ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 96, and 97

[FRL–7203–3]

Response to Court Remand on NO_X SIP Call and Section 126 Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Response to court remand of rules.

SUMMARY: In today's document, EPA is responding to two court decisions directing EPA to reconsider heat input growth rates projected and used in setting nitrogen oxides (NO_X) emission budgets in two rules designed to reduce interstate transport of ozone and NO_X, an ozone precursor. After reviewing the heat input growth rates and considering the court decisions and additional comments, EPA has decided to continue to use the heat input growth rates developed in the rules. One rule, the NO_X State Implementation Plan Call (NO_X SIP Call) under Section 110 of the Clean Air Act (CAA), set ozone season NO_X emission budgets based, in part, on emissions reductions calculated for large, fossil fuel-fired electric generating units (EGUs) in 22 States and the District of Columbia. The second rule, issued in response to petitions by northeastern States under Section 126 of the CAA (Section 126 Rule), included ozone season NO_X emission budgets for EGUs in 12 States and the District of Columbia. The U.S. Court of Appeals for the District of Columbia Circuit (the Court) remanded the heat input growth rates to EPA to either properly justify the growth rates currently used by EPA or to develop and justify new growth rates. After reviewing the matter, EPA believes that the methodology used in developing the heat input growth rates and the resulting growth rates are reasonable based on the information available at the time the rules were issued, confirmed by new information concerning activity to date.

ADDRESSES: Documents relevant to this action are available for inspection at the Docket Office, located at 401 M Street, SW., Waterside Mall, Room M–1500, Washington, DC 20460, between 8:00 a.m. and 5:30 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions, and questions on technical issues concerning today's notice should be addressed to Kevin Culligan, Office of Atmospheric Programs, Clean Air Markets Division, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW. (6204N), Washington, DC 20460, telephone (202) 564–9172, e-mail at *culligan.kevin@epa.gov.* Questions on legal issues concerning today's notice should be addressed to Howard J. Hoffman, Office of General Counsel, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW. (2344A), Washington, DC 20460, telephone (202) 564–5582, e-mail at *hoffman.howard@epa.gov* or Dwight C. Alpern, Clean Air Markets Division, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW. (6204N), Washington, DC 20460, telephone (202) 564–9151, e-mail at *alpern.dwight@epa.gov.*

SUPPLEMENTARY INFORMATION: In today's notice, EPA is responding to two rulings by the Court directing EPA to reconsider growth rates for heat input (i.e., fossil fuel use) for the ozone season (May 1–September 30) projected and used in setting State NO_X emission budgets in two rules designed to reduce interstate transport of ozone and NO_X.[1] On May 15, 2001, the Court issued a decision in *Appalachian Power* v. *U.S. EPA,* 249 F.3d 1032 (D.C. Cir. 2001) concerning the Section 126 Rule (''Section 126 Decision''). As part of that decision, the Court remanded the heat input growth rates that EPA used to calculate NO_X emission budgets set in response to several petitions by northeastern States under Section 126 of the CAA. The Court remanded these growth rates to EPA to either properly justify the growth rates currently used by EPA or to develop and justify new growth rates. On June 8, 2001, the Court issued a similar decision in *Appalachian Power* v. *U.S. EPA,* 251 F.3d 1026 (D.C. Cir. 2001) concerning heat input growth rates used to develop NO_X emission budgets used in the NO_X SIP Call related to interstate transport of ozone (''Technical Amendments Decision''). The Court raised concerns about EPA's explanation of the methodology for developing projected heat input growth rates and about States for which heat input for EGUs had already exceeded the heat input that EPA projected for 2007.

In response to the Court's decisions, EPA has reviewed the heat input growth rates for EGUs and the methodology used to develop those growth rates. Based on that review, EPA believes that the heat input growth rates and the methodology used to develop them were reasonable. Furthermore, in response to the Court's and commenters' concerns, EPA has also reviewed new information concerning current activity. This notice explains why EPA thinks that the growth rates were reasonable based on the information that EPA had available at the time of the original rulemakings, as confirmed by new information.

[1] Unless otherwise stated, all references in this notice to actual or projected ''heat input'' or ''heat input growth rates'' concern heat input during the ozone season for EGUs.

Availability of Related Information

The official record for the Section 126 rulemaking has been established under docket number A–97–43. The official record for the NO_X SIP Call rulemaking has been established under docket number A–96–56. The public version of both records, including printed, paper versions of electronic comments, which does not include any information claimed as confidential business information, is available for inspection from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays. The rulemaking record is located at the U.S. Environmental Protection Agency, 401 M Street, SW, Waterside Mall, Room M–1500, Washington, DC 20460. In addition, the **Federal Register** rulemakings and associated documents are located at *http://www.epa.gov/ttn/rto/,* and certain documents are located at *http://www.epa.gov/airmarkets/fednox/126noda2/index.html.*

Outline

I. Background

A. NO_X SIP Call

In October 1998, EPA issued the NO_X SIP Call—a final rule under Section 110(k)(5) of the CAA, 42 U.S.C. 7410(k)(5)—requiring 22 States and the District of Columbia (''upwind States'') to revise their SIPs to impose additional controls on NO_X emissions.[2] *See* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 FR 57,356 (Oct. 27, 1998). EPA concluded that emissions from the upwind States ''contribute significantly'' to ozone nonattainment in downwind States, in violation of section 110(a)(2)(D)(i). Under the NO_X SIP Call, upwind States are required to reduce emissions by amounts that would allow meeting NO_X emission budgets. EPA determined these budgets by projecting NO_X emissions to 2007 for all source categories and then reducing those amounts by the emissions reductions achievable using the controls that EPA determined to be highly cost effective. EPA defined highly cost-effective controls as those controls capable of removing NO_X at an average cost of $2,000 or less per ton. For EGUs, EPA determined that it was highly cost effective to achieve an average emission rate of 0.15 lb/mmBtu, based on projected 2007 fossil fuel use (i.e., heat input). Projected 2007 heat input for each State was calculated by applying ozone season heat input growth rates developed by EPA for each State for EGUs (referred to as ''State heat input growth rates'') to baseline (the higher of 1995 or 1996) EGU heat input.

EPA recommended that a State could meet the State's NO_X emission budget in part by establishing a cap-and-trade program for NO_X emissions from EGUs. Covered sources would be required to hold NO_X allowances at least equal to their NO_X emissions and could either obtain additional allowances or reduce emissions, e.g., by installing additional controls. The total number of allowances distributed to EGUs would equal the EGU portion of the NO_X emission budget, i.e., the projected 2007 heat input multiplied by a NO_X emission rate of 0.15 lb/mmBtu. States had the option of adopting approaches other than a cap-and-trade program to meet the budgets.

B. Section 126 Rule

On January 18, 2000, EPA issued a final rule to control emissions of NO_X under Section 126 of the CAA, 42 U.S.C. 7426. In the rule, EPA made final its findings that stationary sources of NO_X emissions in 12 upwind States and the District of Columbia contribute significantly to ozone nonattainment in northeastern States.[3] This finding triggered direct Federal regulation of stationary sources of NO_X in the upwind States. The Section 126 Rule further established a cap-and-trade program for NO_X emissions within each upwind jurisdiction, including NO_X emissions from EGUs. This program was essentially the same as that suggested by EPA for State implementation in the NO_X SIP Call. EPA determined the total number of NO_X allowances to be distributed to EGUs in each individual State based on the same methodology used in the NO_X SIP Call (i.e., projected 2007 heat input multiplied by a NO_X emission rate of 0.15 lb/mmBtu).

C. Technical Amendments

When EPA promulgated the NO_X SIP Call on October 27, 1998, EPA reopened public comment on the accuracy of data upon which the emission inventories and budgets were based (63 FR 57,427). On December 24, 1998, EPA extended the comment period ''for emission inventory revisions to 2007 baseline sub-inventory information used to establish each State's budget in the NO_X SIP Call'' and further explained that it was seeking comment on the relevant data and assumptions so the Agency could correct errors and update information used to compute the 2007 budgets. (Correction and Clarification to the Finding of Significant Contribution and Rulemaking for Purposes of Reducing Regional Transport of Ozone, 63 FR 71,220, Dec. 24, 1998). EPA also announced that it would reopen the comment period on equivalent inventory data for the section 126 rulemaking because the rules relied upon the same inventories. *Id.*

Subsequently, EPA published two Technical Amendments revising the NO_X SIP Call emission budgets. In the first Technical Amendment, EPA made some modifications to source-specific 1995 and 1996 emissions data, which resulted in changes in the 2007 NO_X emission budgets (Technical Amendment to the Finding of Significant Contribution and Rulemaking for Certain States for Purposes of Reducing Regional Transport of Ozone, 64 FR 26,298, May 14, 1999). In the second Technical Amendment, EPA made more corrections based upon additional public comments it received and EPA's own internal review of the accuracy of its data and calculations (Technical Amendment to the Finding of Significant Contribution and Rulemaking for Certain States for Purposes of Reducing Regional Transport of Ozone, 65 FR 11,222, Mar. 2, 2000). EPA also explained that the March 2000 Technical Amendment was ''necessary to make the NO_X SIP Call inventory consistent with the inventory adopted'' by the EPA in the Section 126 rule, as the two rules were to be based upon the same inventory. *Id.*

II. Court Decisions

A. Section 126 Decision

On May 15, 2001, the Court ruled on a number of challenges to EPA's Section 126 Rule. *See Appalachian Power* v. *EPA,* 249 F.3d 1032. While the Court's decision largely upheld the Section 126 Rule, the Court remanded two issues to EPA. The Court remanded the Section 126 Rule to EPA to allow EPA to (1)

[2] The States were: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

[3] The States were: Delaware, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

Properly justify either the current or new State heat input growth rates for EGUs used in calculating projected State heat input for 2007 and (2) either properly justify or alter its categorization of cogenerators that sell electricity to the electricity grid as EGUs. With regard to heat input growth rates, the Court was concerned that EPA may have used inconsistent growth rates in different parts of the Agency's analysis and that some States already had heat input exceeding the levels projected by EPA for 2007. EPA is responding to the remand related to the categorization of cogenerators in a separate rulemaking (Interstate Ozone Transport: Response to Court Decisions in NO_X SIP Call, NO_X SIP Call Technical Amendments, and Section 126 Rules, 67 FR 8396, Feb. 22, 2002).

B. Technical Amendments Decision

On June 8, 2001, the Court ruled on a number of challenges to EPA's Technical Amendments. *See Appalachian Power* v. *EPA,* 251 F.3d 1026. In its decision, the Court remanded to EPA the same issues as in the Section 126 Decision concerning (1) State heat input growth rates for EGUs and (2) cogenerators. The Court cited its decision in the Section 126 Decision. *Id.,* 251 F.3d at 1034.

III. Notices of Data Availability

A Notice of Data Availability (NODA) of documents that EPA was considering in response to the remand concerning heat input growth rates was published on August 3, 2001, 66 FR 40609). These documents were placed in the NO_X SIP Call and section 126 Rule dockets. The new documents contain, among other things, information and data on more recent electricity sales and generation. The information and data were not available when the two rules were promulgated. Table 1 of the NODA contains actual heat input values for the 1995–2000 ozone seasons for the District of Columbia and 21 States, which are subject to the NO_X SIP Call and include the States subject to the Section 126 Rule. Comments on the new information and data were requested. Thirty-four comments were received.

The NODA explains that there are substantial fluctuations in State heat input for EGUs on a year-by-year basis. Some of the reasons mentioned for these fluctuations are forced outages, variations in energy costs, weather, and economic conditions. A discussion of the growth rate methodology used by EPA to develop State heat input growth rates for EGUs and of the rationale for different components of the methodology is included in the NODA. EPA states in the NODA that the Agency's preliminary view is that the new data and the existing record in the NO_X SIP Call and Section 126 rulemakings appear to confirm the reasonableness of the heat input growth rates used by EPA in developing NO_X emission budgets for EGUs.

A second NODA was published on March 11, 2002, 67 FR 10844. Documents referenced in this NODA include, among other things, 2001 ozone season heat input data and 1960–2000 annual heat input data and 1970–1998 ozone season heat input data for the District of Columbia and 21 States, which are subject to the NO_X SIP Call. One comment was received on this notice. In the March 11, 2002 NODA, EPA stated that it might place additional documents in the docket, with notice thereof provided on a particular website. EPA did so at various times after March 11, 2002. EPA also stated that if the Agency decided to confirm its previously adopted heat input growth rates, it intended to issue its response to the remand by March 29, 2002.

EPA received a comment on the March 11, 2002 NODA stating that there was no reason to expect that EPA would take additional comments into consideration since the Agency would be issuing its response by March 29, 2002. The commenter also asserted that both NODA's failed to explain the relevance of the documents that were added to the docket.

On March 29, 2002, EPA informed the commenter in writing that the Agency's response to the remand would be issued on or about April 17, 2002 and that the Agency would consider comments submitted sufficiently in advance. In addition, EPA noted that additional documents would be placed in the docket. EPA also identified the purposes for which the data referenced in the March 11, 2002 NODA had been added to the docket. (Docket # A–96–54, Item # XV–E–2.) Copies of all these documents and information were placed in the docket. EPA subsequently received a second comment that was similar to the first comment, and EPA referred the commenter to the relevant documents and information in the docket. Finally, EPA received a third comment stating that the data referenced in the March 29, 2002 NODA were highly germane and supported EPA's heat input growth rate methodology.

IV. States Addressed in Today's Notice

At the outset, it should be established which States should be addressed in today's notice on the heat input growth rate issue, in light of the Court's decisions vacating EPA's rules with respect to certain States and EPA's response to those vacaturs.

A. NO_X SIP Call

As noted above, the NO_X SIP Call covered 22 States and the District of Columbia. In reviewing the NO_X SIP Call, the Court vacated the NO_X SIP Call for Georgia and Missouri on the ground that there was insufficient record evidence concerning portions of those States. *Michigan* v. *EPA,* 213 F.3d 663, 685 (D.C. Cir., 2000). The record included modeling by the Ozone Transport Assessment Group (OTAG)—a partnership among EPA, 37 eastern States and the District of Columbia, industry, and environmental groups—that divided the eastern U.S. into two grids, the ''fine grid'' and the ''coarse grid.'' The grids did not track State boundaries, and Georgia and Missouri were split between the fine and coarse grids. OTAG stated that, based on air quality impacts, it was recommending NO_X emission controls for the fine grid area but not the coarse grid area. In light of OTAG's recommendations, the Court concluded that EPA had not sufficiently explained the basis for including the entire States of Georgia and Missouri, rather than simply the fine grid portions. The Court vacated and remanded the NO_X SIP Call for these States for agency reconsideration. The Court also vacated the rule for Wisconsin on grounds not relevant here. *Id.* at 681.

On February 22, 2002, EPA issued a notice of proposed rulemaking in response to the Court's remand, (67 FR 8396). In that notice, EPA stated that the Agency does not intend to proceed at this time with further action evaluating whether NO_X emissions should be reduced for ozone transport reasons in Wisconsin or the coarse grid portions of Georgia and Missouri. In addition, EPA noted that, while not addressed by the Court, Alabama and Michigan also are divided between the fine grid and the coarse grid in OTAG's modeling. EPA stated that it would therefore treat all four States the same and include in the NO_X SIP Call only counties that are fully within the fine grid portions of the four States. EPA proposed partial State NO_X emission budgets for Alabama, Georgia, Michigan, and Missouri using the State heat input growth rates established for the whole States.

EPA has taken the position that a single heat input growth methodology should be consistently applied to each State, and EPA received numerous comments disputing the application of EPA's heat input growth methodology to these four States, as well as to three other States (i.e., Illinois, Virginia, and West Virginia). Consequently, in the context of responding to the remand on the heat input growth issue in today's notice, EPA's analysis of the reasonableness of that methodology and the resulting heat input growth rates includes Alabama, Georgia, Michigan, and Missouri. As noted below, for Alabama, Georgia, and Missouri, EPA has evaluated the reasonableness of the methodology with respect to both the entire State and the fine grid portion alone. For Michigan, EPA evaluated the methodology for the entire State and not for the fine grid portion alone because the amount of NO_X emissions in the coarse grid portion was trivial for present purposes.[4]

B. Section 126 Rule

As noted above, the Section 126 Rule covered 12 States and the District of Columbia. Of the four States that EPA proposed to include only partially in the NO_X SIP Call, only Michigan is subject to the Section 126 Rule. As discussed above, the NO_X emission budget for Michigan changes very little when the coarse grid portion of the State is excluded, and EPA has therefore analyzed the heat input growth only for the entire State. In addition, with regard to the three other States concerning which EPA received adverse comments on its heat input projections, the Section 126 Rule covers Virginia and West Virginia, but not Illinois. As a result, strictly speaking, the validity of EPA's growth rate methodology for the Section 126 Rule should not depend on its application to Alabama, Georgia, Missouri, Illinois, or any other State covered under the NO_X SIP Call, but not the Section 126 Rule.

V. EPA's Explanation of Heat Input Growth Rate Methodology and Response to Court Remand and Public Comments

A. Overview

After a thorough review, EPA has concluded that its methodology for developing State heat input growth rates, and the resulting growth rates themselves, were reasonable in light of the record developed for the NO_X SIP Call and Section 126 Rule, and remain reasonable in light of new information concerning current activity that has since become available. The reasons are summarized below and explained more fully in the remainder of this notice.

1. EPA believes that its methodology was reasonable in light of the record for the NO_X SIP Call and the Section 126 Rule, based on the following considerations: a. EPA's methodology for projecting future heat input was logical and was consistently applied to all NO_X SIP Call States. EPA used an actual State heat input baseline (the higher of 1995 or 1996 levels) in view of year-to-year variability of State heat input. EPA applied to each State's baseline a heat input growth rate estimated using the Integrated Planning Model (the IPM), a state-of-the-art model for analyzing future electricity markets. EPA's use of the IPM was upheld by the Court.

b. Contrary to the Court's understanding, EPA used consistent State heat input growth rates (i.e., growth rates based on 2001–2010 heat input growth determined using IPM projections for 2001 and 2010) throughout the analysis for the NO_X SIP Call and the Section 126 Rule. EPA did not use, or even have available, 1996–2000 heat input growth rates determined using IPM projections for 1996 and 2000. EPA acknowledges that the Court's misunderstanding on this point stemmed from inadvertently confusing statements EPA made in the record.

c. The specific assumptions that EPA made in using the IPM to develop State heat input growth rates were reasonable. These included assumptions that: (i) Heat input growth rates during 2001–2010 are reasonably representative of heat input growth during 1996–2007; (ii) electricity demand projections should be reduced to take account of demand reductions under the Climate Challenge Action Program (CCAP); and (iii) the use of available data on new units and the historical distribution of generating capacity among States could be used to project the location of new units.

2. The State heat input growth rates and projections were generated using a reasoned methodology and reasonable assumptions, along with data that went through full public review (and were not at issue in the Court remands), and this suggests that the resulting heat input projections are reasonable. To confirm this, and to respond to concerns expressed by the Court and commenters about the plausibility of EPA's projections based on recent, actual heat input data, EPA has examined the projections in light of historical heat input data and new heat input data that have become available since the Agency developed the projections. EPA believes that its heat input projections remain plausible and reasonable based on the following considerations:

a. The State heat input amounts projected by EPA are reasonably consistent with the actual heat input data that have become available since the projections were made. On a regionwide basis, EPA's projected heat input for 2000 and 2001 are 0.1% lower and 2.0% higher respectively than actual regional heat input. Further, for most States, EPA's heat input growth rates have not been specifically challenged. Commenters have disputed EPA's heat input growth rates for seven out of the 22 jurisdictions under the NO_X SIP Call on the ground that the States involved had recent heat input amounts exceeding, or close to, EPA's 2007 heat input projections. However, recently, heat input for several of these States declined significantly. Moreover, State heat input is quite variable from year-to-year and so, in one year or over several years, may increase and then decrease. Indeed, there have been many instances in the past when State heat input has decreased significantly for the last year of a multi-year period as compared to the first year of such period. Consequently, the fact that a State's recent heat input exceeds, or is close to, EPA's 2007 heat input projection does not by itself demonstrate that the projection, or the underlying heat input growth rate, is unreasonable.

b. Commenters who argue that EPA's 2007 projection is unreasonable based on recent heat input data are in effect asserting that predicting a State's 2007 heat input based on trends in recent, short-term heat input data is a better methodology than the one employed by EPA. Some commenters explicitly recommended this approach. In response, EPA examined this approach using historical annual heat input data and found that in most States, recent, short-term data is an unreliable predictor of a State's heat input in the future. Therefore, EPA believes that its methodology, using a state-of-the-art model that takes into account many factors, including the dynamics of regional electricity markets, is more rational.

c. Contrary to the Court's understanding, EPA's 2007 heat input projections do not assume negative growth in electricity generation. State heat input (i.e., fossil fuel use for generation) can decrease while electricity generation increases in the State or in the region as a whole. Within a State, electricity generation does not necessarily vary with heat input because: (i) Significant amounts of

[4] EPA is not analyzing the reasonableness of the growth methodology with respect to Wisconsin because the Court vacated the NO_X SIP Call for that State and EPA does not intend, at present, to further evaluate Wisconsin in the context of ozone transport.

electricity are produced using non-fossil fuel generation; and (ii) efficiency improvements (e.g., from replacement of old units with new, more efficient units) make it possible to produce more electricity with less heat input. Further, electricity is generated and sold on a regional, not on a State-by-State basis. Heat input and electricity generation may decrease in one State because that State is importing more electricity generated in another State in the region. This is consistent with increased electricity generation in the region as a whole.

d. EPA's heat input projections are simply required to be reasonable, not to match perfectly actual heat input. This is because the Courts recognize that predictions of the results of complex activities (in this case, future State heat input, which will result from operation of the regional electricity market) will not necessarily match actual, future results exactly. To require such perfection would be to preclude the use of projections or of a model to develop such projections. EPA's heat input projections thus should not be considered unreasonable even if there were a substantial risk that they would turn out to be less than States' actual 2007 heat input, in light of all the other circumstances. In this case, unavoidable limitations on the accuracy of heat input projections result from: (i) The complexity of the electricity marketing system, which cannot be modeled perfectly because of the necessity to use simplifying assumptions about factors (e.g., fuel prices and electricity demand in the future) affecting future heat input; (ii) the necessity to make State-by-State projections of heat input even though electricity is generated and sold on a regional basis; and (iii) significant variability—on a year-to-year and several year basis—inherent in State heat input. Therefore, EPA's heat input projections should not be considered unreasonable in the current context, even if there were a substantial risk that they would turn out to be less than States' actual 2007 heat input.

e. Commenters overstated the impacts of a State's 2007 heat input exceeding EPA's 2007 heat input projection for that State. The NO_X SIP Call and the Section 126 Rule limit NO_X emissions, not heat input. Even if a State's actual heat input for 2007 turns out to exceed the projected heat input, NO_X emissions would increase at a much lower rate than heat input because the vast majority of new units are, and will continue to be, gas-fired with very low NO_X emission rates and high efficiency. The impact on the stringency of the NO_X emission budget and on the State economy therefore would be much less than claimed by commenters. Further, the NO_X SIP Call and the Section 126 Rule are being implemented through a NO_X cap-and-trade program that further mitigates the cost impact of any differences between projected and actual State heat input.

f. No commenter has identified an alternative methodology for developing State heat input growth rates that would be likely to yield growth rates that would comport better with actual heat input data than the growth rates under EPA's methodology. In light of the variability of State heat input, it is quite possible that any alternative methodology for predicting State heat input will result in projected values for some States that will not match actual heat input in some future year.

g. Commenters failed to show that EPA's heat input growth rate for any of the seven individual States for which adverse comments were received (Alabama, Georgia, Illinois, Michigan, Missouri, Virginia, and West Virginia) are unreasonable. The heat input for several of the States has already decreased to levels below or only slightly above EPA's projection. In addition, the comments failed to address the fact that, in the past, each State has had many multi-year periods when heat input has declined significantly for the last year, as compared to the first year of such periods. Further, in arguing that economic growth or planned new capacity prove that heat input will increase substantially for particular States, the commenters limited the information they provided to statewide data and failed to provide regional data. As a result, these comments are not persuasive because any particular State's heat input is determined by regional, not just that individual State's, demand and supply.

