests will be reduced. Furthermore, reductions in SO_2 and NO_X will reduce fine particulate matter (sulfates, nitrates) and ground level ozone (smog), leading to improvements in public health.

EPA reported in 2003 that the Acid Rain Program has resulted in a large and widespread decrease in the deposition of wet sulfur since 1990, which is directly linked to declines in emissions and deposition of sulfur that have occurred since the 1990 Clean Air Act Amendments. Pursuant to the Acid Rain Program, EPA will continue to periodically evaluate the effectiveness of mandated emission reductions through water quality monitoring measurements. These measurements will help EPA gather additional data to help evaluate whether the Clean Air Act Amendments of 1990 provide enough protection for acid-sensitive watersheds in Virginia and throughout the United States.

Air Quality Planning and Regional Modeling for Visibility, Ozone & PM-2.5

Commenters stated the following with respect to the air quality planning process and regional modeling for visibility, ozone, and PM-2.5:

1. Excess SO_2 emissions are causing adverse impacts on visibility in National Forests.

2. Excess SO_2 emissions are precursors to fine particulate formation that will exacerbate PM-2.5 non-attainment, exceed PSD increments and may cause NAAQS violations of PM-2.5 standards.

3. Since the VCHEC facility alone will likely cause significant visibility impacts at PSD Class I areas, especially at Linville Gorge, a modeling analysis of cumulative visibility impacts at Class I areas must be performed, and is required by the federal land managers (FLM).

4. Ozone modeling is required for demonstrating compliance with the NAAQS.

5. Ozone modeling should be performed to assess the impacts of project emissions on ozone air quality in Wise County and other nearby areas.

6. The Shenandoah National Park, the Great Smoky Mountains National Park and surrounding region routinely suffer from high ozone days.

7. The coal plant might also increase pollution in Northern Virginia, a federal nonattainment area for PM-2.5 and ozone. Data on prevailing winds suggests that pollutants from the coal plant could drift over Northern Virginia within 72 hours of emissions in eight of the twelve months of the year posing an additional health risk to our community.

8. The pollution from Wise County will travel long distances and will threaten areas in Virginia, West Virginia, Tennessee, and North Carolina. In these areas, the permit should assess the impact of SO_2 and PM-2.5 emissions on the attainment status of these areas.

9. Since pollution from coal-fired power plants can travel hundreds of miles, there will be health and environmental risks not only to the residents of Wise County but also James City County.

10. Emissions from the proposed facility will increase regional smog and haze.

Several aspects of the air quality planning and modeling process are discussed below and are relevant to the proper understanding of regional emissions, data trends analysis and regional modeling necessary to address these comments.

Overview of Regional Air Quality Modeling Process
DEQ disagrees with the suggestion that regional modeling for visibility, ozone and PM-2.5 is required as part of the PSD permitting process. Regional modeling is extremely complex and resource intensive and it is not possible for the DEQ to undertake a regional modeling effort that is specific to each PSD permit action. The models can take many months to run and the required computer infrastructure makes it impractical to conduct such an exercise for each PSD permit action.

To create these model simulations, inventory information is prepared for VISTAS member States as well as States in other air quality planning organizations. This information is processed through a variety of computer programs and is meshed with meteorological data so that final future year results for ozone, PM-2.5, and visibility can be estimated. These tools provide useful information to the planning process and are indeed required by the Clean Air Act (CAA) for a variety of planning needs. Certainly, as new information regarding proposed or planned facilities is available to DEQ, that information will be included in any planned regional planning modeling inventory. In instances where modeling studies are not already being created, limited resources cannot be devoted to recreating and running these models to estimate the impact of a single facility on regional air quality. Regional air quality is dependent on all anthropogenic (i.e., man-made) and biogenic (i.e., natural) emissions as well as a number of meteorological factors. It is highly unlikely that the addition of a single facility to the vast emissions inventory, which includes Virginia and the majority of States in the eastern United States, would change estimated outcomes, especially considering that overall emissions are decreasing year to year due to a variety of new and ongoing control programs. Additionally, these regional models are heavily dependent on various States cooperating to create inventories and baselines that can be substantiated and justified. It is not likely that such resources could be marshaled for the necessary cooperative review for a single facility's impact. Though DEQ will always try to keep the future year inventory estimates as up to date as possible, there can be no guarantee that every facility will always be included in a timely regional modeling demonstration.

With respect to the VCHEC, DEQ was fortunate to have facility-specific information, including data such as stack parameters and maximum allowable emission rates, available in a timely manner for inclusion in the regional planning and modeling exercise for the Regional Haze Phase I planning process. The results of this modeling assessment are discussed in greater detail throughout this document. DEQ endeavors to create future year inventories that are as accurate as known information allows and that are conservative in their estimates of future emissions. To that end, the proposed VCHEC facility was included in the inventory preparations. Along with the VCHEC, Virginia's 2018 inventory included emissions from approximately another 2,000 megawatts of coal-fired utility capacity, which has been predicted via the EPA Integrated Planning Model (IPM). Even with the inclusion of these as yet unpermitted plants, Virginia's total emissions, including SO_2, continue to decrease.

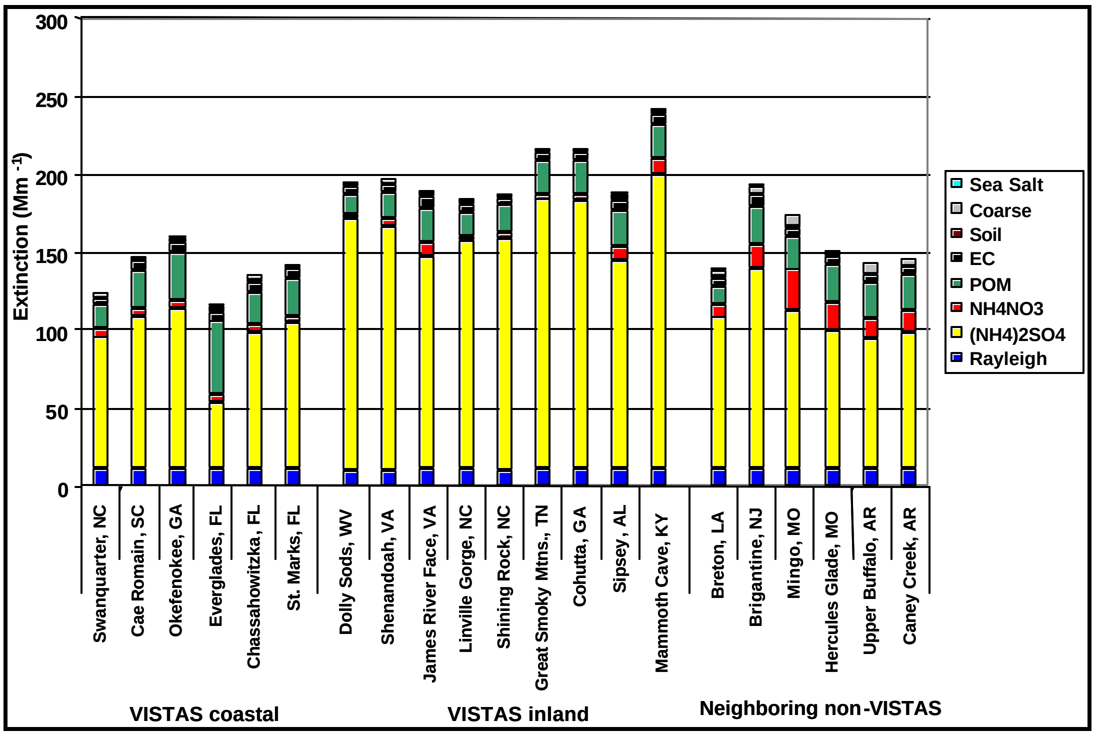
Air Quality Control Programs

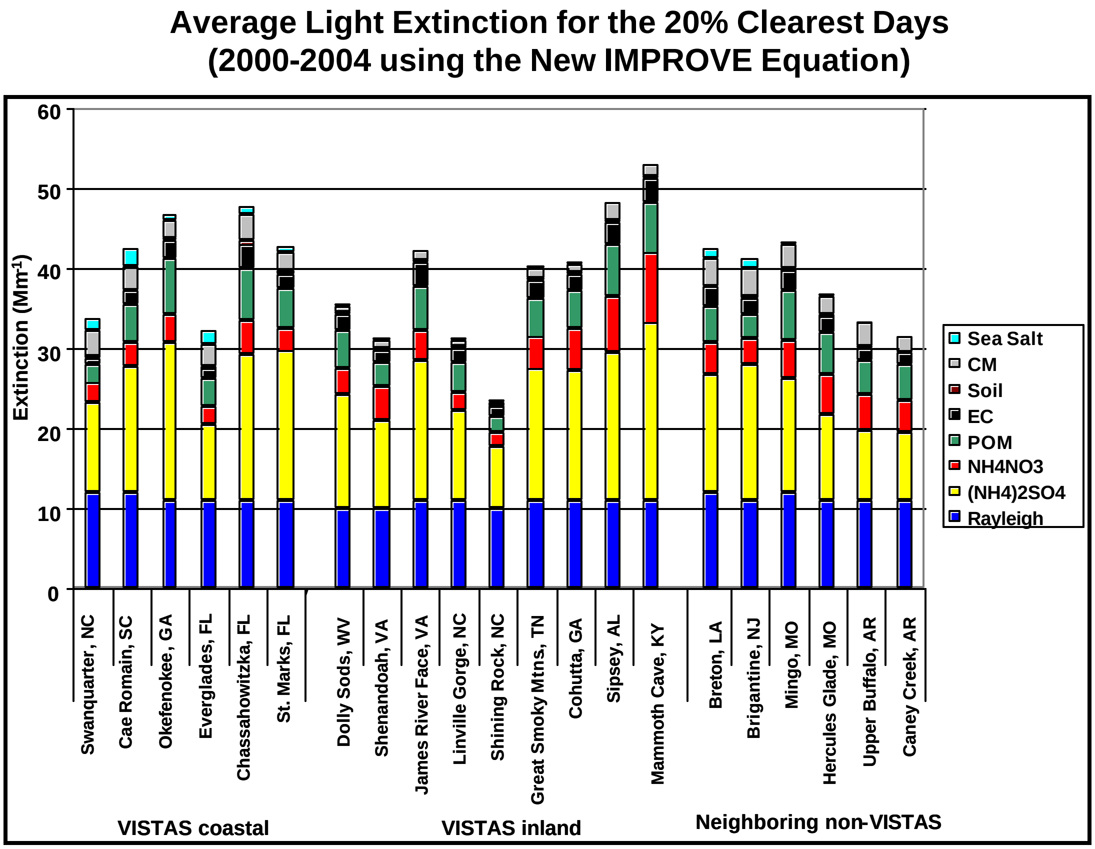
DEQ agrees with the commenters that it is important to evaluate regional air quality impacts on ozone, PM-2.5, and visibility on a holistic basis particularly due to the fact that air quality planning for these pollutants involves a wide array of emissions sources and control programs.

The comments expressed concern about the effect of the VCHEC on visibility; therefore, the focus of this response will address regional haze. However, it is important to note that many of these control programs have a co-benefit in reducing impacts on ozone and PM-2.5 (which also were identified in the comments).

Ammonium sulfate, $(NH_4)_2SO_4$, is the most important contributor to visibility impairment and fine particle mass on the 20 percent haziest and 20 percent clearest visibility days in the Southern Appalachian Class I areas. Sulfate levels on the 20 percent haziest days account for 60-70 percent of the visibility impairment. Across the VISTAS region, sulfate levels are higher at the Southern Appalachian sites than at the coastal sites. On the 20 percent clearest days, sulfate levels are more uniform across the region. This phenomenon is graphically depicted in the two figures below:

Average Light Extinction for the 20% Haziest Days (2000-2004 using the New IMPROVE Equation)





The Regional Haze Program requires Federal and State agencies to work together to improve visibility in 156 national parks and wilderness areas, including the Great Smoky Mountains and Shenandoah National Parks. The monitored data and modeling analyses performed for the Regional Haze State Implementation Plan (SIP) requirements establish that, for the VISTAS region, the key contributors to regional haze in the 2000-2004 baseline timeframe were large stationary sources of sulfur dioxide emissions.

As a result, there are significant control programs being implemented between the baseline period (2002) and 2018 to address regional haze (i.e., visibility issues) as well as other air quality issues. Examples of these Federal and State control requirements that were included in the regional modeling are described below.

<u>Federal and State Control Requirements</u>

1. **CAIR**
   CAIR will permanently cap emissions of SO_2 and NO_X from EGUs in the eastern United States by 2015 through a cap and trading program. When fully implemented, CAIR will reduce SO_2 emissions from EGUs in these States by more than 70 percent, and NO_X emissions by more than 60 percent, from 2003 levels.

2. **NO_X SIP Call**
   Phase I of the NO_X SIP call applies to certain EGUs and large non-EGUs, including large industrial boilers and turbines, and cement kilns. Those States affected by the NO_X SIP call in the VISTAS region have developed rules for the control of NO_X emissions that have been approved by the EPA. The NO_X SIP Call has resulted in a 68 percent reduction in NO_X emissions from large stationary combustion sources. For this analysis, we capped the emissions for NO_X SIP call-affected sources at 2007 levels, and carried forward the capped levels for the 2009 and 2018 future year inventories.

3. **North Carolina CSA**
   Under the act, enacted in 2002, coal-fired power plants in North Carolina must achieve a 77-percent cut in NO_X emissions by 2009 and a 73-percent cut in SO_2 emissions by 2013.

<u>Consent Agreements</u>

Several Federal and State consent agreements that were included in the regional modeling will reduce emissions from particular stationary sources and improve ambient air quality.

1. **TECO [US District Court, Middle District of Florida]**: Under a federal consent decree, by 2008, Tampa Electric (TECO) will install permanent emissions-control equipment to meet stringent pollution limits; implement a series of interim pollution-reduction measures to reduce emissions while the permanent controls are designed and installed; and retire pollution emission allowances that Tampa Electric or others could use, or sell to others, to emit additional NO_X, SO_2, and PM.

2. **VEPCO [US District Court, Eastern District of Virginia]**: Virginia Electric and Power Company (also known as Virginia-Dominion Power) agreed to spend $1.2 billion by 2013 to eliminate 237,000 tons of SO_2 and NO_X emissions each year from eight existing coal-fired electricity generating plants in Virginia and West Virginia. VEPCO is the permit applicant for the VCHEC project.

3. **GULF POWER [State of Florida "Agreement for the purpose of Ensuring Compliance with the Ozone Ambient Air Quality Standards," dated August 28, 2002]**: This 2002 agreement requires Gulf Power to upgrade its operation to cut NO_X emission rates by 61 percent at its Crist generating plant by 2007, with major reductions beginning in early 2005. The Crist plant is a significant source of NO_X emissions in the Pensacola area.

4. **DUPONT [US District Court for the Southern District of Ohio]**: A 2007 consent decree requires Dupont's James River plant, located in Virginia, to install dual absorption pollution control equipment by September 1, 2009, resulting in emission reductions of approximately 1,000 tons SO_2 annually.

5. **STONE CONTAINER [US District Court, Eastern District of Virginia]**: A 2004 consent decree requires the West Point Paper Mill, owned by Smurfit/Stone Container and located in West Point, Virginia, to control with a wet scrubber the SO_2 emissions of #8 Power Boiler. This control device should result in reductions of over 3,500 tons of SO_2 in 2018.

6. **AEP [US District Court for the Southern District of Ohio, Eastern Division]**: American Electric Power (AEP) agreed to spend $4.6 billion dollars to eliminate 72,000 tons of NO_X emissions each year by 2016 and 174,000 tons of SO_2 emissions each year by 2018 from sixteen plants located in Indiana, Kentucky, Ohio, Virginia, and West Virginia.

<u>Ozone SIPs</u>

1. **One-hour Ozone SIPs (Atlanta / Birmingham / Northern Kentucky)**
New SIPs have been submitted to the EPA to demonstrate attainment of the one-hour ozone NAAQS. These SIPs require NO_X reductions from specific coal-fired power plants and address transportation plans in these cities.

2. **8-hour Ozone Nonattainment Area SIPs**
The North Carolina SIP for the Charlotte/Rock Hill/Gastonia nonattainment area includes Reasonable Achievable Control Technology (RACT) for NO_X for two facilities located in the nonattainment area: Philip Morris USA and Norandal USA.

The SIP for the Washington, D.C. Metropolitan area includes reductions in NO_X from the five major power plants in the area. Facilities located in southern Maryland (Dickenson, Chalk Point, and Morgantown facilities) are subject to the Maryland Healthy Air Act, which caps the NO_X and SO_2 emissions for each facility. Facilities located in northern Virginia (Possum Point and Potomac River facilities) are subject to the caps applied in the Virginia CAIR rule, which requires that facilities located within nonattainment areas comply on a facility-specific basis with their emission limitations rather than allowing trading of allowances to demonstrate compliance. Large SO_2 and NO_X reductions are expected based on these requirements by 2018.

Other Control Programs

1. **Heavy Duty Diesel (2007) Engine Standard For On-road Trucks and Buses**
EPA set a PM emissions standard for new heavy-duty engines of 0.01 grams per brake-horsepower-hour (g/bhp-hr), to take full effect for diesel engines in the 2007 model year. This rule also includes standards for NO_X and non-methane hydrocarbons (NMHC) of 0.20 g/bhp-hr and 0.14 g/ bhp-hr, respectively. These NO_X and NMHC standards will be phased in together between 2007 and 2010 for diesel engines. Sulfur in diesel fuel must be lowered to enable modern pollution-control technology to be effective on these trucks and buses. EPA will require a 97 percent reduction in the sulfur content of highway diesel fuel from its current level of 500 parts per million (low sulfur diesel, or LSD) to 15 parts per million (ultra-low sulfur diesel, or ULSD).

2. **Tier 2 Tailpipe (On-road vehicles)**
EPA mobile source rules include the Tier 2 or fleet averaging program, modeled after the standards set forth in the California Air Resources Board's amendments to the California Low Emission Vehicle regulations (LEV II). Manufacturers can produce vehicles with emissions ranging from relatively dirty to zero, but the mix of vehicles a manufacturer sells each year must have average NO_X emissions below a specified value. Tier 2 standards became effective in the 2005 model year.

3. **Large Spark Ignition and Recreational Vehicle Rule**
EPA has adopted new standards for emissions of NO_X, hydrocarbons (HC), and carbon monoxide (CO) from several groups of previously unregulated nonroad engines. Included in these are large industrial spark-ignition engines and recreational vehicles. Nonroad spark-ignition engines are those powered by gasoline, liquid propane gas, or compressed natural gas rated over 19 kilowatts (kW) (25 horsepower). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and a variety of farm and construction applications. Nonroad recreational vehicles include snowmobiles, off-highway motorcycles, and all-terrain-vehicles. These rules were initially effective in 2004 and will be fully phased in by 2012.

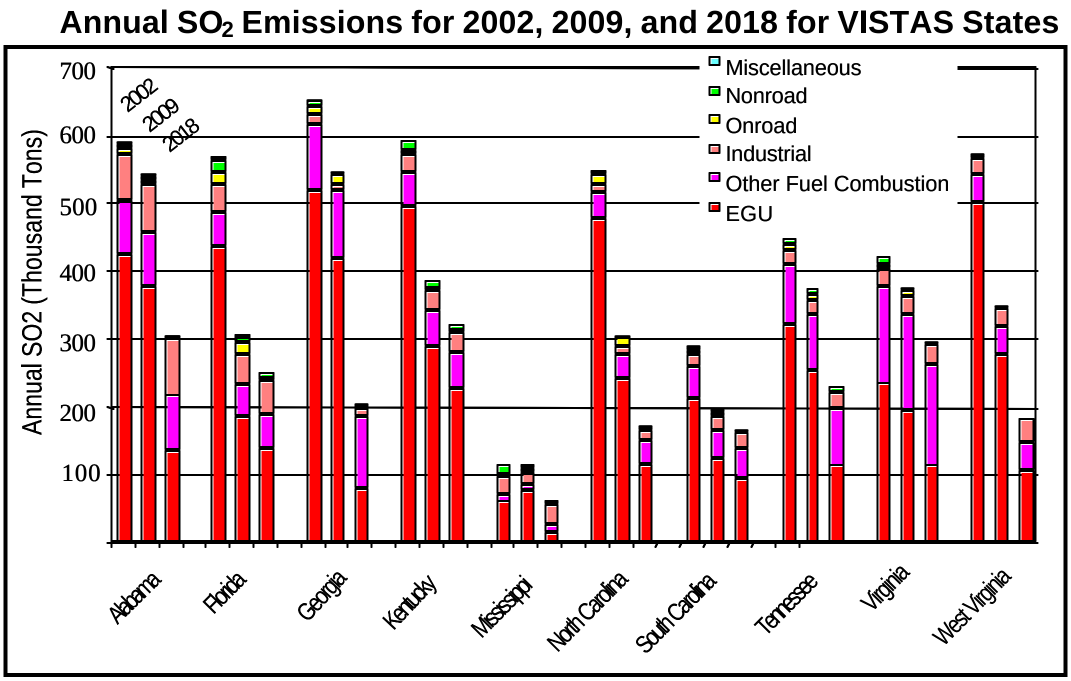
4. **Nonroad Diesel Rule**
This Federal rule sets standards that will reduce emissions by more than 90 percent from nonroad diesel equipment and reduce sulfur levels by 99 percent from current levels in nonroad diesel fuel starting in 2007. This step will apply to most nonroad diesel fuel in 2010 and to fuel used in locomotives and marine vessels in 2012.

