National Rural Electric
Cooperative Association
A Touchstone Energy® Cooperative

October 7, 2011

Administrator Lisa P. Jackson
U.S. Environmental Protection Agency
Room 3000, Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Petition for Administrative Reconsideration of "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals"
76 Fed. Reg. 48208 (Aug. 8, 2011); EPA Docket No. EPA-HQ-OAR-2009-0491

Dear Administrator Jackson:

The National Rural Electric Cooperative Association (NRECA), respectfully requests that the United States Environmental Protection Agency (EPA or the Agency) reconsider its final rule entitled "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," and known as the Cross-State Air Pollution Rule (CSAPR), under the Clean Air Act (CAA or Act). 76 Fed. Reg. 48208 (Aug. 8, 2011). As described below, several important aspects of CSAPR were not addressed in the version of CSAPR EPA proposed initially[1] (the Proposed Transport Rule or PTR), or any of the three notices of data availability that followed the initial proposal in this proceeding.[2] As a result, NRECA had no notice of these aspects of the rule and was not provided an adequate basis on which to comment on them. NRECA's objections to these important aspects of the rule, described below, are of central relevance to the outcome of the CSAPR rulemaking.[3] Therefore, for the reasons set forth below, the Administrator should reconsider the rule to address these important issues. NRECA wants to emphasize that its member electric cooperatives are not-for-profit entities, and therefore, all direct and indirect costs borne by them as a result of CSAPR for self generation and power purchases will ultimately be incurred by the electric cooperative consumer-members. By revising CSAPR to consider issues identified in this petition, the environmental benefits of the rule would be essentially unchanged, while the cost savings to a significant portion the nation's rural electric consumers would be great.

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[1] 75 Fed. Reg. 45210 (Aug. 2, 2010).
[2] 75 Fed. Reg. 53613 (Sept. 1, 2010); 75 Fed. Reg. 66055 (Oct. 27, 2010); 76 Fed. Reg. 1109 (Jan. 7, 2011).
[3] *See* CAA § 307(d)(7)(B), 42 U.S.C. § 7607(d)(7)(B) (establishing criteria for reconsideration of final EPA actions under the CAA that are within the scope of section 307(d)(1), including that the petitioner's objection arose after the public comment period, but within the time specified for judicial review, and is "of central relevance to the outcome of the rule"). Section 307(d)(7)(B) applies to EPA's CSAPR rulemaking, in which EPA imposes federal implementation plans (FIPs) under section 110(c) of the Act, because section 307(d)(1)(B) provides that section 307(d) applies to, among other things, "the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)]." 42 U.S.C. § 7607(d)(1)(B); *see* 76 Fed. Reg. 48352/3 (recognizing that section 307(d) applies to CSAPR).

I. Introduction.

NRECA is a national service organization for more than 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million customers in 47 states. All or portions of 2,500 of the nation's 3,141 counties are served by rural electric cooperatives. Collectively, cooperative service areas cover 75 percent of the U.S. landmass.

Sixty-five rural electric generating and transmission cooperatives (G&Ts) generate and transmit power to 668 of the 841 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. The remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. A significant portion of the power purchased directly by distribution cooperatives originates from coal-fired generation.

Overall, the G&Ts provide 41 percent of all distribution cooperative electric generation needs. Eighty percent of this generation, or 26,000 megawatts (MWs), is coal-fired. Fifty percent of this coal-fired generation was constructed under the CAA new source regulatory mandates and more than 60 percent is equipped with flue gas desulphurization (FGD) units or "scrubbers" to control sulfur dioxide (SO_2) emissions. Over 6,000 MWs of this generating capacity is also retrofitted with state-of-the-art nitrogen oxides (NOx) controls and selective catalytic reduction (SCR) equipment, and virtually all cooperative coal-fired generation is equipped with low-NOx burner technologies. In the aggregate, cooperative coal-fired generation is newer and equipped with more pollution controls as compared to the overall electric utility sector.