B. Description of EPA's Methodology

1. EPA's Methodology for Determining State NO_X Emission Budgets and Heat Input Growth Rates

EPA used a multi-step procedure to determine for each State the portion of the NO_X SIP Call emissions budget attributable to EGUs. In brief, EPA started with the State's baseline of the higher of EGU heat input for 1995 and 1996 and grew that amount to the 2007 level using the projected heat input growth rate for that State based on the IPM. Then, EPA determined the appropriate level of NO_X emissions control (which was the same level for each State) and applied this level to each State's projected 2007 heat input. The result was each State's NO_X emissions budget for EGUs.

Throughout the methodology, EPA relied on the IPM. The IPM simulates the operation of the electricity market in the continental U.S. by using inputs (such as electricity demand and fuel and emission control costs) and by modeling electricity generation, transmission, and distribution on a subregional basis. The IPM projects the least cost scenario for the region for generating electricity consistent with this set of inputs. This scenario includes projections of which units operate at what levels, which units install emission controls, and what type, when, and where new units are built.

To develop the State heat input growth rates, EPA first conducted an IPM run (the ''base case run''). This base case run was designed to yield, as outputs, projections of the heat input necessary to generate electricity sufficient to meet projected electricity demand in the 2001 and 2010 ozone seasons. To conduct this run, EPA used, as model inputs, assumptions regarding, among many other things: (i) electricity demand in 2001–2020, which EPA calculated by determining actual electricity demand in 1997 and applying growth rates in electricity demand for 1997–2020; (ii) reductions in electricity demand based on the CCAP, discussed below; (iii) NO_X emission control requirements and associated costs; (iv) location and costs of projected new units; and (v) fuel costs. For this base case run, EPA assumed no additional NO_X emission controls would be required for ozone transport purposes (62 FR 60318, 60347, Nov. 7, 1997).

With these inputs, the base case run produced, as outputs, the sources of electricity generation for years selected by EPA, including 2001, 2007, 2010, and 2020. In addition, the outputs included the amounts of heat input used by the fossil-fuel-fired sources in those years, the projected NO_X emissions for the 2007 ozone season, and the total cost for generating electricity for the 2007 ozone season.

EPA used the 2001 and 2010 heat input to generate heat input growth rates for each State. For example, the base case run projected that Virginia's base case 2001 and 2010 heat input would be 194,000,000 mmBtu and 243,000,000 mmBtu, respectively. An annual heat input growth rate was then mathematically determined. For Virginia, this annual growth rate is 1.025.

Then, EPA applied each State's annual heat input growth rate to the baseline heat input for the State (the higher of the 1995 or 1996 actual heat input for EGUs) to develop the State's emission budget for 2007 (63 FR 57406–57408). For example, for Virginia, the 1995 heat input was 154,233,310 mmBtu, the 1996 heat input was 172,633,028 mmBtu, and so EPA used the 1996 heat input as the baseline heat input. For West Virginia the opposite occurred. The 1995 heat input was 347,687,307 mmBtu, and the 1996 heat input was 341,738,426 mmBtu, and so EPA used the 1995 heat input as the baseline heat input.

Then, EPA applied to each State's baseline amount—which EPA treated as the 1996 value even if the higher heat input amount actually occurred in 1995—that State's annual heat input growth rate to determine the projected 2007 heat input. For Virginia, this computation (172,633,028 mmBtu multiplied by 1.025 over an 11-year period) yielded 227,875,597 mmBtu.

Next, EPA used projected 2007 heat input to test the cost effectiveness of various NO_X emission control levels. First, EPA selected a set of NO_X emissions control levels as candidates to be tested for appropriateness. The levels tested were, 0.12 pounds of NO_X per mmBtu of heat input (lbs/mmBtu), 0.15 lb/Btu, 0.2 lb/Btu, and 0.25 lb/Btu. Then, EPA applied one of the control levels to each State's projected 2007 heat input. For example, for Virginia the 2007 projected heat input of 227,875,597 mmBtu was multiplied by 0.15 lb/mmBtu to obtain an EGU NO_X emission budget of 34,181,340 pounds or 17,091 tons. In this manner, EPA calculated the NO_X emission budget for each State based on the level of NO_X emissions control to be tested. Then, EPA summed each State's NO_X emissions budget to determine the regionwide NO_X emissions budget for the NO_X control level tested.

Then, EPA conducted another IPM run (the ''cost-effectiveness run'') to determine the cost effectiveness of meeting the regionwide NO_X emission budget for the control level tested. For this run, EPA included in the model each of the assumptions that were used in the base case run. However, EPA added one additional assumption, i.e., the requirement that total NO_X emissions for EGUs in the NO_X SIP Call region could not exceed the regionwide NO_X emission budget (i.e., the sum of the State NO_X emission budgets for EGUs developed using the 2001–2010 heat input growth rates from the base case run and the specified level of NO_X emission controls being tested). This cost-effectiveness run yielded, as an output, the total cost of generating electricity for the 2007 ozone season for the control level. EPA repeated this process for each control level tested.

EPA then performed, for each NO_X emission control level, three calculations to determine the cost per ton of NO_X emissions reduced, of meeting the regionwide NO_X emission budget associated with that control level. First, EPA subtracted the total NO_X emissions in the cost-effectiveness run from the total NO_X emissions in the base case run to calculate the tons of NO_X reduced due to the imposition of the control level. Second, EPA subtracted the total cost of generating electricity in the base case run from the total cost in the cost-effectiveness run to calculate the total cost of meeting the regionwide budget. Third, EPA divided the total cost of meeting the budget by the total tons reduced due to the imposition of the control level to calculate the cost effectiveness of meeting the budget associated with the control level (in dollars per ton). For example, the cost effectiveness of meeting the 0.15 lb/mmBtu control level was $1,440 per ton of NO_X emissions reduced in 2007 (Regulatory Impact Analysis for the NO_X SIP Call, FIP, and Section 126 Petitions, Volume 1: Costs and Economic Impacts, September 1998, at p. ADD–2). Of course, the cost effectiveness was a higher dollar amount for more restrictive control levels (e.g., 0.08 lb/mmBtu) and a lower dollar amount for less restrictive control levels (e.g., 0.2 lb/mmBtu).

Finally, EPA evaluated the cost-effectiveness level for each control level against certain criteria and selected 0.15 lb/mmBtu as the highly cost effective level for EGUs. The basis for this selection, which is not at issue in today's notice, is discussed at 63 FR 57401–2.

Having selected 0.15 lb/mmBtu, EPA set, as the NO_X emission budget for EGUs for each State in the NO_X SIP Call, the State's budget associated with that control level. For example, for Virginia, the NO_X emission budget for EGUs was 17,091 tons.

For the Section 126 Rule, which imposed requirements on individual EGUs in certain States, but did not impose statewide control limitations, EPA used the same State NO_X emission budgets that were developed for the NO_X SIP Call. For the individual EGUs in a given State, EPA allocated a total amount of allowances equal to the amount of tons of NO_X in the State NO_X emission budget for EGUs. Individual EGUs were allocated a proportionate share of the State NO_X emission budget based on its share of the total heat input for EGUs in that State.

2. Use of Consistent Heat Input Growth Rates for Different Parts of EPA's Analysis

One concern that the Court had about the reasonableness of EPA's approach was the belief that EPA ''utilized one set of growth-rate projections to set allowance budgets, [and] another to assess emission reduction costs.'' *Appalachian Power* v. *EPA,* 249 F.3d at 1054. The Court therefore believed that ''EPA had other ways of generating 2007 utilization projections.'' *Id.* The above description of EPA's multi-step procedure makes clear that, in fact, EPA utilized only IPM heat input growth rate projections for 2001–2010. The methodology required (i) developing many inputs in the IPM, including assumptions about growth in electricity demand during 1997–2020; (ii) conducting an IPM base case run and a set of cost effectiveness runs; and (iii) using IPM outputs to make various computations. However, at any step that required IPM generated heat-input growth rate projections—whether for purposes of determining a budget or for purposes of determining the cost effectiveness of control levels—EPA used only the projections for 2001–2010, and not any other period.

EPA respectfully observes that the Court's views to the contrary are misperceptions that resulted from what EPA now realizes was EPA's own inadvertently confusing statement by EPA in the Response to Comment document for the Section 126 Rule. The Response to Comment document states, in relevant part:

> The budgets were constructed using growth rates for 1996–2007 that were consistent with the growth rates in IPM for 2001–2010, which may be higher or lower than the growth rates for the years 1996–2001. EPA's analysis of the costs of complying with these budgets, however, was conducted using IPM, which incorporates internally consistent growth assumptions—i.e., the growth for 1996 through 2001 is based on IPM assumptions for 1996 through 2001, and the growth for 2001 through 2010 is based on IPM assumptions for 2001 through 2010. These IPM growth forecasts are consistent with the NERC forecasts.

Docket # A–97–43, Item # VI-C–01, ''Response to Significant Comments on the Proposed Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport,'' April 1999 at p. 112.

The first two sentences in the response refer to ''growth rates,'' ''growth assumptions,'' or ''growth,'' but unfortunately fail to provide further clarification as to what type of ''growth'' is being referenced. The first sentence indicates that, for budget purposes, EPA determined the ''growth rates'' for 1996–2007 based on ''the growth rates in IPM for 2001–2010.'' The second sentence indicates that, for cost analysis purposes, EPA used ''growth'' for 1996–2001 ''based on IPM assumptions for 1996 through 2001'' and ''growth'' for 2001 through 2010 ''based on IPM assumptions for 2001 through 2010.'' However, the response fails to explain that the references in the first sentence to ''growth rates'' are to growth in heat input, which is an output from IPM runs for the years 2001 and 2010, while the references in the second sentence to the ''growth assumptions'' and ''growth'' for 1996–2001 and 2001–2010 are to growth in electricity demand, which is an input into the IPM. The third sentence confirms that the ''growth assumptions'' in the second sentence are—like the ''North American Electric Reliability Council (NERC) forecasts''—for electricity demand.

The second sentence of the Response to Comment document should not be read to indicate that EPA had available IPM-generated growth rates in heat input for the 1996–2001 period. It is simply not true that EPA had that data available. Rather, EPA had available IPM-generated heat input data for only 2001–2010, and EPA developed the budgets and cost analyses in the manner described in section V.B.1 of this notice. Therefore, of course, EPA did not use such data ''to assess emission reduction costs'' and could not have used such data as another way ''of generating 2007 utilization projections.'' *Appalachian Power* v. *EPA,* 249 F.3d at 2054.[5]

C. Justification for EPA's Methodology and Reasonableness of EPA's Underlying Assumptions

1. Court's and Commenters' Concerns

While upholding in general EPA's use of the IPM and not finding that any specific assumptions or other aspects of EPA's methodology were unreasonable, the Court stated that ''even in the face of evidence [i.e., actual State heat input in excess of EPA's projection] suggesting the EPA's projections were erroneous, EPA never explained why it adopted this particular methodology.'' *Appalachian Power* v. *EPA,* 249 F.3d at 1053.

Moreover, commenters raised concerns about certain assumptions that EPA made in the IPM, or in using the results from the IPM, to develop heat input growth rates. In particular, commenters were concerned about:

(1) The assumption that State-by-State heat input growth rates, derived from the IPM outputs for 2001 and 2010, were reasonably representative of, and reasonably used to calculate, heat input growth rates for 1996 to 2007.

(2) The assumption that electricity demand projections were reasonably reduced by reductions under the CCAP; and

(3) The assumption that the locations of new units were reasonably projected using currently available data on new units and the historical distribution of generating capacity.

As discussed below, EPA believes that its methodology and, in particular, all of the challenged assumptions had a reasonable basis.

2. EPA Reasonably Decided To Develop State NO_X Emission Budgets by Using Heat Input Growth Rates

As noted above, EPA's methodology for projecting 2007 heat input was based, in essence, on establishing a baseline based on actual heat input, and then applying an IPM-determined growth rate to that baseline. The overall approach of using an actual baseline and applying a growth rate was reasonable and consistent with the way EPA projected utilization for other stationary source categories. (Docket # A–96–56, Item # X–B–09, ''Development of Emission Budget Inventories for Regional Transport NO_X SIP Call'', U.S. EPA, Office of Air Quality Planning and Standards, May 1999.)

Starting with an actual baseline obviously constitutes a reasonably accurate starting point for the calculation. Because of the year-to-year variability in heat input, as discussed below, EPA decided to allow each State to use the higher of two years as the baseline. EPA initiated the NO_X SIP Call rulemaking in 1997, and so EPA selected as the two years 1995 and 1996. EPA's approach overstated total actual heat input for the region. Since some States had higher heat input in one year and other States had higher heat input in the second year, the total of the States' baselines exceeded the total heat input for the States in either of the years.

Applying to that baseline an IPM-generated heat input growth rate is also reasonable because the IPM provides a reasonably accurate method of predicting growth in heat input. The model has been thoroughly vetted through public comment in several rulemakings and generally has been upheld by the Court in both the NO_X SIP Call Decision and an earlier decision. *Appalachian Power* v. *EPA,* 247 F.3d at 1052–53; *Appalachian Power* v. *EPA,* 135 F.3d 791, 814–15 (D.C. Cir., 1998). As discussed below, EPA's approach of determining the growth rate of State heat input from one modeled year (here, 2001) to a later modeled year (here, 2010) minimized the effect of necessary, simplifying assumptions used by the IPM and thereby increased the accuracy of the determination.

EPA considered alternative ways to handle heat input growth in determining State NO_X emission budgets. For example, EPA considered not allowing for heat input growth at all. Under this method, EPA would base each State's NO_X emission budget on heat input as of a selected year for which historical data was available, without accounting for changes in future heat input. In the NO_X SIP Call, EPA rejected this method, explaining that although it would have been simpler, it ''may be viewed as less equitable for States with significantly higher projected utilization,'' (62 FR 60318, 60351, Nov. 7, 1997).

EPA also considered using, as the State NO_X emission budget for each State, the amount of NO_X emissions that the IPM projected for the State in 2007 in the cost-effectiveness run.[6] EPA did not use this approach for several reasons. First, this approach would have made it difficult to accommodate changes in the State inventory of EGUs as EPA received better information regarding existing units. EPA undertook multiple notice-and-comment rulemakings to obtain the most accurate data possible about existing units and received new data through each rulemaking. It was relatively simple for EPA to use this new information to adjust the State's 1995 and 1996 emission inventories, and thus the State's baseline, and then apply projected future growth from the IPM to adjust the State's NO_X emission budget. If instead EPA had used the IPM 2007 projected heat input, then, each time new data were received, EPA would have had to rerun the IPM for 2007 with the State inventory of EGUs revised to include the new information. It would have taken significant resources and time to change the IPM on several occasions to reflect this new information.

Further, the IPM is likely to be more accurate in projecting State-by-State

[5] The portion of EPA's brief on the growth rate issue in *Appalachian Power* v. *EPA* reflects the confusing response to comments. As discussed above and contrary to the suggestion in the brief (at 71–2), the cost-effectiveness run and EPA's cost-effectiveness analysis did not use ''1996–2001 growth rates'' for heat input.

[6] In addition, EPA considered, but rejected, the approach of using a single, uniform heat input growth rate in developing all of the State NO_X emission budgets. (See section D.IV.10 of this notice.)

rates of change of an output from one year in an IPM run to another year in that IPM run (here, growth in State heat input from 2001–2010) than in predicting an actual output State-by-State in a particular year (here, actual heat input in 2007). This is because modeling of complex activities requires the use of simplifying assumptions in order to make the model feasible—from the standpoint of resources and time—to run. This is particularly true here, where EPA must develop State-by-State projections of heat input that results from complex activities (i.e., the operation of the regional electricity market). (See sections V.C.3 and V.D.7 of this notice.) Because the same assumptions were made for every year modeled, calculating differences between two model years reduces any inaccuracies caused by these assumptions. Therefore, EPA believes that, on a State-by-State basis, the IPM is likely to be more accurate in projecting rates of change between modeled years.

For these reasons, EPA decided that the approach of applying an IPM-generated heat input growth rate for each State to a baseline State heat input based on historical data would be a reasonably accurate predictor of the State's actual heat input in 2007 and a more accurate predictor, and significantly simpler and less costly from an administrative standpoint, than IPM's projection of the State's 2007 heat input.

3. State Heat Input Growth Rates Based on IPM Outputs for 2001–2010 Were Reasonably Representative of 1996–2007 Heat Input Growth

a. EPA's Methodology. A number of commenters suggested that instead of using heat input growth rates based on 2001 to 2010 projections, EPA should have used State heat input growth rates based on 1996 data and 2007 projections. EPA believes that relying on the IPM projections for 2001 to 2010 is reasonably accurate.

Although EPA had information on, and projections of, annual growth rates in regionwide electricity demand from 1995 or 1996 to 2007 (which EPA used as inputs to the IPM), EPA was not aware of any projected heat input growth rates for that period for each State in the NO_X SIP Call region that were developed using a consistent set of assumptions. *See, e.g.,* 63 FR 57409. Since, as discussed in section V.D.6 of this notice, electricity is generated, transmitted, and distributed on a regional basis, consistent assumptions about regional and subregional factors (*e.g.,* demand for electricity, fuel costs, and cost of new units) must be used to develop the heat input growth rates for all States. The Court has already upheld EPA's decision to rely on an internally consistent methodology for determining heat input, as opposed to recommendations by various commenters favoring State-specific growth rates that would have been inconsistent with each other. *Appalachian Power* v. *EPA,* 249 F.3d at 1052–53.

Since EPA was not aware of any available consistent set of heat input growth rate projections, EPA developed its own projections. EPA decided to use the heat input values from IPM runs for 2001 and 2010 to calculate a long term heat input growth rate for each State. Because, as discussed above, the IPM is a comprehensive model of the electricity market, EPA believes that it provides reasonable heat input growth rate projections. Further, EPA believes that heat input growth rates for the nine-year period 2001–2010 were reasonably representative of the eleven-year period 1996–2007 because, among other things, the periods overlap and are of similar length. In addition, EPA believes that the assumptions used in the IPM runs for 2001 and 2010 are reasonably applicable to the 1996–2001 period as well as 2001–2007. (See section V.D.7 of this notice discussing assumptions in the IPM.) In fact, out of the many assumptions in the IPM, commenters have pointed to only a few that they believe differ pre- and post-2001. As discussed below, EPA examined the assumptions discussed by commenters and maintains that these assumptions do not differ in any way that would affect the reasonableness of the heat input growth rates.

EPA considered developing heat input growth rates based on data developed by OTAG. OTAG developed a heat input growth projection separately for each individual State for the years 1990 to 2007 without considering the interactions among the individual States. EPA chose to use the IPM growth rates because, unlike the OTAG growth projections, the IPM's were not developed separately for each State, but were developed by analyzing performance of the electric industry as a regionwide system. Therefore, the IPM growth rates are a more internally consistent set of growth rates than the OTAG growth rates, (62 FR 60353).

b. Cost of adding run years. Some commenters questioned why EPA did not program the IPM to provide outputs for 1996 in order to generate 1996–2007 heat input growth rates (in lieu of 2001–2010 growth rates) using the IPM. EPA believes that its decision to program the IPM beginning with 2001 was reasonable.

As explained by the Court in the Section 126 Decision:

> [T]he EPA has "undoubted power to use predictive models" so long as it "explain[s] the assumptions and methodology used in preparing the model" and "provide[s] a complete analytic defense" should the model be challenged. *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 535 (D.C. Cir. 1983) * * * (citations and internal quotation marks omitted). That a model is limited or imperfect is not, in itself, a reason to remand agency decisions based upon it.
>
> Ultimately * * * we must defer to the agency's decision on how to balance the cost and complexity of a more elaborate model against the oversimplification of a simpler model. We can reverse only if the model is so oversimplified that the agency's conclusions from it are unreasonable. *Id.*

Appalachian Power v. *EPA,* 294 F.3d at 1052.

The IPM was programed to model specified years starting with 2001. EPA selected these run years to provide information not just for the NO_X SIP Call and Section 126 Rule, but also for several other programs over the next few years, including implementation programs for the recently revised National Ambient Air Quality Standards for ozone and fine particles. (Regulatory Impact Analysis for the No_X SIP Call, FIP and Section 126 Petitions, Volume 1: Costs and Economic Impacts, September 1998, at p.4–2., *http://www.epa.gov/ttn/rto/sip/related.html#doc.*) Adding more run years (*e.g.,* 1996) would not have provided information useful for those other programs, but would have added significant complexity and costs to the modeling.

The model consists of model plants that represent individual generating units (*e.g.,* fossil-fuel-fired boilers, nuclear units and hydro-electric units) that comprise the inventory of electricity producers. Duplicating precisely each of the boilers and generators would be impracticable; accordingly, the model aggregates the fossil-fuel fired units into a series of model plants and aggregates the non-fossil-fuel fired units into separate model plants. (Docket # A–96–56, Item # V–C–03, Report on Analyzing Electric Power Generation Under the Clean Air Act Amendments, at p. 5.)

For each run year, EPA provides various inputs (*i.e.,* constraints), such as the requirement to meet a certain electricity demand for each season and each geographic subregion modeled. In addition, for each run year, the model provides variables, which are values based on the inputs, such as the level of electricity generation from each model plant and the level of emission controls at a model plant. For each year the model is run, the model must optimize (*i.e.,* determine the least cost scenario, including fuel mix, emission controls, and amount of operation) for every model plant to reach each constraint in the model. The IPM includes thousands of constraints and variables.

The complexity of the model—its simulations, inputs, and variables—means that each additional run year adds many more calculations to the model, a task that requires time and resources. To keep the model manageable, meet time schedules, and conserve resources, adding an additional run year would have meant simplifying other assumptions within the model. In other words, because the number of equations would be increased by adding constraints and variables associated with a new run year, other ways would have had to be found to reduce the number of equations. This would have meant either reducing the number of (i) model plants; (ii) constraints, such as the number of subregions, which determines the number of electricity demand constraints; or (iii) variables, such as NO_X emission control technology options.