5. **Industrial Boiler/Process Heater/RICE MACTs**
   The applied Maximum Achievable Control Technology (MACT) control efficiencies were four percent for SO_2 and 40 percent for PM-10 and PM-2.5. However, as of June 8, 2007, the Industrial Boiler/Process Heater MACT standard was vacated. A mandate without a stay was issued July 30, 2007. As a result, sources that were subject to the rule may need to file applications for permits containing MACT limits derived on a case-by-case basis within a time specified by the EPA or DEQ

6. **VOC 2-, 4-, 7- and 10-year MACT Standards**
   Various point source MACTs and associated emission reductions were implemented. No reductions occurring prior to 2002 were counted.

7. **Early Action Compacts (EACs)**
   Seven localities in Virginia, along with DEQ and EPA Region III, signed EACs. By signing the EACs, EPA agreed to defer the effective date of the 8-hour ozone nonattainment designation for participating areas. The DEQ worked with the EPA, state and local governments, industry, environmental groups, and other interested parties to develop strategies to reduce precursors to ozone. As well as requiring NO_X RACT on major sources of NO_X emissions, the compacts contain many programs implemented to reduce emissions from these areas.

Emissions Trends
The following bar chart shows expected decreases in emissions of SO_2 across the VISTAS States from 2002 through 2018. Note that for SO_2 emissions, which are the largest contributors to haze, emissions from electric generating facilities are expected to decrease dramatically (70 percent) between 2002 and 2018. These emissions reductions as listed for Virginia do not take into account the nearly 12,000 tons of SO_2 per year that would be reduced from the gasification of Dominion's Bremo Bluff facility but do account for the proposed allowable emissions from the VCHEC.



The chart below illustrates that total emissions of SO_2, the major visibility impairing pollutant, will decrease in Virginia from years 2002 through 2018. Again, this chart does reflect emissions from the VCHEC but does not reflect expected reductions from the Bremo Bluff facility.

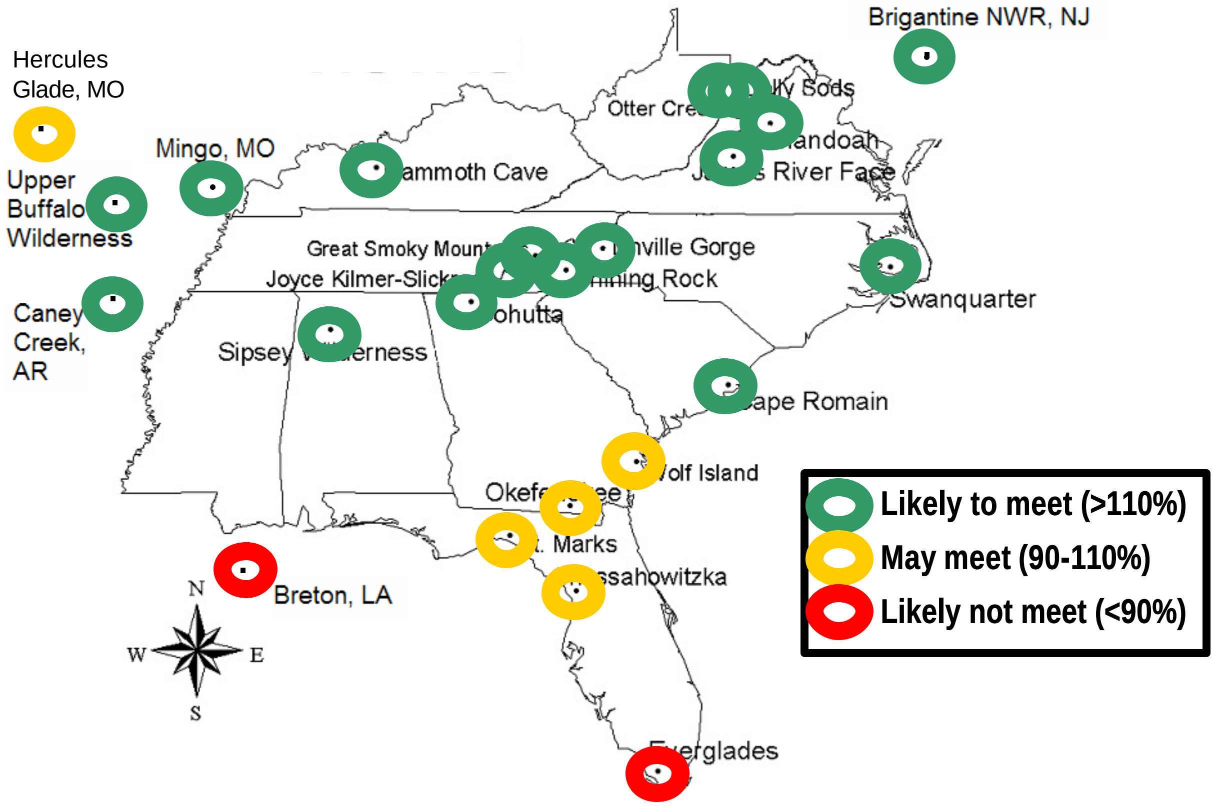
Virginia Annual Emissions for 2002, 2009, and 2018

Year	SO_2 Tons/Yr	NO_X Tons/Yr	VOC Tons/Yr
2002	427,946	482,108	451,612
2009	340,940	356,121	345,244
2018	267,772	274,399	311,396

Regional Haze Modeling Results
These reductions in SO_2 are expected to allow the Southern Appalachian Class I areas (including areas like the national forests and Linville Gorge identified by commenters) to experience visibility improvement in 2018 that exceed the goals of a Uniform Rate of Progress (URP) for the first phase of the regional haze program. The URP is the uniform rate of visibility improvement, or progress, needed to reach natural conditions by 2064 for each Class I area.

Below is a graphical depiction of the 2018 VISTAS Uniform Rate of Progress assessment.

VISTAS Regional Haze Uniform Rate of Progress Assessment
2018 Best and Final Base G4, New IMPROVE equation

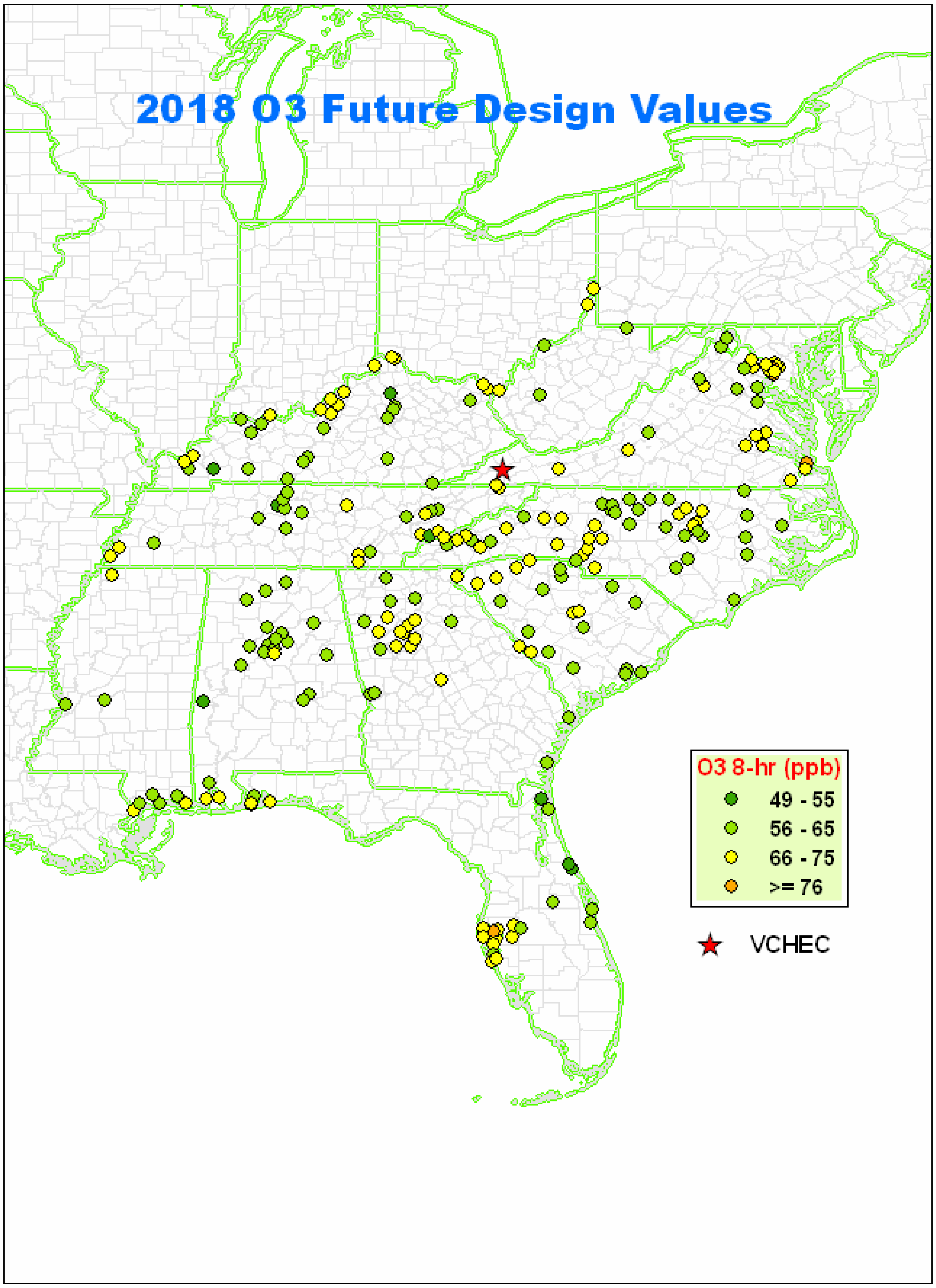


As can be seen by the plot, the Appalachian Class I areas are likely to meet the Uniform Rate of Progress goals set out in the Regional Haze Rule. These visibility modeling results are based on an emissions inventory that explicitly includes the VCHEC. The improved trend in visibility, as recognized by the FLMs, is largely the result of the control measures that have either been adopted or will be adopted as discussed previously.

Ozone Modeling Results

Ozone modeling results for the year 2018 are provided below and represent projected air quality at a time when the proposed plant would be in operation. These results are from a study that was undertaken by VISTAS on behalf of its member States primarily for the Regional Haze SIP. EPA's Models-3/Community Multi-scale Air Quality (CMAQ) modeling system was selected for the analysis primarily because it is a "one-atmosphere" photochemical grid model capable of addressing ozone at regional scale and is considered one of the accepted models for regulatory modeling applications. The procedures followed in the modeling analysis are consistent with the EPA's "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of

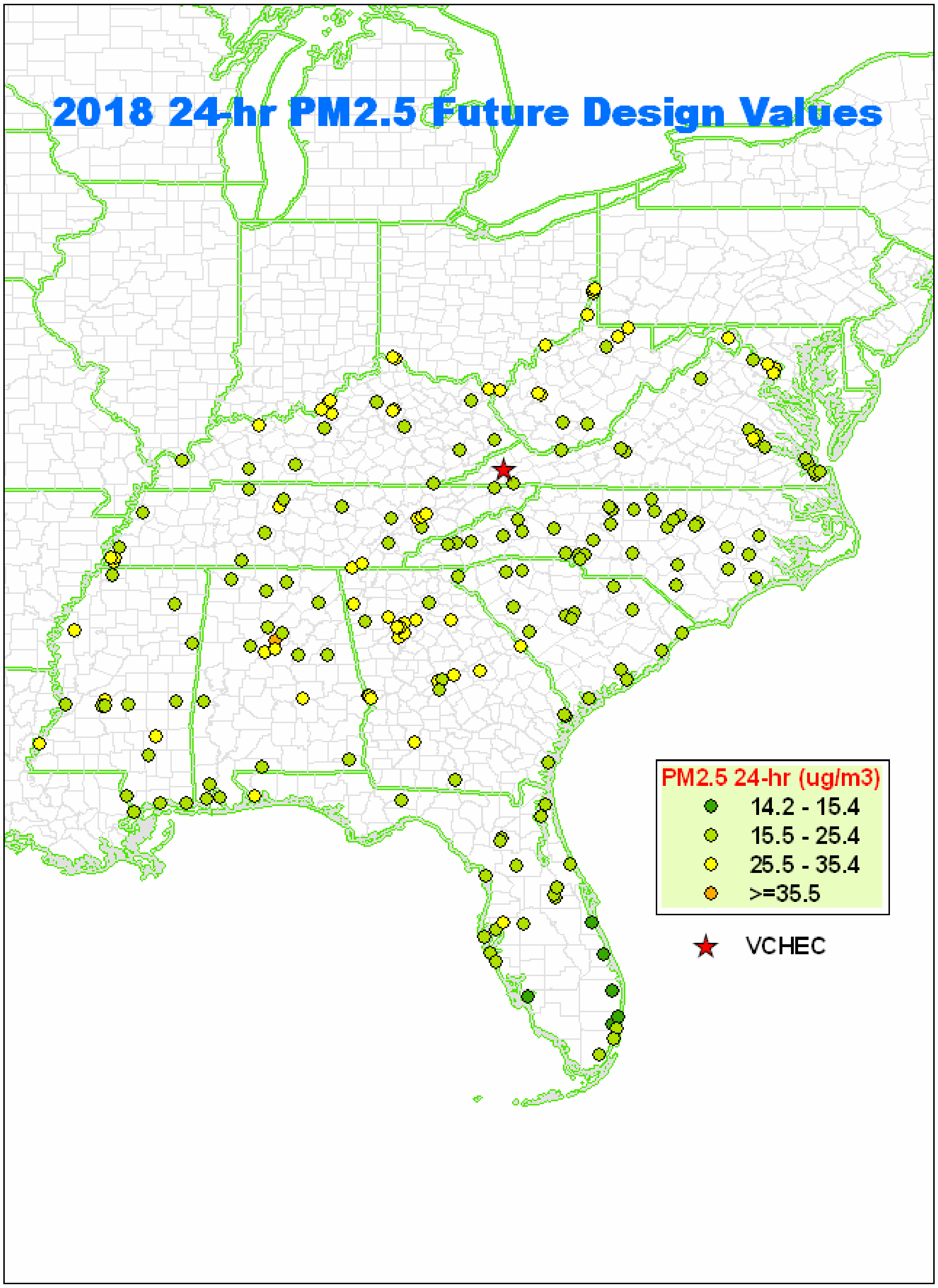
Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze" (EPA-454/B-07-002, April 2007) (see Attachment 30). The results from the modeling are provided in the figure below and present evidence that the vast majority of the Southeast region will be in attainment with the newly revised 8-hour ozone standard of 75 parts per billion by 2018. The emissions inventory used in this analysis includes the VCHEC.


2018 O3 Future Design Values
O3 8-hr (ppb)
49 - 55
56 - 65
66 - 75
>= 76
VCHEC

Lastly, neither state regulations nor the FLM require ozone modeling in support of the PSD application and, as discussed above, modeling to demonstrate compliance with the ozone NAAQS is performed on a regional basis, not on a facility-specific basis as suggested by some commenters. The final recommendations for evaluating ozone impacts in Class I areas are contained in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). The FLAG document provides criteria for evaluating AQRV impacts. As previously stated, the impact of any one proposed project would be insignificant in terms of the overall regional ozone precursor emissions budget.

PM-2.5 Regional Modeling Results

PM-2.5 modeling results for the year 2018 are provided below and are based on the same modeling platform as the aforementioned ozone analysis. The results from the modeling presented in the figure below provide evidence that the vast majority of the Southeastern United States will be well below the 24-hour and annual PM-2.5 NAAQS by 2018. All future design values (DVF) (with the exception of Birmingham, AL) are less than 35 µg/m^3 (24-hour) and less than 15 µg/m^3 (annual). The emissions inventory used in this analysis includes the VCHEC. Further discussion on PM-2.5 air quality analysis is provided under PM-2.5 Air Quality Analysis included in this document.


2018 24-hr PM2.5 Future Design Values
PM2.5 24-hr (ug/m3)
14.2 - 15.4
15.5 - 25.4
25.5 - 35.4
>=35.5
VCHEC

<u>Terrain Downwash</u>
Commenters stated the following with respect to terrain downwash:

1. The increment analysis failed to take terrain downwash into consideration.

DEQ disagrees with the suggestion that terrain downwash is a relevant issue with respect to modeling impacts from the proposed plant. The commenters correctly point out that there is currently no EPA-recommended procedure or model for evaluating the effects of upwind terrain on plume transport and dispersion. As a result, a terrain downwash assessment was not required by the modeling protocol.

The CALPUFF model was chosen to evaluate impacts from the proposed facility because it better represents the variable wind data, slope flows, and channeling of valley winds that are present in the mountainous terrain surrounding the proposed plant when compared to a straight-line plume model such as AERMOD. The applicant responded to the comments made on this issue in the document "Response by TRC to Comments by Ron Petersen and Jeff Reifschneider of CPP on Terrain Downwash, dated February 14, 2008" (see Attachment 31). DEQ concurs with the information provided in this report and supports the position that terrain downwash is not relevant to the modeling of impacts from the proposed facility.

<u>National Ambient Air Quality Standards (NAAQS)</u>
Commenters stated the following with respect to health concerns and risk assessment:

1. Emissions of particulate matter and other pollutants – added on top of the NAAQS-busting levels of particulate matter and SO_2 that Wise County is already receiving from the Clinch River Plant – will further exacerbate the region's already high rates of illnesses such as asthma, coronary disease, and emphysema, and increase cancer rates.

2. Carbon dioxide, sulfur dioxide, and nitrogen emissions all have dire consequences to our health.

The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants from numerous and diverse sources considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves.

EPA has set NAAQS for six principal pollutants, which are referred to as "criteria" pollutants. The criteria pollutants are: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM-10 and PM-2.5), and sulfur dioxide (SO_2).

The current EPA policy for review of the NAAQS includes 4 major components as described in EPA's letter issued on April 17, 2007 (see Attachments 32, 33 and 34):

1. Planning
2. Integrated Science Assessment
3. Risk Exposure Assessment
4. Policy Assessment/Rulemaking

These elements of the NAAQS review process are designed to improve efficiency and ensure EPA's decisions are informed by the best available science and broad participation among experts in the scientific community. The process will assist EPA's goal of reviewing each NAAQS on a 5-year cycle as required by the Clean Air Act without compromising the scientific integrity of the process.

With respect to the VCHEC, the modeling analysis demonstrates that the proposed facility will not cause or contribute to a violation of any applicable NAAQS. In the event that EPA promulgates revisions to the NAAQS, the VCHEC will be required to comply with the revised standards. Additional information on the impacts of the AEP - Clinch River plant is available in this document under <u>NAAQS and PSD Increment Analyses</u>.

<u>Risk Assessment for Mercury and Other Hazardous Air Pollutants</u>
Commenters stated the following with respect to the analysis of mercury:

1. The applicant failed to analyze non-inhalation risks of mercury.

2. The proposed facility would contribute significantly to the mercury deposition in the Great Smoky Mountains National Park and will degrade AQRVs such as soil and vegetation.

3. It would be appropriate and in the best interest of area residents' health to require mercury testing of the local area likely to be affected by the proposed facility. It would be appropriate and in the best interest of area residents' to require a mercury deposition modeling analysis to evaluate bio-accumulation of mercury prior to permit issuance. This is due to the proximity of the proposed facility to the Clinch River and AEP - Clinch River plant.

4. The applicant should assess the impact of mercury emissions from the proposed facility on macro invertebrates, fish, and endangered mussels in the Clinch River.

5. The applicant should conduct research on the bioaccumulation of mercury in the raptor population of Virginia.

6. While the application does look at whether there are significant ambient air concentrations (SAAC) of the several toxic substances such as benzene, hydrogen chloride and hydrogen fluoride VCHEC will emit, the analysis understates potential health effects by ignoring non-inhalation risks such as ingestion of toxins emitted from the plant through soil, drinking water and food. This comparison is not acceptable as a health risk assessment, since it does not quantify the health effects of carcinogens and non-cancer pollutants due to acute and chronic exposure.

7. Cleaner technology is needed so there will be less cancer in the region. We already have one coal power plant (AEP - Clinch River) and Kingsport, Tennessee has smoke stacks from the Eastman Chemical Company that produces air pollution that drifts in our direction.

8. Mercury emissions have dire consequences to our health.

The applicant is not required by state air regulations to perform the following analyses:

1. Non-inhalation risks of mercury and health impacts due to ingestion of toxins emitted from the plant through soil, drinking water and food.

2. Mercury deposition in the Great Smoky Mountains National Park and its impact on AQRVs such as soil and vegetation.

3. Mercury deposition modeling to evaluate bioaccumulation of mercury and its associated impacts on macro invertebrates, fish, mussels and the raptor population of Virginia.

4. Evaluation of cleaner technologies to reduce the rates of cancer in the region. Control technology requirements (i.e., BACT and MACT) are discussed in additional detail in the engineering memos and response to comments documents for the Article 7 and Article 8 permits.

Although an ambient air quality impact analysis for toxic pollutants pursuant to 9 VAC 5-60-300 et seq is not required, the applicant agreed to conduct a Significant Ambient Air Concentration (SAAC) compliance demonstration. The predicted impact for each toxic pollutant was below the corresponding SAAC. The SAAC is designed to be protective of human health.