II. CSAPR Will Significantly Impact NRECA Members.

The aspects of CSAPR to which NRECA objects in this petition will have critical impacts on NRECA's members. CSAPR will require reductions in emissions from electric generating units (EGUs) in 27 states based on EPA's interpretation and application of CAA section 110(a)(2)(D)(i)(I), which requires, in relevant part, that each state's plan for attaining the national ambient air quality standards (NAAQS) "contain adequate provisions . . . prohibiting . . . any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS]." 42 U.S.C. § 7410(a)(2)(D)(i)(I). More specifically, CSAPR will regulate year-round emissions of SO_2 and NOx in states deemed to be contributing significantly to nonattainment or interference with maintenance in downwind states with respect to the $PM_{2.5}$ NAAQS, and will regulate ozone-season emissions of NOx in states deemed to be contributing significantly to nonattainment or interference with maintenance in downwind states with respect to the 1997 8-hour ozone NAAQS. 76 Fed. Reg. at 48222/3.

A significant portion of cooperative fossil fuel electric generation by NRECA members is located within the 27-state region addressed in CSAPR and will be affected by its mandates. NRECA members operating in these 27 states will be subject to significant costs and regulatory burdens, including, for example, more stringent limitations on emissions, increases in operating costs associated with compliance with the requirements of the final rule, and the possibility of burdensome penalties to the extent they are unable to comply by the relevant implementation dates.

In fact, compliance with CSAPR will be particularly burdensome for NRECA members because they operate as not-for-profit cooperatives. As a result, the costs of implementing CSAPR will be unavoidably and directly borne by their consumer-members.

NRECA's members will face serious challenges in complying with CSAPR. Several specific examples are San Miguel Electric Cooperative located in Texas and South Mississippi Electric Power Association (SMEPA). San Miguel provides electricity to 26 member electric cooperatives located across the state. Texas was not included in proposed rule for the SO_2 and NOx annual programs and thus was given no opportunity to review and comment on the Texas SO_2 and NOx annual overall budgets or on the assumptions EPA made in its modeling for the final rule regarding specific emissions control and operating limitations for the San Miguel unit. As a result of CSAPR FIP mandates, the San Miguel unit is saddled with a very significant shortfall of allowances leaving San Miguel with nothing but costly options that include purchasing allowances that in today's market are highly overpriced if available at all, or reducing the output of the power plant, leaving San Miguel's customers with having to find replacement power from a Texas wholesale market that appears to be woefully short of excess power. EPA's preferred option for the unit, reducing operation to non-baseload status, is simply not technically or economical feasible.[4]

San Miguel's unit was built with a wet flue gas desulfurization system (WFGD) and based on 2008 data, the Energy Information Administration recognized San Miguel's WFGD as having the second-highest SO2 removal efficiency in the state. Despite San Miguel's sustained significant reductions in SO_2, under CSAPR mandates that San Miguel reduce its 2010 SO_2 emissions in half.[5]

Like many units in Texas, San Miguel has already exhausted most of its options for reducing NOx, and these reductions have come at a significant cost. In fact, the Texas coal fleet has successfully achieved the lowest NOx emission rate of any fleet of coal plants in the U.S. Despite those successes, San Miguel will be required to reduce its NOx emissions by 39 percent relative to 2010 emissions under CSAPR.[6] San Miguel is taking extraordinary steps to reduce its NOx emissions by installing new and upgraded pollution control equipment, however due to the January 1, 2012 effective date for CSAPR; it will not be able to accomplish the required NOx reductions through pollution control equipment alone.

[4]See the report prepared by James Marchetti, Inc. for NRECA attached hereto for a discussion of erroneous assumptions made by EPA in modeling for the final rule regarding the San Miguel unit and other units owned or co-owned by NRECA members.
[5] The proposed October 6, 2011, revisions to CSAPR would change the reduction to 34 percent.
[6] The proposed October 6, 2011, revisions to CSAPR would change the reduction to 38 percent.

EPA assumes that adequate liquidity will exist in the emission allowance trading programs contemplated under CSAPR. Unfortunately, after contacting several trading companies with significant experience in the emission allowance market, Sam Miguel has not been unable to identify a single company that agrees with EPA's assessment regarding allowance prices. San Miguel does not believe it would be prudent to "bet on the come" with regard to NOx allowances when only EPA seems to believe those allowances will be available. Therefore, effective January 1, 2012, San Miguel plans to reduce the output of its generating facility by approximately 14 percent.