When developing the model, EPA had to decide ''how to balance the cost and complexity of a more elaborate model against the oversimplification of a simpler model.'' *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F. 2d 506, 535 (D.C. Cir., 1983). Balancing these factors, EPA decided to develop the IPM to start in 2001. Under these circumstances, the model adequately served the needs of several programs—the NO_X SIP Call, the Section 126 Rule, and other programs. Moreover, EPA believed that heat input growth rates for the years 2001 to 2010 were reasonably representative of growth during the period 1996 through 2007. In EPA's judgment, any further refinement in the heat input growth rate that may have resulted from adding a 1996 run year would not have merited the additional time and cost and may have been offset by the increase in model inaccuracy that may have resulted from the consequent need to further simplify or otherwise limit the model. Therefore, EPA decided, on balance, that it was reasonable to use 2001–2010 heat input growth rates to develop the 2007 State NO_X emission budgets.

c. Consistency of assumptions. Some commenters questioned whether the 2001–2010 heat input growth rate was representative of growth during 1996–2007, alleging that specific assumptions in the IPM were different for those two time periods and would result in different heat input growth rates for those periods.

As noted above, one of the inputs for the base case and cost-effectiveness IPM runs for 2001 and 2010 was projected electricity demand. To determine electricity demand, EPA began with available information for actual annual electricity demand for 1997, projected the increases out to the IPM run years, and then reduced those projections to take account of reductions in electricity demand expected to result from CCAP. CCAP is a Federal program started in 1993 to significantly reduce emissions of carbon dioxide (CO_2) and thereby address concerns about global climate change. Since consumption of fossil fuel to generate electricity is a significant contributor to CO_2 emissions, a major component of CCAP was a broad set of voluntary programs designed to reduce electricity demand and generation.

Commenters claimed that the assumptions for electricity demand reductions due to CCAP for the years 2001–2010 differed from what would have been used for the years 1996–2001. According to a commenter:

> [b]ecause EPA's assumed CCAP reductions increased by almost 300% from 2001 to 2010 . . . the electricity demand growth rate that EPA used in its analysis decreased substantially from 2001 to 2010. Thus the record establishes that EPA itself assumed vastly different electricity demand growth rates for the 1996–2000 period than the 2001–2010 period * * *

In fact, however, the commenter's conclusion is contradicted by the record. The data in the record supporting IPM runs shows that EPA assumed electricity demand growth rates of 1.6% for 1997–2000 and 1.8% for 2001–2010. Actual electricity demand in 1996 was 3,305 billion KWh.[7] EPA's projected electricity demand without accounting for CCAP was 3,575 billion KWh for 2001 and 4,198 billion KWh for 2010. EPA projected that CCAP would result in electricity demand reductions of 100 billion KWh for 2001, and 389 billion KWh for 2010 (Analyzing Electric Power, Appendix 2 at A2–2). After subtracting projected CCAP electricity demand reductions from assumed electricity demand, EPA projected electricity demand of 3,475 billion KWh for 2001,and 3,809 billion KWh for 2010. This resulted in an annual growth rate for adjusted electricity demand of 1.03% for 1996–2001 and 1.07%, for 2001–2010. (Docket # A–96–56, Item # XV–C–22.) In short, while EPA assumed somewhat lower CCAP reductions in 1996–2001 than in 2001–2010, the Agency also assumed lower electricity demand growth without CCAP adjustments in 1996–2001 than in 2001–2010. The net result was that EPA's projected electricity demand growth rates after CCAP adjustments were very similar for 1996–2001 and 2001–2010.[8]

4. EPA Did Not ''Double Count'' Electricity Demand Reductions Under CCAP

As noted above, one input into the IPM was electricity demand. EPA projected electricity demand by starting with certain industry-sponsored forecasts for demand and then reducing them by projected CCAP demand reductions in accordance with a multi-agency task force's projections, made for purposes of a U.S. Department of State report on the subject.

EPA received comments on the August 3, 2001 NODA alleging that EPA failed to explain, and, indeed, double counted the projected electricity demand reductions under CCAP. According to commenters, the double counting led EPA to underestimate projected heat input for 2007. The EPA believes that its CCAP assumptions are well supported by the record and that no double counting occurred.

a. *EPA's Methodology for Determining Electricity Demand.* EPA started with electricity demand forecasts from the NERC, which is a voluntary association of most of the large electricity generators and sellers in the U.S. and whose purpose is to promote the reliability and security of the electricity system. NERC divides the continental U.S. into regions, each of which has its own council comprised of representatives of the utilities generating and selling electricity in the region. Each utility makes forecasts of electricity demand by its end-use customers and of electricity supply available to that utility and submits these forecasts to the appropriate NERC region. NERC compiles the individual utilities' demand and supply projections by region and reports the compiled projections to the Energy Information Agency (EIA).[9] Since NERC forecasted

[7] Note that while EPA started its electric demand forecasts using NERC forecasts for the year 1997, EPA used here the actual electricity demand for 1996 in order to demonstrate the effective growth rate for 1996–2001, which is referenced by the commenters.

[8] In addition, EPA notes that since the CCAP reductions are assumed to occur on a nationwide basis, any assumptions regarding CCAP would not have been the cause of State-by-State variation in heat input growth rates.

[9] EIA is an independent agency within the U.S. Department of Energy (DOE) that is responsible for, among other things, collecting, compiling, and reporting information on the U.S. electricity industry.

electricity demand out to only 2006 at the time that EPA was developing the IPM for the NO_X SIP Call, EPA used the NERC electricity demand projections for 1996 to 2006 and extended them to 2010 using a 1995 forecast by DRI, a private consulting group. (Analyzing Electric Power, Appendix 2 at A2–3.)

Then, EPA reduced these electricity demand projections by the amounts of demand reductions expected to occur as a result of CCAP. As described above, CCAP, a Federal program established in 1993, includes a broad collection of voluntary programs designed to reduce electricity demand and generation to reduce CO_2 emissions. Some of these programs were in existence before CCAP's establishment in 1993 and were incorporated into CCAP, along with a new set of programs. CCAP was updated in 1995, a process that included revised estimates of the effectiveness of its programs, based on public input solicited through a **Federal Register** notice (60 FR 44022, Aug. 24, 1995) and a public hearing held on September 22, 1995. *See* Review of Climate Change Action Plan: Request for Public Comment; Notice of Meeting, 60 FR 44022, August 24, 1995 (Council on Environmental Quality solicitation of public comment).

In 1997, the U.S. Department of State (''State Department'') developed and issued a report, Climate Action Report, setting forth the expected results from CCAP. The report was developed to fulfill an obligation under the 1992 United Nations Framework Convention on Climate Change.[10] The State Department first issued a draft report and requested public comment on two occasions, in December 1996 and May 1997. (*See* Preparation of Second U.S. Climate Action Report: Request for Public Comments, 62 FR 25988, May 12, 1997). After considering the comments received, the State Department issued the final report in 1997. The report presented a consensus view of the Federal agencies involved, including EPA, the U.S. DOE, and the State Department.

In particular, to determine the effectiveness of the CCAP programs, an interagency work group polled the program managers at EPA, DOE, the U.S. Department of Transportation, and the U.S. Department of Agriculture who were responsible for the various CCAP programs. The program managers provided estimates of reductions for each CCAP program, generally expressed in billion kilowatt hours (billion KWh) of electricity usage and mmBtu of heat input, or other units of measure appropriate for the program. The workgroup compiled and reviewed those projections (Docket # A–96–56, Item # XIV–F–03). EPA used those estimates to reduce the NERC-based electricity demand projections for 2001 through 2020. (*See* Analyzing Electric Power, Appendix 2, at A2–3). In addition, DOE used those estimates to project the amount of greenhouse gas emissions reductions that would result from the CCAP programs. These emissions reductions and other types of savings were included in the State Department's Climate Action Report.

b. The record contains sufficient documentation of the additional CCAP demand reductions that EPA took into account. Some commenters claimed, in response to the August 3, 2001 NODA, that EPA did not provide adequate documentation to explain how the electricity demand reductions under CCAP were derived.

EPA notes that this issue—as well as the issue of double-counting of CCAP demand reductions, discussed below—was not raised in any of the rulemakings to this point or brought to the Court's attention in either the Section 126 or the Technical Amendments cases. Commenters had a full opportunity to raise the issues during the development of the NO_X SIP Call and Section 126 Rule. In fact, some of the parties raising the issues now claimed, in comments in the NO_X SIP Call and Section 126 rulemakings, that no CCAP electricity demand reductions should be considered in projecting electricity demand. These commenters based these claims on the ground that CCAP was a voluntary, rather than a mandatory, program. Thus, these commenters clearly had the opportunity during the earlier rulemakings to raise the issues concerning CCAP that they are raising only now.

The lack of attention to these issues by commenters during the earlier rulemakings has some impact on the extent to which the record addresses them. Had commenters raised these issues earlier, EPA would have been obliged to respond, and the record would have included that dialogue. Thus, if the commenters view the record as deficient, their failure to raise this issue at several earlier junctures should be considered. Moreover, it is questionable whether EPA is required, at this point, to address these issues in light of the commenters' earlier opportunities.

Even so, EPA maintains that its assumptions about the CCAP demand reductions are well supported. The IPM documentation shows the amount of actual electricity demand in 1997, and the amount of projected electricity demand from 1997 to 2010 (and beyond), all expressed in billion Kwh, (IPM basecase modeling runs, *http://www.epa.gov/capi/ipm/npr.htm).* As noted above, EPA based these projections on information supplied by NERC. In addition, other IPM documentation shows the total amount of CCAP reductions, expressed in billion kwh, for 2001 through 2010 (and beyond) (Analyzing Electric Power, Appendix 2 at A2–2).

These total amounts of CCAP reductions ''were taken from the supporting analysis that was done to forecast future U.S. carbon emissions from the power industry that appeared in the U.S. Department of State's Climate Action Report, July 1997,'' (Analyzing Electric Power, Appendix 2 at A2–3). Specifically, this supporting analysis consisted of a spreadsheet, entitled ''CCAP Inputs for April 1997 Update,'' developed by the above-described interagency work group tasked with projecting the amount of reductions for each CCAP program, (Docket # A–96–56, Item # XIV–F–03). The workgroup solicited information from the various agencies charged with administering CCAP programs and, based on that information, prepared the spreadsheet. No commenter requested this information during the NO_X SIP Call and Section 126 rulemakings until the comment period for the August 3, 2001 NODA. At that time, EPA provided the spreadsheet—annotated to reflect the adjustment related to the NERC forecasts, described below—to commenters when requested and placed it in the docket, (Letter from John Seitz to Andrea Bear Field, August 31, 2001, Docket #A–96–56, Item #XIV–F–01, included as Attachment D to Docket Item #A–96–56–XIV–D–31).

The spreadsheet identifies the amount of reductions, expressed in billion Kwh and mmBtu of each of the dozen or so relevant CCAP programs, for the years 2000 and 2010 (as well as 2020). The amount of reductions from these programs for 2010—after the adjustment related to the NERC forecasts, described below—equals the amount included for that year in Analyzing Electric Power, Appendix 2 at A2–2. Moreover, the IPM documentation states that ''EPA did a linear interpolation'' to determine the amount of CCAP reductions assumed for years between 2000 and 2010, including 2001, (Analyzing Electric Power, Appendix 2 at A2–3).

One commenter claimed that it was not clear how EPA converted the CO_2

[10] Parties to the 1992 United Nations Framework Convention on Climate Change (including the U.S.) agreed to submit reports detailing their emissions of greenhouse gases (such as CO_2) and any strategies to reduce those emissions.

reductions cited in the State Department's Climate Action Report into the electricity demand reductions set forth in Analyzing Electric Power or the spreadsheet used by EPA to adjust the NERC electricity demand forecasts. Actually, the CO_2 reductions in the State Department report were based on the electricity demand reductions in the spreadsheet, not the other way around. As noted above, these electricity demand reductions were developed by the agencies involved in implementing CCAP and then were converted to CO_2 reductions for purposes of the State Department report, using a U.S. DOE model (the Integrated Dynamic Energy Analysis Simulation (IDEAS)) of the U.S. energy system. These values were then included in the proposed and final versions of that report.[11]

c. Commenters failed to prove their claim that NERC and EIA projections already included the CCAP demand reductions that EPA took into account. Commenters suggested that the NERC electricity demand forecasts that EPA adjusted for certain CCAP reductions already assumed those reductions. According to commenters, the NERC members that supplied the information used in the NERC forecasts would have been aware of, and in some cases participated in, CCAP programs and so ''would have * * * taken into account'' CCAP programs in the information supplied to NERC. The commenters emphasized that NERC projected electricity demand growth at an annual rate of 1.7%, which is higher than EPA's projection of 1.1%, and therefore concluded that EPA, by purportedly double-counting CCAP reductions, underestimated electricity demand. The commenters made a similar point with respect to electricity demand forecasts by EIA, emphasizing that in 1997, EIA projected electricity demand growth at 1.6% annually, and that, in making this projection, EIA explicitly noted that it was taking account of CCAP.

As discussed below, after weighing all the evidence in the record relevant to the claim that EPA double-counted CCAP demand reductions, EPA concludes that no such double-counting occurred and that commenters failed to show otherwise.

(i) NERC Forecasts

When EPA developed electricity demand forecasts for the NO_X SIP Call and the Section 126 Rule, the NERC forecasts did not mention the energy efficiency programs as a factor that was considered. NERC explained only that it considered an ''economic variable, weather and a random component that expresses unknown determinants of net energy for load.'' (Docket # A–96–56, Item # XV–C–23, *Peak Demand and Energy Projection Bandwidths: 1997–2006 projections,* p. 4, Load Forecasting Work Group of the Engineering Committee North American Electric Reliability Council, June 1997). Consequently, EPA had to exercise its best judgement in determining the extent to which the NERC forecasts took into account CCAP demand reductions. Rather than assuming, from the absence of any affirmative statements by NERC about CCAP reductions, that NERC did not consider any CCAP reductions, EPA took the more conservative approach of assuming that some of the reductions were likely to have been considered by NERC. (*See* Docket # A–96–56, Item # XIV–F–03.) EPA reduced the NERC electricity demand forecasts only to take account of the additional CCAP demand reductions beyond those EPA believed were included in the NERC forecasts. EPA believed that it was appropriate to factor in these additional CCAP demand reductions ''given the extensive Administration, State, and business efforts underway and the promising early results that EPA has seen in some of the CCAP's programs that have substantially lowered electric energy use and saved money for many businesses.'' (Responses to Significant Comments on the Proposed Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone, September 1998, at 182).

In applying this approach to CCAP reductions, EPA did not factor in reductions from either the Green Lights Program or the Energy Star-Products Office Equipment Program, which existed before CCAP and that were simply put under the umbrella of CCAP when CCAP was established in 1993. Green Lights was one of EPA's earliest voluntary energy efficiency programs and was aimed at encouraging the use of energy efficient lighting products. This program was expanded under CCAP. Similarly, the Energy Star Products program included a pre-1993 program to encourage the purchase of energy efficient office equipment. EPA assumed that because Green Lights and Energy Star Products-Office Equipment were pre-existing programs, they were better established and their benefits more predictable by the utilities in forecasting demand; as a result, EPA assumed that the NERC forecasts were more likely to have already taken their reductions into account. These two programs were categorized as commercial programs and were projected to result in over 89 billion Kwh in reduced electricity demand by 2010. (Docket # A–96–56. Item # XIV–F–01). By comparison, the remaining CCAP commercial programs resulted in reduced electricity demand of 119.6 billion Kwh. *Id.* Therefore, EPA assumed that the NERC forecasts accounted for over 42 percent of the reductions from the commercial CCAP programs, including the pre-1993 programs.

EPA also decided not to include reductions from a fuel cells program and renewable energy program, which were projected to total 24.5 billion Kwh by 2010, both for reasons of erring on the side of the conservative (not including those reductions had the effect of increasing electricity demand) and because adding them would have created some technical modeling complexities. Specifically, EPA would have had to decide at what level, and where, to allocate this capacity among the States within and outside of the NO_X SIP Call region. EPA decided, rather than make that judgment, to err on the side of the conservative by assuming that the fuel cell program and renewable energy program did not reduce electricity. In addition, the emission factors for fuel cells and biomass facilities that could have been employed were highly uncertain. (*See* Docket # A–96–56, Item # XIV–F–01).

Nor did EPA factor in reductions from the Climate Challenge program, which was initiated in 1994 as part of CCAP. Under Climate Challenge, utilities agreed to voluntarily reduce emissions of CO_2 through projects for, e.g., improving electricity generation or transmission efficiency. Because Climate Challenge was specifically directed towards utilities, EPA assumed that the utilities submitting their demand estimates to NERC would be familiar with the program and would be more likely to have taken demand reductions from that program into account. In any event, the Climate Action Report workgroup did not assign a specific amount of reductions to this program.

[11] A commenter questioned the accuracy of the projections of reductions attributable to the programs on the spreadsheet because those projections were done a program-by-program basis, without consideration of the interactive effects of the programs. The IDEAS model run, noted above, in effect considered those interactive effects on the programs and provided as an output the total electricity savings expressed in billion Kwh (along with other outputs, including the emissions reductions). The total electricity savings indicated by the IDEAS model run are virtually identical to the total amounts projected on a program-by-program basis. (Docket #A–96–56, XIV–F–03).

All told, EPA assumed that CCAP programs would result in 389 billion Kwh in reductions by 2010 and further assumed that an additional 113.5 billion Kwh from CCAP programs and their pre-1993 predecessors, or 22.6% of the total, had already been included in the NERC estimates. Thus, it is evident that EPA conservatively assumed that NERC took into account demand reductions from some CCAP programs, even though NERC's documentation did not indicate that any CCAP reductions were taken into account and no utility commenter provided documentation that the demand forecasts they submitted to NERC assumed any CCAP reductions.[12]

On the other hand, EPA did factor into the electricity demand projections the reductions from the CCAP programs initiated in 1993 or later that were aimed at a broader group of potential participants than only utilities. Some of the largest of these programs included (i) WasteWise (a voluntary program designed to reduce municipal waste through waste prevention and recycling); (ii) Motor Challenge (a program designed to help industry realize electricity savings by providing industry with the technical expertise concerning management of electric motor systems and purchase of more energy efficient electric motors); (iii) Rebuild America (a program designed to encourage partnerships of various types of companies and organizations—ranging from builders to local governments—to retrofit existing public housing as well as commercial and multifamily buildings to be more energy efficient); (iv) Energy Star Buildings (a program designed to encourage individual building owners, developers, and others to make comprehensive, energy-efficient building upgrades); and (v) Residential Appliance Standards (a program under which DOE would establish by rulemaking standards for improved energy-efficient appliances such as room air conditioners, refrigerators, water heaters, and others). (Docket # A–96–56, Item # XIV–F–01; Climate Action Report, Appendix A). Because such programs were relatively new and were geared primarily to companies other than utilities, it is less likely that utilities would have included demand reductions from these programs in their electricity demand projections.

A commenting group of utilities argued that the NERC forecasts likely already included the CCAP reductions that EPA used to adjust those forecasts, resulting in double-counting. The commenting utility group noted that some utilities participated in two CCAP programs (i.e., WasteWise and Motor Challenge) and speculated that the participating utilities ''would have'' included CCAP reductions in developing the information provided for the NERC forecasts.

However, utilities comprise only a small number of companies participating in WasteWise and Motor Challenge. In 1996, WasteWise involved over 600 partners, representing over 30 industries, including some utilities. (Docket # A–96–56, Item # X–V–C–24, *Wastewise, Third Year Progress Report,* USEPA, November, 1997, at p.2.) Motor Challenge is aimed primarily at industrial end-users, not utilities, (60 FR 61443–47, Nov. 29, 1995). Thus, the commenter's evidence that a few utilities were among the many participants in these two programs provides a very weak basis for speculating that the NERC forecasts included CCAP demand reductions factored in by EPA. Similarly, many other CCAP programs, including the Rebuild America and Energy Star Buildings programs, were generally directed at entities other than utilities.

Moreover, except for Climate Challenge, the CCAP programs are designed to achieve electricity demand reductions from a wide range of electricity end-users (i.e., residential, commercial, and industrial end-users) and were relatively new—only a few years old when the utilities reported their 1997 demand estimates to NERC. The interagency workgroup had estimated amounts of demand reductions from these programs on a national basis, but had not broken those estimates down to the NERC region level that was the basis for individual utilities' reports to NERC. Accordingly, it appears that the individual utilities would have had relatively little experience in analyzing the extent to which their particular customers followed the CCAP programs and would not have had any other source of information for quantifying the CCAP demand reductions in their respective regions.[13]

For these reasons, it seems reasonable to conclude that as of 1997, the only CCAP program reductions that utilities are likely to have included in their reports to NERC would have been the few older programs or those primarily targeting utilities, and not the many other CCAP programs. Indeed, while a commenting group of utilities speculated that utilities must have taken CCAP into account in submitting their electricity demand information to NERC in 1997, EPA did not receive any direct evidence from the utilities that made the submissions stating (much less demonstrating) that their submissions actually took into account any specific CCAP programs or otherwise reflected any specific demand reductions.[14] Particularly, in light of the silence of the individual utilities about what CCAP reductions they actually included (as distinguished from speculation about what they would have included), EPA maintains that its assumptions about what CCAP reductions were included are reasonable.

In addition, the argument that utilities accounted for all CCAP reductions is undercut by utilities' comments in the NO_X SIP Call proceeding. Several utilities commented that because CCAP reductions are voluntary, such reductions should not be considered when making future demand assumptions. Given this view of the CCAP reductions, it seems doubtful that these utilities would have considered, in their demand forecasts submitted to NERC, the CCAP reductions factored in by EPA. Moreover, an analysis, included in comments by the utility group on whether the NO_X SIP Call would have an impact on the reliability of the region's electricity supply in meeting electricity demand, did not take into account any demand reductions under CCAP (Responses to Significant Comments on the Proposed Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone, September 1998, at 181–82; see also Docket # A–96–56, Item # V–J–66, UARG briefing entitled ''The Impact of EPA's Regional SIP Call on the Reliability of the Electric Power Supply in the Eastern United States,'' September 11, 1998.)

Finally, one utility commenter stated that NERC's forecasts were unlikely to consider CCAP demand reductions. The commenter explained:

[12] Many other CCAP programs generated energy savings but in ways other than reducing electricity demand, so that EPA did not take into account benefits from these programs either.

[13] For example, the Residential Appliance Program depended on a series of DOE regulations establishing standards for numerous appliances. By 1997, DOE had not yet promulgated the first of these regulations. As of 1997, the DOE program manager would nevertheless be in a position to estimate the impact of this program on a national level for future years, but individual utilities estimating electricity demand in their areas would not be in a position to do so.

[14] Indeed, several commenters critical of EPA's electricity demand assumptions nevertheless acknowledged that it is unclear to what extent individual utilities incorporated CCAP programs into their demand projections. (Docket # A–96–56, Item # XIV–D–14, Michigan, Attachment, p. 5, and Item # XIV–D–31, UARG, Attachment H, p. 7).