On February 8, 2008, the United States Circuit Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule (CAMR) and overturning EPA's decision to delist electric generating units as sources subject to a Maximum Achievable Control

Technology (MACT) standard under Section 112 of the Clean Air Act. In anticipation of the final mandate from the D.C. Circuit, the applicant applied for a case-by-case MACT preconstruction review permit on February 14, 2008 rather than wait for the court to issue its final mandate. The D.C. Circuit issued its final mandate on March 14, 2008. DEQ processes case-by-case MACT permits under Article 7 of the state regulations for permitting stationary sources (9 VAC 5-80-1400 et seq). DEQ drafted an Article 7 permit (or MACT permit) and noticed the draft permit for public comment. As a result of the D.C. Circuit's ruling, EPA is required to promulgate a MACT standard for electric generating units. If EPA's MACT requirements are more stringent than those required by the Article 7 permit for VCHEC, the applicant will be required to comply with the new requirements.

The emissions controls contained in the draft Article 7 and Article 8 permits include flue gas desulfurization (FGD), fabric filtration, and activated carbon injection (ACI) for control of mercury; limestone injection, FGD, and fabric filtration to reduce acid gas hazardous air pollutants (HAPs); fabric filtration for control of particulate HAPs; and good combustion practices, fabric filtration, and ACI for control of organic HAPs.

Additionally, the Standards to Protect Health and the Environment (Section 112(f) of the Clean Air Act which is known as the "Residual Risk" Program) requires the EPA to assess the risk to public health remaining after the implementation of a MACT standard. If the "residual risk" for a source category does not protect public health with "an ample margin of safety," the EPA must promulgate health-based standards for that source category to further reduce HAP emissions. The EPA is required to set more stringent standards if necessary to prevent adverse environmental effects (considering energy, costs, and other relevant factors). At this time, no residual risk analysis of the VCHEC is required. Additional information on the residual risk future applicable requirements is available at the following link.

http://www.epa.gov/ttn/atw/residriskpg.html

It is also important to note that in 2006 the Virginia General Assembly enacted legislation that requires the DEQ to conduct a detailed assessment of mercury deposition in Virginia to determine whether particular circumstances exist which justify taking additional measures to control mercury emissions beyond state implementation of CAMR. DEQ must finalize and report its assessment by no later than October 15, 2008.

Additionally, the applicant and the Chesapeake Bay Foundation conducted analyses to assess the impacts of air emissions of mercury from the proposed facility on potentially affected watersheds. DEQ conducted a review of these studies although neither was required pursuant to this permit action. Each of these analyses was conducted based on a total plant mercury emission rate of approximately 72 pounds per year (lbs/yr), although the assumptions on mercury speciation varied between the studies.

DEQ believes that the applicant's study (see Attachment 36) generally provides good supporting evidence that the predicted incremental increases of mercury due to emissions from the proposed facility do not appear to present a threat of adverse impacts for aquatic life in the Clinch River. This includes consideration of the additional concern for protecting freshwater mussels.

DEQ's review of the Chesapeake Bay Foundation's study (see Attachment 37) revealed that the predicted increases in total mercury deposition in the Virginia watersheds due to VCHEC are relatively small and insignificant compared to the predicted 2002 baseline rates of mercury deposition. This conclusion is based on total mercury deposition calculated for the Virginia river basins' watersheds from modeling results conducted in support of the Virginia Mercury Study.

DEQ's detailed review of these studies is provided in its memorandum "Technical Review of Mercury Studies Conducted by Dominion Virginia Power and the Chesapeake Bay Foundation in Response to the PSD and MACT Permits for the Proposed Virginia City Hybrid Energy Center", June 9, 2008 (see Attachment 35).

Ambient Air Monitoring

Commenters stated the following with respect to ambient air monitoring:

1. The Class II Modeling Report indicates the 24-hour maximum concentrations for PM-10 and SO_2 will exceed their de minimis monitoring concentration. As a result, onsite monitoring for PM-10 and SO_2 are required by the PSD regulations and should be performed for one full year.

2. The applicant should monitor the emissions after they are released from the stack due to concerns about the proximity of the VCHEC to the AEP - Clinch River plant. Commenters stated the local area would become "the most polluted part of the State."

Currently, before beginning construction of a new major source or a major modification at an existing major source in an attainment area, a source must undergo preconstruction review pursuant to the PSD new source review preconstruction permitting program. This process includes a review of air quality monitoring.

DEQ and EPA recognize that the process of operating a monitoring network and collecting ambient data for up to one year prior to the submittal of a complete PSD application has long been a concern of stakeholders, particularly in cases where there is no perceived need for the data in the air quality analysis at the site. For example, the chance of exceeding an applicable increment or violating an applicable National Ambient Air Quality Standard (NAAQS) may be thought to be negligible at a particular site. In these circumstances, permitting authorities have agreed that the monitoring requirement may impose a substantial and unnecessary burden on the applicant.

Preconstruction monitoring may be required on a case-by-case basis, though most States have a well-established ambient air quality monitoring network. Additionally, when onsite monitoring data is collected, a minimum of four months of data is required if it is shown to DEQ's satisfaction that it represents data during time periods when maximum ambient air concentrations are expected for the pollutant(s). A facility may propose to be exempt from preconstruction monitoring due to modeled impacts below the significant monitoring concentrations which is subject to DEQ review and approval. Alternatively, if the facility cannot be exempted from the preconstruction monitoring requirement based on modeling, the applicant may propose use of existing monitoring data.

The requirement for preconstruction monitoring can be met in the following ways:

1. Existing ambient data may be used if DEQ determines that these data are representative and can establish the attainment status of a particular region.

2. Establish a site-specific monitoring network.

The preconstruction monitoring data for the VCHEC was derived using existing monitoring data collected by DEQ and surrounding States at monitoring stations throughout the region. Background concentrations of SO_2, PM-10, and NO_2 were used in the modeling analysis as part of the assessment of compliance with the NAAQS since the VCHEC concentrations of these criteria pollutants were predicted to be above the SILs. Below are the DEQ criteria that were used to evaluate the preconstruction monitoring requirements:

1. Regional background concentrations are used to represent the air quality analysis impacts from sources that are not explicitly modeled. Due to the fact that these background concentrations are added to the contributions from the VCHEC, as well as from sources within 50 kilometers of the Significant Impact Area (SIA) that are significant (either through proximity or emission rate), they are intended to be representative of the regional concentrations that would be characteristic of the entire area. This means that monitored data used to estimate the regionally representative background should not be unduly influenced by nearby industrial sources or be in urbanized areas not characteristic of the region based on the EPA criteria discussed below.

2. The proposed VCHEC site is in a rural area of southwest Virginia characterized by heavily forested rolling hills. Except for the AEP - Clinch River power plant in Carbo, Virginia, about 13 kilometers east of the project site, the region is relatively free of large industrial sources. The AEP - Clinch River plant was explicitly modeled in the analyses and should not be "double counted" in the measured background concentrations. The nearest significant urban area is about 35 kilometers to the south in Bristol, Virginia.

3. Monitors within approximately 100 kilometers of the project site were evaluated. Air quality data collected over a number of recent years at candidate monitors in the region were reviewed in detail for completeness and representativeness of the proposed site. Additional information on this process is provided in Volume II of the applicant's air permit application.

4. Future year projections performed by DEQ support the position that the area will attain the NAAQS for all pollutants, including ozone and PM-2.5.

5. Modeling does not provide any evidence of a SO_2 NAAQS exceedance in the vicinity of the VCHEC as a result of emissions from the AEP - Clinch River facility. In fact, the AEP - Clinch River facility maximum impacts do not coincide with significant contributions from the VCHEC. The AEP - Clinch River facility analysis demonstrates that the maximum impacts from that plant generally extend to the north and east and not to the west at the proposed VCHEC location. This makes sense based on prevailing winds and the orientation of local valleys. Additionally, in many instances the SO_2 emissions from the AEP - Clinch River facility will be converted to sulfate emissions prior reaching a downwind distance of 13 kilometers, which further mitigates the likelihood of coincidental SO_2 impacts.

6. As illustrated in the table below, the background air quality at the proposed facility location would have to be significantly higher than other representative regional SO_2 and PM-10 monitored concentrations in order for a predicted NAAQS exceedance to occur. Specifically, the PM-10 24-hour background concentration would have to be 227% higher and the SO_2 concentrations would have to be between 1,495% to 1,683% greater than the proposed regional values. It can reasonably be concluded that these excessively higher background concentrations are not likely to occur.

Pollutant	Averaging Period	Proposed Facility Maximum Predicted Concentration (µg/m^3)	Significant Monitoring Concentration (µg/m^3)	Ambient Background Concentration Used in Analysis (µg/m^3)	Ambient Background Concentration Necessary to Cause NAAQS Exceedance (µg/m^3)	NAAQS (µg/m^3)
PM-10	24-hour	31.96	10	52.0	118.04	150
SO_2	3-hour	374.17	NA	55.0	925.83	1300
	24-hour	50.77	13	21.0	314.23	365
	Annual	2.21	NA	5.2	77.79	80

7. The PSD rules do not require that an applicant perform ambient monitoring prior to submittal of an application if adequate monitoring data is already available to perform the required air quality analyses for a proposed project. As stated by EPA in the draft NSR Manual (see Attachment 25), the PSD rules require an applicant "to provide an ambient air quality analysis that may include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted in significant amounts." The draft NSR Manual describes the circumstances in which such monitoring may be required, or waived, at the discretion of the permitting authority. Even where such monitoring data is required, an applicant has the option of requesting that it be allowed to use existing monitoring data that is representative of conditions expected in the impact area of the proposed source. This is what occurred for the proposed plant. The applicant requested that DEQ approve the use of existing monitoring data to satisfy the requirements of the PSD program for pre-application monitoring data for ozone and other pollutants. DEQ approved the request because the selection and use of this existing ambient monitoring data contained in the applicant's air quality analyses adequately represented, or conservatively overstated, levels of existing background air quality in the area surrounding the proposed plant.

8. Based on a review of the following nine EPA-recommended criteria for establishing the boundaries of nonattainment areas, the chance of exceeding an applicable increment or violating an applicable NAAQS is thought to be negligible:

   a. Emission data
   b. Air quality data
   c. Population density and degree of urbanization (including commercial development)
   d. Traffic and commuting patterns
   e. Growth rates and patterns
   f. Meteorology (weather/transport patterns)
   g. Geography/topography (mountain ranges or other air basin boundaries)
   h. Jurisdictional boundaries (e.g., counties, air districts, Reservations, metropolitan planning organizations)
   i. Level of control of emission sources

9. Pursuant to 40 CFR Part 58, Ambient Air Quality Surveillance, the monitoring networks operated by Virginia and adjacent States are subject to an annual monitoring plan and periodic network assessment to determine adequacy. EPA has determined that these existing networks satisfy the requirements of 40 CFR Part 58.

10. Due to the size, remote nature of the site and its historic use by members of an All-Terrain Vehicle (ATV) club, it would have been very difficult to fully secure the area to prevent interference from ATV emissions and associated trail dust and to secure the site from vandalism.

11. The proposed main plant site was essentially the only readily accessible area due to the forested nature and rugged terrain in the area. Placing a monitoring station in this location would have presented a substantial burden upon other required site investigation activities (i.e., soil and drill core samples). These activities could also have caused interference with air quality measurements.

In summary, DEQ decided to accept the use of existing ambient data to fulfill the preconstruction monitoring requirements after considering the applicable guidance and regulations. In this decision, DEQ has established, based on a review of available data, that there would be no likely adverse impact on air quality from the proposed project and that existing air quality data from the monitoring network satisfies the preconstruction monitoring requirement.

Lastly, DEQ has established a condition in the PSD permit that requires post-construction ambient monitoring of SO_2 and PM-2.5 as allowed by the PSD regulations. In this case, post-construction monitoring for certain pollutants such as PM-2.5 will aid DEQ to better account for the proposed plant in the development of Virginia's PM-2.5 attainment demonstration. The additional ambient data for background levels of PM-2.5 will aid in the precision of analysis.

<u>Other Air Quality Analysis Comments</u>
Truck Traffic
Commenters stated the following with respect to truck traffic:

1. The increased truck traffic in coal operation with the proposed plant will also lead to significant deterioration of the air quality for the immediate community. The immediate community is already affected by considerable dust and particle pollution from current coal operations. The additional air quality impacts of this community should also be addressed in the permit, including those from increased truck traffic through appropriate modeling analysis.

The plant is proposed to be located in the Southwest Virginia coalfield region adjacent to a major four-lane highway. This highway is expected to minimize the impact of construction activities and vehicles operated by the permanent work force since it will provide very good accessibility to the site. In addition, due to its location in this region, the need to transport coal long distances would be minimized because the coal from this same region will be used as fuel for the proposed facility. Therefore, the burden on transportation infrastructure and emissions associated with fuel transportation is expected to be minimized.

Additionally, it is not anticipated that the operation of the proposed facility would substantially affect the overall coal mining activity in the region since a significant quantity has been historically mined from this area. Also, even though limestone will be required by the proposed plant to control sulfur dioxide emissions, emissions from such facilities are subject to appropriate air pollution control requirements. Therefore, overall emissions from support industries are not expected to increase considerably.

Fogs and Inversions
Commenters stated the following with respect to fogs and inversions:

1. Fogs settle overnight onto the river and our towns. If there is little or no wind the emissions from the smokestacks would join the fog and then we will be breathing a toxic mix that far exceeds government guidelines. If that fog is over St. Paul, the closest town to the power plant, that would be 34 tons of pollutants, or, about 68 pounds per day, per person.

2. EPA cannot accurately model these difficult situations (inversions, fogs, low winds) that are a natural part of a complex terrain next to a river basin. The state of Virginia would be negligent to not require at least a two-year independent study of the atmospheric anomalies in the designated area surrounding the plant.

3. The evidence that the applicant has offered regarding the use of dispersion models and the impact of emissions assumes that the wind will disperse pollutants far and wide from the smoke stack. Commenters claim that this assumption is flawed because they claim that emissions from the AEP - Clinch River plant are frequently trapped under an inversion and that wind transports this fog cloud to localities downwind from facility. Furthermore, it is asserted that toxic particulates precipitate from these fog clouds into the Clinch River and must be properly evaluated.

The commenters' claim that fog forms in the local valleys is correct. As background, fogs are composed of fine droplets of water suspended in the air near the earth's surface. The presence of these droplets acts to scatter the light and thus reduce the visibility near the ground. The formation of a fog layer occurs when a moist air mass is cooled to its saturation point (i.e., dew point). Valley fog forms as a result of air being radiatively cooled during the evening on the slopes of topographical features (i.e., mountains). The cooled air becomes denser than its surroundings and starts migrating down the slope. The eventual result of this process is the creation of a pool of cold air at the valley floor. If the air is cold enough to reach its dew point, fog formation occurs.

The commenters also correctly point out that an inversion can lead to pollution being trapped close to the ground, with possible adverse effects on health. In meteorology, an inversion is a deviation from the normal change of an atmospheric property with altitude and is almost always referred to as a temperature inversion (i.e., an increase in temperature with height as is present in valley fog conditions).

DEQ believes that the meteorological models (MM5 and CALMET) used in the air quality analysis are appropriate for assessing impacts from the proposed facility. Specifically, the MM5 model physics options such as precipitation physics, boundary layer process parameterization and atmospheric radiation schemes are designed to replicate the presence of inversions in mountainous terrain. Additional information on this subject is provided under the response titled <u>Meteorological Data</u>.

It is possible that emissions from the proposed plant may deposit locally in the form of acid compounds when reacted with fog water droplets. The proposed plant is subject to acid rain permitting requirements established under Title IV of the 1990 Clean Air Act Amendments - The Acid Rain Program. The acid rain permit requirements ultimately will be included in the facility's Title V operating permit. Additional information on the acid rain permitting requirements and trends in acid deposition is available under the response titled <u>Air Quality Related Values (AQRV) and Class I Area Analysis</u>.

Although there are no specific acid deposition thresholds that have been established for PSD Class II areas, the regulations require an analysis of the impacts from the proposed facility on soils and vegetation. This analysis was performed by comparing predicted ambient air quality concentrations with screening levels presented in the EPA document "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA 1981) (see Attachment 39). All impacts for the soils and vegetation analysis were below the EPA screening levels and therefore, no adverse impacts on soils or vegetation were identified. Additional discussion on this topic is provided under the response titled <u>Class II Area Air Quality Impacts - Specific Locations</u>.

Lastly, the technical basis for the allegation that light or calm wind conditions would result in "a toxic mix that far exceeds government guidelines" is unclear. The applicant's modeling assessment demonstrates compliance with applicable air quality standards under worst-case operating scenarios, including worst-case meteorological conditions that include temperature inversions. Similarly, there is no technical support provided to justify the statement that each person in St. Paul, Virginia would breathe 34 tons of pollutants or about 68 pounds per day.

<u>Class II Area Air Quality Impacts - Specific Locations</u>
Commenters stated the following with respect to PSD Class II area air quality and visibility impacts with specific references to High Knob and a nature preserve in Meigs County, Ohio:

1. Impacts from the proposed facility on High Knob should be evaluated.

2. The proposed facility could negatively impact a nature preserve in Meigs County, Ohio.

The commenter appears to be referring to the High Knob Recreation Area (HKRA). The HKRA is located in the Clinch River District of Jefferson National Forest on the western front range of the Appalachian Mountains in southern Wise County, approximately 15 miles west of St. Paul and the proposed VCHEC site. DEQ is keenly aware of the importance of protecting the many natural resources of the HKRA. The opportunity to hike, camp, fish and view a variety of plants and animals contribute to this area's broad appeal.

Meigs County, Ohio is located in southeastern Ohio more than 200 kilometers from the proposed VCHEC site. While the commenter did not specify the nature preserve that was being referred to, the forest and fields in Meigs County provide a habitat for a variety of wildlife species and offer hunting, hiking, camping and general sightseeing. The Ohio River, which forms the eastern and southern boundary of the county, and its tributaries offer a variety of fish including sauger, striped bass, catfish, bluegill, crappie and large and small mouth bass.

The HKRA and Meigs County, Ohio are regulated under PSD regulations as a Class II Area. The emissions from the proposed facility that are subject to PSD review have been evaluated in a manner consistent with the requirements set forth in the Virginia PSD program, which is approved by EPA under 40 CFR Part 51.166. In addition to the criteria pollutant analyses, emissions of regulated hazardous air pollutants have been evaluated and found to be below the established Significant Ambient Air Concentrations (SAACs) for each pollutant.

The impacts in all Class II area locations from the VCHEC are predicted to be below the applicable air quality standards or limits. Therefore, the proposed facility is not expected to significantly affect air quality in the HKRA, Meigs County or anywhere within the surrounding nearby and distant Class II areas.

Additionally, in accordance with the PSD regulations, an analysis of the impacts from the proposed facility on soils and vegetation was conducted by the applicant as part of the additional impact analyses. The analysis of soils and vegetation air pollution impacts due to the proposed VCHEC was conducted on sensitive vegetation types with significant commercial or recreational value or sensitive types of soil. The analysis was performed by comparing predicted concentrations with screening levels presented in the EPA document "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA 1981) (see Attachment 39). The majority of the screening levels is equivalent to or exceeds NAAQS and/or PSD increments. Therefore, demonstrated compliance with NAAQS and PSD increments provide compliance assurance with sensitive vegetation screening levels. However, the SO_2 3-hour and annual sensitive vegetation screening levels, 786 $\mu g/m^3$ and 18 $\mu g/m^3$, respectively, are more stringent than the comparable NAAQS. Also, there is a 1-hour screening level for SO_2 (918 $\mu g/m^3$) for which there is no NAAQS equivalent. Based on the analysis, the maximum predicted concentrations for the SO_2 1-hour, 3-hour and annual averaging periods were all below their corresponding screening level concentration. In addition, the NAAQS and PSD increment analyses conducted for the proposed facility demonstrated that the proposed facility would not cause or significantly contribute to a predicted violation of any applicable NAAQS or PSD increment. Furthermore, deposition of trace elements on soils was evaluated using the screening techniques presented in this EPA document by comparing calculated soil concentrations to acceptable soil screening levels provided in this document. Soil concentrations were also used to calculate plant tissue concentrations assuming default plant-to-soil ratios provided by the screening methodology. Plant tissue concentrations were then compared to acceptable tissue screening concentrations and dietary screening concentrations for animals. As a result, all impacts for the soils and vegetation analysis were below the EPA screening levels and therefore, no adverse impacts on soils or vegetation were identified.

General and Specific Comments on BACT

A number of general comments addressed the application of Best Available Control Technology (BACT) in the draft PSD permit. Commenters addressed the following with respect to BACT:

1. IGCC, not CFB, represents BACT for coal-fired electric generating units.
2. Lower temperatures associated with fluidized bed combustion will increase levels of toxic hydrocarbon emissions.
3. Twice as much waste coal is necessary to provide equivalent energy as mined coal.
4. Dedicated controls are not provided for mercury emissions.
5. Proposed limits and controls for particulate matter emissions.