The depreciation and amortization expense associated with new and upgraded equipment, additional O&M expense associated with operating the equipment, combined with the effect of reducing the output of the San Miguel facility will increase San Miguel's power costs by an estimated 20 percent for 2012. In addition, San Miguel's members will be forced to find replacement energy to cover the reduction in San Miguel's output in a Texas wholesale market that appears to be significantly short of excess power.

In short, meeting the requirements of CSAPR will be very costly to San Miguel's 26 member cooperatives and its more than 550,000 electric cooperative consumer-members.

Another example, South Mississippi Electric Power Association (SMEPA), a NRECA member operating in Mississippi, a state regulated under CSAPR based on the 8-hour ozone NAAQS promulgated in 1997, will be required to reduce ozone-season NOx emissions from its units by nearly 70 percent in order to avoid exceeding its 2012 allowance allocation under CSAPR. Based on the limited time between release of the rule and the first compliance deadline, it is unlikely that SMEPA will be able to comply with the rule through emission reductions alone. And like San Miguel, SMEPA is concerned that it will be unable to comply through allowance purchases. Indeed, SMEPA believes that, due to reluctance on the part of other electric generators to sell allowances, sufficient allowances will not be available for purchase.[7]

SMEPA is particularly concerned about how compliance with the rule will affect two of its facilities – Plant Morrow and Plant Moselle. Each of these plants provides more than 30 percent of the reactive reserves required for the generation and transmission (G&T) system. Plant Moselle is located in the geographic center of SMEPA's transmission system and provides voltage support necessary to support the 69 kV portion of SMEPA's transmission system during the peak summer season. Similarly, Plant Morrow is located in the southern portion of SMEPA's transmission system, and is the largest and most efficient generation source in the system, providing voltage support necessary to support the 161 kV portion of SMEPA's transmission system during the peak summer season. Because of their geographic locations and SMEPA's transmission configuration, these two plants are considered "must run" plants during peak system loading conditions. Without the critical voltage support they provide, SMEPA could encounter low voltage

[7] Any allowances available for purchase may be priced at levels substantially higher than the "reasonable" prices that EPA projected when it released the final rule. *See* the petition for reconsideration of CSAPR filed by the Utility Air Regulatory Group (UARG Petition) at Section IV. The UARG Petition is discussed in greater detail below.

conditions over portions of its transmission system during normal operating and contingency outage conditions.

In addition to providing critical voltage to SMEPA's transmission systems, Plant Morrow and steam units at Plant Moselle provide a combined 60 percent of the generation capacity connected with the G&T area. The loss or reduction in operating capability of either plant could affect SMEPA's ability to provide reliable electricity to its member systems. Compliance with the ozone-season NOx allowances allocated to units at these plants would require significant reductions in operating capacity at both plants. Plant Morrow and Plant Moselle would have to reduce their ozone-season NOx emissions by approximately 65 percent and 32 percent respectively, compared to their 2010 ozone-season NOx emissions, to avoid exceeding the numbers of allowances allocated to their units under CSAPR.[8] SMEPA projects that the impact of CSAPR on these two plants will result in a deficiency in generation capacity of 224 MW in 2012.

SMEPA expects that it will also face a reduction in capacity available under several power purchase agreements, possibly resulting in a loss of another 240 MW of generating capacity. If implemented as scheduled, SMEPA estimates that CSAPR will result in the loss of approximately 32 percent of its G&T area generation capacity and approximately 26 percent of its total system generation capacity. Considering the combined effect of CSAPR on all of its generation resources, SMEPA projects its total system capacity will be deficient by approximately 464 MW in 2012. This level of deficiency would present significant reliability issues, as well as significant economic consequences for SMEPA.

These are just a few specific examples of the significant adverse impacts CSAPR will have on affected NRECA members, and all cost impacts will have to be absorbed by the electric cooperative consumers.

III. CSAPR Contains Numerous Procedural Flaws That Are of Central Relevance to the Rule.

As a member of the Utility Air Regulatory Group (UARG), NRECA had the opportunity to review the petition for reconsideration that UARG will be filing today. NRECA endorses UARG's petition for reconsideration in its entirety and incorporates it by reference herein. The following is a discussion of portions of UARG's petition for reconsideration that are particularly relevant to NRECA's members.

