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Leonard K. Peters
Secretary

October 1, 2010

EPA Docket Center, EPA West (Air Docket)
Attention Docket ID No. EPA-HQ-OAR-2009-0491
U.S. Environmental Protection Agency
MailCode: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Docket ID No. EPA-HQ-OAR-2009-0491

To Whom It May Concern:

The Kentucky Division for Air Quality hereby submits its enclosed comments on the U.S. Environmental Protection Agency's (EPA's) Proposal to Issue Federal Implementation Plans (FIPs) to Reduce Interstate Transport of Fine Particulate Matter and Ozone (75 Federal Register 45210, August 2, 2010). The Division appreciates the opportunity to comment on the U.S. EPA's proposed Transport Rule.

In addition, the Division is providing a copy of comments on the proposed Transport Rule recently received from the Utility Information Exchange of Kentucky (UIEK) for EPA's consideration. If you have any questions regarding the Division comments being provided, please contact Mr. Martin Luther, of my staff, at (502) 564-3999.

Sincerely,

John S. Lyons
Director

JSL:mrl
Enclosures

Kentucky Division for Air Quality (Division) Comments on the U.S. Environmental Protection Agency's (EPA's) Proposal to Issue Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (commonly called the Transport Rule) (75 FR 45210, August 2, 2010)

General Comments

- The Division encourages EPA to finalize the Transport Rule consistent with the following principles previously provided by Southeastern States Air Resource Managers, Inc. (SESARM). We ask that EPA carefully consider and implement such comments to the extent possible.

  - Levels of control should be based on sound air quality analysis using accepted evaluation tools.

  - Establishment of emission reduction mandates should be guided solely by what is needed to achieve and maintain attainment with national standards. Such analyses must give consideration to the impacts of emissions of local origin as well as transported emissions. However, the cost and relative air quality value of local versus distant emission controls must be evaluated and final emission limits should be based on cost-effectiveness and proven technology.

  - Deadlines for achieving mandated emission reductions should be designed to support the attainment deadlines prescribed for the standards. At the same time, the regulated community must be granted the required time to design and implement control equipment and operational changes necessary to meet new emissions limits.

  - Authority must be maintained to allow for states to implement additional programs necessary to address attainment and maintenance issues within their borders.

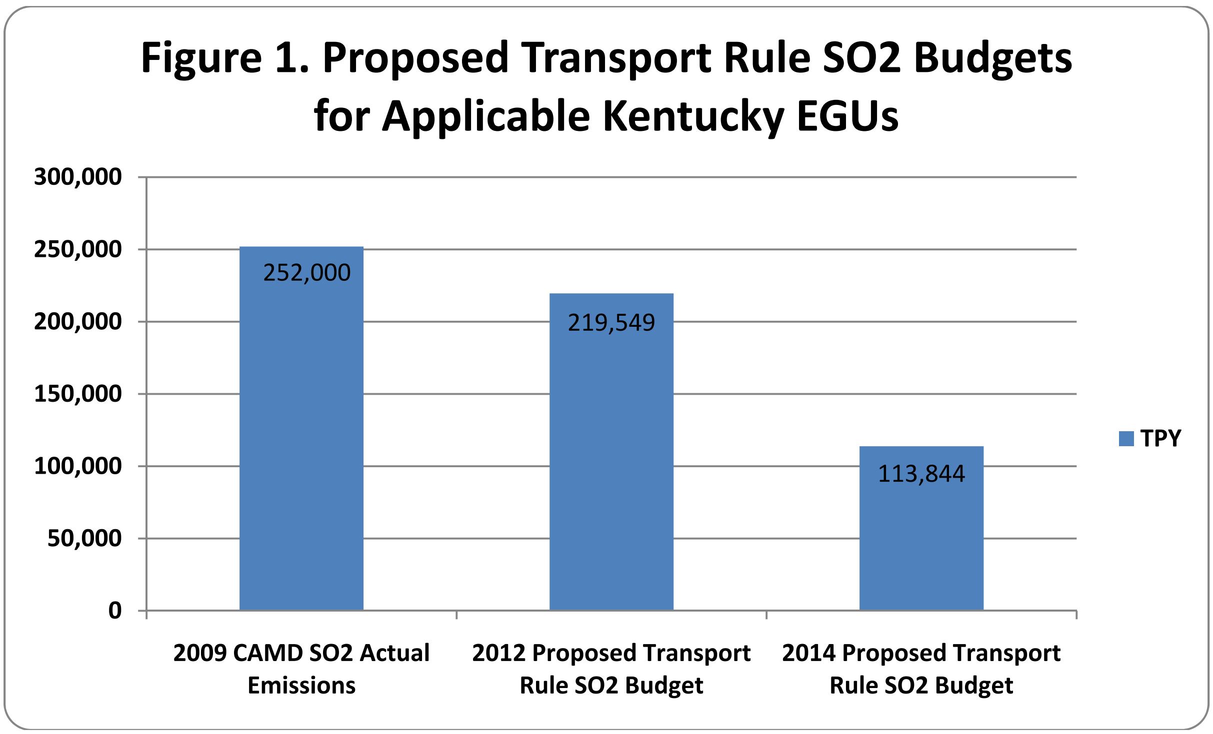
  - Timely guidance from EPA is extremely critical to implementation of the final Transport Rule. This guidance should be issued concurrent with finalization of the rule.