In addition to these general comments from various commenters, detailed comments were submitted by the Southern Environmental Law Center (SELC) addressing specific aspects of the BACT analysis by Dominion, DEQ's evaluation of the BACT analysis, and the resulting proposed BACT limits in the draft permit. These detailed comments on BACT are part of a larger submittal of comments on the project by the SELC, dated March 12, 2008. All of the comments submitted by SELC also were submitted on behalf of Appalachian Voices, Chesapeake Climate Action Network, Sierra Club and Southern Appalachian Mountain Stewards (the comments are hereinafter referred to as "SELC comments"). The National Park Service and Natural Parks Conservation Association also submitted detailed comments dated March 12, 2008.

The DEQ disagrees with the comments suggesting that integrated gasification combined cycle combustion technology (IGCC) is BACT for the proposed facility. This comment seeks to have DEQ require Dominion to redefine the source itself as part of the BACT analysis in a manner not contemplated by Federal or State law. The DEQ cannot require or dictate to any applicant what type of source to construct. It is the role of DEQ to determine if the proposed source will meet all applicable rules and regulations. This approach is consistent with DEQ's historical interpretation of BACT and EPA guidance, which makes clear that the BACT analysis is to consider the facility proposed. With respect to the VCHEC, application of the IGCC process to VCHEC would fundamentally change the basic design of the equipment that Dominion proposes and alter the objective and purpose of Dominion to burn a mix of Virginia fuels, including making use of coal waste as fuel. With respect to the equipment proposed, Dominion has proposed a facility that utilizes a mix of fuels, including Virginia coals, local waste coals, and biomass in a circulating fluidized bed to generate steam to drive an electric turbine. An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal-fired boiler. *See* Response to Public Comments on Draft PSD Permit for Deseret Power Electric Cooperative (Bonanza Power Plant), EPA Region 8 at 15 (Aug. 30, 2007) *citing SEI Birchwood Inc.*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779 (Adm'r 1992). Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. The controlled chemical reaction of coal gasification is much more akin to technology employed in the chemical manufacturing industry than the true combustion process generally used in power generation. Further, as EPA has found, use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce electricity. These fundamental differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source. Further, the VCHEC is being proposed to combust a mix of fuels, including Virginia coal, local waste coals, and biomass. IGCC technology does not lend itself to utilization of varying amounts of these materials in the fuel mixture, especially for fuels including lower-grade fuels like waste coals.

The DEQ also notes that as part of its permit application, Dominion provided an analysis of IGCC as an alternative technology. Dominion indicated they specifically chose circulating fluidized bed coal combustion technology for a variety of reasons including the available fuel types and Virginia legislation that encourages and provides incentives for the development of an electric generating facility in the Virginia coalfields. Information available to the DEQ indicates that application of IGCC technology is neither technologically nor economically feasible in situations where considerable fuel flexibility is necessary. Such is the case with the VCHEC, where they will seek to remediate coal waste piles, utilize readily available run-of-mine coal, and use a considerable amount of biomass. Indeed, one premise for the facility is the reduction of piles of waste coal in the region. Precipitation falling on these piles of waste coal generate leachate having suspended solids, which results in them being major contributors to degradation of area streams by water pollution. Such low quality fuels, in terms of heat and ash content, have not been tested with IGCC processes. See Response to Comments on Draft PSD Permit for Deseret Power Electric Cooperative, U.S. EPA Region 8 at 16-18 (Aug. 30, 2007). Additionally, the DEQ believes that data and information reviewed for operating IGCC facilities indicates the technology is not adequately developed to the point that IGCC would be immediately suitable for reliable baseload electricity generation.

A comment notes that there are no dedicated controls for mercury. It is true that the BACT limit of 71.93 lb/yr of mercury is based on the use of concurrent removal of 98% of the mercury associated with the co-beneficial use of the dry flue gas desulfurization and the fabric filter in tandem. Accordingly, the draft PSD permit requires the use of activated carbon injection control for mercury only if the BACT limit cannot be met with the dry flue gas desulfurization and fabric filter controls. Additionally, the permit limit for mercury, based on a BACT analysis, was demonstrated to be in compliance with the

Significant Ambient Air Concentration (SAAC) guidelines in Virginia's State Toxics Rule, 9 VAC 5-60, Article 5, of Virginia's air pollution control regulations. These standards are designed to be protective of human health. The mercury limit in the draft permit also was demonstrated to be compliant with the mercury standard for electric steam generating units contained in 40 CFR Part 60, Subpart Da that was applicable at the time the permit was drafted. As discussed below and later in this document, the mercury standard set forth in 40 CFR Part 60, Subpart Da no longer applies as a result of the vacatur of the Clean Air Mercury Rule (CAMR). See the section in this document regarding proposed permit changes for further information about NSPS Da (40 CFR Part 60, Subpart Da) regulatory citations that appeared in the draft permit.

As a result of the recent vacatur of the Clean Air Mercury Rule (CAMR) by the United States Court of Appeals for the District of Columbia Circuit, the proposed facility is subject to a case-by-case Maximum Achievable Control Technology (MACT) determination and air quality permit in accordance with the provisions of 9 VAC 5-80, Article 7, of Virginia's air pollution control regulations (also known as a Clean Air Act section 112(g) permit). The provisions of Article 7 are not applicable to the evaluation conducted for the PSD permit; however, the MACT determination and permit required by Article 7 will require the use of activated carbon injection for control of mercury emissions subject to a lower emissions limit, beginning with initial CFB operation. The DEQ regards the Article 7 permit process as a distinct but parallel process, which will produce a mercury emission limit that may supplant the limitation established by the PSD permit. Once emission limits are established in the Article 7 permit, the PSD permit may be amended to reflect the more stringent limitation.

One comment makes reference to page 35 of the Engineering Analysis in regard to comparisons of BACT requirements for particulate matter emissions from seven other power plants, and notes that DEQ concurs with a statement in the permit application that fabric filtration represents the top feasible control technology, but that the Engineering Analysis does not concur with the emissions levels proposed by Dominion as representative of BACT for fabric filtration. The comments also state that the BACT comparison in the Engineering Analysis indicates that the emissions limits established for the seven noted plants are half of Dominion's proposal. These comments correctly note that DEQ has determined that significantly lower emissions levels have been demonstrated for filterable particulate matter (PM) and total (filterable and condensable) particulate matter with aerodynamic diameter less than or equal to 10 microns (PM-10) from fabric filtration than the levels proposed by Dominion in their original application dated June 2006, and updated August 2007. The Engineering Analysis concludes that BACT is represented by a filterable PM limit of 0.010 lb/mmBtu and a total PM-10 limit of 0.012 lb/mmBtu, as opposed to proposed limits of 0.015 lb/mmBtu for filterable PM and 0.050 lb/mmBtu for total PM-10 in the June 2006 submittal, and 0.010 lb/mmBtu for filterable PM and 0.030 lb/mmBtu for total PM-10 in the August 2007 update. These limits determined as BACT are incorporated in the draft PSD permit.

Another comment states that temperatures associated with fluidized bed combustion will increase levels of toxic hydrocarbon emissions. The 0.005 lb/mmBtu BACT limit for volatile organic compounds (VOC) is within the range of corresponding limitations for recent PSD permits for CFB boilers. Expected emissions of individual volatile organics, which are also hazardous air pollutants (HAPs), are all below either their respective exemption levels or the corresponding Significant Ambient Air Concentrations (SAACs), established for a given compound in the Virginia standards for toxic air emissions. At least two recent PSD permits have VOC limits of 0.002 and 0.003 lb/mmBtu, but these have not been demonstrated by stack testing. The permit development process for the VCHEC has accepted slightly more margin in the development of limits for VOC and carbon monoxide, in order to optimize the combustion process and controls for the lowest possible limits on nitrogen oxides. The requirement for activated carbon injection for additional mercury removal for the CFB boilers with the Article 7 permit also should result in additional concurrent VOC removal beyond the requirements of this PSD permit.

References are made to waste coal in a number of comments, with the admonition that twice as much waste coal (or gob) must be burned to provide the equivalent input heat capacity as run-of-mine (ROM) coal. Generally, it is correct that more waste coal must be burned to yield the same heat input as a ROM coal. Individual constituent concentrations can be higher or lower in the gob piles as compared to ROM coals. Nevertheless, regardless of whether the CFB boilers are burning waste coal, ROM coal, biomass or a blend of these proposed fuels, the draft permit requires that they meet the same BACT emissions limitations.

SELC Comments

As noted above, SELC submitted detailed comments regarding the BACT analysis. The SELC comments include some errors in the listing of total limited pollutants for the facility in the Introduction of its submittal. SELC comments at 2. These include 739 tons per year of particulate matter and 72 tons per year of mercury. The latter value for mercury should actually be 72 <u>pounds</u> per year. The value for particulate matter in the SELC comments appears to be some combination of the different size fractions of particulate matter (PM, PM-10 and PM-2.5). PM includes both PM-10 and PM2.5, and PM-10 includes PM2.5. Total expected facility emissions from the draft PSD permit are actually 340.9 tons per year of PM (filterable particulate matter), 366.0 tons per year of total PM-10 (less than or equal to 10 microns and including both filterable and condensable matter), and 359.3 tons per year of total PM-2.5 (less than or equal to 2.5 microns and including both filterable and condensable matter).

The SELC comments suggest that Dominion provided and DEQ accepted erroneous or misleading data for the BACT analysis and note that Dominion determined technology not to be feasible in an unacceptable manner for a BACT analysis for a PSD permit. SELC comments at 3-4. The DEQ considered more current and robust data sources, as applicable, rather than simply accepting only input data from Dominion in regard to the BACT analysis. This was done for a number of pollutants, particularly PM-10, SO_2

and mercury. In addition, DEQ required Dominion to evaluate the use of Selective Catalytic Reduction (SCR) for control of NO_X emissions in a "tail-end" configuration, instead of accepting Dominion's original assertion that use of SCR would not be feasible due to blinding of the catalyst with conventional placement of the SCR control system. In summary, DEQ worked with Dominion through the permitting process to properly evaluate control technologies through the BACT analysis. All control technologies eventually eliminated were on the basis of technical infeasibility, inadequate performance, environmental impacts and/or adverse economic impacts.

The SELC comments suggest that DEQ has not provided "site specific information" to concerned members of the public, necessary to complete the BACT evaluation. SELC comments at 6. The comments continue asserting that if DEQ does not have any such information deemed necessary, then it is incumbent upon the agency to either provide it for the public, or explain the absence of the same. In response, DEQ has provided all information required for public notice by both the PSD regulations and agency precedent. Copies of all submittals, correspondence and meeting notes associated with the permitting process were placed in the local public library in St. Paul, and were available in hard copy or electronic format at the DEQ regional office in Abingdon. All additional requests for information by the public have been answered and addressed.

Comments from SELC assert that the BACT analysis does not properly consider alternate fuels, coal processing, and alternate combustion technologies, including IGCC, supercritical CFB and other supercritical technologies. SELC comments at 13, 28-29 & 45-46. As discussed in responses above, VCHEC is being designed to remediate coal waste piles, utilize readily available run-of-mine coal, and use a considerable amount of biomass. The Electric Restructuring Bill encourages and provides incentives for the development of a coal-fired electric generating facility in the Virginia coalfields. Further, through this legislation the Virginia General Assembly has determined that the construction of such a facility is in the public interest. See Va. Code § 56-585.1. In this case, requiring the use of alternate fuels would redefine a fundamental aspect of the project which is designed to burn Virginia coals and waste coals consistent with incentives provided by, and the public interests established by, the Virginia General Assembly. *See In re: Prairie State Generating Company*, EAB, Order Denying Review, PSD Appeal No. 05-05 (Aug. 2006). A more detailed discussion of consideration of Powder River Basin coal is set forth later in this document.

With respect to the coal processing referred to in the comment, the BACT evaluation did consider air jigging and wet processing for cleaning coal. Air jigging was determined to be technically infeasible on the basis of the specific gravities of the materials to be separated. Wet processing has adverse environmental impacts through the generation of waste materials, and also has been determined to be cost prohibitive in terms of cost per ton of SO_2 removed/avoided. Wet processing would also require inert material such as sand to be added to the fuel mixture to replace the ash removed by cleaning, which is also necessary for proper operation of the CFB boilers. A more detailed discussion of consideration of air jigging is set forth later in this document. Additionally, the reader should reference the section below in which the use of alternative coal sources, such as Powder River Basin coal, is discussed.

The reader can refer to DEQ's response earlier in this document regarding consideration of alternative combustion technologies such as IGCC. At the time of this writing, there were no known demonstrated supercritical CFB installations in operation. Therefore, supercritical CFB technology was eliminated as an alternative for consideration. The application of supercritical PC boiler technology to the VCHEC project was considered, but determined to be inappropriate due to the intended use of locally available fuels. The DEQ cannot require or dictate to any applicant what type of source to construct. It is the role of DEQ to determine if the proposed source will meet all applicable rules and regulations. This approach is consistent with DEQ's historical interpretation of BACT and EPA guidance which makes clear that the BACT analysis is to consider the facility proposed and to not redefine the source proposed.

The SELC comments assert that the BACT analysis failed to consider emissions levels of mercury and other HAPs resulting from use of the selected control technology. SELC comments at 13. In response DEQ notes that mercury, hydrogen chloride, hydrogen fluoride and lead were considered in the BACT evaluation. Permit limits based on BACT were established in the draft PSD permit for all of these pollutants, except for lead, which has expected emissions below the PSD significance level. These BACT limits do not circumvent the case-by-case MACT limits for HAPs in the Article 7 permit currently under development.

The SELC comments assert that Dominion elevated cost above all other factors in evaluating control technology in the BACT analysis, and that cost is actually a secondary consideration, comparable to energy impacts. SELC comments at 16. In response, it should be noted that BACT is ultimately an emission limitation, which is particularly relevant in this case, as the actual suite of control technologies for control of criteria pollutant emissions from CFB boilers is well established and nearly universal. Much effort in the associated BACT evaluation is focused on determining current and appropriate limits for these technologies. Cost is a factor, however, in evaluating potential additions or changes to these established control technologies. The EPA Major NSR Workshop Manual (October 1990 draft) indicates that unless there is a concern over an overriding environmental impact or other consideration, an acceptable demonstration of an adverse economic impact can be an adequate basis for eliminating a control alternative.

The SELC comments appear to suggest that performance data for CFB boilers were not considered in the BACT analysis. SELC comments at 19-20. Performance data for CFB boilers at JEA Northside, Spurlock Unit 3 and Reliant Energy Seward were considered in depth for the BACT evaluation and development of emissions limitations for the draft PSD permit for the proposed VCHEC.

The SELC comments include a reference to 2004 CEMS data for NO_X emissions from a CFB boiler operating in Gilberton, Pennsylvania. SELC comments at 20, fn. 30. The note states that emissions are in a consistent 0.04 to 0.05 lb/mmBtu range, and cites this as support for a limit lower than the 0.07 lb/mmBtu value (30-day average) included in the VCHEC draft PSD permit. In response, DEQ refers to a technical paper by Sean Li entitled, "Operating Experience of Foster Wheeler Waste-Coal Fired CFB Boilers." This paper includes an analysis of the operating history of the 70 MW (net) Gilberton Power Company facility, which includes two Foster Wheeler CFB boilers and is fired by anthracite coal refuse. The paper includes a table listing stack test results of 43 milligrams of NO_X per megajoule, which is equivalent to 0.1 lb/mmBtu of NO_X emissions. The paper also includes data for Colver and Northampton plants, with NO_X emissions of 0.136 lb/mmBtu and 0.096 lb/mmBtu, respectively. It should also be noted that the Spurlock Unit 3 and JEA Northside CFB boilers have performance results for NO_X which are higher than VCHEC's proposed 0.07 lb/mmBtu limit.

The SELC comments appear to disagree with a statement in the permit application that CFB combustion is a technology with inherently low NO_X emissions. SELC comments at 22. This statement, however, is supported by a wide range of sources, based on the lower temperatures associated with fluidized bed combustion. These sources range from professional periodicals such as *Power Engineering* (February 2008), to multiple BACT analyses for recent PSD permits, including those for pulverized coal boilers, such as for the Longleaf Energy Station in Georgia. The SELC comments state that the 0.07 lb/mmBtu emissions rate selected as BACT, and incorporated as a draft PSD permit limit, "is far greater than what is actually the best achievable rate of NO_X emissions today." SELC comments at 23. The 0.07 lb/mmBtu limit as a 30-day rolling average, is identical to the most stringent NO_X emissions limits incorporated in recent PSD permits for CFB boilers (Spurlock Unit 4, Highwood Generating Station, and the Big Cajun I Power Plant for Louisiana Generating, LLC). It is more stringent than the 0.09 lb/mmBtu limit in the PSD permit for Great River Energy's Spiritwood Station in North Dakota, and the 0.08 lb/mmBtu limit in the PSD permit issued by EPA in August 2007 for Deseret Power Electric Cooperative's Bonanza Power Plant in Utah.

The SELC comments assert that use of SCR should not have been rejected by the BACT analysis as technically infeasible in a "high dust" configuration immediately following the exhaust from the CFB boilers. SELC comments at 23-25. The comments continue by stating that, "It matters little to [the] BACT analysis whether something has been actually put into commercial use or not." The draft October 1990 NSR Workshop Manual notes EPA guidance that it is not expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type, such as SCR in a "high dust" CFB configuration as part of the BACT analysis. As noted previously, DEQ did require Dominion to evaluate the use of SCR in a lower dust "tail-end" configuration.

The SELC comments include references to three installations outside the United States with SCR controls for NO_X emissions from CFB boilers. These include a Foster Wheeler pilot plant in Scandinavia, a facility at Norrkopings, Sweden, and the Wien-Simmering plant in Austria. Unlike the VCHEC facility, these facilities combust only wood and/or biomass. The Norrkopings facility burns only biomass and recycled wood (90%), with the balance being tire-derived fuel. The other two facilities burn only wood/biomass, producing much less ash in the boiler than a coal-fired CFB application. Additionally, the 1-MW Foster-Wheeler pilot plant does not operate on a commercial scale.

The SELC comments question the economic analysis performed by Dominion in its evaluation of the application of SCR in a location downstream of the fabric filter controls for particulate emissions from the CFB boilers. SELC comments at 26. This point of application requires reheating the flue gas to a temperature compatible with SCR operation. The comments question the use of cost data from the Greene Energy PSD application in Pennsylvania, and from Foster Wheeler. The comments go on to question an initial $2.9 million "plant cost adjustment for auxiliary power", $1.734 million in "auxiliary power costs" on an annual basis, and $22.6 million as part of the total capital cost to cover "engineering, procurement, supervision and contingencies." The Greene Energy PSD permit was issued in July 2005 for two CFB boilers rated at 2,756 mmBtu/hr each. Foster Wheeler is a boiler vendor, and provided some of the cost data associated with the Greene Energy project. Use of the Greene Energy cost data for Dominion's tail-end SCR evaluation was conservative, as it was not increased to account for inflation and rise in construction costs associated with the later time frame for the VCHEC project, or the total increase in heat input capacity from 5,512 mmBtu to 6,264 mmBtu per hour. The recurring $1.734 million is the cost of electrical fan power to redirect the flue gas through a heat exchanger and the SCR system to accomplish the reheating (described above), and the $2.9 million in capital cost is to increase the capacity of the facility to compensate for this loss of power, in order to allow for the same net output of 585 megawatts of power. The $22.6 million figure is actually for engineering, procurement, construction supervision and contingencies, plus contractor fees, startup and performance testing for the system. The SELC comments also state that the inclusion of $1.16 million for property taxes is very excessive, considering Dominion's statement that the project in its entirety will contribute $6 million in property tax revenue. The calculation of the cost of property taxes, however, is based on 1% of total capital costs per EPA's Cost Control Manual (February 1996). Also, even if the property tax value is somewhat inflated, the $1.16 million is only 2.5% of the $45,650,000 annual cost, and will not significantly alter the resulting average cost effectiveness value of $14,000 per ton.

The SELC comments also question the technical basis of the 100ºF temperature difference driving the reheating requirement, and the corresponding fuel consumption costs for the tail-end SCR configuration. SELC comments at 27. Low-temperature SCR is proposed as a method to reduce the reheating requirement. A 100ºF temperature difference is necessary for good transfer in a gas-to-gas heat exchanger, even if a low-temperature SCR catalyst is used. The flue gas would normally be at 160-170ºF, and would have to be heated to 325-450ºF for low-temperature SCR under the most favorable conditions.

The SELC comments also assert that conditions in the PSD permit for the Big Cajun I Power Plant in Louisiana include more stringent requirements for the application of SNCR for the control of NO_X emissions. SELC comments at 27. These permit conditions were evaluated by DEQ in drafting the VCHEC permit, and a current examination still shows that the NO_X limitations in both permits are very similar. Both include a 0.07 lb/mmBtu limit as a 30-day rolling average, with the VCHEC permit applying this limit at loads of 75% or more, while the Big Cajun I permit applies the limit at loads of 60% or more. The Big Cajun I permit only applies a 249.6 lb/hr limit to the 2,330 mmBtu boiler below 60% load. The VCHEC permit applies a 0.11 lb/mmBtu weighted average limit at 50% to less than 75% load, and a 0.15 lb/mmBtu weighted average limit below 50% load.

The SELC comments assert that the proposed BACT limit for SO_2 in the draft VCHEC permit is based on 97% reduction. SELC comments at 28. This appears to be based on the calculation of 97.4% removal, using the 0.15 lb/mmBtu limit on a 3-hour basis and the use of all run-of-mine (ROM) coal. This is misleading, as the removal efficiency is 98% based on use of all ROM coal, and the 0.12 lb/mmBtu limit applied on a 24-hour basis. In addition, as illustrated later in this document, the use of the dominant 0.12 lb/mmBtu limit, yields a 98.1% removal efficiency for a 60% waste coal/40% ROM coal blend, and a 98.4% removal efficiency for the use of all waste coal.