As an initial matter, UARG's petition addresses the results of an analysis by James Marchetti, Inc. (Marchetti) of errors in the unit-level data underlying the parsed data files that EPA used in its modeling for the Proposed Transport Rule and for CSAPR. *See* UARG Petition at Section I for a description of the analysis Marchetti completed for UARG, and the report by Marchetti of the analysis attached to UARG's petition. EPA created these parsed data files using its Integrated Planning Model (IPM) and used them to model nonattainment and maintenance problems at receptor sites in downwind states

[8] Plant Morrow emitted 3,063 tons of NOx during the 2010 ozone season, and its 2012 ozone season NOx budget is 1,063 tons; Plant Moselle emitted 193 tons of NOx during the 2010 ozone season, and its 2012 ozone season NOx budget is 131 tons.

and to quantify projected contribution of emission in upwind states to annual and 24-hour $PM_{2.5}$ and 8-hour ozone at those downwind sites. This modeling assisted EPA in determining which states would be included in the rule. EPA also used the parsed data files to project the benefits of the emission reductions from the rule. 76 Fed. Reg. at 48229/1-2.

Because there was insufficient time to evaluate the data for all generating units covered in the key IPM runs, UARG asked Marchetti to focus on evaluating unit-level data in the 2012 and 2014 parsed data files for units in eight states. UARG asked Marchetti to identify two types of errors in particular: instances in which an error (i) occurred in the parsed data files EPA used in the modeling runs for the Proposed Transport Rule, (ii) was pointed out to EPA in rulemaking comments on the Proposed Transport Rule, but (iii) was not corrected in the parsed data files used in the modeling runs for CSAPR; and instances in which unit-level data were correct in the parsed data files EPA used in the modeling runs for the Proposed Transport Rule, but were erroneously changed in the parsed data files used in the modeling runs for the final rule. The results of this analysis revealed that there were numerous and widespread unit-level errors in the parsed data files concerning, for example, whether and when SO_2 and NOx emission reduction control technologies can and will be installed on affected EGUs; whether and when affected EGUs will be able to switch fuels in order to reduce emissions; and whether and when affected units might be retired.

Several of the errors identified in the analysis performed for UARG involved errors in data for units owned by NRECA members. NRECA retained Marchetti to perform a similar analysis of all data in EPA's parsed data files pertaining to units owned by NRECA members. The results of that analysis also revealed numerous significant errors. Please see the report prepared by Marchetti for NRECA, attached hereto, for a description of the specific errors identified in the parsed data files pertaining to units owned by NRECA members. NRECA cannot be certain that all cooperative unit errors of significance have been identified in the attachment. Due to time constraints some errors may have been missed.

The kinds of errors that Marchetti identified in both the analysis prepared for UARG and the analysis prepared for NRECA are the types of errors that can significantly affect predictions regarding the impacts of SO_2 and NOx emissions from upwind states on air quality in downwind states. The errors can also significantly affect the state-specific NOx and SO_2 budgets, resulting in significantly different budgets as compared to what they would have been had EPA not made such errors in the parsed data files for IPM. Errors such as this at the state-budget level can result in under-allocation at the unit level. Cooperative units receiving allowance shortfalls will likely face difficult and expensive choices where the installation of additional emission control devices cannot be accomplished by compliance deadlines. In these instances a cooperative will have to rely on allowances purchases that in today's markets are significantly far more expensive than EPA has predicted[9], or purchase additional power from the wholesale market where prices are likely to be far higher that the cost of self-generation.

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[9]See note 7 *supra.*

In addition, NRECA remains particularly concerned about under-allocation of allowances to new units under CSAPR. NRECA submitted comments on the proposed rule regarding the under-allocation of allowances to new units and over-allocation of allowances to retired and non-operating units in the proposed rule. NRECA, Comments on Proposed Rule for Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone, EPA-HQ-OAR-2009-0491-2723, at 4-8 (Oct. 1, 2010).[10] While NRECA commends EPA for amending the new unit set aside provisions in the final rule to account for "planned" and "potential" units, 76 Fed. Reg. at 48291/2-3, and for allocating allowances to new units during the first control period of commercial operation, *id.* at 48290/3, these changes do not result in sufficient allocations of allowances to new units. EPA should allocate allowances to new units at levels reflecting best available control technology (BACT) emission limitations applicable to each new unit. This approach is appropriate because BACT emission limitations are, by definition, set at cost effective levels – just as state CSAPR budgets are.