  - Emissions trading should be allowed to the extent authorized under the Clean Air Act. Any such trading program in the final Transport Rule should be operated at no cost to the local and state agencies.

Specific Comments

Proposed Transport Rule State SO2 Budgets for Kentucky

- Pursuant to the proposed Transport rule Preamble Section IV.E., State Emissions Budgets (75 FR 45290-45292), the Division is concerned that the Transport Rule SO2 emission budgets being proposed by EPA for Kentucky, especially in 2014, represent a drastic SO2 emission reduction which may not be achievable by Kentucky sources. Based on the Division's review of 2009 actual SO2 emissions for Kentucky Electric Generating Units (EGUs) (an estimated 252,000 tpy per 2009 EPA CAMD data), the proposed Transport Rule SO2 budget in 2012 (219,549 tpy) will be difficult to meet and the proposed rule's SO2 budget for 2014 (113,844 tpy) will be much more difficult and problematic to achieve given that most large Kentucky EGUs already have flue gas desulfurization (FGD) scrubbers operational before 2012 (*See below Figure 1 and see the attached Table 1 for Kentucky SO2 FGD controls and 2009 CAMD emissions*). Kentucky has only one remaining large unit (800 MWe) that is not scrubbed. Per a consent decree, this unit will install a FGD scrubber by December 31, 2015. However, this alone cannot achieve the needed SO2 budget reduction proposed by EPA for 2014.



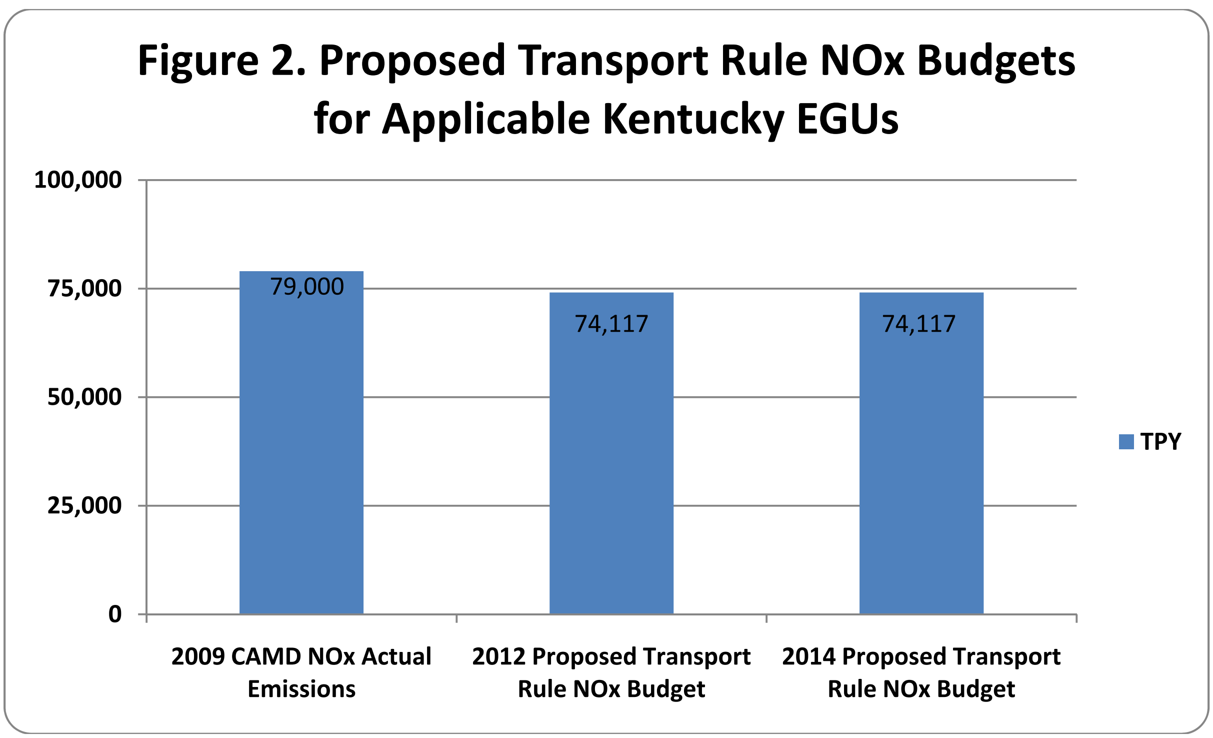
As indicated by Figure 1, the Transport Rule as proposed would require Kentucky EGUs to reduce their 2009 SO2 emissions by an estimated 13% by 2012 and reduce their 2009 emissions by an additional 42% by 2014 resulting in a total EGU SO2 emission reduction of 55% from the Kentucky 2009 EGU SO2 emission level. In addition, the proposed 2014 Transport Rule SO2 budget reflects a 48% decrease from the proposed 2012 Transport Rule SO2 budget for Kentucky EGUs. Even if these drastic emissions reductions being proposed by the Transport Rule are technologically feasible, which is in question, they are unrealistic and not practicable given that achieving such reductions may: (1) lead to disruptions in a reliable power supply in the region; (2) cause certain economic hardships for industry sectors; and (3) drive up the cost of consumer electricity rates. The Division requests that EPA reconsider the SO2 emission reductions in light of these probable outcomes.