The SELC comments also assert that the BACT analysis for the proposed project rejects consideration of the use of alternative fuels, such as Powder River Basin coal, with lower sulfur content. SELC comments at 29. As discussed in responses above, VCHEC is being designed to remediate coal waste piles, utilize readily available run-of-mine coal, and use a considerable amount of biomass. The Electric Restructuring Bill encourages and provides incentives for the development of a coal-fired electric generating facility in the Virginia coalfields. Further, through this legislation the Virginia General Assembly has determined that the construction of such a facility is in the public interest. See Va. Code § 56-585.1. In this case, requiring the use of alternate fuels would redefine a fundamental aspect of the project which is designed to burn Virginia coals and waste coals consistent with incentives provided by, and the public interests established by, the Virginia General Assembly. *See In re: Prairie State Generating Company*, EAB, Order Denying Review, PSD Appeal No. 05-05 (Aug. 2006). The BACT analysis utilized worse-case values for coal fuels from Virginia. Subsequently, Dominion performed an economic analysis for the use of alternative coal fuels. The incremental cost effectiveness for the use of Powder River Basin coal was demonstrated to be prohibitive at $12,900 per ton of SO_2 reduced.

The SELC comments also state that the BACT analysis fails to consider coal cleaning for SO_2 reduction (noting that air jigging of the waste coal was given cursory consideration and rejected). SELC comments at 29-30. In response, DEQ notes that air jigging is evaluated and rejected as technically infeasible in a letter from Miltech Energy Services dated January 7, 2007, and a letter from Dominion dated August 16, 2007. This determination is made on the basis of limited differences in specific gravities of the materials to be separated. Only 7% of the materials differ by a ratio of 2.1 times the specific gravity of water, which provides a workable separation on the basis of specific gravity. It should also be noted that the Moss #3 waste coal was originally produced by a wet separation and cleaning process. This is noted in the August 2007 letter from Dominion, which includes the letter from Miltech Energy Services as an attachment. Finally, coal cleaning primarily only reduces the ash content of coal.

The SELC comments state that the BACT analysis and DEQ's Engineering Analysis do not explicitly give a level of SO_2 reduction through limestone injection in the CFB boiler itself. SELC comments at 30. The comments presume from the calculated overall control efficiency of 98% (for ROM coal only), that the engineering analysis assumes 80% reduction through the boiler. In response, the Engineering Analysis calculated overall removal efficiencies on the basis of the limit of 0.12 lb/mmBtu (24-hour basis), which was reduced by DEQ from Dominion's original proposal of 0.15 lb/mmBtu (24-hour basis), and the inlet SO_2 formation associated with the sulfur content for the proposed coal and waste coal to serve as fuel for the project. This was done in order to assure that the 0.12 lb/mmBtu limit, which applies for any fuel combination for the facility, corresponds to overall removal efficiencies in a range typical of those for BACT analyses for CFB boilers. It is this overall removal efficiency, for both the boiler with limestone injection and the dry flue gas desulfurization (FGD) system, which is the ultimate and relevant SO_2 reduction for comparison purposes. Multiple BACT analyses for CFB boilers cite overall removal efficiencies in the 97% to 98% range noted in the analysis for the Highwood Generating Station in Montana. The MDU-Westmoreland Gascoyne BACT analysis cites an overall removal efficiency of 98% with a flash dryer absorber as the dry FGD system, and 98.9% with a spray dryer absorber as the dry FGD system, with 90% for the boiler with limestone injection as a baseline. The PSD permit for the Deseret Power Electric Cooperative Bonanza Plant issued by EPA in August 2007, utilizes an overall removal efficiency of 97.7% for "average" coal (ROM coal from the Deserado mine), and 98.8% for "worse-case" coal (waste coal from the Deserado mine). Responses to comments for this permit also cite a removal efficiency of 98.3% associated with the PSD permit for the AES Puerto Rico project, also issued by one of EPA's regional offices, which has the lowest known corresponding emission limit of 0.022 lb/mmBtu. Even the range of overall SO_2 removal efficiencies (based on a 24-hour averaging period) presented by Mr. Don Shepherd in comments on this project for the National Park Service, run from 97.7 to 98.9 percent.

The SELC comments contend that Dominion's statements in the BACT analysis concerning environmental impacts of wet flue gas desulfurization and water use are without merit. SELC comments at 31. The comments do acknowledge that protecting endangered mussels in the Clinch River may be a reason for minimizing water usage, but assert that Dominion never provides this rationale, either explicitly, or in any other manner. On page 5-15 of Volume 1 of the August 2007 permit application (page 5-13 of June 2006 version), however, the text notes that minimizing water consumption is viewed as an essential component of project planning, "due to historical concerns expressed regarding the ecological impact of water withdrawal in the area." This is also the reason the project will employ air-cooled condensers, instead of a water-cooled condenser for the steam turbine to operate with both CFB boilers.

The SELC comments also assert that Dominion's BACT analysis states incorrectly that the proposed dry flue gas desulfurization (FGD) system will not use any water. To the contrary, this is not stated or implied at any point in the June 2006 or August 2007 PSD permit applications. They state that flash dryer absorbers and spray dryer absorbers, both forms of dry FGD systems, use varying amounts of water in their respective processes. A flash dryer absorber hydrates either fly ash recovered as dust in the fabric filter, or an absorbent containing lime, for injection back into the flue gas from the CFB boiler. Volume 1 of the August 2007 application states explicitly on page 5-16, that water is added to the fly ash or absorbent in a mixer prior to injection in the flue gas. More water is used with a spray dryer absorber, in order to generate a lime slurry, which is sprayed as a fine mist into the flue gas. It is stated that SO_2 emissions will be controlled by a "semi-dry flue gas desulfurization system," on page 2-5 of the August 2007 application.

The SELC comments characterize water usage for a wet FGD system as 430 gallons per minute, water usage for a dry FGD system as 341 gallons per minute, and the resulting 89 gallon per minute difference, as representative of only an incremental increase in water use between the two types of SO_2 control systems. SELC comments at 32. The BACT analysis for the Gascoyne project, however, estimates a difference between the two types of systems of 74.5 million gallons on an annual basis for a CFB boiler with a 175 MW net generating capacity. Scaling this up on the basis of the 585 MW net generating capacity of the proposed VCHEC facility, yields an annual increase of 249 million gallons of water consumption with a wet FGD system, as opposed to an annual value of 46.78 million gallons as stated in the SELC comments. Comments in response to this issue from Dominion's engineering consultant calculate the difference at 800 million gallons per year. In summary, water consumption with a wet FGD system is significantly higher than with a dry FGD system, entailing significant impact on water withdrawal for the Clinch River. The disposal of the volume of sludge produced by wet scrubbers presents another area of environmental impact. Finally, the increased moisture level in the flue gas associated with wet scrubbing is also noted as contributing to higher sulfuric acid mist (H_2SO_4) emissions, and an increase in the condensable portion of total PM-10 emissions.

The SELC comments state that vendors can guarantee 98% control efficiency for wet FGD systems and that 99% control efficiency has been demonstrated. SELC comments at 32. The comments go on to note that EPA has recognized that the current generation of wet scrubbing systems has demonstrated "above 98 percent" removal efficiencies. As noted in our responses to previous comments, the 0.12 lb/mmBtu SO_2 emissions limit, which applies under all conditions on a 24-hour basis, translates to removal efficiencies from 98% to 98.4%, depending on the type of coal or coal blend serving as fuel. This is the same order of magnitude of control cited by the SELC for wet FGD systems.

The SELC comments contend that if Dominion had at least used 95% removal efficiency in its BACT analysis for the evaluation of the cost effectiveness of wet FGD, it would have calculated an incremental cost effectiveness of $4,000 per ton of SO_2 removed, instead of $8,100 per ton. SELC comments at 33. The $8,100 per ton calculation in Dominion's evaluation is based on 90% removal efficiency. However, a 95% level of removal is not likely following the initial reduction of SO_2 by limestone injection in the boiler. The Gascoyne BACT analysis also used 90% control efficiency for a wet scrubber in calculating an incremental cost effectiveness of $19,600 per ton. The BACT analysis for the Highwood Generating Station yielded $27,365 per ton as the incremental cost effectiveness. It should be further noted that the $8,100 per ton figure from Dominion's analysis does not include a cost for water, which is a significant cost at a rate of up to 1,500 gallons per minute.

The SELC comments ascribe SO_2 removal efficiencies ranging from 99.5% to 99.9% for wet scrubbers designed and marketed by Mitsubishi Heavy Industries (MHI), based in Japan. Vendor literature supplied by the SELC for one of the Japanese wet flue gas desulfurization systems (CT-121) by Chiyoda Corporation, notes the cited 99% control efficiency as a maximum instantaneous value. Applications of the CT-121 system in the United States with higher sulfur coals have vendor guarantees on the order of 95% for SO_2 reduction. The actual desulfurization efficiency achieved by the FGD system installed by MHI at the Hirono power station was 98.3%.

The SELC comments conclude that the BACT limit for SO_2 should be lower in terms of emissions. SELC comments at 34. The comments cite 0.06 lb/mmBtu as a 30-day average, at a maximum, as the BACT emission level. In response, DEQ is satisfied that the limits in the permit represent BACT for SO_2. The proposed 0.12 lb/mmBtu limit (24-hour average) will require the proposed control systems to achieve SO_2 emissions significantly below 0.12 lb/mmBtu on the basis of a 30-day average. As discussed later in this document, a 30-day average limit will be proposed to complement the 24-hour VCHEC limit.

The SELC comments question the basis of the BACT and case-by-case MACT proposed limits, and contend that the BACT proposal is now invalidated by the case-by-case MACT proposal, which is driven by the decision by the D.C. Circuit Court of Appeals to vacate EPA's Clean Air Mercury Rule on February 8, 2008. SELC comments at 34-35. The SELC comments also assert that the BACT standard cannot be less stringent than a MACT standard developed under Section 112 of the Clean Air Act. In response, the BACT proposal was developed before the judicial decision with any potential requirement for a MACT standard, and is based on 98% co-beneficial removal of mercury by the combination of the dry FGD system and fabric filtration. The BACT limitation of 71.93 lb/yr was also developed on the basis of 0.51 ppm, as the worse-case mercury content of the coal fuels proposed for the VCHEC boilers. The case-by-case MACT and Article 7 permit development process was initiated by Dominion as a proactive response to the court decision. Both the PSD and Article 7 permits must be issued before construction can commence. Both the BACT and case-by-case MACT standards would be applicable upon initial operation of the proposed facility, and the limits would be streamlined with the more stringent MACT standard in the subsequent Title V operating permit.

The SELC comments interpret DEQ's statement that it is following EPA guidance on using PM-10 as a surrogate for PM-2.5, to mean that modeled concentrations of PM-10 must be compared to National Ambient Air Quality Standards (NAAQS) for PM-2.5, in order to assess compliance with the same. SELC comments at 36. It links this assertion, to what it states is an incomplete (or omitted) BACT analysis for PM-2.5. SELC comments at 4 & 36. Neither EPA nor Virginia interprets the applicable guidance in this manner. The DEQ Air Guidance Memorandum Number APG-307, dated October 10, 2006, has been interpreted to mean that modeled compliance with NAAQS for PM-10 is used as an interim surrogate for compliance with PM-2.5 standards. David Campbell of EPA Region III, confirmed that this is consistent with EPA policy for areas in attainment with PM-2.5 standards, in an e-mail to Mike Kiss of DEQ, dated March 26, 2008. The draft PSD permit for VCHEC uses PM-10 as a surrogate for PM-2.5 and thus includes a BACT limit for PM-2.5 which is set equal to the BACT limit for PM-10, with a provision to potentially reduce the PM-2.5 limit, based on the results of stack testing. A more in depth response to the use of PM-10 as a surrogate for PM-2.5 in the air quality analysis for the facility is discussed in the section regarding PM-2.5 Air Quality Analysis.

The SELC comments seem to suggest that a wet electrostatic precipitator, as evaluated (and rejected) for the CFB boiler for the Bonanza Power Plant for the Deseret Power Electric Cooperative, would provide superior control at 86% removal efficiency for total (filterable and condensable) particulate matter, than the fabric filter control proposed for the CFB boilers for the VCHEC facility. SELC comments at 38-39. The comments cite an overall control efficiency from another source (AES Deepwater) of 95-97% for fine particulate matter with a wet electrostatic precipitator. The comments reference a paper entitled, "The Past, Present, and Future of Wet Electrostatic Precipitators in Power Plant Applications," (Staehle and Triscori, *et al*), as a supporting basis for the combination of a wet electrostatic precipitator and fabric filter for the control of emissions of fine particulate matter. This source, however, does not endorse, nor address, such a combination. A fabric filter provides a level of control for total particulate matter at typical removal efficiencies of 99.9% and above, which is far better than removals possible with a wet electrostatic precipitator. Fabric filters constitute the particulate control systems for all CFB boilers in the United States, and wet electrostatic precipitators are not used in conjunction with CFB boilers. The BACT limit for PM-10 for

VCHEC (0.012 lb/mmBtu for total PM-10) is far more stringent than the limit for Deseret Power's Bonanza Plant (0.03 lb/mmBtu for total PM-10). In addition, the VCHEC permit has a 0.012 lb/mmBtu limit for total PM-2.5, (revision only by reduction on the basis of stack testing), while the Bonanza Plant has no limit for PM-2.5 emissions, as is the case for most current PSD permits issued for coal-fired utility boilers.

The SELC comments' discussion of BACT for PM-10 emissions are concluded with comments noting that the condensable fraction of PM-10 emissions would be inclusive of emissions of VOC, HF, HCl and sulfuric acid mist. SELC comments at 41-42. The comments add the draft permit limitations for these parameters to yield a total 0.017 lb/mmBtu limit, to which they then add the 0.010 lb/mmBtu limit for filterable PM-10, and obtain a total of "essentially 0.03 lb/mmBtu." This exercise provides the rationale for the assertion that the 0.012 lb/mmBtu limit for total PM-10 is in error, while noting provisions in the draft permit that could allow for a secondary limit for total PM-10 under certain conditions. The comments finally conclude that the primary PM-10 and PM-2.5 limits are "sham" limits, due to inadequate provision for condensable components. These comments are misleading and appear to be contradictory. The primary 0.012 lb/mmBtu limit on total PM-10 is identical to limits in the PSD permits for Spurlock Unit 4 and Greene Energy, with the latter also having a potential secondary limit to address possible problems with the magnitude of condensables. The 0.012 lb/mmBtu limit on total PM-10 emissions (includes filterable and condensable components) has been demonstrated by some of the stack testing conducted at Spurlock Unit 3 and the Reliant Energy Seward facility. A secondary total PM-10 limit for the CFB boilers for the proposed VCHEC facility would only be an issue if the boilers fail the initial stack test for total PM-10, and then fail a retest, on the basis of condensables, following optimization of equipment. Any adjustment to condensables for the total PM-10 limit would be based on <u>actual</u> condensables from stack test results under the optimized conditions, up to a maximum of 0.020 lb/mmBtu, and in turn a maximum of 0.030 lb/mmBtu for total PM-10 emissions. The flexibility for this possible adjustment is recommended, since the proportion of condensables cannot be precisely determined from empirical data alone, but must be ascertained from source testing. Also, there is no provision for a secondary limit for the 0.012 lb/mmBtu limit for total PM-2.5 emissions. This limit can only be reduced, based on the results of stack testing.

The SELC comments question the BACT analysis for hydrogen fluoride and the draft permit limits for the same. SELC comments at 42-43. The comments contend that BACT is represented by a wet electrostatic precipitator, and note that BACT proposed for Seminole Power is based on 97% removal efficiency and a 0.00023 lb/mmBtu limit for fluorides. A removal efficiency of 99% is also cited for the permit for the Kyanite Mining Company in Virginia, but the 0.00023 lb/mmBtu emissions limit proposed for Seminole Power is reiterated as representative of BACT. In addition, this section addresses a secondary limit provision included in the draft permit at a potential maximum of 0.0023 lb/mmBtu, based on 98% removal efficiency; but the SELC mistakenly attributes language cited in this regard to the DEQ Engineering Analysis, rather than Volume 1 of Dominion's August 2007 updated permit application. The

BACT limit proposed by DEQ is 0.00047 lb/mmBtu for hydrogen fluoride (HF), and is the same limit included in the Spurlock Unit 3 permit. This limit and a concurrent 99.6% removal efficiency have been demonstrated by stack testing of Spurlock 3's CFB boiler firing coal with 119.5 ppm fluorine content. Coal samples of proposed fuels for the VCHEC boilers, which have been evaluated to date, are on the order of 860 ppm for fluorine content. The proposed BACT limit of 0.00047 lb/mmBtu requires a removal efficiency of 99.6% at the 860 ppm level for fluorine content of the coal. This limit and the 99.6% removal efficiency compare favorably to the values cited above by the SELC, and to limits listed for recently issued PSD permits for CFB boilers in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. The most recent HF limit listed in the database for a CFB boiler is 0.0008 lb/mmBtu for Entergy Louisiana's Little Gypsy Generating Plant. A provision for a secondary limit at a maximum value of 0.0023 lb/mmBtu, based on testing, optimization, and retesting, is included in the VCHEC draft PSD permit. This is due to uncertainty in regard to the fluorine content of all the coal fuels to be utilized by the proposed VCHEC facility.

The SELC comments contend that the BACT analysis, and subsequent evaluation by DEQ, did not consider alternative sulfuric acid mist control technologies, and should consider BACT as the addition of a wet electrostatic precipitator to the current proposal of the dry FGD system and the baghouse. SELC comments at 44. A BACT limit of 0.0006 lb/mmBtu is asserted for this addition, based on the application of 86% removal to the current BACT limit of 0.005 lb/mmBtu for dry FGD and baghouse. This assertion, however, presumes that a removal efficiency of 86% for the wet electrostatic precipitator (90% given for AES Deepwater), which is based on much higher input levels of sulfuric acid mist, could still be accurately applied to the low levels of sulfuric acid mist remaining after the currently proposed dry FGD and baghouse controls for the VCHEC boilers. It is highly unlikely that this level of additional reduction would be possible. In fact, a combination of baghouse and wet electrostatic precipitator controls is included in Ohio's PSD permit for two pulverized coal boilers for the American Municipal Power Generating Station, dated February 7, 2008. The American Municipal Power permit applies a BACT limit of 0.0075 lb/mmBtu to emissions of sulfuric acid mist, which is 50% higher than the comparable limit in the VCHEC draft permit. (It should also be noted that the BACT limit for PM-10 emissions in the American Municipal Power permit is 0.025 lb/mmBtu, significantly higher than the comparable VCHEC draft limit.) Although, the current BACT limit of 0.005 lb/mmBtu is in the range of limits in recently issued PSD permits, DEQ is investigating the applicability of the 0.0035 lb/mmBtu limit from the PSD permit for the Deseret Power Electric Cooperative Bonanza Plant to the CFB boilers for the proposed VCHEC facility. This would be in conjunction with the possible related use of the Bonanza Plant's 98.8% removal efficiency for SO_2 emissions from the CFB boiler to derive a 30-day SO_2 emissions limit for the VCHEC boilers. A similar value is obtained by adjusting a Spurlock Unit 3 test result of 0.004 lb/mmBtu, for lower VCHEC inlet SO_2 of 5.86 lb/mmBtu (ROM).

The SELC comments take the same approach on the BACT analysis for hydrochloric acid (HCl) emissions as they did for sulfuric acid mist. SELC comments at 45. The comments again contend that BACT is represented by the addition of a wet electrostatic precipitator to the combined dry FGD and baghouse controls, which are currently proposed as BACT for the VCHEC boilers. An 86% removal efficiency for a primary wet electrostatic precipitator is again applied in a polishing role with the current BACT limit of 0.0066 lb/mmBtu, yielding a value of 0.001 lb/mmBtu, which the SELC then notes as the proper BACT limit. In response, DEQ believes that this removal efficiency is overly optimistic in a polishing role, and that any associated analysis for incremental cost effectiveness would provide a result that shows it to be cost prohibitive. The controls proposed for BACT for this pollutant are universal for recent CFB boiler permits, and the emission limit of 0.0066 lb/mmBtu is in the range of those in current PSD permits for coal-fired electrical generating units. In addition, as noted in DEQ's Engineering Analysis, higher HCl emissions associated with bituminous coal have some beneficial effect with the oxidation of mercury vapor, which enhances the removal of mercury through the dry FGD and fabric filter control systems.