NERC's reliability planning mission suggests just the opposite. NERC projections of future demand growth are used to determine how much capacity is needed to meet demand to ensure electric system reliability. The projections are a compilation of individual utility projections sent to each of the NERC regional councils to ensure adequate supply exists to meet demand in each region. The projections must be conservative and err on the side of overstating demand to avoid supply shortfalls—it is of little consequence if NERC overestimates demand, but of potentially great consequence if it underestimates it. For this reason, although the compiled nature of NERC's forecasts makes it virtually impossible to assess its underlying assumptions, it is reasonable to assume NERC projections largely ignore new, uncertain electricity demand dampening impacts, such as voluntary programs with no clear track record of affecting electricity consumption. (See Docket # A–96–56, Item # XIV–E–01, Letter from Mark Brownstein, Public Service Electric & Gas, Sept. 15, 2001, at p. 8)

(ii) EIA Forecasts

Several commenters pointed out that NERC's electricity demand forecast (1.8% demand growth per year) and EIA's electricity demand forecast (1.7% demand growth per year) are similar and higher than EPA's forecast. Emphasizing that EIA explicitly took CCAP reductions into account, commenters suggested that the EIA forecast factored in the proper amount of CCAP demand reductions and that the similarity of the EIA and NERC forecasts therefore shows that the NERC forecasts already properly factored in such demand reductions.

However, EIA's explanation, in the Annual Energy Outlook for 1998, of its electricity demand forecast indicated that while EPA factored into its forecasts all the CCAP demand reductions projected by the State Department's Climate Action Report, described above, EIA factored into its forecasts only a small portion of those reductions. This different treatment of CCAP reductions explains much of the difference in demand reductions between EIA and EPA.

The Climate Action Report organizes virtually all of the CCAP programs that affect electricity demand into three categories: residential, commercial, and industrial, (Climate Action Report, Table 1–2). The report indicates that the residential and commercial programs were expected to generate reductions of carbon emissions totaling 53 million metric tons by 2010. *Id.* Not including the reductions from programs that EPA assumed were included in the NERC estimates, EPA reduced projected electricity demand in 2010 due to these programs by 282.5 billion KWh (Docket # A–96–56, Item # XIV–F–01). EIA, however, reduced projected electricity demand in 2010 from these programs by much less. In explaining its analysis of the impact of CCAP residential and commercial programs, EIA stated:

> Other CCAP programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs which are cooperative efforts between the EPA and home builders and energy appliance manufacturers encourage the development and production of highly energy-efficient housing and equipment. At fully funded levels, residential CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 28 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 8 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies. * * *
>
> At fully funded levels, commercial CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 25 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be just over 9 million metric tons in 2010, primarily because of differences in estimated penetration of energy-saving technologies.

(*Annual Energy Outlook 1998* (AEO98), Energy Information Administration, December 1997 at 209–10).

In other words, EIA believed that CCAP residential and commercial programs would be about one-third as effective at reducing energy use (including electricity use) as the State Department and EPA and other sponsors projected and included the lower estimate of the energy use reductions in the ''reference case'' on which EIA based its electricity demand forecasts.

EIA similarly assumed much fewer energy savings from CCAP industrial programs than EPA believed based on the Climate Action Report. As EIA explained:

> For their annual update, the program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 20 billion kilowatt hours * * * However since the energy savings associated with the voluntary programs are, to a large extent, already contained in the AEO98 baseline total CCAP energy savings were reduced. Consequently, CCAP is assumed to reduce electricity consumption by 9 billion kilowatt hours. *Id.* at 210.

EIA essentially assumed that CCAP industrial programs resulted in relatively few additional energy saving activities beyond those activities that industrial companies were already carrying out and that were therefore already reflected in the ''AEO98 baseline'' or ''reference case'' on which EIA based its electricity demand forecasts. By comparison, the State Department analysis projected that industrial CCAP programs would generate reductions of 96.4 billion Kwh (counting an adjustment from programs categorized as commercial) (Docket # A–96–56, Item # XIV–F–01). Thus, EIA projected that these industrial programs would generate savings of less than one-tenth the amount that EPA did.

As discussed above, EPA's more aggressive assumptions were taken from the supporting analysis for the State Department's Climate Action Report, which included reduction estimates that were developed through interagency consultation and were subject to public comment. EPA believes it was appropriate to use them.

Some commenters suggest that EPA should assess whether the CCAP demand reductions are still justified based on any new information that has become available since EPA issued the Section 126 Rule and the Technical Amendments. EPA believes that it is appropriate for the Agency to rely on the information that was available during the rulemakings that resulted in those rules. However, EPA notes that commenters did not provide any specific information showing that EPA's projected CCAP demand reductions were incorrect.[15] Further, new, current information provides some confirmation that EPA's projected CCAP demand reductions were reasonable. A recent report, (Docket # A–96–56, Item # XV–C–25, *The Power of Partnerships Energy Star and Other Voluntary Programs—2000 Annual Report*, EPA , 2001 at p. 6) states that the Energy Star Program, which promotes highly efficient equipment such as energy efficient refrigerators, dish washers, and windows, has exceeded the level forecasted by CCAP for 2000 by more than 20 percent of the forecasted level in the CCAP.[16] Furthermore, EPA has expanded CCAP to cover other uses of electricity (e.g., at hospitals) that will increase savings further. (See Docket # A–96–56, Item # XV–C–26, EPA Administrator Launches New Energy

[15] A commenter stated that CCAP has not generated the expected level of reductions because it did not achieve its goal of reducing U.S. greenhouse gas emissions to 1990 levels. However, the amounts of reductions projected by the Climate Action Report for particular CCAP programs affecting electricity demand, which are the ones relevant for present purposes, were far less than would be necessary to reduce overall U.S. greenhouse gas emissions to 1990 levels.

[16] Only a small part of the Energy Star reductions were considered to be included in the NERC forecasts because they involved programs in existence before 1993.

Star Rating Tool for Hospitals, Honors First Hospital to Earn Energy Star Label, November 15, 2001.)

In short, commenters failed to show that the EIA electricity demand forecast properly factored in the CCAP demand reductions, much less that the NERC forecast (which was higher than the EIA forecast) already included the CCAP demand reductions that EPA used to reduce the NERC forecast.

(iii) Consistency With Regional Heat Input

Finally, EPA notes that ''the electricity demand reductions [under CCAP] were distributed evenly throughout the United States, and therefore have no influence on the share of the total amount of NO_X emissions that each State receives,'' (63 FR 57414). Any overestimation of the CCAP demand reductions would therefore be likely to result in regionwide projections of heat input being lower than actual levels, rather than in only a few States' projections being lower than actual levels. Yet, as explained below, EPA's heat input projections have been reasonably accurate on a regionwide basis. EPA's projections were 0.1% lower than actual regionwide heat input for 2000 and 2% higher than actual regionwide heat input for 2001. This indicates that the CCAP assumptions were reasonable and did not lead to ''stark disparities between [EPA's] projections and real world observations.'' *Appalachian Power* v. *EPA*, 249 F.3d 1054.[17]

5. EPA's Assumptions Regarding the Location of New Units Were Reasonable

Commenters on EPA's August 3, 2001 NODA expressed concern about the methodology that EPA used to assign new units to individual States.[18] The IPM divided the country into geographic regions that are based on NERC regions. These regions are further subdivided to account for transmission bottlenecks or areas that have different environmental requirements. These regions and subregions do not correspond to State boundaries, in many cases. For example, part of Illinois and part of Missouri is split between two NERC Regions, the East Central Reliability Area Council (ECAR) and the Mid America Interconnected Network. Similarly, Virginia and Kentucky are split between ECAR and the Southern Electric Reliability Council (SERC). While Alabama and Georgia are both located entirely within the SERC Region, in IPM they have been further subdivided into multiple IPM subregions to more closely match the constraints within the electric distribution system. The IPM runs indicated which new units would operate in which subregions but did not specify in which States in these subregions. In order to develop State budgets, EPA had to develop a methodology to disaggregate these new units from the subregional level to the State level.

Under EPA's methodology, new units that had commenced construction or received financing, at the time that the model was updated (i.e., in 1998) for use in the NO_X SIP Call and the Section 126 Rule, were included in the State in which they existed or were planned. Second, new units that had not commenced construction or received financing at that time, but that were projected by the IPM to be built were assigned to an individual State based on the share of the subregion's generation capacity (both fossil and non-fossil) that was located in the State. EPA maintains that this was a reasonable approach that took into account the then most current, available information on new unit construction and financing.

EPA also notes that the only alternative approach suggested by commenters was to use new information on the commencement of construction and financing of new units. To the extent that this type of information was available at the time that EPA updated the IPM (i.e., in 1997) for use in the NO_X SIP Call and the Section 126 Rule, EPA did use such information. However, EPA rejects the approach of now using new information of this type, for units that have been more recently built or are currently being built, that was not available when the IPM was updated. EPA believes that it reasonably relied on the most current information available around the time the IPM was updated and that it would not be reasonable to require the Agency to redo its analysis whenever, as inevitably occurs, more recent information becomes available. Imposing such a requirement would be a prescription for endless rulemaking.

It should also be noted that, while coal-fired and nuclear units make up about 77% of existing electricity generation capacity (with gas- and oil-fired units making up 13% and hydroelectric and renewal facilities making up the rest), the only new units projected by the IPM in the runs for the NO_X SIP Call (and applicable to the Section 126 Rule) were gas-fired units. Because new gas-fired units will likely have very high levels of NO_X control and much lower NO_X emissions as compared to existing units (see discussion of new units' low NO_X emissions in section V.D.8 of this notice), these units will have a much smaller impact on NO_X emissions than do existing units. Therefore, even if some new units locate in different States than those projected by the IPM, those units will not significantly increase the NO_X emissions in the States where they locate and so will not significantly increase the stringency of the NO_X emission reduction requirements for other units in such States. In conclusion, EPA believes that its heat input growth rate methodology—including the challenged assumptions on new unit location, electricity demand, and representativeness of the 2001–2007 heat input growth rates—is reasonable.

D. Actual Heat Input Compared to EPA Projections of Heat Input

1. Court's and Commenters' Concerns

The Court expressed concern about the perceived discrepancies between EPA's heat input projections and actual heat input data. The Court stated: ''In Michigan and West Virginia, for example, actual utilization in 1998 already exceeded the EPA's projected levels for 2007. This, on its face, raises questions about the reliability of the EPA's projections.'' (*Appalachian Power* v. *EPA,* 249 F.3d at 1053). The Court added that ''[f]urther growth projections that implicitly assume a baseline of negative growth in electricity generation over the course of a decade appear arbitrary, and the EPA can point to nothing in the record to dispel this appearance.'' *Id.*

Commenters expressed similar concerns. Through the August 13, 2001 NODA, EPA put in the docket data indicating ozone season heat input for each State in the NO_X SIP Call region for the years 1997–2000. Commenters pointed out that this data indicated that in 2000, actual heat input for four other States—Alabama, Georgia, Illinois, and Missouri—exceeded EPA's projected heat input for the year 2007. Commenters claimed that this showed

[17] EPA also notes that the Agency's use of assumed CCAP reductions did not significantly affect the cost effectiveness of the NO_X emissions reductions on which the State NO_X emission budgets are based and did not change whether the reductions met EPA's cost effectiveness criteria. As explained in the NO_X SIP Call, EPA examined the impact of the CCAP reductions and found that ''even if the Agency did not assume the CCAP reductions, it was still highly cost effective to develop a regional level NO_X budget for the electric power industry, based on the level of control that EPA has assumed,'' (63 FR 57414). (*See also* Regulatory Impact Analysis for the Regional NO_X SIP Call, at 6–24 and 6–25, September 1998).

[18] This issue, like the CCAP issues, was raised by commenters for the first time in response to the August 3, 2001 NODA and was not raised in any earlier rulemaking or before the Court. Nevertheless, EPA is addressing all these issues on the merits in today's notice.

that EPA's heat input growth rates and projections were unreasonable. Through the March 11, 2002 NODA, EPA put in the docket comparable data for the year 2001 and, subsequently, put in annual data for each State for 1960–2000. (See Docket # A–96–56, Item #'s XV–C–18 and XV–C–19).

After careful review of these and other data in the record and the Court's and commenters' concerns, EPA concludes that the available, actual heat input does not indicate that the Agency's heat input growth methodology is unreasonable.

2. EPA's Heat Input Projections for the Region Are Consistent With Actual Heat Input Data

EPA's heat input projections for EGUs for the NO_X SIP Call region (21 States and the District of Columbia), taken as a whole, are consistent with the actual heat input data that are available. EPA projected heat input for 2007 by applying State heat input growth rates to 1995 or 1996 baseline heat input. Although 2007 is the only year for which EPA was projecting heat input and for which EPA established NO_X emission budgets for EGUs, the EPA methodology can be applied to yield heat input values for other years, such as 2000 and 2001. When compared with actual heat input data now available for 2000 and 2001, EPA projections for those years are consistent with the actual data.

Specifically, EPA's projections for total regionwide heat input for EGUs are 6,250,350,678 mmBtu for 2000 and 6,328,056,922 mmBtu for 2001.[19] These projections are 0.1% lower and 2% higher respectively than actual regionwide heat input for EGUs for 2000 and for 2001 (see Table 1).

In commenting on the data presented by the August 3, 2001 NODA, which included the actual heat input values for years up to 2000, commenters stated that the closeness of the regionwide projection for 2000 and actual regionwide heat input did not cast doubt on their view that EPA's heat input growth methodology provided unreasonably low growth rates. Rather, commenters asserted, the closeness was ''pure coincidence'' resulting from EPA using an inflated 1995–1996 baseline and applying to it a ''less-than-reasonable'' heat input growth rate.

According to the commenters, in subsequent years, EPA's regionwide projection would diverge significantly from actual regionwide heat input.

The actual heat input values for 2001 became available after the submission of comments on the August 3, 2001 NODA and were put in the docket. As noted above, the regionwide, actual heat input for 2001 remains quite close to, and in fact is a little lower than, the EPA's regionwide heat input projection for 2001. Of course, regionwide electricity demand, and so regionwide heat input, in the 2001 ozone season were probably somewhat lower than they otherwise would have been because of the unusual reduction in economic activity immediately after the September 11, 2001 terrorist attacks. Even so, regionwide electricity demand still grew slightly over 2000 ozone season levels. (Docket #A–96–56, Item # XV–C–12, summarizing EIA electricity sales data for the ozone season for the NO_X SIP Call States during 1995–2001). With the continued closeness of EPA's projected and the actual values for regionwide heat input, it is difficult to give the commenters' assertion of ''pure coincidence'' much credence. Moreover, as discussed above, EPA's methodology for developing heat input growth rates, and the assumptions underlying the methodology, are reasonable, and so it is logical to expect that the heat input projections resulting from that methodology are reasonable.

3. EPA's Heat Input Growth Rates and 2007 Projections for Most States Are Not Disputed by Commenters

EPA's heat input growth rates and 2007 projections for most States in the NO_X SIP Call region, and for most States covered by the Section 126 Rule, are not specifically disputed by commenters. Of the 21 States and the District of Columbia covered by the NO_X SIP Call, or recently proposed to be covered, the heat input growth rates and 2007 projections for only seven States (Alabama, Georgia, Illinois, Michigan, Missouri, Virginia, and West Virginia) are disputed by commenters. Of the 12 States and the District of Columbia covered by the Section 126 Rule, these values for only three States (Michigan, Virginia, and West Virginia) are disputed by commenters.

As noted above, petitioners and the Court raised concerns about EPA's growth rates and projections for Michigan and West Virginia, stating that EPA's State heat input growth rates resulted in State projections for 2007 below the 1998 actual heat input values. Subsequently, in comments on the August 3, 2001 NODA, commenters raised concerns that the heat input growth rates for five other States (Alabama, Georgia, Illinois, Missouri, and Virginia) were too low because, for each State, the actual heat input in 2000 exceeded or were close to EPA's 2007 projection. For the remaining 15 jurisdictions in the NO_X SIP Call region, EPA's heat input growth rates and projections were not disputed by any petitioner and are not disputed in any comments on the August 3, 2001 and March 11, 2002 NODA's or on any other documents added to the docket concerning the remand on growth rates.

The fact that no objections have been raised with respect to the majority of the States is an indication of the reasonableness of EPA's heat input growth methodology. Further, as discussed below, all of the States about which the Court or commenters expressed concern have recently had decreases in their heat input, in some cases to levels below EPA's 2007 projections. Also as discussed below, because in a number of instances State annual heat input has decreased significantly over multi-year periods, the fact that a State has recently had heat input exceeding or close to EPA's 2007 projections does not mean that the projection is unreasonable.

4. Historical Data Show That a State's Heat Input Can Decrease Significantly Over Multi-Year Periods

As noted above, the Court indicated significant doubt that a State's heat input could decrease over a long period of years. The Court seemed to be concerned that underlying a decrease in State heat input would have to be a decrease in electricity generation. Consequently, the Court questioned the reasonableness of EPA's heat input growth rate methodology because the methodology resulted in a State exceeding its 2007 level nine years in advance. However, historical heat input data shows that, on many occasions, State annual and ozone season heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods.

Table 1 below shows the ozone season heat input for EGUs for 1995–2001 for each State in the NO_X SIP Call region. For each ozone season, EPA summed the heat input data for Acid Rain Program units, as reported to EPA under 40 CFR part 75, and for other EGUs, as reported to EIA.

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[19] As noted in the August 3, 2001 NODA, EPA's methodology called for projecting 2007 heat input, not heat input at interim points in time. However, for purposes of responding to concerns about the reasonableness of the methodology, it is useful to examine what the methodology would project if applied to interim points in time when data concerning actual heat input are available.

Table 1 - Heat Input for EGUs for 1995-2001 Ozone Seasons

State	1995 Ozone Season Heat Input	1996 Ozone Season Heat Input	1997 Ozone Season Heat Input	1998 Ozone Season Heat Input	1999 Ozone Season Heat Input	2000 Ozone Season Heat Input	2001 Ozone Season Heat Input
AL	350,059,204	350,907,982	350,328,372	369,978,200	389,364,461	400,689,850	391.665,691
CT	48,093,524	61,678,648	64,381,511	56,591,808	75,967,544	61,324,920	54,430,209
DC	2,026,082	128,205	645,846	3,113,446	3,173,633	1,153,593	1,272,251
DE	42,077,856	45,204,267	39,315,387	45,932,682	39,394,171	35,185,752	38,898,944
GA	356,963,346	335,977,013	351,207,750	403,716,898	387,781,101	420,260,694	374,355,956
IL	347,985,300	379,029,184	406,127,886	450,929,580	418,420,171	436,052,570	434,282,881
IN	514,611,872	523,672,522	536,772,484	577,059,852	582,006,636	523,711,122	564,472,583
KY	410,472,859	414,304,687	406,480,534	431,861,492	455,747,249	440,776,959	447,829,251
MA	124,983,468	113,298,531	123,844,201	136,001,859	147,443,919	124,327,323	122,126,098
MD	143,395,098	136,794,146	146,128,637	182,217,612	183,980,736	148,950,008	153,654,978
MI	362,883,707	351,493,214	356,684,564	408,239,157	396,605,048	381,142,911	374,318,406
MO	283,776,902	276,038,736	298,106,042	314,731,878	335,273,139	332,332,587	329,668,165
NC	320,845,066	340,609,864	325,299,250	372,494,163	351,368,932	330,683,806	340,211,360
NJ	106,479,866	88,074,347	92,928,677	78,088,747	113,385,505	106,900,335	117,188,481
NY	374,784,148	286,550,572	291,440,062	360,671,489	408,149,310	347,004,497	354,257,069
OH	554,457,657	566,131,821	543,431,600	596,937,824	590,290,990	571,651,486	540,109,544
PA	527,611,362	566,917,544	534,849,419	578,757,472	493,042,169	516,308,527	499,158,768
RI	16,066,757	43,102,370	12,029,849	11,140,079	34,133,203	30,158,008	28,428,750
SC	136,790,135	156,359,804	148,194,438	175,584,043	186,256,000	187,329,450	186,606,291
TN	281,896,512	269,960,693	268,808,769	256,156,350	261,568,838	281,169,294	269,012,650
VA	154,233,310	172,633,028	179,436,621	219,246,917	225,665,092	212,075,792	213,583,835
WV	347,687,307	341,738,426	364,757,289	386,442,663	391,592,231	380,868,435	360,185,154
Total	5,808,181,338	5,820,605,605	5,841,199,188	6,415,894,211	6,467,884,728	6,268,189,238	6,195,717,293

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This ozone season data shows decreases in State heat input for several States for the last year, as compared to the first year, of multi-year periods of 3 to 6 years.[20] For example, during 1995 through 2001, Delaware, Georgia, Illinois, Indiana, Massachusetts, Maryland, Michigan, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia had decreases in heat input for the last year, as compared to the first year, of the 3-year period 1998–2001. Heat input decreases for other multi-year periods occurred during 1995 through 2001 for Delaware (6-year period 1995–2001), North Carolina (5-year period 1996–2001), New Jersey (3-year period 1995–1998), New York (6-year period 1995–2001), Pennsylvania (6-year period 1995–2001) Rhode Island (4-year period 1996–2000), and Tennessee (6-year period 1995–2001).

EPA also examined long-term, fossil fuel use data. The long-term data from EIA show fossil fuel use (in mmBtu) on an annual, not an ozone season, basis for the 21 States subject to the NO_X SIP Call for 1960–2000.[21] (Because of the large amount of data, the full set of 1960–2000 annual data is provided in Docket #A–96–56, Item #XV–C–18, rather than being included in today's notice.) These data demonstrate that decreases in State annual heat input, like decreases in State ozone season heat input, are not unusual.

Specifically, the 1960–2000 annual heat input data show significant decreases in State annual heat input for the last year, as compared to the first year, of multi-year periods of 3 to 10 years (or longer). In fact, all but one of the 21 States under the NO_X SIP Call has had significant decreases in annual heat input over many multi-year periods ranging from 3 to 10 years; one of the States (Indiana) has had such decreases over multi-year periods, within that range, of only 3-years. Tables 2, 3, 4, 5, 6, 7 ,8, and 9 summarize this information by showing the largest percentage decreases (for the last year, as compared to the first year, of multi-year periods) that the listed States have had in annual heat input over 3-year, 4-year, 5-year, 6-year, 7-year, 8-year, 9-year and 10-year periods respectively.

[20] EPA, of course, recognizes that there also can be significant increases in State heat input over multi-year periods. However, commenters suggested that significant decreases could not occur. The point is that, since significant decreases can occur, the fact that State's recent heat input exceeds or is close to EPA's 2007 projection does not make the projection unreasonable.

[21] EIA collected, on a long term historical basis, monthly and annual plant-by-plant data on quarterly and heat content of fuel used. EIA used these data to determine annual heat input for each State and did not determine State heat input on an ozone season basis. EPA notes that its analysis does not include the District of Columbia, for which a full set of historical, annual heat input data was not available. However, the heat input growth rate for the District of Columbia is not disputed by commenters.