Proposed Transport Rule SO2 Unit Allocation

- Pursuant to the proposed Transport Rule Preamble Section V.D.4., Allocation of Emissions Allowances (75 FR 45309-45312), the EPA SO2 unit allocations may be incorrect. Even though the 2014 Transport Rule SO2 budget decreased by 48% from the 2012 Transport Rule SO2 budget, certain unit's SO2 allocation in 2014 actually increased and in some cases significantly. Based on the Division's experience in providing previous allocations for the NOx SIP Call and Clean Air Interstate Rule (CAIR) NOx emissions trading programs, the Division contends that the 2014 allocation could not have been performed on a proportional (pro rata) basis since in that instance no unit's allocation for 2014 would have increased from its 2012 allowance allocation. Therefore, the Division requests that EPA verify the SO2 unit allocations to ensure that they were allocated properly.

Proposed Transport Rule State NOx Budgets for Kentucky

- Pursuant to the rule preamble Section IV.E., State Emissions Budgets (75 FR 45290-45292), based on the Division's review of 2009 actual NOx emissions for Kentucky EGUs (an estimated 79,000 tpy per 2009 EPA CAMD data), the proposed Transport Rule NOx budget in 2012 and 2014 (74,117 tpy) will also be difficult for certain Kentucky EGUs to meet since most Kentucky EGUs already have some type of NOx controls in place (*See below Figure 2 and see the attached Table 1 for Kentucky NOx controls and 2009 CAMD emissions*).



- As indicated by Figure 2, the Transport Rule as proposed would require Kentucky EGUs to reduce their 2009 annual NOx emissions by an estimated 6% by 2012. Notwithstanding the difficulty in obtaining this reduction, the Division is perplexed that EPA has proposed such a drastic budget reduction for SO2 from 2012 to 2014 for

Kentucky (See Figure 1), but has kept the 2012 and 2014 proposed Transport Rule NOx budgets the same (See Figure 2). The Division requests that EPA provide its rationale for this decision.

Proposed Transport Rule NOx Unit Allocation

- Pursuant to the proposed Transport Rule Preamble Section V.D.4., Allocation of Emissions Allowances (75 FR 45309-45312), in light of the Division's comments on EPAs SO2 unit allocations, the Division requests that EPA verify the NOx unit allocations to ensure that they were allocated properly.

Proposed Transport Rule Should Include NOx SIP Call Non-EGU Units Currently in CAIR

- Pursuant to the proposed Transport Rule Preamble Section V.G.2., NOx SIP Call Interactions (75 FR 45340-45341), the Division urges EPA to reconsider its decision not to allow the inclusion of its NOx SIP Call Non-EGUs now in CAIR into the proposed Transport Rule NOx ozone season trading program. Due to the very small emissions budget for the Division's six NOx SIP Call Non-EGUs (64 ozone season (OS) tons) that was added to the CAIR NOx OS budget, Kentucky disagrees with EPA's contention that including these units in the proposed Transport Rule would jeopardize a state's ability to eliminate its part of significant contribution and interference with maintenance that EPA has identified. As EPA has indicated in the preamble, states need a way to continue to meet their NOx SIP Call obligation for Non-EGUs and the Division believes that the transport rule should be that new way. Therefore, given the limited number of subject Non-EGUs and the small amount of their NOx ozone season budget emissions, the Division requests that EPA include the NOx SIP Call Non-EGUs into the proposed Transport Rule. If EPA changes its position to include the NOx SIP Call Non-EGU units, then the Division requests that EPA consult with the Division to ensure that all applicable Kentucky Non-EGUs are properly accounted for in the Transport Rule.