The SELC comments contend that Dominion should have considered integrated gasification combined cycle (IGCC), supercritical CFB, and other supercritical combustion technologies in evaluating alternatives in their BACT analysis for lead, VOC and greenhouse gases. Lead, however, is not considered a PSD significant pollutant for this facility, as the potential emissions for the facility are less than the 0.6 ton per year PSD significance level. Lead emissions, however, are controlled by the fabric filters as a component of particulate matter emissions. Greenhouse gas emissions are not regulated New Source Review (NSR) pollutants under Federal or State regulations. Emissions data for the two operating IGCC plants in the United States (Polk and Wabash River Power Stations), indicate lower VOC emissions (0.0013 lb/mmBtu and 0.0021 lb/mmBtu, respectively) than the 0.005 lb/mmBtu limit proposed for the CFB boilers for the VCHEC project. They also have lower carbon monoxide emissions, however, both IGCC plants have significantly higher sulfuric acid mist, mercury and NO_X emissions than the limits proposed for the VCHEC boilers. Both IGCC plants also have essentially equivalent, or higher, emissions of SO_2 and PM-10. The situation is similar in a comparison to the recently issued Longleaf and Cliffside PSD permits for supercritical pulverized coal boilers. The Cliffside permit has lower limits for VOC and carbon monoxide at 0.003 lb/mmBtu and 0.12 lb/mmBtu respectively, but higher limits for PM-10 and particulate matter, mercury and SO_2 emissions. The Longleaf permit has lower limits for VOC emissions at 0.0036 lb/mmBtu and mercury emissions at 35.1 lb/yr, but higher emissions limits for particulate matter and hydrogen fluoride emissions. Finally, as noted in the responses to general comments on BACT, it is the role of DEQ to determine if the proposed source will meet all applicable rules and regulations. This approach is consistent with DEQ's historical interpretation of BACT and EPA guidance which makes clear that the BACT analysis is to consider the facility proposed. As discussed previously in this document, a requirement for the permit applicant to incorporate IGCC or supercritical combustion technologies as control technologies in the BACT analysis would constitute a redefinition of the project.

Mr. Don Shepherd with the National Park Service submitted comments dated March 12, 2008. Most of these comments have been addressed in the DEQ responses to comments from the SELC. Additionally, the Park Service comments included a number of comments regarding BACT for SO_2, NO_X and PM-10 emissions as related to proposed BACT levels for a CFB boiler at East Kentucky Power Cooperative's J.K. Smith Station and which will be addressed below. Park Service comments at 7. The Park Service comments contend that BACT for SO_2 is represented by the 0.075 lb/mmBtu emission level proposed by East Kentucky as a 24-hour average. The comments continue by noting that SO_2 emissions would be reduced by 27.5%, with the adoption of this level as a BACT emissions limit. In response, DEQ notes that this emissions level has not been demonstrated by East Kentucky, nor has it been incorporated in a final PSD permit. Nevertheless, a similar percentage reduction in annual SO_2 emissions with the VCHEC boilers may be possible with the adoption of a complementary 30-day average limit, in order to match the 98.8% removal efficiency (for waste coal only, as worst-case fuel) used to calculate the 30-day average limit for the CFB boiler to be constructed for Deseret Power Electric Cooperative's Bonanza Plant.

The National Park Service comments, also on page 7, contend that the J.K. Smith Plant represents BACT for NO_X emissions, with East Kentucky's proposal of 0.07 lb/mmBtu as a 24-hour average. This is noted as a 30% reduction in NO_X emissions limited by the current VCHEC draft PSD permit. As noted in the DEQ response to the Park Service comment in regard to SO_2 emissions, the J.K. Smith proposal has not been incorporated in a final PSD permit. The application of the 0.07 lb/mmBtu limit on a 24-hour basis, is also more stringent than any NO_X limitation that DEQ is aware of in a PSD permit issued for any CFB boiler. An examination of stack testing and CEMS data for JEA Northside and East Kentucky's Spurlock Unit 3 also does not support such a limit.

The Park Service comments also assert that adoption of the filterable PM and total PM-10 emissions levels of the J.K. Smith proposal would reduce particulate emissions by 10% in comparison to emission limits in the current VCHEC draft PSD permit. The limits on particulate matter emissions for the two proposed facilities, however, are very close. The total PM-10 limits of 0.012 lb/mmBtu (as measured by 3-hour stack test) are identical. The J.K. Smith proposal for filterable PM is 0.009 lb/mmBtu (as a 30-day average and measured by a PM CEMS), versus a 0.010 lb/mmBtu limit (as measured by 3-hour stack test) for VCHEC. Compliance with the short-term 0.010 lb/mmBtu limit for VCHEC may be an equally or more stringent requirement, as compliance with the 0.009 lb/mmBtu limit is based on a considerably longer averaging period (30 days).

The Park Service provides comments on BACT for mercury, which also impact case-by-case MACT requirements for mercury, as incorporated by DEQ in a separate draft Article 7 permit. Park Service comments at 8. The Park Service comments note the PSD permit for the Highwood Generating Station as a model for mercury BACT requirements for the proposed VCHEC facility. The Highwood PSD permit actually was used as a model for some aspects of the development of the mercury BACT requirements for the CFB boilers for the VCHEC facility. The VCHEC limit was made more stringent at 71.93 lb/yr, compared to a value of 82.3 lb/yr, if it had been developed on the 0.0000015 lb/mmBtu basis of the Highwood permit. The Park Service comments note that the Highwood permit requires the installation of activated carbon injection. This is not a direct requirement, and it is this provision of the Highwood permit that was used as a model for the draft PSD permit for the VCHEC boilers. Both the Highwood and VCHEC PSD permits require the installation of activated carbon injection systems if the CFB boilers are unable to meet the annual mercury emissions limits with their dry FGD and baghouse controls. The Park Service correctly notes that the Longleaf PSD permit requires the upfront installation and operation of an activated carbon injection system. This also is a requirement of the proposed Article 7 permit for VCHEC which includes case-by-case MACT limitations for mercury.

Comments from the National Parks Conservation Association (NPCA) were received on March 12, 2008. Most of these comments have been addressed in the DEQ responses to comments from the SELC and the National Park Service. In addition to the comments already addressed, the NPCA comments contend that IGCC or supercritical pulverized coal (SCPC) technologies must be considered by Dominion as alternatives to the proposed CFB combustion technology; and that sufficient high quality coal is available in the region to supply IGCC or SCPC generating units. NPCA comments at 13-14. The proposed Dominion facility, however, is designed for the use of 20% waste coal and up to 20% biomass by input heat capacity, with one premise for the facility being the reduction of piles of waste coal in the region. Precipitation falling on these piles of waste coal generate leachate having suspended solids, which results in them being major contributors to degradation of area streams by water pollution. Such low quality fuels in terms of heat and ash content have not been tested with IGCC processes, as EPA Region 8 notes in its response to a similar comment on the proposed CFB boiler for the Deseret Power Electric Cooperative. Page 18 of the EPA response to comments document, dated August 30, 2007, notes that contact with personnel involved with IGCC test programs indicates that IGCC technology has not been tested on coal with heat content (3,051 to 5,326 Btu/lb) comparable to the waste coal to be used with the Deseret project. This equals or exceeds the heat content of the waste coal (2,738 Btu/lb) and wood waste (4,000 Btu/lb) to be used at the Virginia City Hybrid Energy Center. The EPA response to comments document for the Deseret project also notes that the, “Department of Energy’s Power Systems Development Facility near Wilsonville, Alabama, has only utilized coal as low as 6,000 to 7,000 Btu/lb.” In addition, as noted in DEQ responses to other comments on the VCHEC draft PSD permit, it is the role of DEQ to determine if the proposed source will meet all applicable rules and regulations. This approach is consistent with DEQ’s historical interpretation of BACT and EPA guidance which makes clear that the BACT analysis is to consider the facility proposed. As discussed previously in this document, a requirement for the permit applicant to incorporate IGCC or supercritical combustion technologies as control technologies in the BACT analysis would constitute a redefinition of the project.

The NPCA comments also state that Dominion failed to include IGCC in its BACT analysis and that as a result, Dominion fails to provide a “differential analysis” between the proposed CFB and potential IGCC emissions for collateral environmental impacts (part of additional impact analyses of the Class I and Class II modeling evaluations) on soils and vegetation of the Great Smoky Mountains National Park. NPCA comments at 16-17. Both the Class I and Class II modeling evaluations demonstrated impacts for soils and vegetation below the EPA screening levels and consequently, no projected adverse impacts on the same. Therefore, no such “differential analysis” is required, as the project with the proposed BACT emission levels has been shown to pose no adverse collateral impacts for either Class I or Class II areas. In addition, as noted in DEQ responses to other comments, both of the operating IGCC plants in the United States have higher sulfuric acid mist, mercury and NO_X emissions than the limits proposed for the CFB boilers for the VCHEC project. Both also have emissions of SO_2 and PM-10 equal to or higher than the limits proposed for the CFB boilers for the VCHEC. Although the two IGCC plants have lower emissions levels for carbon monoxide and VOC, those pollutants are not significant parameters for impacts on soil and vegetation.

Sociological and economic issues

A considerable number of comments were received from individuals with opinions about both the positive and negative attributes of having a facility, such as the VCHEC, in the community and region. Positive factors were predominately related to more and better-paying jobs for residents, increased direct tax revenue for local governments and collateral economic stimulus from the new businesses and expanded businesses in the area. The company estimates that an economic investment of $1.8 billion will be required to construct the facility and bring it into service by 2012. During construction of the facility, more than 1,200 jobs will be created in a variety of the construction and service industries. The annual payroll of the facility, when in normal operation, is estimated to be $4 million and local tax revenues are expected to be close to $6 million per year. The permanent jobs at the facility are anticipated to cover a range of professional and skilled categories, including engineers, technicians, tradesmen, business staff, and operations personnel. In addition to the direct benefit the facility will provide in creating short-term and long-term jobs and in providing important tax revenue, the secondary effect the facility will have in stimulating and indirectly creating support service businesses and industries is anticipated to be significant.

There were comments received which expressed concerns about the possibility for detrimental impact on tourism and eco-tourism, negative impact on property values, desire for “clean jobs” for Wise County, burden on an already inadequate health care system, and impact on public infrastructure, such as the highway system. With current and future road and highway modifications that are taking place in the area, it is believed there should be sufficient transportation infrastructure in place to handle any increased traffic load that may result from the construction and operation of the plant.

As discussed elsewhere in this document, operation of this facility is not anticipated to have an adverse impact on visibility or scenic vistas. Visibility modeling for Virginia indicates the trend is for improving visibility conditions over the next decades. Additionally, modeling has demonstrated there is no direct or significant impact from the facility with regard to health and welfare-based air quality standards. Therefore no ascertainable adverse impact on tourism is expected as it relates to outdoor activities conducted in southwest Virginia, attendance at events or attractions in the region, or travel and eco-related commerce.

As part of providing a complete permit application, the company obtained from the local governing authority (Wise County Board of Supervisors) a Local Governing Body Certification Form. In the form, the governing body certified that the facility, as proposed, would be in compliance with all known ordinances, which is understood to include zoning and land use. In addition to the discussion above and elsewhere in this document concerning sociological and economic issues, the facility's impact on area economics, property values, public infrastructure, and culture and society would have been considered, as applicable, by the local government officials at the time certification was granted.

Mercury/HAPs/Toxics

Mercury Emissions From Power Plants

Many commenters voiced concerns about emissions of mercury from the proposed facility into the environment and the various impacts produced. Some comments were specific to air, water and waste issues, health effects from exposure, and the ultimate fate of mercury in the environment. Below is a brief overview regarding mercury emissions, followed by a discussion addressing more specific comments.

Mercury is a naturally occurring element that is found in virtually all soils, rocks, bodies of water, and also in the atmosphere. Mercury exists in many chemical forms, but it is found predominately in elemental or mineral forms. Mercury is likewise present in trace amounts in fossil fuels.

Mercury may be emitted into the air from various sources, both from natural and human activities. Currently, there is significant uncertainty regarding the inventory of mercury emissions from natural sources. Most emissions of mercury are thought to result from natural sources (including "re-emission" of mercury discussed below) such as oceans and other waters, soils, forest fires, and volcanic activity. However, many human activities result in mercury emissions into the environment. One particular area of current public concern is the power generation industry. According to EPA, roughly 40% of U.S. mercury emissions (not including those from natural sources) in 1999 came from coal-fired power plants, totaling 48 tons. EPA estimates that this figure accounts for about 1% of global mercury emissions.

Mercury emissions into the atmosphere are primarily in the form of elemental mercury vapor, and may remain entrained in the air for many months and travel thousands of miles. Some of the mercury is bound to small particles and is deposited by gravity and weather, settling back to the ground surface, where it may eventually be carried into streams. Once in streams, most mercury becomes attached to organic matter and is retained in the sediments or suspended in the water. A small amount of the mercury that remains in the water column (typically less than 10%) may be converted through the activity of microorganisms to methylmercury, a toxic compound. Also, some mercury compounds volatilize and leave the water to enter the atmosphere. The methylmercury remaining in the water becomes available to plants and animals in their food chain, and can bioaccumulate in fish tissue where it may be transferred to humans via fish consumption.

Coal, coal refuse, and biomass fuels contain trace amounts of metal constituents, including mercury. Upon combustion in a boiler, most of the mercury is volatilized to elemental mercury vapor and transferred to the flue gas to be directed through control devices. Some of the mercury combines with chlorine in the fuel to form a salt, which may be more easily removed. Many factors combine to affect the chemical state of mercury, the effectiveness of control systems, and the resultant potential emission rates. Some of these factors are fuel-specific and site-specific.

Because some mercury vapor may condense and become bound to particulate matter in the flue gas, removal of particulate matter has the co-benefit of also removing some mercury. Mercury's chemical affinity for carbon and the chlorine contained in the coal also serves to form mercury precipitates that can be collected as particulate matter. Dominion proposes to install and operate a dry flue gas desulfurization system and a fabric filter that in combination may provide as much as 98% mercury removal. Other trace metals may also be removed by these devices. Such high levels of removal have been documented by previous measurements of other CFB units. Collected material and ash will be disposed in a regulated solid waste landfill or sold as aggregate for use in other manufacturing processes.

One commenter asked about how much mercury is considered legally allowable. In the case of the proposed plant, emissions of mercury were scrutinized in a number of ways. First, mercury was regarded as a pollutant subject to best available control technology (BACT) review as part of the PSD permit application. This evaluation resulted in establishing a mercury emissions limitation in the draft permit. As is discussed elsewhere, the facility also is subject to the permitting requirements for a case-by-case maximum achievable control technology (MACT) determination with respect to mercury emissions. This permit is in a draft stage and is undergoing public review at the time of this writing. In addition, as discussed elsewhere in this document, the company evaluated mercury and many other pollutants under Virginia's toxic air pollutant requirements. Future federal or state requirements also may apply to mercury emissions from the facility. All of these requirements determine allowable amounts of mercury.

A number of commenters stated that the proposed facility does not employ dedicated mercury control devices. As stated above, removal of particulate matter, acid gases, and sulfur dioxide emissions, through the operation of a dry flue gas desulfurization system and a fabric filter, also serves in removing mercury emissions from the flue gases as a co-benefit. In addition, according to the draft PSD permit, if the company cannot demonstrate sufficient removal of mercury from the flue gas emissions utilizing the above-mentioned control systems, activated carbon injection also will be required to further reduce mercury emissions. At the time of this writing, the draft Article 7 (MACT) permit contains a requirement for the source to apply activated carbon injection to the facility to further reduce mercury emissions. Activated carbon injection is viewed as a promising control method, although system design and effectiveness varies from system to system.

<u>Mercury and Metals in Coal, Coal Refuse, and Ash</u>
Emissions of many toxic air pollutants as products of combustion are related to the amounts of toxic compounds (such as mercury and metals) contained in the fuels originally. The following comments and discussion relate to this issue.

Some commenters raised concerns about mercury, lead, and other metals being liberated from ash, causing contamination of streams in the region. Based on information available such as that through the Powell River Project, a research effort conducted in cooperation with Virginia Tech to examine effects and practices of the coal mining industry in the coalfields of southwest Virginia, coal combustion products (ash) can release quantities of metals through leaching. Testing of ash samples produced from combustion of southwest Virginia coals, however, showed that the metals are typically released in amounts much lower than allowable limits based on testing using the standard Toxicity Characteristic Leachate Procedure. In particular, mercury levels were below the detection limitations of the test, and were therefore considered to have minor impacts. Comparison studies of CFB ash and coal refuse from facilities in Pennsylvania indicate that the ash has lower capacity to release metals than coal refuse, and levels of metals in leachates from ash are similar to levels of the same metals in leachates from soils. Other data indicates that lead is leached at low levels in normal (alkaline) conditions. Ash will be disposed of according to state requirements in an approved solid waste landfill site. The ash from the VCHEC must meet testing/monitoring criteria to demonstrate that it does not contain leachable quantities of metals that render it dangerous and that it is not otherwise hazardous. Handling, transportation, storage and disposal of such material will also be regulated by other authorities within DEQ, and the Virginia Department of Mines, Minerals, and Energy, as well as federal authorities.

Several commenters expressed concern about the levels of mercury in bituminous coal and bituminous coal refuse, and some argued that cleaning the coal would reduce mercury emissions. The mercury content of coal varies from seam to seam and is present in rock and soil surrounding the coal. Dominion proposes to utilize run-of-mine (uncleaned) bituminous coal, biomass, and coal refuse that has been discharged from the coal cleaning plants in the area. According to coal data included in the permit application, the mercury content of the seams of coal as mined ranges from 0.20 ppm to 0.51 ppm of mercury. The coal refuse analysis provided shows a mercury content near the high end of this range, indicating that the content of mercury in the refuse is similar to that of the corresponding coal. The draft PSD permit contains a mercury emission limitation that was derived from the worst-case coal being burned exclusively by the CFB units.

Coal preparation, as discussed previously in this document, removes much of the non-combustible material from coal, and therefore removes that quantity of metal constituents contained in the non-combustible portion. Coal preparation, however, was not proposed or considered as a control measure for mercury emissions, because the BACT analysis concluded that mercury emissions would be adequately controlled through the use of add-on control systems. Such coal processing requires more transportation, handling, and energy inputs, and produces a significant quantity of coal refuse that potentially has additional environmental impacts.

A commenter expressed concern over radionuclide contamination in coal ash. Both thorium and uranium are found naturally in trace quantities in coal. However, most soils and rocks contain approximately twice the radioactivity that coal exhibits. Emissions of radionuclides were not estimated in this analysis due to the minute quantities potentially emitted. According to EPA, risks associated with radionuclide emissions from coal-fired power plants are much lower than the risk of exposure to natural background levels. Radionuclides are hazardous air pollutants (HAPs) identified by EPA, but no standards have been developed for such emissions from coal-fired power plants. Radionuclides are not toxic air pollutants regulated by DEQ.

Many commenters objected to coal mining practices, particularly to the practice referred to as mountain top removal. Some expressed concern about exposure to mercury and metals resulting from the mining processes. One commenter asked if the company had conducted an analysis on mountain top removal as it relates to removing natural buffers to mercury exposure. The company was not asked to provide this type of analysis as part of the air permitting process. The draft PSD permit evaluation does not contain or require this type of analysis because the applicable air quality permitting regulations and authority do not address mining practices used to provide fuel for the proposed plant. The draft permit pertains only to activities occurring at the proposed plant site. The draft permit contains provisions for limiting fugitive dust and particulate matter process emissions resulting from on-site activities, including coal and limestone transfer, storage, handling, crushing, and screening operations. Matters pertaining to coal mining techniques and practices are regulated by various other state and federal authorities.

<u>CFB Combustion</u>
Circulating fluidized bed combustion differs from traditional pulverized coal furnaces in many aspects of its operation. The PSD permit application and the draft engineering

evaluation contain a discussion of this combustion technology. The following comments and discussion relate to this issue.

One commenter voiced concern about the injection of limestone into the CFB units contributing to emissions of toxic hydrocarbons. The injection of limestone is proposed to aid in removal of sulfur dioxide and other acid gases from the flue gases, and it may also help to reduce mercury and other pollutant emissions. Limestone injection may add to the particulate load of the flue gas, which is readily recovered by the particulate control devices. None of the data reviewed by DEQ, however, suggests limestone injection actually increases hydrocarbon emissions. As part of the PSD permit application, the company was required to estimate emissions of organic pollutants known to be produced by coal combustion and establish whether these emissions would comply with Virginia's requirements for toxic air pollutants found in 9 VAC 5-60-300. The analysis showed that all pollutants evaluated, including metals and certain volatile organic compounds, would comply with toxic air pollutant standards.

Another commenter stated that because CFB units operate at lower temperatures than traditional pulverized coal furnaces, more hydrocarbon emissions result. The lower combustion temperatures, however, are still high enough at approximately 1,600°F to destruct most organic compounds, and the CFB design reportedly provides for more residence time in the combustion zone than traditional furnace designs. Also, lower temperatures in the flue gas may promote condensation and collection of mercury and other toxic air pollutants to a greater degree. CFB units therefore have some positive design characteristics that traditional furnaces do not have.

A commenter expressed concern that the ash resulting from the combustion of coal refuse is more toxic than the ash from typical coal combustion. Another commenter asked if limestone injection would make ash less leachable. Based on publicly available information from other states that have regulated CFB units burning coal refuse, this is not usually the case. Coal and coal refuse burned in CFB units typically produces more ash than traditional coal furnaces. In addition, a limestone sorbent is injected along with the fuel, contributing to the quantity of collected ash. Because of the high levels of ash produced, metals in the ash reportedly do not concentrate markedly, and because the ash is alkaline in nature, the metals tend to remain in the ash particulate when subjected to leaching conditions. The metals content of the ash is also dependent upon that of the corresponding fuel. Also, the quality of the ash is affected by addition of other sorbent materials and treatments employed for controlling air pollutants (i.e. flue gas desulfurization, activated carbon injection, etc). Therefore, the quality of the ash varies from site to site.