TABLE 2.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER THREE YEARS

State	3-year period	% decrease in heat input
Alabama	1979—1982	17
Connecticut	1989—1992	6
Delaware	1995—1998	24
Georgia	1989—1992	9
Illinois	1986—1989	17
Indiana	1979—1982	3
Kentucky	1997—2000	8
Massachusetts	1997—2000	42
Maryland	1978—1981	26
Michigan	1979—1982	19
Missouri	1990—1993	12
New Jersey	1989—1992	46
New York	1990—1993	34
North Carolina	1981—1984	17
Ohio	1979—1982	11
Pennsylvania	1996—1999	14
Rhode Island	1990—1993	88
South Carolina	1981—1984	19
Tennessee	1979—1982	16
Virginia	1979—1982	35
West Virginia	1988—1991	13

TABLE 3.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER FOUR YEARS

State	4-year period	% decrease in heat input
Alabama	1980—1984	9
Connecticut	1989—1993	55
Delaware	1996—2000	25
Georgia	1988—1992	12
Illinois	1984—1988	18
Indiana	None	None
Kentucky	1996—2000	5
Massachusetts	1989—1993	34
Maryland	1978—1982	23
Michigan	1979—1983	19
Missouri	1989—1993	13
New Jersey	1989—1993	48
New York	1990—1994	37
North Carolina	1983—1987	48
Ohio	1979—1983	12
Pennsylvania	1980—1984	14
Rhode Island	1989—1983	86
South Carolina	1980—1984	15
Tennessee	1978—1982	24
Virginia	1979—1983	35
West Virginia	1989—1993	14

TABLE 4.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER FIVE YEARS

State	5-year period	% decrease in heat input
Alabama	1977—1982	15
Connecticut	1989—1994	55
Delaware	1993—1998	28
Georgia	1987—1992	14
Illinois	1983—1988	23
Indiana	None	None
Kentucky	1995—2000	2
Massachusetts	1989—1994	35
Maryland	1976—1981	24
Michigan	1978—1983	17
Missouri	1988—1993	13
New Jersey	1989—1994	44
New York	1989—1994	40
North Carolina	1982—1987	25
Ohio	1979—1984	11
Pennsylvania	1980—1985	13
Rhode Island	1988—1993	90
South Carolina	1981—1986	14
Tennessee	1977—1982	23
Virginia	1977—1982	38
West Virginia	1988—1993	12

TABLE 5.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER SIX YEARS

State	6-year period	% decrease in heat input
Alabama	1976—1982	11
Connecticut	1989—1994	52
Delaware	1993—1999	28
Georgia	1985—1991	14
Illinois	1983—1989	25
Indiana	None	None
Kentucky	1993—1999	2
Massachusetts	1989—1995	37
Maryland	1974—1980	27
Michigan	1976—1982	13
Missouri	1987—1993	9
New Jersey	1989—1995	45
New York	1990—1996	44
North Carolina	1981—1987	29
Ohio	1977—1983	8
Pennsylvania	1980—1986	15
Rhode Island	1987—1993	91
South Carolina	1977—1983	11
Tennessee	1976—1982	24
Virginia	1977—1983	38
West Virginia	1985—1991	11

TABLE 6.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER SEVEN YEARS

State	7-year period	% decrease in heat input
Alabama	1975—1982	8
Connecticut	1986—1993	53
Delaware	1993—2000	31
Georgia	1985—1992	17
Illinois	1981—1988	22

TABLE 6.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER SEVEN YEARS—Continued

State	7-year period	% decrease in heat input
Indiana	None	None
Kentucky	1993—2000	1
Massachusetts	1989—1996	40
Maryland	1974—1981	37
Michigan	1975—1982	15
Missouri	1984—1991	7
New Jersey	1989—1996	54
New York	1989—1996	47
North Carolina	1981—1988	27
Ohio	1977—1984	7
Pennsylvania	1980—1987	14
Rhode Island	1986—1993	89
South Carolina	1977—1984	6
Tennessee	1976—1983	15
Virginia	1976—1983	38
West Virginia	1984—1991	10

TABLE 7.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER EIGHT YEARS

State	8-year period	% decrease in heat input
Alabama	1974–1982	12
Connecticut	1986–1994	52
Delaware	1991–1999	29
Georgia	1984–1992	11
Illinois	1980–1988	28
Indiana	None	None
Kentucky	None	None
Massachusetts	1992–2000	41
Maryland	1974–1982	35
Michigan	1974–1982	13
Missouri	1984–1992	11
New Jersey	1984–1992	53
New York	1988–1996	42
North Carolina	1980–1988	24
Ohio	1976–1984	5
Pennsylvania	1991–1999	12
Rhode Island	1985–1993	88
South Carolina	1978–1986	2
Tennessee	1976–1984	13
Virginia	1977–1985	36
West Virginia	1985–1993	11

TABLE 8.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER NINE YEARS

State	9-year period	% decrease in heat input
Alabama	1973–1982	17
Connecticut	1984–1993	51
Delaware	1991–2000	33
Georgia	1984–1993	3
Illinois	1990–1989	31
Indiana	None	None
Kentucky	None	None
Massachusetts	1991–2000	47
Maryland	1972–1981	31
Michigan	1974–1983	13

TABLE 8.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER NINE YEARS—Continued

State	9-year period	% decrease in heat input
Missouri	1984–1993	20
New Jersey	1984–1993	54
New York	1987–1996	35
North Carolina	1981–1990	26
Ohio	1979–1988	2
Pennsylvania	1990–1999	14
Rhode Island	1984–1993	88
South Carolina	None	None
Tennessee	1973–1982	18
Virginia	1974–1983	35
West Virginia	1984–1993	9

TABLE 9.—LARGEST DECREASES IN STATE ANNUAL HEAT INPUT OVER TEN YEARS

State	10-year period	% decrease in heat input
Alabama	1973–1983	9
Connecticut	1983–1993	48
Delaware	1988–1998	31
Georgia	None	None
Illinois	1979–1989	32
Indiana	None	None
Kentucky	None	None
Massachusetts	1990–2000	48
Maryland	1972–1982	28
Michigan	1973–1983	11
Missouri	1983–1993	16
New Jersey	1983–1993	55
New York	1989–1999	31
North Carolina	1980–1990	23
Ohio	None	None
Pennsylvania	1989–1999	21
Rhode Island	1983–1993	88
South Carolina	1973–1983	6
Tennessee	1973–1983	8
Virginia	1972–1982	36
West Virginia	1981–1991	6

Although the longer term EIA annual heat input data and EPA's shorter term ozone season data show the same types of multi-year period decreases, EPA conducted further analysis in order to confirm that ozone season and annual State heat input have similar fluctuations. Specifically, EPA used EIA monthly data on fuel quantity (which was available for years starting with 1970) and generic heat content factors in order to derive estimated ozone season heat input data for 1970–1998. [See Docket # A–96–56, Item # XV–C–19 (explaining how EPA derived estimated ozone season data and providing that estimated data)]. Because of the nature of the simplifying assumptions that EPA made in order to derive long-term ozone season data, EPA's analysis in this notice relies primarily on the long-term State annual heat input data, not the derived long-term State ozone season heat input data. However, EPA believes that the latter data confirm EPA's annual-data analysis because the long-term ozone season data show multi-year decreases in State heat input that are very similar in length and magnitude to those shown by the long-term State annual heat input data. *Id.*

In summary, historical data show that heat input (whether for the ozone season or the entire year) in individual States is quite variable and has decreased significantly over multi-year periods on a number of occasions. EPA respectfully submits that the data provide a basis for the Court to reconsider its concern that the fact that heat input values for some States for certain years have already exceeded EPA's 2007 heat input projections supports objections to the reasonableness of EPA's heat input growth methodology.

5. Approach of Using Recent State Heat Input To Project Future State Heat Input Is Not Statistically Sound

Commenters claimed that, because the recent heat input for seven States (Alabama, Georgia, Illinois, Michigan, Missouri, Virginia, and West Virginia) has exceeded or been close to EPA's 2007 heat input projections, EPA's projections are unreasonable. In making this claim, commenters implicitly assumed that future heat input can reasonably be projected using a relatively short period of years of actual State heat input data.

In order to test the validity of this assumption, EPA simulated that approach using historical annual heat input data for the 21 NO_X SIP Call States for 1960–2000 (or in some States where less data was available, from 1970–2000). Using this data, EPA used 6 years worth of historical data (e.g., 1960–1966) to project annual heat input for the sixth year after the 6-year period (e.g, 1972). EPA did this on a rolling basis, using historical 6-year periods from 1960 to 1994 (or 1970 to 1994), to project annual heat input for the years 1972 (or 1982) to 2000. EPA tested how well the historical data predicted future annual heat input value by comparing the projected value with the actual value for the same year. Specifically, EPA performed an r-squared test on the actual annual heat input vs. the projected annual heat input for the same year. This test provides a measure of how much a change in one variable (here, actual annual heat input) is related to a change in a second variable (here, projected annual heat input). For instance, an r-squared value of 1 implies that all of the change in the first variable is related to change in the second value. Conversely, an r-squared value of 0 implies that none of the change in the first variable is related to change in the second variable.

EPA found that, in testing the actual annual heat input data vs. the projected annual heat input data for each State, 10 States (including Illinois, Michigan and Virginia) out of the 21 NO_X SIP Call States had r-squared values below 0.12. An additional six States (including Missouri and West Virginia) had r-squared values below 0.32. Because the r-squared test showed that less than one-third of the variability in projected annual heat input can be explained by the variability in actual annual heat input for 16 of the NO_X SIP Call States, EPA believes that it is clear that historical heat input cannot be used as a reliable indicator of future heat input. Moreover, the r-squared values for the remaining States were: Alabama, 0.63; Georgia 0.42; Indiana, 0.80; Kentucky, 0.67; New Jersey (0.59). Except for Indiana, this indicates only a weak correlation between actual heat input data and projected heat input data because 33% to 58% of the variability of projected heat input data cannot be explained by the variability in actual heat input data. Even in Indiana where the correlation was strongest, the projections ranged from 13.4% below the actual value to 10.9% above the actual value. For Alabama, 15 of the 29 projections were more than 10% above or below the actual value, and the projections ranged from 26.7% below the actual value to 27.9% above the actual value. (See Docket # A–96–56, Item #'s XV–C–19 and XV–C–20.) For other States, disparities between the projected values and the actual values were even wider. The variability in the projections for the States where concerns have been raised are summarized below.

State	Number of projections off by more than 10%	Range of projections
Alabama	15 of 29	−26.7% to 27.3%
Georgia	14 of 29	−50.9% to 37.0%
Illinois	21 of 29	−46.4% to 40.1%
Michigan	25 of 29	−33.4% to 54.6%
Missouri	23 of 29	−36.4% to 31.9%
Virginia	25 of 29	−60.2% to 71%
West Virginia.	21 of 29	−44.0% to 37.9%

In short, historical State heat input for a relatively short period of years is not a reliable method for predicting future State heat input.

6. EPA's Heat Input Projections Do Not Implicitly Assume Negative Growth in Electricity Generation

In *Appalachian Power* v. *EPA,* 249 F.3d at 1053, the Court expressed concern that, for States whose actual heat input for EGUs already exceeded EPA's projections for 2007, EPA's projection "implicitly assume a baseline of negative growth in electricity generation." Although the Court expressed concern about electricity generation, it should be recalled that in the NO_X SIP Call and Section 126 Rule, the regulatory requirements were computed with reference to heat input, and not electricity generation. Accordingly, in expressing concern about electricity generation, the Court apparently was concerned that a decrease in heat input would necessarily mean a decrease in electricity generation and that a projection of a heat input decrease would implicitly assume decreased electricity generation.

In response, EPA respectfully submits that fossil-fuel use at the State level—which is at issue in the present case—is but one factor associated with electricity generation. Many other factors affect electricity generation as well. Accordingly, EPA respectfully submits that a decrease in State heat input (whether actual or projected) does not implicitly mean a decline in electricity generation.

Indeed, State heat input can decrease while electricity generation in the State or in the region increase. There are at least two reasons why this can happen. First, even within a State, heat input does not necessarily correlate with electricity generation because of electricity generated using non-fossil fuel sources and increased efficiency of fossil fuel generation. Second, because electricity is sold on a regionwide basis, electricity generation can decrease in one State and increase in another State, with increased electricity being sold and used in the first State.

a. State heat input does not necessarily correlate with electricity generation in the State. Electricity generation in a State can increase at the same time that heat input (i.e., fossil fuel use) decreases in that State. One reason for this is that significant amounts of electricity can be generated from non-fossil sources, such as nuclear units or hydro-electric facilities.

Commenters suggested that heat input will have to increase in the next several years because nuclear power plants are already operating at near capacity. This may be generally correct on a regionwide basis, and EPA projects increased regionwide heat input in 2007. However, this is not true on a State-by-State basis for all States. For example, in Illinois several nuclear power plants recently received approval by the Nuclear Regulatory Commission to increase their generation capacity. Four units (Dresden Units 2 and 3 and Quad Cities Units 1 and 2) plan to increase their capacity by 17 to 18% in 2002 and 2003.[22] Carrying out these plans will tend to reduce heat input, while increasing electricity generation. Further, two units at the Cook Nuclear Plant in Michigan underwent an extended, unexpected outage in 1998–2000. The outage of the two units tended to increase fossil fuel use, and bringing them back online tended to decrease fossil fuel use. An increase in nuclear generation can reduce heat input without reducing total electricity generation in a State.

Heat input can also decrease, without decreasing electricity generation, because the efficiency of fossil-fuel fired electricity generating units can be increased, allowing generation of the same amount of electricity with use of less fossil fuel. One way this can occur is through replacement of existing boilers, which are on average between 33% and 35% efficient at converting fossil fuel to electricity, with combined cycle turbines, which can be up to 60% efficient. For example, on February 25, 2000, Illinois approved a permit for Ameren Corporation to replace two coal-fired units at the Grand Tower Generating Station with two combined cycle gas turbines.[23]

Efficiency can also be improved through modifications at existing generation facilities. For example, improvements can be made to the boiler that allow better transfer of heat from the burning coal to the steam used to power the turbine-generators; the

[22] See http://www.nrc.gov/reading-rm/doc-collections/news/archive/01–136.html.

[23] See http://yosemite.epa.gov/r5/il_permt.nsf/50d44ae9785337bf8625666c0063caf4/b04c4b1ab67564e48625685d0068df82/$FILE/99080101fnl.PDF; and http://www.dom.com/operations/station-fossil/unit.html.

efficiency of auxiliary equipment such as fans can be improved; the efficiency of the turbine generators that convert the steam to electricity can be improved; and combustion optimization software, which can reduce NO_X emissions while increasing efficiency, can also be added.[24] Greater efficiency, whether from improvements to existing facilities or from new units, can result in the same or more electricity generation in a State with less heat input. EPA notes that the incentives for companies that generate electricity for sale to improve the efficiency of electricity generation has increased with deregulation of electricity generation and increased competition in the electricity market.

b. Electricity is generated and sold on a regional, not on a State-by-State basis. Electricity generation may decrease in one State but, because electricity is generated and sold on a regional basis, the decrease may simply reflect the fact that customers are using electricity generated in another State. Three factors—the deregulation of electricity generation, the restructuring of the electricity industry, and the efforts of the Federal Energy Regulatory Commission to promote market-based rates of electricity and nondiscriminatory access for all electricity supplies to the transmission system—have resulted in significant amounts of electricity being generated in one State and sold in another. For example, in 1993, West Virginia generated three times the amount of electricity sold in that State, and in 1999, Alabama generated one and a half times the amount of electricity sold in that State. Historically, electricity was generated and sold by vertically integrated utilities providing for generation, transmission, and distribution for all customers in a designated franchise service area, which often was within a single State.

With electricity deregulation, restructuring, and Federal policies promoting competition and open transmission access, the industry has been changing ''from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation.'' *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations,* Energy Information Administration, December 1999 at pg. 5. Non-utilities are participating in the electricity market to an increasing extent by generating electricity for sale to utilities or to end-users. *The Changing Structure of the Electric Power Industry 2000: An Update,* Energy Information Administration, October 2000 at pp. ix, xi, and 117. Significant amounts of new generating capacity (about 82% of total capacity additions in 1998) have been built by non-utilities in order to generate electricity for sale in the regional electricity market. *Id.* at xi.

[24] See http://www.sargentlundy.com/fossil/plant.asp; and http://www.pegasustec.com/docs/NICE3.pdf.

7. Even if There Were a Substantial Risk That EPA's State Heat Input Projection Would Be Less Than a State's Actual 2007 Heat Input, This Would Not Make EPA's Projection Unreasonable

For the reasons discussed above, commenters failed to show that having recent State heat input exceeding or close to EPA's 2007 heat input projection means that the actual 2007 State heat input will exceed EPA's 2007 projection. However, EPA believes that, even if they had shown that there was a substantial risk that the actual heat input would turn out to exceed the projection in 2007, this would not make EPA's projection unreasonable. Projections may not match perfectly actual, future values and are not required to do so. *See Appalachian Power* v. *EPA*, 249 F.3d at 1052 (stating that the fact that ''a model is limited or imperfect is not, in itself, a reason to remand agency decisions based upon it''). If the projections of the results of complex activities (here, State heat input resulting from the operation of the regional electricity market) were required to match actual, future results, this would, in effect, preclude the use of projections or a model to develop such projections.

In this case, where EPA developed State heat input growth rates using the IPM and applied them to a State baseline to project 2007 State heat input, there are unavoidable sources of variability between projections and actual, future heat input data. These sources of variability are: the necessity to make simplifying assumptions in a model; the necessity to model regional activities (i.e., electricity generation, transmission and distribution) but make State-by-State projections of heat input resulting from those activities; and the inherent, year-to-year variability of actual State heat input.

a. Models, such as the IPM, necessarily contain simplifying assumptions. The IPM simulates the complex operation of the electricity generation, transmission, and distribution sector. Like any model designed to simulate complex phenomena, the IPM must use simplifying assumptions in order to make it feasible to construct and run the model. Furthermore, the model uses inputs that are themselves projections (e.g., electricity demand and fuel costs). Because of these simplifying assumptions and projected inputs, the results from the IPM, like those from any model, may well differ from reality. For example, the IPM assumes typical electricity demand each year, which reflects typical conditions like typical weather and typical economic growth. The basis for assuming typical conditions is the assumption that periods of high or low demand or hot or cold weather tend to average out over time. In reality, of course, there are years of unusually warm weather or unusually high economic growth, resulting in unusually high electricity demand. For example, in 1998, large parts of the NO_X SIP Call region experienced particularly warm weather, and the country experienced an economic boom. The model will not predict extra heat input in such years.

The IPM accounts for unplanned outages in a similar way. It assumes that, on average, plants will be available some portion of time less than 100%. The model also includes assumptions about a capacity reserve margin, thereby assuring that the costs of building plants that may be needed to meet demand are accounted for. However, the model does not assume that any specific units are out for any extended length of time. In reality, unplanned outages do not affect every unit for the same amount of time every year. Therefore, the model will not predict exactly the dispatch pattern of units in the real world. These differences could be substantial in a year or more. For example, if several large nuclear units went out of service in one geographic region for an extended period of time (as was the case, discussed below, when two units at the Cook Nuclear Plant went out of service during 1998 through 2000), fossil fuel-fired units might have a significant increase in heat input to provide the electricity that would otherwise have been generated by the nuclear units. The model would not predict this large increase in heat input.

The IPM also picks the optimum way to minimize costs given the constraints that have been included in the model. In the real world, different people and different companies may have differing viewpoints about what future constraints may be. This may lead them to act differently than the model projected. For instance, the model is given specific constraints regarding the projected future demand for electricity. It assumes that there are just enough units to meet that demand plus a reserve margin. In the real world, future demand is less certain, and this can lead to construction of fewer or more units than projected by the IPM.

For any particular State, a series of events may occur that differ from the model's assumptions, such as a period of higher electricity demand first caused by warmer weather than assumed in the model, followed by a period of higher economic activity than assumed in the model. This series of events may lead, over a year or more, to actual heat input that is higher than modeled for that State. In subsequent periods, the different-than-modeled factors may return to levels closer to those modeled, so that heat input returns to levels closer to those modeled.

In short, in designing the IPM, EPA necessarily made many assumptions. These assumptions may well result in differences between projected and actual State heat input for a specific year or specific years. However, this would not make the heat input projection methodology or the resulting heat input projection unreasonable.

b. While the electricity industry functions on a region-wide basis, budgets must be established on a State-by-State basis. Another source of differences between projected and actual State heat input is that, while NO_X emission budgets must be projected on a State-by-State basis, electricity is generated and sold on a regionwide, not State-by-State, basis. As discussed above in section V.D.6 of this notice, deregulation of electricity generation, restructuring of the electric industry, and Federal policies promoting market-based electricity prices and open access to transmission have resulted in development of a regional electricity market. The IPM necessarily models electricity generation and sales on a regional basis in order to reflect the regional nature of the electricity sector. For instance, as explained above, the model divides the U.S. into subregions based on the NERC regions and on transmission constraints, not based on State boundaries. (See section V.C.5 of this notice discussing subregions in the IPM.)

However, EPA had to develop State-by-State NO_X emission budgets under the NO_X SIP Call. EPA used those same budgets under the Section 126 Rule in order to allow a single cap-and-trade program to be developed and implemented under both the NO_X SIP Call and the Section 126 Rule. EPA had to disaggregate regionally-developed heat input projections down to the State level in order to establish State NO_X emission budgets, and this disaggregation may well create additional differences between projected and actual State heat input. These differences should not be taken to indicate that the heat input growth methodology or the resulting projections are unreasonable.

c. Actual State heat input is inherently variable. State heat input is quite variable, as discussed in section V.D.4 of this notice. This is because heat input results from the activities of the complex, regional electricity market. The variability of State heat input from year to year may well result in additional differences between projected and actual State heat input for any particular year. Again, these differences should not be taken as an indication of unreasonableness of the heat input growth methodology or the projections.

8. Commenters Overstated the Impacts of Actual State Heat Input Exceeding Projected State Heat Input

Even if EPA's heat input projections turn out to be lower for some States than actual 2007 heat input, the impacts of any such differences will not be as significant as commenters suggest. This is because the impacts will be mitigated by: (i) The fact that much of heat input growth will come from new, very low NO_X emission units; and (ii) the flexibility provided by the NO_X cap-and-trade program.

a. Higher than projected State heat input will not mean proportionately higher NO_X emissions. Commenters claimed that EPA's projections underestimate heat input for certain States and would result in sources in those States facing underestimated, and so overly stringent, NO_X emissions budgets. Commenters also stated that underestimated State heat input would cause electric supply interruptions. In addition, commenters suggested that underestimated State heat input would jeopardize or prohibit economic growth in those States by increasing EGU operating costs and jeopardizing access to adequate electricity by preventing new EGUs from locating in the State.[25]

The NO_X SIP Call and the Section 126 Rule limit units' NO_X emissions, not their heat input. EPA anticipates that, as State heat input grows from 1996 to 2007, a State's total EGU NO_X emissions will grow at a much slower rate than heat input because of the addition of new, very low NO_X emission units accounting for much of the increased heat input. The vast majority of new units added since 1996 are or will be gas-fired combustion turbines and combined cycle units that include gas-fired combustion turbines and duct burners. Because NO_X emissions from these units will be very low and significantly below the 0.15 lbs/mmBtu level used to set the State NO_X emission budgets for EGUs, the rate of increase in NO_X emissions in any State will be significantly less than the actual 1996–2007 growth rate in State heat input.