NRECA also objects to the unreasonable and unrealistic assumptions in CSAPR regarding installation schedules for control equipment. In its modeling for the Proposed Transport Rule, EPA said it assumed that EGUs could be retrofitted with SCR equipment "in approximately 21 months" and with FGD equipment in "approximately 27 months." 75 Fed. Reg. at 45273/1. NRECA submitted comments on the Proposed Transport Rule explaining that EPA's assumptions regarding installation of SCR and FGD equipment by the 2014 compliance deadlines were unrealistic. NRECA Comments at 7-8. Nonetheless, EPA retains these assumptions in the final rule, and attempts to support them with examples of instances in which – EPA claims – electric generating companies were able to install control equipment in very short periods of time. As UARG explains in its petition for reconsideration, EPA's claims are meritless. *See* UARG Petition at Section II.

NRECA also objects to EPA's changes to its modeling and analyses that led to significant reductions of the emission budgets for several states between the proposed rule and the final rule without allowing an opportunity for public comment on the effects of those changes. *See* UARG Petition at Section V. Emission budget reductions in many of the states in which NRECA members operate will only exacerbate the effects of CSAPR on those members. For example, one NRECA member operating in Louisiana predicts substantial costs associated with compliance with the final rule that it could not have anticipated during the public comment period on the proposed rule, due to the 37 percent decrease in Louisiana's 2012 and 2014 ozone-season NOx budgets between the proposed and final rules. *Compare* 75 Fed. Reg. at 45291 (Table IV.E-2) *with* 76 Fed. Reg. at 48262 (Table VI.D-4). This NRECA member predicts that it will face reliability issues if its power provider is unable to upgrade its equipment in time for compliance. Additionally, Nebraska's electric cooperatives are also significantly affected by the severe reductions of that state's annual NOx budget allocations in CSAPR as compared to the proposed rule. Although not self generators, these cooperatives must purchase power from Nebraska's electric generators that are highly impacted by the new reduced NOx allocations in CSAPR and thus would incur significant cost in the purchase of

[10] NRECA also hereby incorporates its comments by reference into this petition.

wholesale power. As identified in State of Nebraska's petition for reconsideration and stay of CSAPR, the NOx state budget is reduced by almost 39 percent in the final rule as compared to the proposal.[11]

Finally, NRECA objects to EPA's determination that CSAPR will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). 76 Fed. Reg. at 48345/1. Several NRECA members are small entities under the RFA and they indisputably will incur significant economic impacts due to CSAPR. As a result, NRECA requests that EPA convene a small entity review panel in conjunction with its reconsideration proceeding. To this end NRECA notes that EPA has recently short circuited its own stated process for complying with the RFA by the convening of small business panels under short notice with no effective opportunity for small entity representatives to recommend options to minimize impacts of the rule on small business entities.[12] Small business representatives must have an opportunity to effectively contribute to the rulemaking process as clearly intended under the RFA.

IV. Conclusion.

In sum, NRECA joins UARG in each of the objections set forth in its petition for reconsideration of CSAPR. These issues are of central relevance to the outcome of the rule for the reasons described by UARG in its petition, and EPA should grant reconsideration of CSAPR to address them.

Respectfully submitted,

/S/

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Attachment

cc: Gina McCarthy, Assistant Administrator
Elizabeth Craig, Acting Director of the Office of Atmospheric Programs
Sam Napolitano, Director of the Clean Air Markets Division
EPA Docket No. EPA-HQ-OAR-2009-0491

[11] *See* the Nebraska petition filed with the CSAPR docket.
[12] NRECA Comments on the National Emissions Standards for Hazardous Air Pollutants for Coal-and-Oil Fired Electric Utility Steam Generating Units, Electric, EPA-HQ-OAR-2009-0234-17689, at 4-5 (August 4, 2011).