Metallic and organic pollutant emissions resulting from combustion were quantified and evaluated by the company. The evaluation was included in the PSD permit application. Approximately 45 toxic air pollutants were examined under Virginia's toxic air pollutant regulations, and compliance was predicted for each pollutant.

The company has applied for a permit to locate a solid waste landfill for ash produced from the proposed plant. If approved by state and federal authorities, the landfill would include a liner to prevent leachates from escaping the site, a leachate collection and treatment system, and groundwater monitoring wells to ensure that local streams and water supplies are not adversely impacted. Any ash not meeting state and federal requirements, or that is otherwise deemed hazardous, will have to be disposed offsite at an approved facility.

Some commenters stated that mercury emissions from IGCC units are controlled to a greater degree. Because coal undergoes a rigorously constrained and controlled gasification process in IGCC as opposed to traditional modes of coal combustion, lower amounts of trace minerals and metals are emitted. The IGCC design has several advantages and disadvantages. As discussed elsewhere in this document, however, the mercury emission limits in the draft PSD permit (when compared in pounds of mercury per million Btu) for the VCHEC boilers are considerably lower than the corresponding emission limits for the two IGCC facilities currently operating in the United States.

Deposition Impacts

Because the proposed facility will not discharge polluted effluents to streams, potential transmission of mercury and other metals to water bodies will be limited to other modes, such as deposition from the air.

Several commenters expressed concern over the potential environmental impacts due to local and long-range deposition of mercury from the proposed facility. According to current information available from EPA, most mercury emissions from coal combustion are not deposited locally because the predominant elemental form of mercury is not readily water soluble and so it is not "washed" out of the air due to precipitation or the effect of moisture. Rather, it is deposited over large areas over longer periods of time primarily through dry deposition. However, the divalent vapor form of mercury is water soluble, and a small percentage may be deposited locally as it would be affected by moisture. The emissions of mercury from the facility are predicted to be very small, and when dispersed over the local area, rates of deposition are expected to be similar to background deposition rates. Long-range deposition rates may vary depending upon a multitude of meteorological and other factors. The process of such deposition is considered a slow one, and the mercury vapor tends to remain aloft for potentially long periods of time entering the global mercury cycle. This is an area of study that has not been well developed at this point.

Many commenters expressed concern about the effect mercury deposition or leachate will have on local waters and aquatic life, and they cited concerns about impaired waterways in Virginia. The nearest major stream to the proposed plant is the Clinch River. There are currently no fish consumption advisories for the Clinch River. There are no current fish consumption advisories in the area that pertain to mercury or other metals potentially emitted from the proposed plant. The waters in the area of the plant are monitored by DEQ, and are currently meeting Virginia Department of Health guidelines for mercury and other metals. Given that the potential mercury emissions from the proposed plant are of a small quantity, and that very small amounts would be expected to be deposited locally and/or transported into waterways, and even smaller amounts would ultimately convert to methylmercury, the mercury emissions from the proposed plant are not expected to adversely impact these waters.

In a study prepared by Dominion for the DEQ Water Permit Division, the company estimated mercury deposition impacts using emissions modeling results obtained as part of the PSD permit analysis. Additional discussion of this study is provided elsewhere in this document. The results showed that predicted mercury deposition rates combined with the mercury levels measured in water samples, were orders of magnitude lower than the Virginia Water Quality Standard for mercury, and produce concentrations having low potential impact to fish and mussels. DEQ personnel reviewed the company study and found that the study results provide evidentiary support that local deposition from the proposed facility will not adversely impact aquatic life in area streams (see Attachments 35 and 36).

DEQ personnel also reviewed a second study presented by the Chesapeake Bay Foundation designed to estimate mercury deposition impacts on various Virginia watersheds. The results of this study also provided evidence that the projected impact of mercury emissions from the proposed plant on Virginia waters is quite small (see Attachments 35 and 37).

Some streams in the area are, however, under fish consumption advisories for polychlorinated biphenyl compounds (PCBs), although deposition from the air is not the suspected source. PCBs are not pollutants that have been associated with the proposed facility.

Several commenters identified other streams in Virginia that currently have fish consumption advisories because of mercury. Only one such stream, the North Fork Holston River (between Saltville and the Virginia/Tennessee state line), is in the general region of the proposed plant, and for reasons already discussed is not expected to be significantly impacted by deposition from the proposed facility. The mercury advisory for the North Fork Holston River was established in 1974, and was the result of industrial discharges.

Commenters asked about the threat of mercury from the proposed plant to animal and plant life, including macro invertebrates, mussels, fish and raptors. Mercury is known to accumulate in the bodies of animals as they consume other animals containing mercury. This presents potential dangers to many animals, such as raptors, and also to humans. That is why stream and fish monitoring is considered the most effectual means of measuring mercury impacts upon humans and animals alike. Since there will be no direct discharges of effluents from the proposed facility to area waters, any stream impacts will be limited to deposition from the air. Current mercury levels in area streams are below regulatory thresholds. As discussed above, mercury deposition is expected to produce minor effects due to the small quantities of emissions, the degree of dispersion, and the complex interactions between mercury and the environment.

Although mercury poses a greater danger to animal life, according to EPA information, mercury may also be transferred to plants from the air, as well as through uptake from the soil. However, this normally occurs at minor rates and the mercury concentration in plants is usually very small, posing low threats to animals and humans alike. Therefore, mercury impacts to the environment are measured more efficiently through monitoring fish and the water column. The impact of trace metals on plant and animal life was evaluated as part of the PSD permit application. The evaluation showed that the predicted concentrations of trace metals in the soil and in plant life are below screening thresholds. This analysis is discussed in another section of this document related to Class II Area Air Quality Impacts - Specific Locations.

A commenter asked if DEQ has conducted a risk analysis to determine impacts to biological communities taking into account emissions from the proposed power plant and the nearby existing power plant. DEQ has not conducted a risk analysis for toxic air pollutants as part of the engineering evaluation for the proposed facility. The company submitted as part of the PSD permit application a modeling analysis for Class I and Class II areas, which accounted for criteria pollutant emissions from the existing power plant. Also, as mentioned above, the company provided an analysis of potential impacts of trace metal emissions on soil, plants, and animal life. However, a risk analysis is not an element of the PSD permit analysis. The company did conduct a deposition study as part of an application for a DEQ Water Division permit, as discussed elsewhere in this document.

One commenter asked that the local area be tested for mercury exposure. If the commenter is referring to human exposure trials, DEQ does not have the ability or expertise to conduct such studies. This would fall under the authority of the Virginia Department of Health. The DEQ identifies excess mercury in the environment by monitoring stream quality for selected stream bodies. Based on current information for the area, no mercury threat is known for streams in the local area, as stated elsewhere in this document.

Specific concerns were raised by commenters about the impact of mercury deposition on the Great Smoky Mountain National Park. The commenters stated that mercury deposition is already excessive in the park. The PSD permit application contains a Class I area evaluation of ambient air impacts to the nearest national park sites, including the Great Smoky Mountain National Park. The modeling analysis indicates that all ambient air impacts to this site meet EPA and Federal Land Managers' requirements. No concerns about mercury deposition were identified by federal authorities. As stated earlier, deposition of small amounts of mercury from the proposed facility are not expected to adversely impact any Class I area.

The National Atmospheric Deposition Program, a research cooperative between state and federal agencies, private organizations, academic institutions, and tribal governments, collects mercury deposition data as part of the Mercury Deposition Network. The network includes an ambient monitoring site in the Great Smoky Mountain National Park. Wet-deposition samples are collected weekly and analyzed in a laboratory to determine mercury content. If this program is continued, deposition data will be monitored and made available. The station has collected data since 2002. Both mercury deposition and concentration data is gathered and is electronically available from the Mercury Deposition Network website found here http://nadp.sws.uiuc.edu/mdn. No historic trends have been established based on the data.

Commenters asked if mercury re-emissions were evaluated in the PSD analysis. Re-emission of mercury can occur when mercury from natural and man-made sources is deposited onto the ground or waters, and then later undergoes chemical change only to be volatilized back into the atmosphere. Mercury re-emissions were not specifically evaluated as a part of this review. DEQ is unaware of appropriate estimation tools to make such determinations. Known sources of re-emission include both natural sources and man-made activities, and the mechanism by which mercury may be re-emitted is not well understood. The mercury emission estimates made by DEQ are based on the worst-case mercury content of the combusted fuels. This is the primary source of mercury impacts from the facility. The company will be required to take precautions in order to limit fugitive particulate matter emissions from material transfer, storage and handling activities, including wet suppression. The trace amounts of mercury in soil or fuel material that may be re-emitted as a consequence of material handling is considered so small as not to be quantifiable.

Several commenters stated that the local area is already identified as a "hot spot" with respect to mercury, and that additional mercury from the proposed plant would only exacerbate an existing problem. As indicated elsewhere in this document, the local streams are not currently identified as impaired by mercury or metals contamination. Based on the latest stream monitoring data available, the Clinch River is currently meeting water quality standards for mercury and metals. One stream in the region, the North Fork of the Holston River, is currently impaired by mercury contaminants believed to have been released decades ago from a single industrial source. Deposition from utilities is not a suspected source of mercury contamination in this instance. EPA defines a "utility hot spot" as a water body with excessive methylmercury contamination solely attributable to emissions from utilities. By that criterion, no utility hot spots for mercury have been identified in the region. Based on the low levels of mercury potentially emitted from the facility, and the low deposition rates anticipated, no adverse impacts to the region are predicted.

Clean Air Mercury Rule

A federal regulation called the Clean Air Mercury Rule (CAMR) was developed specifically to address mercury emissions from electric generating units. Several recent developments have occurred with respect to this rule.

Several commenters referenced the recent decision by a federal court to vacate federal mercury standards. Some commenters believed such action requires reconsideration of mercury emission limits for the proposed facility.

Section 112 of the Clean Air Act Amendments of 1990 requires EPA to develop a list of source categories for which standards for hazardous air pollutant (HAP) emissions must be developed. The EPA is required to develop these technology-based standards through maximum achievable control technology (MACT) determinations. If EPA fails to develop a standard for a source category, states are required to either make case-by-case MACT determinations through Section 112(g) for proposed new sources or make a determination through Section 112(j) in the case of existing sources.

On March 29, 2005, EPA published a determination to remove coal and oil-fired electric utility steam generating units from the list of source categories requiring MACT determinations. In lieu of the MACT determination, EPA established mercury emissions requirements under Section 111 of the Clean Air Act on May 18, 2005, referred to as the Clean Air Mercury Rule (CAMR).

On February 8, 2008, the U.S. Circuit Court of Appeals for the D.C. Circuit, ruled that EPA had inappropriately removed coal and oil-fired electric utility steam generating units from the list of source categories. The Court vacated the CAMR, effectively requiring that such sources be "re-listed" for development of MACT standards. In the absence of a federal MACT standard, states are required to develop case-by-case MACT requirements.

Dominion applied for a case-by-case MACT determination for the VCHEC from DEQ by seeking a permit under 9 VAC 5-80, Article 7. The DEQ drafted an Article 7 permit which, at the time of this response, was undergoing a public review process. This draft Article 7 permit establishes total annual mercury emissions limits for the CFB units at less than 50 pounds per year based on MACT. Once finalized, the Article 7 permit would contain mercury emission limits that would supplant the mercury emission limitation in this PSD permit.

On March 14, 2008, the U.S. Court of Appeals for the D.C. Circuit issued the mandate for the vacatur of the CAMR ensuring the need for the preconstruction permit under 9 VAC 5-80, Article 7, which is currently in the public review process.

Commenters stated that the mercury limit in the PSD permit must reflect any emission limit established by a case-by-case MACT determination. The commenters believe the best available control technology (BACT) limit for mercury cannot be less stringent than the MACT standard, and therefore the PSD permit should be amended to reflect the draft mercury emission limit developed in the Article 7 permit. In response, DEQ regards the Article 7 permit process a distinct but parallel process, which will produce a mercury emission limit that may supplant the limitation established by the PSD permit.

Once emission limits are established in the Article 7 permit, the PSD permit may be amended to harmonize with the more stringent limitation.

<u>Health Effects of Mercury</u>
The potential health effects from high levels of mercury exposure are well established and much studied by health professionals.

Many commenters identified health issues in the literature that have been related to excessive mercury exposure, including prenatal effects, childhood developmental effects, autism, impaired motor function, and many other conditions, including death. These commenters expressed alarm about exposure to additional sources of mercury. Some commenters cited statistics regarding segments of the population being exposed to mercury. One commenter presented information indicating that the facility will have little impact on the level of mercury to which the population or the environment is exposed.

Mercury exposure in all its forms, in excessive amounts, has many potential physiological effects. As mentioned previously, mercury and other metals have the unfortunate ability to accumulate in the bodies of animals and humans, impacting many areas of health, and these metals are not easily removed. Therefore, acute and chronic exposure to mercury is of concern.

In July 2005, the Centers for Disease Control and Prevention issued their *Third National Report on Human Exposure to Environmental Chemicals* on evaluating the U.S. population's exposure to 148 environmental chemicals. The report is based on a survey of thousands of Americans constituting a statistical representation of the U.S. population, including adults and children. The report concludes that mercury levels in the blood of all participants in the survey were below threshold levels that are associated with known health effects. Also, the study showed that 5.7% of women who were of childbearing age exhibited mercury levels in the blood that were within one-tenth of the health effects threshold. These results indicate that current levels of mercury exposure in the national population are below thresholds that are regarded as unsafe.

As part of their permit application, Dominion provided emissions estimates of federal hazardous air pollutants (HAPs) known to result from coal combustion, including approximately 45 toxic air pollutants regulated under Virginia requirements (9 VAC 5, Chapter 60, Article 5). The pollutants evaluated included mercury, lead, arsenic, nickel, and dozens of other organic and inorganic compounds. The Virginia toxic air pollutant regulation establishes a health-based ambient air standard for each pollutant, and is intended to protect the health of the most susceptible person on both a short-term and longer-term basis.

The company provided results of the modeling analysis predicting maximum concentrations of pollutants to which an individual might be exposed. When the predicted concentrations were compared to the individual pollutant standards, compliance was shown in each case. The modeling analysis indicated compliance when compared to the 1-hour and the annual standards for each pollutant.

One commenter stated that the company failed to conduct a health-based risk assessment analysis for toxic air pollutant emissions from the facility in order to estimate health costs to the community as part of the BACT analysis. The commenter states that the Virginia toxic air pollutant requirements do not comprehensively address all modes of exposure, other than inhalation. A toxic air pollutant risk assessment is not required by PSD regulations. The BACT analysis is discussed elsewhere in this document and a health-based risk assessment is not an element of that BACT analysis. Also, Virginia standards for toxic air pollutants are established to guard primarily against acute and chronic inhalation threats. There are other standards for other modes of exposure to toxic materials that are enforced by other state and federal authorities.

Several commenters made statements regarding mortality figures, both nationally and in Virginia, that the commenters stated are directly attributable to coal-fired power plants. These figures can be traced to documents referencing statistical methodologies employed to estimate risks from exposure to fine particulate matter rather than mercury. Such information is useful to policymakers and those authorities who establish and review ambient air standards and regulations, aiding them in revising standards and regulations. However, DEQ implements previously established air regulations and standards through the air permitting processes.

General air quality issues

Many of the comments received pertained to the anticipated human health and environmental impacts of the combustion emissions from the proposed electric generating facility. Specific areas of concern included potential pollutant effects on the elderly and young populations, as well as those with pulmonary and/or respiratory ailments. Questions were also raised regarding the impacts of the expected pollutants on sensitive natural environments and waterways.

The Clean Air Act requires the U.S. Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves.

The EPA has set NAAQS for six principal pollutants, which are referred to as "criteria" pollutants. The criteria pollutants are: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM-10 and PM-2.5), and sulfur dioxide (SO_2).

The proposed VCHEC will be a major source of air pollution and therefore must obtain a PSD permit prior to construction. As part of the PSD permitting process, Dominion conducted dispersion modeling of the maximum expected criteria pollutant emissions from the proposed facility. These maximum expected emissions rates were based on combustion of the worse-case (most polluting) fuel feedstocks that the plant will be allowed to utilize. The results of these models predict that the criteria pollutant emissions from the proposed plant will not cause or contribute to any ambient air concentrations that exceed any NAAQS at any location at any time. These locations include Class I areas, national parks, and both populated and unpopulated areas. Other sections of this response document provide a more detailed response to dispersion modeling and air quality analysis-related comments.

<u>GOB</u>
Several comments were provided that questioned the use of waste coal ("gob") piles as a fuel source. Waste coal piles typically contain more non-combustible materials than raw coal, and have correspondingly lower Btu contents. Leachate from gob piles can have considerable adverse environmental impacts on local watersheds. Utilization of gob as a fuel source for CFB boilers may be an environmentally preferable means of managing gob piles and thereby mitigating potential adverse impacts from runoff into surface waters.

The air dispersion modeling conducted by Dominion predicts that the pollutant emissions from the combustion of clean coal, raw coal, waste coal, and/or wood at the VCHEC, will not cause or significantly contribute to any ambient air concentrations of those pollutants that exceed any NAAQS at any location at any time.

<u>Environmental Justice</u>
Some of the public comments received involved environmental justice issues. Assertions were made that the rural southwest Virginia plant site was specifically selected due to its limited economic and educational resources and would therefore be less able to stand up to Dominion than would a more urban area of Virginia.

Generally, the site selection for a proposed facility is made through agreements between the proposed business, the landowner, and the local governing body. The DEQ does not promote any potential plant sites, but rather evaluates the proposed site in order to assure that the proposed facility at the proposed location does not cause a violation of any ambient air quality standards.

Environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies. Meaningful involvement means that: (1) people have an opportunity to participate in decisions about activities that may affect their environment and/or health; (2) the public's contribution can influence the regulatory agency's decision; (3) the public's concerns will be considered in the decision making process; and (4) the decision makers seek out and facilitate the involvement of those potentially affected.

2000 U.S. Census Data
Data from the 2000 U.S. Census will be used to evaluate potential environmental justice issues associated with the proposed VCHEC. The borders of Wise, Russell, Scott, and Dickenson Counties are all within roughly five miles of the proposed plant site and thus census data for these counties will be compared to that of the Commonwealth of Virginia as a whole.

Southwest Virginia Counties	**Wise County**		**Russell Co.**		**Scott County**		**Dickenson**		**Virginia**	
	Number	%	Number	%	Number	%	Number	%	Number	%
General Characteristics										
Total Population	40,123		30,308		23,403		16,395		7,078,515	
Male	19,543	48.7	15,353	50.7	11,297	48.3	8,017	48.9	3,471,895	49.0
Female	20,580	51.3	14,955	49.3	12,106	51.7	8,378	51.1	3,606,620	51.0
Median Age (years)	37.8		38.7		41.4		39.7		36	
Under 5 years	2,313	5.8	1,626	5.4	1,203	5.1	875	5.3	461,982	6.5
18 years and over	30,889	77	23,887	78.8	18,573	79.4	12,776	77.9	5,340,253	75.4
65 years and over	5,588	13.9	4,041	13.3	4,160	17.8	2,373	14.5	792,333	11.2
One Race	39,878	99.4	30,188	99.6	23,282	99.5	16,322	99.6	6,935,446	98.0
White	38,870	96.9	29,118	96.1	23,055	98.5	16,224	99.0	5,120,110	72.3
Black or African American	713	1.8	934	3.1	139	0.6	58	0.4	1,390,293	19.6
American Indian or Alaskan Native	64	0.2	34	0.1	32	0.1	19	0.1	21,172	0.3
Asian	121	0.3	15	0	17	0.1	12	0.1	261,025	3.7
Native Hawaiian and Other Pacific Islander	4	0	1	0	4	0	0	0	3,946	0.1
Some other race	106	0.3	86	0.3	35	0.1	9	0.1	138,900	2.0
Two or more races	245	0.6	120	0.4	121	0.5	73	0.4	143,069	2
Hispanic or Latino (of any race)	292	0.7	237	0.8	99	0.4	70	0.4	329,540	4.7

Southwest Virginia Counties	**Wise County**		**Russell Co.**		**Scott County**		**Dickenson**		**Virginia**	
	Number	%	Number	%	Number	%	Number	%	Number	%
Household population	39,012	97.2	28,818	95.1	23,060	98.5	16,258	99.2	6,847,117	96.7
Group quarters population	1,111	2.8	1,490	4.9	343	1.5	137	0.8	231,398	3.3
Average household size	2.44		2.44		2.35		2.42		3	
Average family size	2.91		2.87		2.82		2.88		3	
Total housing units	17,792		13,191		11,355		7,684		2,904,192	
Occupied housing units	16,013	90	11,789	89.4	9,795	86.3	6,732	87.6	2,699,173	92.9
Owner-occupied	12,057	75.3	9,557	81.1	7,657	78.2	5,525	82.1	1,837,939	68.1
Rental-occupied	3,956	24.7	2,232	18.9	2,138	21.8	1,207	17.9	861,234	31.9
Vacant housing units	1,779	10	1,402	10.6	1,560	13.7	952	12.4	205,019	7.1
Social Characteristics										
Population 25 yrs and over	26,731		21,362		16,846		11,308		4,666,574	
High school graduate or higher	16,711	62.5	13,357	62.5	10,846	64.4	6,665	58.9	3,801,964	81.5
Bachelor's degree or higher	2,898	10.8	2,000	9.4	1,404	8.3	753	6.7	1,374,988	29.5
Civilian veterans (civilian population 18 years and over)	3,595	11.6	2,413	10.1	2,387	12.9	1,334	10.4	786,359	15.1
Disability status (population 5 yrs and over)	10,765	28.7	8,620	31.5	6,413	29.1	5,364	34.9	1,155,083	18.1
Foreign born	183	0.5	112	0.4	71	0.3	31	0.2	570,279	8.1
Male, Now married, except separated (population = 15 yrs)	9,756	61.8	8,619	67.5	6,141	66.4	4,020	61.4	1,584,272	58.2
Female, Now married, except separated (population = 15 yrs)	9,566	56.6	7,574	61.2	6,013	59.1	3,998	57.5	1,547,987	53.4
Speak a language other than English at home (population = 5 yrs)	781	2.1	505	1.8	266	1.2	234	1.5	735,191	11.1

Southwest Virginia Counties	Wise County		Russell Co.		Scott County		Dickenson		Virginia	
	Number	%	Number	%	Number	%	Number	%	Number	%
Economic Characteristics										
In labor force (population 16 years and over)	16,063	50	11,695	47.2	9,827	51.5	5,535	41.7	3,694,663	66.8
Mean travel time to work in minutes (workers 16 years and over)	23.6		31.2		30.6		35.8		27	
Median household income in 1999 (dollars)	26,149		26,834		27,339		23,431		46,677	
Median family income in 1999 (dollars)	32,898		31,491		33,163		27,986		54,169	
Per capita income in 1999 (dollars)	14,271		14,863		15,073		12,822		23,975	
Families below poverty level	1,877	16.1	1,152	13.0	923	13.0	832	16.9	129,890	7
Individuals below poverty level	7,827	20	4,727	16.3	3,882	16.8	3,460	21.3	656,641	9.6
Housing Characteristics										
Single-family owner-occupied homes	7,744		5,677		4,263		2,909		1,510,798	
Median value (dollars)	65,700		69,800		69,100		55,900		125,400	
Median of selected monthly owner costs With a mortgage (dollars)	703		624		659		605		1,144	
Not mortgaged (dollars)	195		186		179		189		263	

Minorities
The minority (non-white) populations in each of the four Southwest Virginia counties accounted for less than 4% of the total population. The 2000 U.S. Census reports that the statewide average minority population was approximately 27.7%.