Specifically, EPA projects that gas-fired generation will increase at a greater rate than coal-fired generation. (See Analyzing Electric Power at pg. 7, Table 1, Winter 1998 Base Case Forecast for the U.S. of Electric Power Generation by Fuel Type (billion KWh), which indicates that coal generation will increase by 85 billion KWh between 2001 and 2005 and by 95 billion KWh between 2001 and 2007, while oil/gas generation[26] will increase by 95 billion KWh between 2001 and 2005 and 158 billion KWh between 2001 and 2007.)[27] In other words, EPA projects that gas-fired generation will increase at a rate 1.66 times faster than coal-fired generation (for every 3 Mwh increase in coal-fired generation, there would be a 5 Mwh increase in gas-fired generation.) Because gas-fired combined cycle units are more efficient than coal units, heat input from both categories of units will increase at a similar rate, even though generation from the gas-fired units will increase at a faster rate. This projected trend of increasing use of gas-fired combined-cycle use is consistent with observed results. For example, for the years 2000–2004, electric utilities reported plans to add 38,051 MW of generating capacity in new units. Ninety-three percent of this total is gas-fired capacity (*Inventory of Electric Utility Power Plants in the U.S. 1999,* Energy Information Administration, September 2000, at pg. 1). This is a continuation of the trend in 1997–1999, when most new capacity for utilities (81% in 1997 and 88% in 1998 and 1999) has been gas-fired combustion turbines and combined cycle units.[28]

[25] One commenter claimed EPA's heat input growth methodology thereby results in ''draconian economic sanctions'' and a ''no-growth policy'' for Michigan. As discussed below in section V.D.9 of this notice, there is no basis for claiming that EPA's heat input growth rate underestimates Michigan's future heat input. In fact, Michigan's actual heat input has never exceeded EPA's 2007 projection and, since 1998, has declined to where for 2001 it is 8.7% below that projection.

[26] Oil/gas units are included in the same category because many units that burn one fuel can also burn the other. However, as the analysis points out, more inefficient oil/gas boilers are being retired and most of the increase in generation comes from highly efficient, highly controlled natural gas combined cycle units. Analyzing Electric Power at 8.

[27] EPA notes that oil generation will account for a trivial amount of oil/gas generation.

[28] *Inventory of Power Plants in the U.S. as of January 1, 1998,* EIA, December 1998, at pg. 3; *Inventory of Electric Utility Power Plants in the U.S.*

New EGUs are subject to new source review requirements and, therefore, are well controlled. New combined cycle turbines generally are permitted at 9 ppm or less (i.e., less than 0.035 lb/mmBtu).[29] This means these new units will emit about one-fifth of the average 0.15 lb/mmBtu NO_X emission rate assumed for EGUs in the NO_X SIP Call and Section 126 Rules. Most existing combined-cycle units are controlled to levels similarly below 0.15 lb/mmBtu. Consequently, NO_X emissions will grow at a much lower rate than heat input as these units come online.

For example, consider the hypothetical case where 1996–2007 heat input growth would be 10% and about equally divided between generation from new gas-fired units and increased capacity utilization at existing coal-fired units. Because emissions from the gas-fired units are only one-fifth of the 0.15 lb/mmBtu NO_X emission rate assumed in the NO_X SIP Call and the Section 126 Rule, NO_X emissions would grow only 1% while heat input would grow 5% at new gas-fired units. A 5% growth in heat input at existing coal-fired plants emitting at the 0.15 lb/mmBtu NO_X emission rate would result in a 5% growth in NO_X emissions from the coal-fired units in this example. Thus, the total NO_X emissions growth would be about 6% when total heat input growth was 10%.

In summary, even if State heat input grows at a rate faster than projected by EPA, NO_X emissions will grow at a much slower rate than State heat input and the impact on the State's EGU NO_X emission budget from the difference between actual and projected heat input growth will be significantly reduced. This is reflected in EPA's modeling showing that increased heat input growth would not significantly increase the cost of meeting the State NO_X EGU budget. Even when electricity demand growth is assumed to be higher than EPA projected (e.g., with no electricity demand reductions under CCAP), the average cost of meeting the NO_X EGU budgets only increased $40/ton.

Since higher than projected State heat input growth results in much less than proportionately higher State NO_X emissions, the commenters greatly overstated the impacts of higher-than-projected State heat input on the stringency of the NO_X emission rate reflected in the State NO_X emission budget. Similarly, commenters greatly overstated the impacts of higher-than-projected State heat input on the State economy. Since new units tend to have very low NO_X emissions, higher-than-projected State heat input will not prevent the location of new units in the State to the extent suggested by commenters. Moreover, the amount of electricity available in a State is not tied to the amount of electricity generated in that State since electricity is generated and sold on a regionwide, not State-by-State, basis. Therefore, higher than projected State heat input will not limit the amount of electricity available for industrial, commercial and residential customers in that State. (See section V.D.6 discussing that State heat input is not necessarily correlated with availability of electricity and economic growth in the State.) Since the commenters ignore the fact that a State's electricity supply is not limited to the generation capacity in that State and since, as discussed above, EPA's regional heat input projections are consistent with actual regional heat input, the commenters failed to show that underestimated State heat input will prevent access to adequate electricity supply.

Finally, some commenters claiming that low heat input growth rates would prevent new units from locating in certain States also claimed that large numbers of new units are being located in those States and that this shows that EPA's heat input growth rates are too low. However, the fact that new units are continuing to be located in these States indicates that the selected locations in these States continue to be economically desirable for new units, despite the NO_X emission budgets that EPA established under the NO_X SIP Call in 1998 and modified in the Technical Amendments in 1999. One reason for this, of course, is that most of these new units are gas-fired units with very low NO_X emission rates.

b. *The cap-and-trade program will further limit the impact of higher than projected State heat input.* The NO_X SIP Call and the Section 126 Rule are being implemented through a cap-and-trade program that will reduce the cost of meeting the State NO_X emission budgets and thus will limit the cost impact of higher than projected State heat input. Under the NO_X SIP Call, each State is required to revise its SIP to meet the NO_X emission budget for 2007, which was developed using, among other things, the State's heat input growth rate projected by EPA. Each State has the option of meeting its NO_X emission budget by submitting a revised SIP that adopts EPA's recommended cap-and-trade program covering NO_X emissions from EGUs. Most States have already taken this option by submitting a SIP and final regulations adopting such a program, and EPA has approved a number of State rules, including Alabama's (66 FR 36919, July 16, 2001) and Illinois' (66 FR 56434, Nov. 8, 2001). West Virginia has developed final regulations adopting EPA's recommended cap-and-trade program, as have North Carolina, South Carolina, and Tennessee. Michigan, Virginia, and Ohio have draft regulations adopting such a program. Only Georgia and Missouri do not have draft or final regulations since EPA has not yet finalized a rule responding to the Court's remand of the NO_X SIP Call for those two States. (See Docket A–96–56, Item # XII–K–84).

Under the Section 126 Rule, EPA required affected units to participate in a cap-and-trade program, which is virtually identical to the cap-and-trade programs that have been (or are likely to be) adopted by States under the NO_X SIP Call. In fact, EPA has stated that it intends to integrate the approved SIP trading program with the Section 126 trading program into a single cap-and-trade program.

Under the cap-and-trade program, the State EGU NO_X budget is allocated among the affected units in the form of NO_X allowances, each allowance providing an authorization to emit one ton of NO_X during the ozone season for which the allowance is allocated or for any subsequent ozone season. After the end of each ozone season, the owner or operator of each affected unit is required to surrender a number of NO_X allowances equal to the number of tons that the unit emitted during that period. Owners or operators (or any other person) may buy or sell allowances or bank allowances for use in future years. The ability to trade and bank allowances provides units in a State flexibility in complying with the NO_X emission limit under the NO_X SIP Call and the Section 126 Rule and thereby limits the impact that higher than projected heat input would have on the cost of compliance.

Specifically, the owner or operator of a unit with an allowance allocation lower than the unit's tonnage of NO_X emissions for an ozone season has several compliance options, including the options of installing and operating additional NO_X emission controls at the unit or of purchasing allowances allocated to other units in the same State or in other States under the trading program. The owners or operators will presumably choose the most economically efficient option. If the cost of allowances in the regionwide market

1999 With Data as of January 1, 1999, EIA, November 1999, at pg. 1; *Inventory of Electric Utility Power Plants in the U.S. 1999,* EIA, September 2000 at pg. 1.

[29] See EPA Region 4 National Combustion Spreadsheet maintained at http://www.epa.gov/region4/air/permits/national_ct_list.xls.

for allowances under the trading program is less than the cost of installing and operating additional controls at the unit, then the owner or operator will purchase allowances. Assuming, for the sake of argument, the unit is in a State where actual heat input for the year exceeds EPA's projected 2007 heat input and actual NO_X emissions exceed the NO_X emission budget, the cost impact of the difference between actual and projected heat input is limited by the owner's or operator's option to buy allowances, rather than installing emission controls.[30]

Moreover, as discussed above in section V.D.4 of this notice, State heat input is quite variable. Even if actual State heat input exceeds EPA's projected 2007 heat input in one or more years, it is quite possible that actual State heat input will be less than EPA's projected 2007 heat input in a later year. Under the NO_X cap-and-trade program, the owner or operator in the example above who has to buy allowances in one year may have excess allowances during the subsequent year of reduced State heat input. That owner or operator may sell allowances and thereby offset, at least in part, the cost of buying allowances in the previous year. EPA is not suggesting that such an offset of costs will always be available. Rather, EPA notes that the cap-and-trade program will tend to create the potential to offset in one year a unit's shortfalls in allocations (whether or not attributable to higher than projected State heat input) in another year.

9. Discussion of Individual States for Which EPA's Heat Input Growth Rates Are Disputed by Commenters

Out of the 21 States and the District of Columbia for which EPA developed heat input growth rates and heat input projections for EGUs for 2007, commenters specifically disputed the heat input growth rates and projections for 7 States, i.e., Alabama, Georgia, Illinois, Michigan, Missouri, Virginia, and West Virginia. In six States, the commenters claimed that EPA's heat input growth rates and heat input projections are unreasonable because these States recently had actual heat input that exceeded EPA's projected heat input for 2007.[31] In the seventh State, Virginia, commenters claimed that the State's heat input had almostexceeded EPA's projections and would soon do so. With regard to some States, commenters also suggested that actual data and projections concerning electricity demand, economic output, population, and new generating capacity for these individual States support higher heat input growth rates than the rates adopted for those States by EPA.

EPA believes that, in general, these comments have common flaws that prevent them from providing a basis for concluding that EPA's heat input growth rates are unreasonable for the particular States at issue. First, several commenters flatly stated or implicitly assumed that significant negative growth in heat input was not plausible for their respective States between now and 2007. As noted above, historical heat input data show that individual State's heat input can decrease significantly in the last year, as compared to the first year, of multi-year periods and is quite variable from year-to-year. (See section V.D.4 of this notice.)

Indeed, the State heat inputs for four of the States that, as commenters have emphasized, rose to over or nearly over EPA's 2007 projections, have recently decreased to below or nearly below the 2007 projections. Specifically, the heat input of Michigan—which in 1998 was close to EPA's 2007 projection and, along with West Virginia, was the focus of the Court's concerns about EPA's growth rates—has declined since 1998 and remained well below EPA's 2007 projection. The heat input of West Virginia was higher in 1998, and still is slightly higher, than EPA's 2007 projection but has declined over 8% since 1998. Georgia's heat input recently increased above EPA's 2007 projections but decreased in 2001 below that projection. EPA maintains that the recent heat input decreases and the variability in State heat input show why the fact that current heat input for a State exceeds, or is close to, EPA's 2007 heat input projection for the State does not show that EPA's heat input growth rate and 2007 projection for the State are unreasonable.

Second, several commenters compared EPA's heat input growth rate for an individual State with the heat input growth that the State had during 1996–2000 and either asserted or implied that EPA should project the State heat input for 2007 using the actual 1996–2000 growth rate. However, EPA believes that it is inappropriate to project long-term heat input growth to 2007 based on a short-term historic trend (here, 1996–2000 heat input growth) for several reasons. Because heat input can vary greatly from year to year because of factors such as the weather and the economy, short-term trend data can be greatly skewed.

Moreover, as discussed above, in order to test the validity of using a relatively short period of years of actual State heat input data to project future State heat input, EPA simulated that approach using historical annual heat input data for the 21 NO_X SIP Call States for 1960–2000 (or in some States where less data was available, from 1970–2000). See section V.D.4 of this notice. Based on this data, EPA used 6 years' worth of historical data (e.g., 1960–1966) to project annual heat input for the sixth year after the 6-year period (e.g, 1972). EPA did this on a rolling basis. For 16 States, EPA found that there was a very little correlation between the predicted value based on the historical 6-year periods and the actual value for the sixth year after that period. For four of the remaining five States, the correlation was weak. In short, the commenters' approach of using historical State fossil fuel use for a relatively short period of years is not a reliable method for predicting future State heat input.

Third, in pointing to certain factors concerning each individual State to support the claim that the State's heat input could not reasonably be projected to decline, commenters implicitly assumed that the State's heat input is determined solely by those State-specific factors, rather than by the operation of the regional electricity market as a whole. EPA believes that heat input for an individual State cannot reasonably be projected by considering only the State's projected electricity demand and other State-specific factors. Because electricity is generated and sold in a regional electricity market, an individual State's heat input is not determined, and cannot reasonably be projected, based solely on factors relating only to that State. Rather, a State's heat input must be projected using a comprehensive approach that considers the regional market. Largely for this reason, EPA used the IPM—which models electricity markets in the continental U.S. and the regional electricity market for the NO_X SIP Call area—in its analysis for the NO_X SIP Call and the Section 126 Rule, including the analysis for making heat

[30] Commenters have characterized EPA's preliminary views in the August 3, 2000 NODA as attempting, in essence, to argue that the only thing that matters is the regionwide heat input growth rate, not the individual State growth rates. This is a mischaracterization. EPA believes that as long as the regionwide projection is reasonably close to the actual regionwide heat input, then, as a matter of simple arithmetic, trading opportunities will likely be present for any State whose actual NO_X emissions exceed its NO_X emission budget. As discussed above, the availability of trading, in turn, limits the impact of higher than expected heat input.

[31] In one of those States, Michigan, EPA's heat input projections have not actually been exceeded.

input growth projections.[32] *See Appalachian Power* v. *EPA*, 249 F.3d at 1053 (upholding EPA's determination that ''the IPM offered a more comprehensive and consistent means of allocating emission allowances than sorting through the various state-specific projections'').

Contrary to this comprehensive approach to projecting individual State's heat input, commenters presented projections of significant economic and population growth for individual States. While these economic and population projections for a State may suggest that there will be significant growth in electricity demand in that State, these State-specific factors suggest little about whether the State's increased electricity demand will be met from in-State EGUs. It may be met through increased generation from units within the State, which may increase that State's heat input, or it may be met through increased generation from units outside the State from which the State imports electricity, which may increase the heat input for another State. Even if the electricity demand is met by units in the State that has the increased demand, the State's heat input may be affected by the amount of electricity that the State exports to other States, as well as by the amount of electricity used within the State. The State's heat input may still decline under these circumstances if such exports decline. In short, because electricity is generated and sold on a regional basis, a State's heat input can decrease even as the State's electricity demand increases. Because the comments on individual States failed to address these regional factors, the commenters' claims that the respective State's heat input could not be expected to decline to the level of EPA's 2007 projection are unpersuasive.

Another State-specific factor on which some commenters relied in challenging EPA's heat input growth rate for an individual State is the amount of new capacity that has been permitted or that is under construction in that State. The commenters assumed that a significant amount of new, permitted capacity or capacity under construction necessarily means that the State's heat input will increase significantly. However, owners and operators may seek permits for units that, as it turns out, are not actually built. Further, new units that are built and operated may displace existing units and, since the new units are likely to be more efficient in converting heat input to electricity, the State's heat input may actually decline. (See sections V.D.6 and 8 of this notice discussing that most new units are gas-fired units and are likely to be more efficient than existing units.) Moreover, the amount of electricity that the new units produce will depend on the supply and demand factors in the regional electricity market, not simply on supply and demand in the State where the units are located. Thus, projected increased new capacity may potentially be a factor pointing to increased heat input in the State where the new capacity is to be located, but, because so many other factors are involved, that does not necessarily mean heat input will increase in that State.

In light of the above discussion, EPA does not believe that commenters have demonstrated that it is unreasonable to project that the heat input for those States with recent heat input exceeding EPA's 2007 projections will decline by 2007 to the levels projected by EPA. EPA addresses below the specific comments made about each State whose heat input growth rate and heat input projection are in dispute.

a. Alabama

(i) Comments

A commenter stated that Alabama's gross State product is projected to grow at 2.5% per year during 2001–2010. The commenter also noted that the ''average annual economic growth rate for the region'' was 3.9% per year during 1995–2000, Alabama has recently had ''economic annual growth'' well over 3%, and seasonal heat input growth for Alabama has averaged 3.37% per year in 1996–2000. Noting that Alabama's heat input in 1999 and 2000 exceeded EPA's 2007 heat input projection, the commenter claimed that ''[n]egative growth between now and 2007 for Alabama is simply not a plausible scenario.'' The commenter compared EPA's heat input growth rate to the State's historical heat input growth rate for 1995–2000. Claiming that nuclear generation increased during 1995–2000 but is not expected to increase significantly during 2001–2007, the commenter suggested that Alabama's heat input will grow even more than the historical heat input growth rate. Finally, the commenter stated that the NO_X SIP Call currently applies only to the northern two-thirds of the State, where most of the State's population centers are located and most economic growth will be concentrated. This is cited as another reason why EPA's heat input growth rate is inadequate and unrealistic.

(ii) Response

EPA notes that in 1999 and 2000, Alabama's ozone season heat input (389,364,461 mmBtu and 400,689,850 mmBtu) exceeded EPA's 2007 heat input projection (385,998,780 mmBtu) by 0.9% and 3.8% respecteviely. However, in 2001 Alabama's heat input (391,665,691 mmBtu) fell 2.5% and was only 1.4% above EPA's 2007 projection. Further, as discussed above, EPA intends to include only the northern portion of Alabama in the NO_X SIP Call. When actual heat input for 2001 for northern Alabama is compared with EPA's recently proposed 2007 projection for northern Alabama, the actual heat input in northern Alabama (284,528,783 mmBtu) is 7.9% below EPA's 2007 projection (308,912,352 mmBtu).[33]

Moreover, as discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In fact, historical data for 1960–2000 shows that there have been periods in the past when Alabama's annual heat input decreased significantly for the last year, as compared to the first year, of a multi-year period. For example, for the 8-year period 1974–1982 (comparable in length to the period 1999–2007), Alabama's annual heat input decreased by 12%.[34] Ozone season heat input decreased 17% over the same period, 1974–1982. Thus, the fact that Alabama's most recent heat input exceeded EPA's 2007 projection

[32] EPA also used the IPM in order to make sure that consistent assumptions were used for projecting each State's heat input growth.

[33] EPA calculated the partial State heat input budgets for large EGUs for Alabama, Georgia, and Missouri by summing the heat input for 1996, 1995, and 1995 respectively for all such units in the fine grid counties of the particular State and applying the appropriate growth rate. This information is in Docket Item XV-C–29 and is consistent with the partial State NO_X emission budgets proposed in 67 Fed. Reg. 8395, 8416, Feb. 22, 2002.

[34] EPA's review indicates that one out of the 33 eight-year periods from 1960–2000 had a decrease in annual heat input of well over 3.8% (Docket # A–96–56, Item # XV–C–18, at 1), while three out of the 20 eight-year periods from 1970–1998 had a decrease in ozone season heat input, with a decrease of well over 3.8% for two periods (Docket # A–96–56, Item # XV–C–19, at 1). Since these periods—although a minority—indicate that such decreases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

does not mean that the projection is unreasonable.

Further, while the commenter did not provide the data to support its claims about Alabama's economic growth or growth in gross State product, EPA used data from the Bureau of Economic Analysis to evaluate the commenter's claims. The commenters assumed, but did not demonstrate, that growth in gross State product necessarily results in growth in heat input. In fact, data for 1996–1999 for Alabama, as reflected in Table 10 below, shows that growth in gross State product does not necessarily result in growth in heat input. For example, in 1997, State heat input declined 0.2% while gross State product grew 3.4%. In 1996, while Gross State Product grew at 2.8%, heat input grew at a much slower rate of 0.2%. EPA tested the correlation of heat input growth rate to gross State product growth rate using the r-squared test, which is described above in section V.D.5 of this notice. EPA found that the two sets of growth rate data have a r-squared value of 0.12, showing very little correlation between growth in heat input and growth in gross State product.

TABLE 10.—GROSS ALABAMA STATE PRODUCT GROWTH RATE VS. HEAT INPUT GROWTH RATE FOR 1996–1999

Year	BEA Gross State product growth rate (percent)	Heat input growth rate (percent)
1996	2.8	0.2
1997	3.4	−0.2
1998	2.9	5.6
1999	4.2	5.2

There are several reasons that EPA believes that heat input growth on a State level does not correlate with economic growth. First, electricity demand is affected by many variables. This includes not only economic growth, but also other factors such as weather and changes in efficiency in the use of electricity.

Second, as discussed above, a State's heat input does not necessarily correlate with the State's electricity demand. (See section V.D.6 of this notice discussing that State heat input can decline when State electricity use increases.) For instance, in the case of Alabama, the State is generally a net exporter of electricity. In 1999, Alabama EGUs generated 120,865,327 Mwh of electricity. In that same year, only 80,401,000 Mwh of electricity were sold in Alabama. Therefore, in order to assess whether electricity generation or heat input in Alabama will grow, it is necessary to consider not only electricity demand in Alabama, but also electricity demand and supply in the regional market for electricity outside of Alabama. The commenter did not provide any information on future electricity demand and supply outside of Alabama and how they might affect future generation and heat input in Alabama.

The lack of strong correlation between economic growth and heat input is confirmed by historical data on electricity demand and heat input in northern Alabama. Noting that the NO_X SIP Call now covers only the northern part of Alabama (the fine grid counties), the commenter presented evidence suggesting that the economy and population are growing faster in the northern part than in the southern part of the State. The commenter suggested that heat input will therefore grow faster in northern Alabama than in the State as a whole. EPA reviewed heat input data for Alabama and found that, despite higher growth in the economy and population in northern Alabama, heat input has actually grown faster in the southern part of the State. The data are summarized in Table 11 below.

TABLE 11.—HEAT INPUT (MMBTU) IN ALABAMA FOR 1996–2001

	Fine grid counties	Outside fine grid counties	All counties
1995	279,392,756	70,666,448	350,059,204
1996	280,829,411	70,078,571	350,907,982
1997	277,733,999	72,594,373	350,328,372
1998	298,464,504	71,513,696	369,978,200
1999	318,056,030	71,308,431	389,364,461
2000	314,726,690	85,693,161	400,689,850
2001	284,528,783	107,136,907	391,665,690
Avg Annual Growth Rate 1996 to 2001	0.4	8.7	2.3

Finally, EPA notes that the commenters' claim concerning the effect of Alabama's nuclear generation on the State's heat input growth rate appears to be overstated. The commenters stated that nuclear generation in Alabama increased during 1995–2000 and is not expected to continue to increase and that therefore the State's heat input will increase at a greater rate starting in 2001. However, while Alabama's ozone season nuclear generation increased significantly from 1995 to 1996 (8,371,445 Mwh to 13,161,369 Mwh during the ozone season), EPA used 1996 as the baseline year for determining Alabama's NO_X emission budget. During 1996–2000, nuclear generation in Alabama grew much less than during 1995–2000. Nuclear generation was 13,321,089 Mwh in the 1999 ozone season and 13,578,728 Mwh in the 2000 ozone season. Because there was only limited growth in nuclear generation from 1996 to 2000, there is no basis for commenters' claim of increased heat input growth in the future to offset limited growth from nuclear units. Furthermore, the Nuclear Regulatory Commission is anticipating that applications will be submitted to increase the generating capacity of two nuclear powered units at the Brown's Ferry Plant by 14%. (Docket # A–96–56, Item # XV-C–27.) While these applications do not necessarily mean that nuclear generation will increase, they cast doubt on the commenters' assertion that nuclear generation will not grow.