Identification of Unit Errors in Integrated Planning Model (IPM) Runs for the Final Cross-State Air Pollution Rule

Prepared by James Marchetti

Key:
Parsed File Runs
BC_P_12 - 2012 Base Case for Proposed Transport Rule
BC_F_12 - 2012 Base Case for Final Transport Rule (CSAPR)
BC_F_14 - 2014 Base Case for Final Transport Rule
RC_F_12 - 2012 Remedy Case for Final Transport Rule
RC_F_14 - 2014 Remedy Case for Final Transport Rule

TX:
San Miguel 1 - EPA in its Proposed and Final Base & Remedy Cases has modeled this 391 MW lignite coal unit for seasonal use only, which is incorrect. San Miguel Electric Cooperative in its comments to EPA on the proposed rule on October 1, 2010, indicated this modeling was unrealistic and that San Miguel 1 is a base load unit with annual heat input between 32 to 35 TBtu and provides least cost electricity to its members. In addition, EPA has used extremely low SO2 emission rates for San Miguel 1 in both BC_P_12 and BC_F_12, in comparison to actual data. In its comments to EPA on the proposed rule (October 1, 2010), San Miguel indicated that it used a lignite coal with a 2.72% Sulfur content (2009) and a heat content of 5,280 Btu/lb (2009), which trans slates into an SO2 emission rate of 10.3 lbs/mmbtu. The WFGD at San Miguel had an actual FGD removal efficiency of 93.8% in 2009 , which translates into a final SO2 emission rate of 0.64 lb/mmbtu, which is almost identical to the 2010 final emission rate of 0.63 lbs/mmbtu. EPA uses 0.15 and 0.13 in BC_P_12 and BC_F_12, respectively indicating that EPA may have used the wrong sulfur content or FGD removal efficiency.

GA:
Errors were made in the parsed IPM files concerning when Wet Flue Gas Desulfurization (WFGD) systems would be required by the Georgia Multi-Pollutant Rule (GaMPR) at Plant Scherer units 1 & 2. The correct information is that Scherer units 1 & 2 WFGD systems are required by the GaMPR on December 31 of 2014 and 2013, respectively. The CSAPR's Base and Remedy Case runs for 2012 -- BC_F_12 and RC_F_12 – incorrectly assume WFGD retrofits for units 1 & 2 by 2012.

Also, errors were made in the parsed IPM files concerning when selective catalytic reduction (SCR) systems would be required by the GaMPR at Plant Scherer units 1 & 2. The correct information is that retrofits of SCR systems are required by the GaMPR on Scherer Units 1 and 2 on December 31, of 2014 and 2013, respectively. The CSAPR's Base and Remedy Case runs for 2012 -- BC_F_12 and RC_F_12 – incorrectly assume a SCR retrofit for unit 2 by 2012.

Another error with regard to the Scherer units is the coal rank that was assigned in both BC_P_12 and BC_F_12. In BC_P_12, EPA had Scherer Units 1 & 2 burning a bituminous coal which is an error. In BC_F_12 EPA had Units 1 & 2 burning subbituminous/ bituminous blends and, which is also an error. Since 2004, Scherer units 1 & 2 have been burning subbituminous Powder River Basin coal and there are no current plans to shift to another coal, even when both WFGDs are operational.

KS:

Comments by Westar, KCP&L and KCBPU on the proposed transport rule (October 1, 2010) focused upon how EPA overestimated emissions, which is also a focus of the state's recent suit against EPA. The focus of their comments were upon NOx emission rate data at Jeffery 1 -3, LaCygne 1, Quindaro 2 and Nearman 1, with some discussion of SO2 rates at Jeffery and LaCygne 1. Based upon their comments, EPA seems to have corrected many of the errors related to NOx emission rates in BC_P_12, and the state's total 2012 NOx emissions were reduced form 70,700 tons (BC_P_12) to 37,100 tons (BC_F_12). However, there are still some SO2 emission rates in BC_F_12 that are extremely high relative to their 2010 SO2 emission rates, and they are as follows:

Unit	BC_F_12 SO2 Rate	2010 SO2 Rate
Quindaro 2	0.94	0.59
Nearman Creek 1	0.94	0.63
Holcomb	0.29	0.12
LaCygne 2	0.94	0.68
Lawrence 3	1.26	0.62
Lawrence 4	0.40	0.06
Lawrence 5	0.71	0.12
Tecumseh 9	1.22	0.60
Tecumseh 10	1.21	0.63

The consequence of using these high 2012 high SO2 emission rates results in a 2012 state emission total of 68,000 tons, which translates into a state-wide emission rate of 0.39, which is significantly greater than the state's 2010 SO2 emission total of 45,200 tons and a state-wide emission rate of 0.23. An interesting note in KS, EPA estimates that 99.9% of the state's total Btus in 2012 will come from coal-fired generation.