Economics
The 2000 U.S. Census data indicates that the percentages of families living below the poverty level in each of the four Southwest Virginia counties ranged from 13% to 16.9%, while the state average was 7%. Median household incomes ranged from $23,431 to $27,339 in the four counties, while the state average was $46,677. The proposed power plant is expected to have a positive impact on the local economy through the creation of new jobs and tax revenues for Wise County.

The 2000 U.S. Census data reports that the median home value in the four Southwest Virginia counties ranged from $55,900 to $69,800, while the state average was $125,400. Monthly home ownership costs in the each of four counties were roughly half those of the state average.

Education
The 2000 U.S. Census data reports that the number of individuals aged 25 years and older with high school educations in each of the four SW Virginia counties ranged from 58.9% to 64.4%, while the state average was 81.5%. College graduates ranged from 6.7% to 10.8% in the four counties while the state average was 29.5%.

The air quality modeling performed for this project demonstrates that this facility will not cause or significantly contribute to any exceedance of the national ambient air quality standards. The proposed location of the facility is not expected to cause an adverse economic impact on the area. An assessment of the economic impact of this facility is contained elsewhere in this document. The Virginia General Assembly has determined that the construction of a coal-fired power plant in southwest Virginia is in the public interest. *See* Va. Code § 56-585.1.

Proposed Changes

A number of changes are proposed to the draft permit as a result of comments received during the public comment period, as a result of input from the State Air Pollution Control Board, or as a result of court action and regulatory changes. All of the proposed changes result in requirements that are equally or more stringent than the requirements in the original draft permit. Therefore, additional public notice and public comment are not necessary. The proposed changes to the draft permit are outlined below:

<u>Continuous Emission Monitoring System (CEMS) for particulate matter</u>
The original draft permit gave the source the option of utilizing a COMS or PM CEMS. In response to input from the State Air Pollution Control Board and a commitment on the part of the company, Condition 45 of the permit has been changed to make it a requirement that a particulate CEMS be used at this facility. The permit condition also will indicate the monitor is for filterable particulate matter and achieves the level of technological advancement commensurate with the current state of technology in the industry.

<u>Addition of a 30-day limitation for filterable PM</u>
Because a PM CEMS will be utilized, a 30-day average limit for filterable PM of 0.009 lb/mmBtu is recommended for the permit. This limit is comparable to a limit in the permit for East Kentucky Power Cooperative's Spurlock #4.

Permit conditions and regulatory citations regarding NSPS Da (40 CFR 60, Subpart Da)

As discussed above, coincidental with the vacatur of the Clean Air Mercury Rule was the elimination of the regulatory requirements pertaining to mercury that were originally codified in 40 CFR Part 60, Subpart Da (NSPS Da). Regulatory citations appearing in conditions in the draft permit that reference federal regulations and the section of Virginia Administrative Code where NSPS subparts were incorporated by reference, have been removed. Because the regulatory authority for such citations has been vacated, inclusion of the regulatory citations in the permit is no longer appropriate. All such citations have been removed from the permit and commensurate changes have been made to permit condition wording.

Regulatory citations regarding NSPS IIII

Virginia has not accepted delegation of authority for NSPS IIII for internal combustion engines. All regulatory citations appearing under conditions have been removed. Commensurate changes have been made to permit condition wording. The requirements of NSPS subpart IIII remain valid, federal conditions, with which the source must comply. Since Virginia has no authority for the subpart, it is appropriate that citations be removed.

Addition of 1.5 % fuel sulfur content limit

A reduction in allowable fuel sulfur content, measured on an annual basis, will be incorporated in the permit. The current limit of 2.28 weight percent, as fired (determined weekly), will remain in the permit and the additional limit of 1.5 weight percent on an annual basis will be added. Appropriate changes to permit conditions will be made where the limitation occurs and where monitoring and recordkeeping requirements appear.

Addition of a 30-day limitation for SO_2 emissions

A 0.09 lb/mmBtu limit for SO_2 on a rolling 30-day average will be added as a complement to the existing 0.12 lb/mmBtu limit on a 24-hr average and 0.15 lb/mmBtu on a 3-hr average. A revised annual limit (2,469.3 tons) will be based on this 30-day average limit. The basis for the 30-day limit is derived in part from EPA's PSD permit dated August 30, 2007, for the Deseret Power Electric Cooperative.

The proposed Deseret Power facility is designed to burn mined coal and waste coal, with the waste coal being its primary fuel. Waste coal also is its "worst-case fuel" as determined by 4.73 lb/mmBtu of uncontrolled SO_2 emission potential. This is less than the comparable value of 7.30 lb/mmBtu for VCHEC with waste coal. Controlled SO_2 emissions for Deseret Power are calculated for mined coal on a monthly basis with a 97.7% sulfur dioxide removal efficiency. As can be seen with comparisons to the VCHEC calculations (see below), this is less than the 98.0% removal efficiency used for VCHEC and run-of-mine coal on a 24-hour basis. The Deseret Power permit, however, uses a removal efficiency for SO_2 for waste coal of 98.8% as its worse-case fuel on a monthly basis. This exceeds the 98.4% removal efficiency calculated below for the VCHEC firing waste coal only. Developing an equivalent 30-day SO_2 emissions limit for VCHEC on the basis of the 98.8% removal efficiency can be performed in the following manner:

[(100 – 98.8)/(100 – 98.4)] (0.12 lb/mmBtu) = 0.09 lb/mmBtu

This limit will be in proportion to the ratio between 30-day and 24-hour SO_2 limits for other permits, such as the Highwood Generation Station, and the 98.8% removal efficiency for VCHEC is one of the highest values reported in BACT analyses for a dry scrubber.

- Illustration of calculation of SO_2 control efficiencies for VCHEC:

The BACT limit for the CFB boilers of 0.12 lb/mmBtu for SO_2 (24-hour basis), is the result of deliberations and negotiations between DEQ and Dominion, following the original proposal of 0.15 lb/mmBtu in the June 2006 application. The 0.12 lb/mmBtu limit corresponds to expected emissions of 751.68 lb/hr of SO_2 at the combined maximum input heat capacity of 6,264 mmBtu for the two CFB boilers.

Run-of-mine (ROM) coal to be used as fuel for the facility is rated at 7,782 Btu/lb for heating value, and contains a maximum of 2.28% sulfur by weight. The waste coal to serve as fuel has a heating value of 2,738 Btu/lb, and contains a maximum of 1.0% sulfur by weight. The firing rate of ROM coal is 804,934 lb/hr, at the maximum input heat capacity of 6,264 mmBtu/hr for both CFB boilers. This is derived by dividing the 6,264 mmBtu/hr value by 7,782 Btu/lb, as the heating value of ROM coal. Waste coal is expected to be burned as a unit load of 60% waste coal and 40% ROM coal.

The molecular weight of SO_2 is 64, based on atomic mass of 32 for sulfur and 16 for oxygen.

Removal/control efficiency for SO_2 with combustion of ROM coal only:
Hourly input of sulfur at maximum load = (804,934 lb/hr)(2.28/100) = 18,352.5 lb/hr
Hourly formation of SO_2 = (18,352.5 lb/hr)(64/32) = 36,705 lb/hr

$$\text{Removal efficiency} = \frac{36{,}705 \text{ lb/hr} - 751.68 \text{ lb/hr}}{36{,}705 \text{ lb/hr}} = 0.9795 \ (\times 100) = 98\%$$

Removal/control efficiency for SO_2 with combustion of waste coal only:
Hourly input of waste coal at max. load = (6,264)(10^6 Btu)/(2,738 Btu/lb) = 2,287,801 lb
Hourly input of sulfur at max. load = (2,287,801 lb/hr)(1/100) = 22,878 lb/hr
Hourly formation of SO_2 = (22,878 lb/hr)(64/32) = 45,756 lb/hr

$$\text{Removal efficiency} = \frac{45{,}756 \text{ lb/hr} - 751.68 \text{ lb/hr}}{45{,}756 \text{ lb/hr}} = 0.9836 \ (\text{x } 100) = 98.4\%$$

Removal/control efficiency for SO_2 with combustion of 60% waste/40% ROM coal:
Heat content of waste/ROM coal = (0.6)(2,738/lb) + (0.4)(7,782 Btu/lb) = 4,755.6 Btu/lb
Hourly input of waste/ROM coal = (6,264)(10^6 Btu)/(4.755.6 Btu/lb) = 1,317,184 lb
Hourly input of waste coal = (0.6)(1,317,184 lb) = 790,310 lb
Hourly input of ROM coal = (0.4)(1,317,184 lb) = 526,874 lb
Hourly input of sulfur = (790,310 lb)(0.01) + (526,874 lb)(0.0228) = 19,915.8 lb
Hourly formation of SO_2 = (19,915.8 lb)(64/32) = 39,831.7 lb

$$\text{Removal efficiency} = \frac{39{,}831.7 \text{ lb/hr} - 751.68 \text{ lb/hr}}{39{,}831.7 \text{ lb/hr}} = 0.9811 \ (\text{x } 100) = 98.1\%$$

Adjustment of annual SO_2 limit
With the incorporation of a 30-day SO_2 limit discussed above will be a commensurate reduction in the annual emission limit. The calculation of the resultant annual limit is illustrated below.

(0.09 lb/mmBtu x 6,264 mmBtu/hr x 8760 hr/yr) / 2000 lb/t = 2469.3 t/yr

Adjustment to FLM mitigation
The sulfur dioxide emission mitigation plan previously negotiated with the Forest Service FLM, will be adjusted to account for the lower sulfur dioxide emission limit adjustment discussed above. The original plan was for a 50% mitigation of the originally proposed limit. Permit conditions will be changed to reflect a 50% reduction of the new tonnage limitation (2469.3).

Adjustment of sulfuric acid mist emission limitations
A new limit for sulfuric acid mist will be established in the VCHEC permit that is commensurate with the limit of 0.0035 lb/mmBtu from the Deseret PSD permit. The new, lower limit would replace the 0.005 lb/mmBtu limit in the current VCHEC draft PSD permit. This reduction is directly resultant from and in conjunction with SO_2 reductions from the 0.15 lb/mmBtu SO_2 limit on a 24-hr average and the 0.005 lb/mmBtu limit for sulfuric acid mist as a 3-hr average in Dominion's original June 2006 BACT analysis.

With the adjustment of the short-term sulfuric acid mist limit discussed above will be a commensurate reduction in the annual emission limit. The calculation of the resultant annual limit is illustrated below.

(0.0035 lb/mmBtu x 6,264 mmBtu/hr x 8760 hr/yr) / 2000 lb/t = 96.03 t/yr

Permit revision to require submittal of monitoring protocol

Based on DEQ review of the draft permit, it has been determined that Condition 70 of the draft permit should be revised to add clarifying wording indicating that a formal monitoring protocol is required.

Mercury BACT/MACT

The permit limit for mercury, based on a Best Available Control Technology analysis, was demonstrated to be in compliance with the Significant Ambient Air Concentration (SAAC) guidelines in Virginia's State Toxics Rule, 9 VAC 5-60, Article 5, of Virginia's air pollution control regulations. These standards are designed to be protective of human health and the environment. The mercury limit in the draft permit also was demonstrated to be compliant with the mercury standard for electric steam generating units contained in 40 CFR Part 60, Subpart Da that was applicable at the time the permit was drafted. As discussed below and later in this document, the mercury standard set forth in 40 CFR Part 60, Subpart Da no longer applies as a result of the vacatur of the Clean Air Mercury Rule (CAMR). See the section in this document regarding proposed permit changes for further information about NSPS Da (40 CFR Part 60, Subpart Da) regulatory citations that appeared in the draft permit

A MACT mercury limit will be established in a separate Article 7 (112(g)) permit. For the PSD permit, it is recommended the current mercury and other HAP and toxic pollutant limits be retained as drafted. The regulatory authority citations appearing under the draft permit conditions pertaining to these pollutants will be amended to reflect general authority, instead of BACT or other specific regulatory authority. A clarifying statement will be added to Condition 29 of the permit to acknowledge the anticipated existence of more stringent emission limitations and the primacy of those lower limitations over higher limitations appearing in the PSD permit.

Recommendation

Considerable interest in this project has been noted from individuals and groups in the public, governmental, business, environmental and industrial sectors. Review of volumes of technical and regulatory documents, along with thousands of pages of public comment materials, has required over two years of analysis and study. Thorough and exhaustive analysis of the permit application and its supporting information, as well as careful and deliberate consideration of the numerous and varied public comments received has led DEQ staff to recommend approval of the permit, with the changes discussed above. Technical staff has concluded that the facility, when operated within permit limits, will comply with all applicable air quality regulatory requirements.

Supporting Reference Documents	
PM-2.5 Air Quality Analysis	
Attachment 1	Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM-2.5), Final Rule, 73 Fed. Reg. 28321 (May 16, 2008).
Attachment 2	Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM-2.5) - Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentrations (SMCs), Proposed Rule, 72 Fed. Reg. 54112 (Sept. 21, 2007).
Attachment 3	“Interim Implementation of New Source Review for PM-2.5,” APG-307, (October 10, 2006).
Attachment 4	PM-2.5 Assessment for the Virginia Hybrid Energy Center, March 19, 2008.
Meteorological Data	
Attachment 5	McNally, D, Annual Application of MM5 for Calendar Year 2001, Topical report to EPA, March 2003. (36-kilometer horizontal grid resolution)
Attachment 6	McNally, D, Annual Application of MM5 for Calendar Year 2001 at a 12km Resolution, Topical report to EPA, December 2004.
Attachment 7	MM5 2002 Modeling in Support of VISTAS (Visibility Improvement - State and Tribal Association of the Southeast), Task 3f Deliverable, Don Olerud and Aaron Sims, Baron Advanced Meteorological Systems, LLC, North Carolina State University Marine Earth and Atmospheric Sciences, Raleigh, North Carolina, August 4, 2004. (Additional MPE information is also available at http://www.baronams.com/projects/VISTAS/)
Attachment 8	Meteorological Modeling Performance Summary for Application to PM2.5/Haze/Ozone Modeling Projects (Kirk Baker - LADCO, Matthew Johnson - Iowa DNR, Steven King - Illinois EPA, Wusheng Ji - Wisconsin DNR), February 18, 2005, Lake Michigan Air Directors Consortium, Midwest Regional Planning Organization.
Attachments 9, 10	Evaluation of MM5 Meteorological Fields Prepared for Use in CALMET, TRC Environmental Corporation on behalf of Dominion Virginia Power.

Supporting Reference Documents	
Air Quality Model	
Attachment 11	Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Final Rule, Fed. Reg. 68218 (Nov. 9, 2005).
Attachment 12	"Use of CALPUFF for Near-Field Class II Air Quality Modeling of Proposed Coal-Fired Power Plant in Southwest Virginia"
Attachments 13, 14	"Evaluation of the CALPUFF Dispersion Model with Two Power Plant Data Sets," David G. Strimaitus, Joseph S. Scire, and Joseph C. Chang, Earth Tech, Inc., 10th Joint Conference on the Applications of Air Pollution Meteorology, January 11-16, 1998, Phoenix, AZ.
Attachment 15	EPA Approval Letter to Allow the Use of the CALPUFF Model in the Air Quality Analysis for the Virginia City Hybrid Energy Center, December 6, 2007, Donald S. Welsh, EPA Region III Administrator to James Sydnor, DEQ Air Division Director.
Attachment 16	"New Developments in the CALPUFF Modeling System," Joseph Scire, David Strimaitus, Christopher DesAutels and Milena Borissova, 11th Annual Energy & Environmental Conference (EUEC), Tuscon, AZ, January 28, 2008.
NAAQS and PSD Increment Analyses	
Attachment 17	EPA Region IV Memorandum, James T. Wilburn, Chief - Air Management Branch, Air and Waste Management Division to Mr. W. Fin Johnson - Chief, Air Quality Section, Division of Environmental Management, North Carolina Department of Natural Resources & Community Development, June 12, 1984.
Attachment 18	Prevention of Significant Deterioration and Nonattainment New Source Review, Proposed Rule, 61 Fed. Reg. 38250, 38292 (Jul. 23, 1996).
Attachments 19, 20	Cumulative PSD Increment Analysis with Revised Inventory, March 19, 2008.
NAAQS and PSD Increment Emissions Inventory	
Attachment 21	December 12, 2006 e-mail from Haidar Alrawi of the Tennessee Air Pollution Control Division.
Attachment 22	Eastman Chemical Company emission control project announcement.
Attachment 23	Prevention of Significant Deterioration New Source Review: Refinement of Increment Modeling Procedures; Proposed Rule, 31372 (June 6, 2007).

Supporting Reference Documents	
Attachment 24	December 14, 2007 Letter from Marisue Hilliard, Forest Supervisor, to Rob Feagins, DEQ SWRO Air Permits Manager.
Attachment 25	EPA, Draft New Source Review Workshop Manual, October 1990.
Visibility Modeling	
Attachment 26	Federal Land Managers' Activities and Issues, by John Notar, NPS, presentation to the EPA State Modeler's Workshop on May 16, 2007.
Attachment 27	"Comments on the PSD Class I Visibility Impacts of the Proposed Gascoyne 500 Generating Station," submitted on behalf of the Lignite Energy Council by ENSR Corporation, February 29, 2008.
Attachment 28	"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," Electric Power Research Institute (EPRI) Technical Update Report 1014773, March 2007.
Air Quality Related Values (AQRV) and Class I Area Analysis	
Attachment 29	January 22, 2008 Letter from Marisue Hilliard, Forest Supervisor, to Rob Feagins, DEQ SWRO Air Permits Manager.
Air Quality Planning and Regional Modeling for Visibility, Ozone & PM-2.5	
Attachment 30	Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze (EPA-454/B-07-002, April 2007).
Terrain Downwash	
Attachment 31	Response by TRC to Comments by Ron Petersen and Jeff Reifschneider of CPP on Terrain Downwash, dated February 14, 2008.
National Ambient Air Quality Standards (NAAQS)	
Attachments 32, 33, 34	"Modifications to Process for Review National Ambient Air Quality Standards", Marcus Peacock, Deputy Administrator, EPA to Dr. George Gray, Assistant Administrator, Office of Research and Development and William L. Wehrum, Acting Assistant Administrator, Office of Air and Radiation, April 17, 2007.
Risk Assessment for Mercury and Other Hazardous Air Pollutants	
Attachment 35	"Technical Review of Mercury Studies Conducted by Dominion Virginia Power and the Chesapeake Bay Foundation in Response to the PSD and MACT Permits for the Proposed Virginia City Hybrid Energy Center", Virginia Department of Environmental Quality, June 9, 2008.

Supporting Reference Documents	
Attachment 36	“Mercury Modeling in the Clinch River”, ENSR on behalf of Dominion, February 13, 2008.
Attachment 37	“Virginia City Power Plant Modeling: Mercury Deposition in the Commonwealth of Virginia and Impacts to Impaired Waters”, Chesapeake Bay Foundation, May 16, 2008.
Attachment 38	“Mortality Reductions from Use of Low-Cost Coal-Fueled Power: An Analytical Framework”, Daniel Klein and Ralph Keeney.
Class II Area Air Quality Impacts - Specific Locations	
Attachment 39	A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA-450/2-81-078, December 12, 1980).