For the above reasons, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection of Alabama are unreasonable.

b. Georgia

(i) Comments

Commenters pointed to EPA's data as showing that Georgia's ozone season heat input increased more than 3.3% per year from 1995 to 2000, as compared with EPA's projected increase of 1.01% per year through 2007. Further, commenters noted that Georgia's current heat input exceeds EPA's 2007 heat input projections and so the State's heat input will have to decrease by 2007 in order for the projection to be correct. Commenters cited several factors—i.e., rapid population growth, projected growth in peak demand for electricity, and rapid growth in gross State product—to show that Georgia's heat input will continue to grow faster than EPA projected. Commenters also stated that the NO_X SIP Call will cover only the northern part of Georgia (the fine grid counties), whose population is growing faster than in the southern portion of the State. The commenters suggested that the heat input will therefore grow even faster for the northern part of Georgia.

(ii) Response

EPA notes that Georgia's heat input in 1998 (403,716,898 mmBtu) and 2000 (420,260,694 mmBtu) exceeded EPA's 2007 heat input projection (403,368,582 mmBtu). However, in both cases, heat input fell significantly the next year and was below EPA's 2007 projection. Georgia's heat input fell 3.9% between 1998 and 1999 and 10.9% between 2000 and 2001. In 2001, the State's heat input (374,355,956 mmBtu) was 7.2% below EPA's 2007 projection. Further, as discussed above, EPA intends to include only the northern portion of Georgia in the NO_X SIP Call. When actual heat input for northern Georgia for 2001 is compared with EPA's recently proposed 2007 projection for northern Georgia, actual 2001 heat input (360,162,148 mmBtu) is 8.2% below projected heat input (392,215,442 mmBtu).

Moreover, as discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In the past, Georgia's annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased by 17% over the seven-year period 1985–1992 (comparable in length to the period 2000–2007).[35] Ozone season heat input decreased 9.9% over the same period, 1985–1992.

Furthermore, as discussed above, EPA does not believe that commenters have shown that increases in parameters such as population, economic output, or peak electricity demand in a particular State necessarily mean that heat input will increase in that State. In fact, EPA's analysis of the heat input data for the northern and southern portions of Georgia shows that recently heat input has increased more in the southern part of the State, where, according to commenters there has been less growth in population, than in the northern part of the State. The data are summarized in Table 12 below.

TABLE 12.—HEAT INPUT (MMBTU) IN GEORGIA FOR 1995–2001

	Fine grid counties	Outside fine grid counties	All counties
1995	347,093,311	9,870,035	356,963,346
1996	326,944,480	9,032,533	335,977,013
1997	342,870,775	8,336,975	351,207,750
1998	390,888,493	12,828,405	403,716,898
1999	370,011,938	17,769,163	387,781,101
2000	399,110,359	21,150,335	420,260,694
2001	360,162,148	14,193,808	374,355,956
Avg Annual Growth Rate 1995 to 2001	0.6	6.2	0.8

For the above reasons, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection of Georgia are unreasonable.

c. Illinois

(i) Comments

Commenters were concerned that EPA initially proposed to establish the Illinois heat input growth rate at 34%, but then adopted a final growth rate of 8%. Commenters contended that the 8% growth rate does not reflect a realistic growth projection for the State, in light of the actual heat input growth in Illinois during 1995–2000. According to the commenters, the actual heat input growth for 1995–2000 exceeded EPA's projected growth rate, and by 1998 Illinois' heat input exceeded EPA's heat input projection for 2007. Commenters pointed to the 2000 ozone season (described as a relatively mild summer) when heat input was 15% higher than the 1996 baseline. Commenters suggested that total growth from 1996 to 2007 could exceed 30%, far above EPA's 8% estimate, and that the data support a growth of 34% and certainly no lower than 22%. Commenters asserted that it is also not likely that heat input in the State will decline below 2000 levels because Illinois has approved an additional 436.6 million mmBtu/ozone season in generating capacity since 1999 for which construction has been initiated, with an additional 25.2 million mmBtu pending.

(ii) Response

With regard to EPA's revision of Illinois' annual heat input growth rate from 34% to 8%, EPA explained in the NO_X SIP Call that the Agency took comment on using two alternative electricity demand forecasts to develop the State NO_X emission budgets and to perform the cost-effectiveness analysis. One alternative was a 1995 electricity demand forecast, modified by demand reductions under CCAP, that was used in an IPM run (''1996 IPM Base Case forecast'') and would have resulted in certain heat input growth rates (''corrected'' growth rates), including a growth rate of 34% for Illinois. The second alternative was a 1997 electricity demand forecast, modified by demand reductions under CCAP, that was used in a later IPM run (''1998 IPM Base Case forecast'') and resulted in another set of heat input growth rates (''revised'' growth rates), including a growth rate of

[35] EPA's review indicates that four out of the 34 seven-year periods from 1960–2000 had a decrease in annual heat input, with a decrease of over 4% for three periods (Docket # A–96–56, Item # XV–C–18, at 10), while two out of the 21 seven-year periods from 1970–1998 had a decrease in ozone season heat input, with one of those decreases greatly exceeding 4% (Docket # A–96–56, Item # XV–C–19, at 10). Since these periods—although a minority—indicate that such decreases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

8% for Illinois. As explained in the NO_X SIP Call (63 FR 57409), EPA used the 1998 IPM Base Case forecast (as the base case run described in section V.B.1 of this notice) and resulting heat input growth rates because that forecast reflected assumptions that had been revised based on public comment and that ''lead to a better projection of electricity generation nationally, by region and by State.'' [36]

EPA notes that Illinois' heat input in 1998 (450,929,580 mmBtu) exceeded EPA's 2007 heat input projections (409,351,519 mmBtu), by 10.2% and has continued to exceed that projection. However, the State's heat input peaked in 1998 and has remained below the 1998 level since then. By 2001, Illinois' heat input (434,282,881 mmBtu) declined by 3.7% from the 1998 level and was 6.1% higher than EPA's 2007 projection. As discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In the past, Illinois' annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased 31% over the 9-year period 1981–1990 (comparable in length to the 1998–2007 period).[37] Ozone season heat input decreased 25.8% over the same period, 1981–1990. Thus, the fact that Illinois' recent heat input exceeded EPA's 2007 projection does not mean that the projection is unreasonable.

Illinois' decreases in heat input over the last few years may be partly attributed to an increase in nuclear generation in Illinois since 1998, as shown in Table 13. In both 1997 and 1998, five nuclear units representing over 5000 MW of capacity (nearly 14% of the total installed capacity in Illinois) were offline. This resulted in significantly less generation from nuclear units. It appears that at least some of the generation was made up by additional fossil-fired generation. In 1999, when three of the nuclear units returned online, heat input declined. During this period, electricity demand in Illinois increased.

TABLE 13.—HEAT INPUT, NUCLEAR GENERATION, AND ELECTRICITY SALES IN ILLINOIS FOR 1995–2001

Year	Heat Input (mmBtu)	Nuclear generation (Mwh)	Electricity sales (Mwh)
1995	347,985,300	35,410,101	55,960,000
1996	379,029,184	29,038,573	53,348,000
1997	406,127,886	23,038,672	53,357,000
1998	450,929,580	25,331,514	58,665,000
1999	418,420,171	37,004,253	60,470,000
2000	436,052,570	38,287,858	59,834,000
2001	434,282,881	38,590,400	60,310,000

The commenters did not provide any information on future nuclear generation in Illinois and how that might affect future generation and heat input in the State. However, the Nuclear Regulatory Commission recently approved significant expansions in generating capacity for several nuclear units in Illinois (i.e., a 17% expansion to about 912 MW each for Dresden 2 and 3 and a 17.8% expansion to about 912 MW each for Quad Cities 1 and 2). The upgrades are scheduled for completion during outages in 2002 and 2003. (Docket A–96–56, Item # XV–C–07, ''NRC Approves Power Uprates for Dresden 2, 3 and Quad Cities 1, 2,'' Nuclear Regulatory Commission Press Release, December 26, 2001.) Once the capital investment is made in expanding nuclear capacity, nuclear generation has relatively low operating costs.[38] As a result, nuclear generation in Illinois may well increase in the next 2 years and therefore may be one factor tending to reduce heat input for the State.

Another factor that may have been a partial cause of increased heat input in Illinois and that may change in the future is Illinois' recently increased exports of electricity to other States. In 1994, Illinois was exporting 14% of its electricity; by 1999 that number had reached 19%. Heat input increased along with this increase in export of electricity. Whether this level of exports will continue will depend on electricity supply and demand in the regional electricity market. For example, increases in generation in neighboring States may lead to less of an export market and therefore a decrease in heat input. The commenters did not provide any information on future electricity demand and supply outside of Illinois or how they might affect future generation and heat input in Illinois.

Finally, the commenters pointed to approval or construction of new units in Illinois as showing that Illinois heat input will continue to grow through 2007. However, as discussed above, approval or construction of new units is not a definitive indicator of increased heat input in the future.

For the reasons above, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection for Illinois are unreasonable.

[36] EPA stated that the improvements in the 1998 IPM Base Case forecast included ''using the most recent NERC estimate for regional electricity demand; the latest available EIA and NERC generation unit data; updated fuel forecasts; updated assumptions on nuclear, hydro-electric and import assumptions (with special attention to differences in summer use); and an increase in the level of detail in the model to more accurately capture the transmission constraints that exist for moving power between various regions of the country.'' *Id.* In addition, the forecast included updated assumptions ''on the size and operation of all electricity generation units of utilities and independent power producers (with special attention to cogenerators)'' and ''planning reserve margins and the costs of building new generation capacity.'' *Id.*

[37] EPA's review indicates that 13 out of the 32 nine-year periods from 1960–2000 had a decrease in annual heat input, with a decrease of more than 10.2% in eight of those periods (Docket #A–96–56, Item #XV–C–18, at 13), while 11 of the 19 nine-year periods from 1970–1998 had a decrease in ozone season heat input, with a decrease of more than 10.2% in eight of those periods. (Docket #A–96–56, Item #XV–C–19, at 13). Since these periods—although a minority—indicate that such decreases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

[38] This contrasts with fossil fuel-fired units, whose operating costs are higher because of the cost of fossil fuel.

d. Michigan

(i) Comments

Commenters stated that Michigan's heat input in 1998 exceeded EPA's 2007 heat input projection. Commenters also stated that the Michigan Public Service Commission estimates Michigan's growth in electricity demand to be twice the amount that EPA ''presumed in its calculations'' for the NO_X SIP Call and Section 126 Rule and that there is no basis for the ''presumed'' negative growth in energy demand for Michigan. Further, commenters pointed to weather as the major reason for year-to-year variability in Michigan's heat input. Noting the hot temperatures in 1995, 1998, and 1999 and the cool temperatures in 1996, 1997, and 2000, they stated that weather was the primary cause of the dramatic increase in heat input in 1998 and the decline in 2000. The commenters compared the years with similar summer weather patterns to find an ozone season growth rate of 2.0% or 2.1% per year, which is much higher than EPA's 1.1% projected annual growth rate. Commenters also pointed to operational problems at the fossil-fuel fired Monroe Plant as contributing to the lower State heat input in 2000. Finally, commenters suggested that the modeling of unit dispatch in the IPM does not accurately reflect unit dispatching in Michigan because the IPM dispatches on a national basis.

(ii) Response

EPA notes that Michigan's heat input has never actually exceeded EPA's 2007 heat input projection. In 1998, Michigan's heat input (408,239,157 mmBtu) came close to (i.e., 0.4% below) EPA's 2007 projection (410,058,589 mmBtu). Since 1998, Michigan's heat input has declined each year. Michigan's 2001 heat input (374,318,406 mmBtu) was 8.7% below EPA's 2007 projection. Moreover, as discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In the past, Michigan's annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased by 10.9% over the 9-year period 1973–1982 (comparable in length to the 1998–2007 period).[39] Ozone season heat input decreased 13.4% over the same period, 1973–1982.

EPA believes that Michigan's decline in heat input in the last few years may be at least partly attributable to resolution of operational problems at the Cook Nuclear facility, as reflected in Table 14 below.[40] The spike in Michigan's heat input in 1998 coincides with the outage of two nuclear units at the Cook Nuclear Plant in Michigan. These two units are capable of generating a total of 2285 MW, which represents over 9% of the capacity in Michigan. Cook Unit 2 did not return to service until the middle of the 2000 ozone season, and Cook Unit 1 did not return to service until after the 2000 ozone season. These outages resulted in significantly less generation from nuclear plants and coincided with significantly more fossil fuel generation and heat input in 1998 and 1999. As the nuclear units came back into service and increased their generation, fossil fuel generation and heat input in Michigan declined. Under these circumstances, the fact that Michigan's 1998 heat input came close to EPA's 2007 projection does not demonstrate that EPA's projection is unreasonable.

TABLE 14.—NUCLEAR GENERATION VS. TOTAL UTILITY GENERATION FOR MICHIGAN IN 1995–2001

Year	Ozone Season nuclear generation (Mwh)	Total Utility Ozone Season Generation[41] (Mwh)
1995	8,779,412	38,175,367
1996	12,708,112	41,024,588
1997	12,804,255	40,660,688
1998	4,923,916	36,618,364
1999	6,472,871	38,679,849
2000	8,195,891	39,550,421
2001	10,456,684	40,844,263

[41] EIA provided generation data for this entire period only for large utility units. In the State of Michigan, non-utility units make up about 12% of the generation capacity.

With regard to the comment that EPA's heat input projections are not consistent with the Michigan Public Utility Commission's electricity demand projections, EPA notes that electricity demand and heat input are not necessarily correlated. (See section V.D.6 of this notice.) For example, from 1988 to 1993, Michigan's electricity sales grew 6.1% at the same time that the State's heat input dropped 8%.

Several comments suggest that Michigan's 2000 heat input was not representative because 2000 was a cool summer and that the State's heat input therefore should be disregarded in considering the reasonableness of EPA's 2007 heat input projection. The commenters seem to suggest that the fact that the summer was relatively cool meant that electricity demand, and so heat input, were lower in Michigan in 2000. However, EPA notes that Michigan's electricity demand in 1998 was 44,451,681 Mwh and has been higher every year since 1998. In other words, even though electricity demand has grown since 1998, heat input has not. As for the comment that operational problems at the Monroe Power Plant reduced Michigan's heat input in 2000, EPA notes that Michigan's heat input in 2001 continued to decrease from 2000, even though there was much less of a decrease in heat input from the Monroe Power Plant from 2000 to 2001. Furthermore, EPA believes that heat input should not be evaluated on a plant-by-plant basis, because declines in heat input for one plant may well be accompanied by increases in heat input for another plant. For instance, while the Monroe Power Plant had lower heat input in 2000 than it had in previous years, heat input from the David E. Karn Plant in Michigan was significantly higher in 2000 than in previous years, and the amounts of the decrease in

[39] EPA's review indicates that eight out of the 32 nine-year periods from 1960–2000 had a decrease, or an increase of no more than 0.4%, in annual heat input (Docket # A–96–56, Item # XV–C–18, at 28), while 2 of the 19 nine-year periods from 1970–1998 had a decrease, or an increase of no more than 0.4%, in ozone season heat input. (Docket # A–96–56, Item # XV–C–19, at 28). Since these periods—although a minority—indicate that such decreases and small increases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases and small decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

[40] It has been suggested that Cook nuclear generation has been taken up by out-of-state affiliates of Cook and therefore that Cook's operational problems have not affected fossil-fired generation in Michigan. However, EPA has not received specific information purporting to demonstrate this pattern. Indeed, the Michigan Public Utility Commission has highlighted that the resumption of normal operations by the Cook Nuclear facility increases both available generation and the ability to import power, which suggests that Cook and fossil-fired Michigan generators are interrelated. Summer 2001, Energy Appraisal, Michigan Public Utility Commission, http://www.cis.state.mi.us/mpsc/reports/energy/01summer/electric.htm.

Monroe heat input and the increase in Karn heat input were about the same.

Finally, EPA disagrees with the comment that the modeling of unit dispatch in the IPM is inaccurate for Michigan because the IPM models the entire U.S. The IPM divided the U.S. into multiple subregions (including a subregion comprising most of Michigan). This allows the model to reflect both local dispatch patterns and the interstate nature of the electric grid.

For the reasons above, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection of Michigan are unreasonable.

e. Missouri

(i) Comments

A commenter noted that Missouri's average actual heat input growth rate for 1995–2000 exceeded EPA's heat input growth rate by about three times. The commenter also noted that Missouri's heat input in 1998 exceeded EPA's 2007 heat input projection for the State.

(ii) Response

EPA notes that Missouri's 1999 heat input (335,273,139 mmBtu) exceeded EPA's 2007 heat input projection (309,316,824 mmBtu)by 8.4%. Since 1999, Missouri's heat input declined to 332,332,587 mmBtu in 2000 and 329,668,165 mmBtu in 2001, but continued to exceed EPA's projection. Missouri's 2001 heat input exceeded EPA's 2007 projection by 6.2%. The heat input decline occurred even though, during this time, electricity demand in Missouri increased from 31,704,000 Mwh in 1999 to 33,519,000 Mwh in 2000 and 32,539,000 Mwh in 2001. Further, as discussed above, EPA intends to include only the eastern portion (the fine grid counties) of Missouri in the NO_X SIP Call. When actual heat input for eastern Missouri for 2001 is compared with EPA's recently proposed 2007 projection for eastern Missouri, the difference between the actual 2001 heat input (184,541,335 mmBtu) and the projected 2007 heat input (178,431,621 mmBtu) narrows to 3.4%.

TABLE 15.—HEAT INPUT (MMBTU) IN MISSOURI FOR 1995–2001

	Fine grid counties	Outside fine grid counties	All counties
1995	163,698,735	120,078,167	283,776,902
1996	159,770,676	116,268,060	276,038,736
1997	176,843,306	121,262,736	298,106,042
1998	190,237,705	124,494,173	314,731,878
1999	200,802,706	134,470,433	335,273,139
2000	196,392,883	135,939,703	332,332,587
2001	184,541,335	145,126,830	329,668,165
Avg Annual Growth Rate 1995 to 2001	2.0	3.2	2.5

Moreover, as discussed above, individual State heat input is quite variable, is not necessarily correlated with electricity demand in the State, and can decrease significantly over multi-year periods. In the past, Missouri's annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased 11% over the 8-year period 1984–1992 (comparable in length to the 2000–2007 period).[42] Ozone season heat input decreased 9.1% over the same period, 1984–1992. Thus, the fact that Missouri's most recent heat input exceeded EPA's 2007 projection does not mean that the projection is unreasonable.

For the reasons above, EPA rejects the commenter's claims that EPA's heat input growth rate and 2007 heat input projection of Missouri are unreasonable.

f. Virginia

(i) Comments

Commenters asserted that there are various data omissions and errors in the heat input data for baseline year (1995) and for subsequent years through 1999 for Virginia, particularly as applied to independent power producers. According to commenters, the lack of heat input data for several of these facilities resulted in understated baseline heat input and, in the Section 126 Rule, in understated allowance allocations for certain units, whose allocations were based on 1995–1998 heat input. Commenters requested that EPA correct the allowance allocations in the Section 126 Rule. Commenters also stated that there has been a substantial increase in Virginia's heat input between 1995 and 2000 and that the State's heat input in 1997 and 1998 was within 7% of EPA's 2007 heat input projections and within 1.3% in 1999. Commenters predicted that the State's 2007 heat input level will be 319,087,054 mmBtu, for existing units based on the ''historical trend'' of heat input, and 395,216,765 mmBtu, based on ''power generation output,'' as compared to EPA's projection of 228,699,872 mmBtu. Commenters also were concerned that EPA underestimated Virginia's new generation capacity. Virginia has 12,000 MW of potential new capacity at various stages of the permitting process. According to the commenters, EPA's estimate of new generation capacity is underestimated by over 3,000 MW, and the 5% set aside in the State's EGU NO_X emission budget under the Section 126 Rule is inadequate to accommodate projected new capacity.

(ii) Response

EPA notes that its 2007 heat input projection for Virginia (227,875,597 mmBtu) has not been exceeded, though Virginia's 1999 heat input (225,665,092 mmBtu) was close to (i.e., 1% below) the 2007 projection. Since 1999, Virginia's heat input has declined, and in 2001 the State's heat input (213,583,835 mmBtu) fell to 6.3% below

[42] EPA's review indicates that six out of the 33 eight-year periods from 1960–2000 had a decrease in annual heat input, with a decrease of 8.4% or more in one of these periods (Docket # A–96–56, Item # XV–C–18, at 31), while two out of the 20 eight-year periods from 1970–1998 had a decrease in ozone season heat input, with a decrease of 8.4% or more in one of these periods (Docket # A–96–56, Item # XV–C–19, at 31). Since these periods—although a minority—indicate that such decreases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

EPA's 2007 projection. Moreover, as discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In the past, Virginia's annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased 38% over the 6-year period 1977–1983 (comparable in length to the 2001–2007 period).[43] Ozone season heat input decreased by 23.9% over 1978 and 1984.[44]

Further, as discussed above, because heat input is quite variable, EPA believes that it is inappropriate to project long-term heat input growth to 2007 based on a short-term trend like Virginia's heat input growth for 1995–2000. With regard to comments concerning the new generation capacity that is at various stages of permitting in Virginia, projected new units do not necessarily result, as discussed above, in increased State heat input.

For the reasons above, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection of Virginia are unreasonable.

EPA notes that the comments on Virginia's 1996 baseline heat input and on unit-specific allowances allocations and the size of the set-aside for new units under the Section 126 Rule are outside the scope of the remand and today's notice. The Court remanded EPA's heat input growth rates and 2007 heat input projections and did not address or remand any issues concerning the data used to calculate State's 1995 or 1996 baseline heat input. In addition, the Court did not remand any issues concerning the determination of individual units' allowance allocations or the size of the set-aside for new units. Consistent with the Court's remand, EPA explained in the August 3, 2001 NODA that EPA was not seeking comments on the data used to calculate 1995 or 1996 baseline heat input or on allowance allocations, (66 FR. 40616). EPA is therefore not addressing today the comments on Virginia's 1996 baseline heat input, unit-specific allowance allocations, and the set-aside for new units.[45] However, data for subsequent years were not used in calculating Virginia's 1996 baseline heat input. EPA has incorporated the commenters' data corrections for 1997–1999 for purposes of the Agency's review of Virginia's heat input growth rates.[46]

g. West Virginia

(i) Comments

Commenters argued that EPA's growth factor for West Virginia is inaccurate, technically unjustifiable, and significantly lower than the growth rates assigned to neighboring States. Commenters pointed to the discrepancy between actual heat input growth during 1995–2000 in West Virginia (1.84% a year) to EPA's heat input growth rate of 0.25% a year. According to commenters, extrapolating the 1.84% growth rate to 2007 would result in a 32.3% increase in heat input compared to EPA's projected 3% increase. Commenters also noted that West Virginia's actual average heat input for 1998–2000 exceeds EPA's 2007 heat input projection by 8%. Commenters asserted that in order for EPA's projections to be reasonably accurate, West Virginia's heat input will have to decrease as much as 6% over the next 6 years.