WI:

Dairyland - James Madgett - EPA has a SCR installed in 2012 under RC_F_12; however, this installation is unlikely since Dairyland's plans call for an SCR after 2014. Since EPA indicated that all controls for 2012 are in the pipeline, this is an error.

Dairyland - Alma 4 & 5 - EPA in both BC_P_12 & BC_F_12 has both units burning 100% subbituminous coal, which is incorrect. Alma 4 & 5 burns a blend of subbituminous /bituminous coal.

Other States:

Big Rivers - HMP&L Station 2 FGDs (KY) - EPA has these FGDs listed as dispatachable FGDs and not operating in BC_P_12 and BC_F_12. This is an erroneous assumption. These two FGDs are CAAA - Phase I FGDs that were installed in 1995 and have been operating continuously ever since.

CORN BELT & NW IA - George Neal 4 (IA)- A DFGD is planned for George Neal 4 in October 2013; however, EPA does not have this DFGD listed in BC_F_14.

East Ky Power - Cooper 2 (KY) - EPA correctly places a FGD on Cooper in 2012 (BC_F_12); however, it is wrong type of FGD. EPA installs a WFGD, when it should be a DFGD.

Power South -Miller 1 (AL) - The Miller 1 FGD went into service in January 2011 and is classified by EPA as a dispatchable WFGD; however, the WFGD at Miller 2, which went into service in the Spring of 2010 is not dispatchable and EPA has operating. It seems illogical that two new FGDs placed in service six months apart, that one would be economical to operate anther would not.

Big Rivers - DB Wilson (KY) - EPA listed an FGD SO2 emission rate for DB Wilson in BC_P_12 of 0.60 lbs./mmbtu, which closely approximates the current SO2 emission rates of 0.50 and 0.52 lbs./mmbtu. However in BC_F_12, EPA increased the SO2 emission rate to 0.73 lbs./mmbtu, which seems to be incorrect. In addition, EPA has the wrong fuel being consumed at DB Wilson. Specifically, in both BC_P_12 and BC_F_12 EPA has Wilson burning 100% Pet Coke, which is wrong. Wilson has historically burned a blend of bituminous coal and pet coke.

Hoosier - Merom 1 (IN) - EPA set a SO2 emission rate of 0.11 lb./mmbtu in BC_F_12; whereas, for Merom 2 EPA had a SO2 emission rate of 0.25 lbs./mmbtu for the same BC_F_12. Both units burn the same coal, so it seems EPA erred in the Merom 1 emission rate. If Merom 1 continues to burn the same type of coal in 2012, which has an SO2 level of 5.46 lbs./mmbtu, and meets the Consent Decree enforceable 96% removal efficiency, it should have a SO2 emission rate of about 0.22 lbs./mmbtu, which closely matches the SO2 emission for Merom 2.

Associated -New Madrid (MO)- In BC_P_12, EPA had erroneous SO2 emission rates (4.4 lbs./mmbtu) on Units 1 & 2, but did adjust them downward in BC_F_12 to 0.94 lbs./mmbtu. However, these adjusted emission rates are still wrong. Both New Madrid units have current SO2 emission rates between 0.41 and 0.43 lbs./mmbtu; consequently, EPA has more than doubled the SO2 emissions associated with these two units.

Big Rivers - RD Green (KY) - In BC_P_12, EPA had SO2 emission rates for both units at 0.12 lbs./mmbtu, which is somewhat lower than the actual of 0.14 to 0.16 lbs/mmbtu. However, in BC_F_12, EPA erroneously increases the SO2 emission rates to 0.52 lbs/mmbtu, which increases emissions by a factor of 3.

Associated - Thomas Hill (MO) - In BC_F_12, EPA increased the SO2 emission rates on all three Hill units to 0.94 lbs/mmbtu (from 0.58 lbs/mmbtu in BC_P-12), which is incorrect. Current SO2 emission rates range between 0.41 to 0.43 lbs/mmbtu. By increasing these SO2 emission rates in BC_F_12, EPA more than doubled the SO2 emissions at the Thomas Hill facility.