Further, commenters described West Virginia as an electricity exporter and argued that the State can be expected to have heat input increases commensurate with rising national electricity demand. Commenters pointed to the actual 1.84% increase in ozone season heat input from 1995–2000, which they argued is comparable to the projected 1.8% increase in electricity demand over the next 20 years in the National Energy Policy.

The commenters claimed that the unreasonableness of EPA's methodology is further demonstrated by comparing West Virginia's heat input relative to the total heat input for the NO_X SIP Call region. With EPA's heat input growth rates and 2007 heat input projections, the State was allotted only 5% of the regional heat input, but use of the 2001 and 2010 IPM heat input projections show West Virginia with 6.9% and 6.4% respectively of regional heat input. In addition, commenters noted that the IPM run for 2007 projects heat input for West Virginia that exceeds EPA's 2007 heat input projection for the State.

Commenters stated that year-to-year variation in heat input did not explain the difference between West Virginia's current heat input and EPA's 2007 heat input projection, which is lower. Commenters asserted that West Virginia has lower year-to-year variability in heat input than surrounding States.

Finally, commenters contended that EPA's heat input growth rates fail to account sufficiently for new EGU units in the State. According to the commenters, while eight new EGUs with a combined generating capacity of 5,833 MW have been planned and committed for construction, EPA projected 1,049 MW of new natural gas fired units to West Virginia through 2010.

(ii) Response

EPA notes that West Virginia's heat input exceeded EPA's 2007 heat input projection (358,117,926 mmBtu) beginning in 1997 when it exceeded EPA's 2007 projection by 1.9%. The State's heat input peaked in 1999 (391,592,231 mmBtu), exceeding EPA's 2007 projection by 9.3%. Since 1999, West Virginia's heat input declined by 8% over the next 2 years, and the 2001 heat input (360,185,154 mmBtu) exceeded EPA's 2007 projection by only 0.6%. Moreover, as discussed above, individual State heat input is quite variable and can decrease significantly over multi-year periods. In the past, West Virginia's annual heat input has decreased significantly for the last year, as compared to the first year, of multi-year periods and, for example, decreased 5.5% over the 10-year period 1981–1991 (comparable in length to the 1997–2007 period) and decreased 10.9% over the 8-year period 1983–1991 (comparable in length to the 1999–2001 period) [47] and 13% over 1984–1992.

[43] EPA's review indicates that ten out of the 32 nine-year periods from 1960–2000 had a decrease, or an increase of no more than 1%, in annual heat input (Docket # A–96–56, Item # XV–C–18, at 58), while 7 of the 19 nine-year periods from 1970–1998 had a decrease, or an increase of no more than 1%, in ozone season heat input (Docket # A–96–56, Item # XV–C–19, at 58). Since these periods—although a minority—indicate that such decreases and small increases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases and small increases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

[44] Monthly data was not available for the year 1983, so a comparison of the period between 1977 and 1983 cannot be made.

[45] EPA notes that it previously solicited corrections to baseline heat input data and responded to requested corrections through the Technical Amendments in 1999 and 2000. EPA also notes that, based on the data provided by commenters, the requested changes to 1996 heat input would have very little impact on Virginia's EGU NO_X emission budget. Virginia's 1996 baseline heat input (which was used to develop the budget) would increase by 131 tons, and, with the application of EPA's growth factor of 1.32 for Virginia, the State's EGU NO_X emission budget would increase by 173 tons or 1%.

[46] EPA similarly incorporated other specific data corrections requested by commenters for other States for 1997 or later.

[47] EPA's review indicates that two out of the 31 ten-year periods from 1960–2000 had a decrease in annual heat input, with the largest decrease being 5.5% (Docket # A–96–56, Item # XV–C–18, at 61), while four out of the 18 ten-years periods from

Continued

Ozone season heat input decreased 9.1% over 1982–1992.[48] Thus, the fact that West Virginia's heat input has recently exceeded EPA's 2007 heat input projection does not mean that EPA's projection is unreasonable.

Further, while EPA agrees that West Virginia is a significant exporter of electricity, EPA does not believe that it necessarily follows that West Virginia's heat input will continue to grow. Since less than a third of the electricity generated in West Virginia is sold in West Virginia, the ability to export electricity plays an important part in the amounts of both electricity generation and heat input in West Virginia. The level of West Virginia's exports in the future will depend on electricity supply and demand in the regional electricity market. The commenters did not provide any information on future electricity demand and supply outside of West Virginia and how they might affect future generation and heat input in West Virginia. West Virginia's heat input declined over 8% during 1999–2001 despite the fact that electricity sales increased 1.2% in the NO_X SIP Call region.

While commenters provided a graph to demonstrate that West Virginia's heat input has been less variable than other States' heat input, that graph covers only 1995–2000 and so fails to show the variability reflected by the heat input decrease between 2000 and 2001. Further, since the range of movement, up and down, of lines on a graph can vary depending on the range of the vertical and horizontal scales presented in the graph, the variability of the graphed parameter (here, State heat input) cannot be determined simply by looking at the graph. Commenters provided no other support for the claim of less variable heat input. Moreover, the 1995–2001 ozone season data and the 1960–2000 annual heat input data for West Virginia show, contrary to the commenters, that the State's heat input is quite variable, as reflected in significant decreases over multi-year periods. (See Tables 2 through 9 above.)

Finally, as discussed above, because heat input is quite variable, EPA believes that it is inappropriate to project long-term heat input growth to 2007 based on a short-term trend like West Virginia's heat input growth for 1995–2000. With regard to comments concerning the heat input, or percentage share of heat input, projected for West Virginia by the IPM, EPA maintains that the IPM is more accurate in predicting the change in State heat input between modeled years than in pinpointing State heat input for a particular year. (See section V.C.2 of this notice.) With regard to comments concerning the new gas-fired generation capacity that is planned in West Virginia, projected new units do not necessarily result, as discussed above, in increased State heat input.

For the reasons above, EPA rejects the commenters' claims that EPA's heat input growth rate and 2007 heat input projection of West Virginia are unreasonable.

10. No Heat Input Growth Rate Methodology Has Been Presented That Would Have Results That Better Comport With Actual Heat Input

As discussed in detail above, EPA believes that the fact that a State's recent heat input exceeds a heat input projection for the State for 2007 does not make the projection unreasonable. However, in light of the Court's and commenters' concerns over cases where recent actual State heat input exceeded the 2007 projection, EPA decided to compare the heat input growth rates and 2007 heat input projections under the Agency's methodology to those under the alternative heat input growth methodologies considered previously by EPA or discussed by commenters. In making this comparison, EPA focused on how the 2007 projections compared with actual heat input data to date for most of the NO_X SIP Call States. EPA excluded Connecticut, Massachusetts, and Rhode Island from the comparison of the growth rate methodologies because they entered into a February 1999 Memorandum of Understanding in which they reallocated their NO_X emission budgets for EGUs, and effectively reallocated their projected heat input, among the three States. This agreement, which was implemented in their SIPs approved on December 27, 2000, rendered moot any potential issues concerning the 2007 heat input projections used to calculate their original NO_X emission budgets. As discussed below, EPA found that, while the alternative methodologies resulted in higher 2007 projected heat input for some individual States, overall the alternative 2007 projections would not comport better than EPA's 2007 projections with the actual heat input data for the NO_X SIP Call States.

The first alternative methodology would involve using heat input growth rates from OTAG. During the NO_X SIP Call rulemaking, EPA reviewed NO_X emission projections by OTAG and converted them into heat input projections and growth rates. The EPA and OTAG heat input growth rates are compared in Table 16 below.

TABLE 16.—COMPARISON OF OTAG AND EPA STATE HEAT INPUT GROWTH FACTORS[49]

State	OTAG growth rate	EPA growth rate
AL	1.21	1.10
DC	1.00	1.36
DE	1.15	1.27
GA	1.03	1.13
IL	1.08	1.08
IN	1.12	1.17
KY	1.08	1.16
MD	1.05	1.35
MI	0.94	1.13
MO	1.05	1.09
NC	1.10	1.21
NJ	1.10	1.21
NY	1.08	1.05
OH	1.04	1.07
PA	1.06	1.15
SC	1.03	1.43
TN	1.13	1.21
VA	1.07	1.32
WV	1.05	1.03
Region	1.04	1.1

[49] Throughout this notice the term growth rate (expressed in percent) has been used. In the original rulemaking EPA actually used growth factors (a factor used to multiply the baseline heat input). Growth factors can be converted to growth rates by subtracting 1 and expressing the value in terms of a percent (e.g. a growth factor of 1.08 is equivalent to a growth rate of 8%). In other words, increasing a baseline heat input by 8% growth rate is equivalent to multiplying the baseline heat input by a 1.08 growth factor.

Focusing first on the States for which EPA's heat input growth rates have been disputed by commenters, EPA notes that EPA's State heat input growth rate is higher than OTAG's for three States (Georgia, Michigan, and Virginia), lower for three States (Alabama, Missouri, and West Virginia) and the same for one State (Illinois). Further, as shown in Table 19 below, the 2007 heat input projection based on OTAG's growth rates would be exceeded by actual State heat input in a recent year for ten jurisdictions, as compared to seven jurisdictions when 2007 projections are

1970–1998 had a decrease in ozone season heat input, with the largest decrease being 9.1% (Docket # A–96–56, Item # XV–C–19, at 61). Since these periods—although a minority—indicate that such decreases can occur, EPA believes that its methodology should not be considered unreasonable based on the recent State heat input. Moreover, while these long-term historical data certainly show the potential for such decreases, the data are otherwise of limited use in projecting future heat input. As explained in Section V.D.6. of this notice, the electricity industry has been undergoing deregulation of generation and restructuring. As a result, trends in the past, as reflected in the data, may not continue in the future. The IPM reflects these changes, and by using the IPM in developing heat input growth rates, EPA has taken these changes into account.

[48] The periods for decreasing ozone season heat input obviously differ slightly from the periods for decreasing annual heat input.

based on EPA's growth rates.[50] In addition, using OTAG's heat input growth rates, the overall heat input growth rate for the entire NO_X SIP Call region would be less than the overall growth rate using EPA's growth rates, and the heat input projections for 2007 for the region would be lower. In summary, using OTAG's growth rates, rather than EPA's heat input growth rates would result in more States recently exceeding their 2007 heat input projections and lower heat input for the region as a whole.[51]

A second alternative methodology that EPA considered in the NO_X SIP Call rulemaking and that a commenter proposed is use of a single, regionwide heat input growth factor based on the 2001–2010 heat input growth rate under the IPM (i.e., 1.15%). This would result in the same projected heat input for the NO_X SIP Call region as a whole, but in a different apportioning of that heat input among the States in the region. With regard to the States whose heat input is disputed by commenters, EPA's State heat input growth rate is higher than under this second alternative for four States (Georgia, Illinois, Michigan, and Virginia) and lower in three States (Alabama, Missouri, and West Virginia). Further, as shown in Table 18 below, the 2007 heat input projection based on the single, regionwide growth rate would be exceeded in a recent year by actual State heat input for nine jurisdictions, as compared to seven jurisdictions when 2007 projections are based on EPA's growth rates. Thus, using this second alternative methodology, rather than EPA's methodology, would result in additional States exceeding their 2007 heat input projections.[52]

During the NO_X SIP Call rulemaking, EPA received comment on a third alternative methodology to project heat input. The commenter suggested using growth factors based on actual 1996 data and 2007 IPM projections. These growth rates, which would be applied to 1996 heat input, are set forth in Table 17 below.

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During the NO_X SIP Call rulemaking, EPA received comment on a third alternative methodology to project heat input. The commenter suggested using growth factors based on actual 1996 data and 2007 IPM projections. These growth rates, which would be applied to 1996 heat input, are set forth in Table 17 below.

TABLE 17.—COMPARISON OF 1996–2007 STATE GROWTH RATES AND EPA HEAT INPUT GROWTH RATES

State	Commenter growth rate	EPA growth rate
AL	1.07	1.10
DE	1.53	1.36
DC	0.40	1.27
GA	1.11	1.13
IL	1.25	1.08
IN	1.09	1.17
KT	1.13	1.16
MD	1.08	1.35
MI	1.24	1.13
MO	1.33	1.09
NJ	2.3	1.21
NY	1.07	1.21
NC	1.33	1.05
OH	1.02	1.07
PA	1.10	1.15
SC	1.45	1.43
TN	1.11	1.21
VA	1.47	1.32
WV	1.35	1.03

With regard to the States whose heat input is disputed by commenters, EPA's State heat input growth rate is higher than under this third alternative for two States (Alabama and Georgia) and lower in five States (Illinois, Michigan, Missouri, Virginia, and West Virginia). Further, as shown in Table 18 below, the 2007 heat input projection based on the third alternative methodology would be exceeded by actual State heat input in a recent year for seven jurisdictions. Thus, using this third alternative methodology would result in the same number of jurisdictions exceeding their 2007 heat input projections in a recent year as under EPA's methodology.[53]

TABLE 18—STATES THAT IN A RECENT YEAR HAVE EXCEEDED 2007 HEAT INPUT UNDER DIFFERENT PROJECTION METHODS

State	EPA method	OTAG growth rate	Uniform growth rate	1996–2007 growth rate
AL	Exceeded	Exceeded	Exceeded	Exceeded
DC[54]	Exceeded	Exceeded	Exceeded	Exceeded
DE				Exceeded

[50] While EPA's 2007 heat input projection was exceeded by New York's 1999 heat input, no commenter disputed the heat input growth rate for that State. Moreover, the State's heat input has decreased since 1999 and is now well below EPA's projection. In fact, heat input in every year other than 1999 has been lower than the actual heat input in 1995.

[51] As discussed in section V.C.3 of this notice, OTAG's projections also are fundamentally flawed in that they are not based on consistent assumptions.

[52] Further, as a conceptual matter, EPA considers this alternative less reasonable than EPA's methodology because this alternative assumes the same amount of heat input growth for each State, a phenomenon that is demonstrably unrealistic, based on both historical experience and model projections.

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[53] As a conceptual matter, EPA considers this alternative less reasonable than EPA's methodology because it calculates growth between an actual year of heat input (1996) and a modeled year of heat input. *See* section V.C.2 of this notice.

TABLE 18—STATES THAT IN A RECENT YEAR HAVE EXCEEDED 2007 HEAT INPUT UNDER DIFFERENT PROJECTION METHODS—Continued

State	EPA method	OTAG growth rate	Uniform growth rate	1996–2007 growth rate
GA	Exceeded	Exceeded	Exceeded	Exceeded
IL	Exceeded	Exceeded	Exceeded	
IN				Exceeded
KY		Exceeded		
MD		Exceeded	Exceeded	
MI		Exceeded		
MO	Exceeded	Exceeded	Exceeded	
NC				
NJ			Exceeded	
NY	Exceeded	Exceeded		Exceeded
OH				Exceeded
PA				
SC			Exceeded	
TN				
VA			Exceeded	
WV	Exceeded	Exceeded		

[54] EPA notes that the District of Columbia is unique in that it has only six units and so its heat input is particularly variable.

Finally, some commenters suggested using more recent data to develop 2007 heat input projections. One such approach continues to use EPA's heat input growth rates, but applies them to the 2000 actual State heat input data, instead of actual data representing the higher of a State's 1995 or 1996 heat input. While EPA believes that it was appropriate to use, to the extent feasible, the most up-to-date heat input data available during the NO_X SIP Call and Section 126 rulemakings in order to project 2007 heat input, the 2000 heat input data that the commenter suggests using became available in 2001 and was, obviously, not available when EPA issued the NO_X SIP Call (1998), the Section 126 Rule (1999), and the Technical Amendments (2000). EPA believes that the Agency cannot reasonably be required to modify the heat input growth rate projections or other aspects of the NO_X SIP Call and Section 126 Rule simply to use future data that inevitably becomes available with the passage of time. Requiring EPA to do so would be a prescription for endless rulemaking.

Moreover, in this case, the data involved, i.e., State heat input, are quite variable from year to year. It therefore seems likely that, as subsequent years of actual State heat input data become available, some of the States' heat input may increase in one particular year more rapidly than reflected in the heat input growth rates and result in heat input for that year exceeding the new 2007 heat input projections under this fourth alternative methodology. The fact is that, as the latest year of actual State heat input data advances, the set of States with current, actual heat input exceeding 2007 projected heat input may well change. As discussed above, this already occurred during 1998–2001, when the set of States with current, actual heat input exceeding or close to 2007 projected heat input changed somewhat almost every year. EPA believes that this demonstrates both that the exceedance in a particular year of a State's 2007 heat input projection does not make the projection unreasonable and that commenters failed to demonstrate that EPA's heat input growth methodology is unreasonable.

E. Procedural Issues

As a procedural matter, EPA is responding in today's notice to the Court's remand in the Section 126 and the Technical Amendments cases of the heat input growth rate issue by providing a clearer explanation of the Agency's methodology. Before issuing today's notice, EPA outlined its proposed response in a notice in the **Federal Register**, i.e., the August 3, 2001 NODA (66 FR 40609–16). In that NODA, EPA relied largely on the existing record, but also pointed to new information that EPA placed in the docket at that time. EPA received some 30 comments on the NODA. EPA then developed additional new information and placed that in the docket through a second NODA dated March 11, 2002 (67 FR 10844–45). In the March 11, 2002 NODA, EPA also noted that some additional information might be put in the docket later. EPA did so at various times after March 11, 2002.

Commenters raised several procedural issues concerning EPA's response to the Court's remand of the heat input growth rate issue.

1. Notice-and-Comment Rulemaking

Commenters stated that EPA was required to have completed today's response to the Court's remand through notice-and-comment rulemaking.

EPA believes that its procedure is appropriate for today's response to the Court's remand. The response to remand does not entail promulgation of a new or revised rule reflecting new or revised heat input growth rates. Rather, it involves a clearer explanation, based on the existing record and confirmed by supplemental information, of the same heat input growth rates that EPA previously used in the NO_X SIP Call, the Section 126 Rule, and the Technical Amendments. Under these circumstances, notice-and-comment rulemaking is not required. *See generally National Grain & Feed Ass'n, Inc.* v. *OSHA*, 903 F.2d 308 (5th Cir., 1990).

A notice-and-comment rulemaking would have been appropriate had the Court vacated the rulemaking with respect to the heat input growth rate issue, but the Court did not do so in either the Section 126 Decision or the Technical Amendments Decision. Indeed, in the Section 126 case, the Court denied a post-decision procedural motion specifically requesting such a vacatur.

In any event, as a practical matter, an opportunity to comment was afforded interested parties. By the August 3, 2001 NODA, EPA placed in the docket additional factual information that it compiled in the course of responding to the remand, and EPA allowed a 30-day comment period on that additional information. Many parties commented, and EPA has responded to those comments in today's notice. The August

3, 2001 NODA also outlined EPA's preliminary explanation in response to the remand, interested parties commented on that explanation, and EPA responded. Further, by the March 11, 2002 NODA, EPA again placed additional factual information compiled in the course of responding to the remand. As discussed above, two comments were submitted questioning whether there was time for submission of comments on the new information and questioning how the new data related to the response to remand. EPA thereafter explained to the commenters and the public the relevance of the documents and stated that the Agency would delay issuance of the final response to the remands until on or about April 17, 2001 and would consider timely submitted comments. EPA also received a third comment stating that the data referenced in the March 11, 2002 NODA were highly germane and supported EPA's heat input growth rate methodology.

A commenter claimed that section 307(d)(1) of the CAA requires that EPA provide a comment period and hold a hearing on its response to the remand. EPA disagrees.

Paragraph (1) of subsection (d) of section 307 provides that the procedural requirements found in subsection (d) apply to the items listed in subparagraphs (A) through (U). Each of these items refers to the ''promulgation'' (and, in almost all cases, the ''revision'') of a regulation or requirement under a provision of the CAA, except for subparagraph (N), which refers to an ''action of the Administrator under section 126,'' and subparagraph (U), which is a catch-all category that refers to ''such other actions as the Administrator may determine.'' EPA believes that the term ''action'' in subparagraph (N) is intended to cover both a grant or denial of a request for a finding under section 126(b), as well as a rulemaking establishing compliance requirements under section 126(c).

However, EPA does not believe that term should be read so broadly as to include today's response to the remand. Reading the term ''action'' so broadly would require that every remand response involving section 126 meet the procedural requirements of section 307(d), while a remand response involving any other provision referenced in section 307(d)(1) would not have to meet such requirements so long as the response was not a ''promulgation'' or ''revision'' of a regulation. EPA considers such a unique result for section 126 to be anomalous and therefore rejects that interpretation of the term ''action'' in section 307(d)(1)(N).

EPA also notes that, in today's response, the Agency is not taking any ''action'' under section 126. [55] Rather, EPA is simply explaining more clearly the basis for the ''action'' that it took in the section 126 Rule issued in January 2000, i.e., the final rulemaking that established compliance requirements, including State NO_X budgets for EGUs.

2. Petition to Reconsider

Some commenters requested that EPA should treat any of their comments that EPA considered to be outside the scope of today's notice as petitions to reconsider and that EPA should respond to such petitions at the same time that it issues today's notice. Because EPA is responding on the merits to the comments submitted by these commenters, this request is moot.[56]

However, as discussed in section V.D.8 of this notice, a few comments by some other commenters are outside the scope of the remand and of today's response to remand. EPA does not regard the reconsideration request to apply to these comments.

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements.

40 CFR Part 52

Air pollution control, Ozone, Reporting and recordkeeping requirements.

40 CFR Part 96

Administrative practice and procedure, Air pollution control, Nitrogen oxides, Ozone, Reporting and recordkeeping requirements.

40 CFR Part 97

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Reporting and recordkeeping requirements.

Dated: April 23, 2002.

Christine T. Whitman,

Administrator.

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[55] Under **Federal Register** drafting requirements, EPA must have an ''Action'' caption in every document published in the **Federal Register**. The use of caption at the beginning of today's notice does not make the notice an ''action'' under Section 307(d)(1)(N). The ''Action'' caption is required for all notices, including policy statements and interpretations for which public notice and comment and a public hearing are clearly not required.

[56] One of these commenters argued that EPA should remove any limit on the size of the Compliance Supplement Pool, which is a pool of extra allowances established by EPA for each State for use in the first 2 years of the NO_X SIP Call and the section 126 Rule by sources that may not be able to install NO_X emissions in time. Not only is this claim outside the scope of this notice, but also the Court has already ruled on and upheld EPA's imposition of the cap on the Compliance Supplement Pool. *See Michigan* v. *EPA*, 213 F.3d at 694.