Applicable Units

- Pursuant to the proposed Transport Rule Preamble Section V.D.4., How the Proposal Would Be Implemented, Applicability (75 FR 45306-45309), the Calvert City Cogeneration EGU (turbine – ORIS - 55308-Gen1) as shown in EPA's Technical Support detailed allocation file (*BADetailedData.xls, Units Characteristics Worksheet*) should indicate a capacity of 26 MWe instead of 23 MWe as is listed. This cogeneration EGU was part of the NOx SIP Call NOx ozone season trading program and was brought into the CAIR NOx ozone season program. However, the unit was exempted from the CAIR NOx annual program since it met the CAIR NOx annual program cogeneration exemption. Even with the CAIR ozone season cogeneration exemption, the unit was subject to the CAIR NOx ozone season trading program since it was previously subject to the NOx SIP Call NOx ozone season program which did not provide a cogeneration exemption. The Division requests that EPA work with the Division to verify that the Calvert City Cogeneration EGU is also exempt from the proposed Transport Rule NOx annual trading program pursuant to the Transport Rule cogeneration exemption and to include this unit in the proposed Transport Rule NOx ozone season trading program.

- E.ON U.S., (ORISID 6071) Trimble Unit 2, which started operation in 2010, should be included in the proposed Transport Rule emissions trading programs. <u>In addition, the Division recommends that before the Transport Rule unit allocations are finalized and recorded that EPA consult with the Division to make sure that all existing units subject to the proposed Transport Rule have been properly accounted for in the proposed rule's unit allocations.</u> The Division reserves the right to inform EPA of any additional unit omission or incorrect inclusion for EPA's Transport Rule even after the comment period deadline has passed.

Emissions of Other Sources Also Need to Be Reduced to Eliminate Transport

- Pursuant to the rule preamble Section V.B.2., Other Source Categories Are Not Included (75 FR 45300), the Transport Rule fails to include all sources that contribute significantly to transport. Given that EPA's new 8-hour ozone standard will be more stringent and a more difficult standard for states to attain and maintain, the Division requests that EPA obtain additional emission reductions from other relevant source categories especially from onroad mobile sources. Onroad mobile source emissions remain a significant source of ozone precursor emissions that have contributed to many areas' previous ozone nonattainment problems. EPA could assist state and local agencies by requiring additional emissions reductions from other source categories that are significant contributors of ozone and PM2.5 precursor emissions, such as onroad vehicles, locomotives, oceangoing marine engines, and nonroad vehicles. If EPA does not incorporate emission reductions for the aforementioned source categories in the proposed Transport Rule, then the Division requests that EPA consider these other source category emission reductions, especially for onroad mobile vehicles, when EPA proposes its Transport Rule II.

Support of EPA Preferred Approach with Assurance Provisions for the Transport Rule and the Adding of Variability Limits to the State Emission Budgets

- Pursuant to the rule preamble Section V.D.4., State Budget/Limited Trading Proposed Remedy (75 FR 45305), EPA's preferred approach is to allow limited interstate trading, but to also include assurance provisions to ensure that the majority of power plants in each state control their own emissions rather than buy out-of-state allowances. This option is implemented by adding variability limits to each state budget starting in 2014, and if a state's emissions exceed the budget plus the variability limit, sources in the exceeding state are penalized (through the turn-in of allowances) based on their proportional share of the overage in emissions. The Division supports EPA's preferred approach with assurance provisions and the inclusion of variability limits added to each state's budgets. The Division agrees with EPA's position that variability limits should be included to account for unplanned increased emissions in a state due to situations such as extreme weather events, unplanned outages or unexpected load demands because of an unusually hot summer.

More Time Needed to Install Controls

- Pursuant to the rule preamble Section IV.D., Emissions Reductions Cost Curves (75 FR 45273), the time available for affected units to install new SO2 and NOx controls by the 2012 and 2014 timeframes is not sufficient, especially for NOx, which has less flexibility in the emission reduction options available. Therefore, the Division requests EPA to take this comment into consideration when finalizing the Transport Rule.

More Recent Ambient Air Quality Data Should Have Been Utilized in EPA's Modeling

- Pursuant to the proposed Transport Rule IV.C.2., How did EPA project future nonattainment and maintenance for the 1997 and 2006 air quality standards (75 FR 45246), EPA's approach for projecting future ozone and PM2.5 design values involved the use of 2003-2007 ambient air quality data. The Division finds that this approach to be somewhat lacking when more recent data for 2007-2009 was available. The use of more recent air quality data in EPA's modeling analysis for the proposed Transport Rule may have provided different final modeling results by more realistically capturing some of the air quality benefits and improvements provided by CAIR which began on January 1, 2009.

Given Adequate Time Prefer a SIP to a FIP

- Pursuant to the proposed Transport Rule preamble Section III.A., Summary of Proposed Rule (75 FR 45214), the Division is concerned about the Federal Implementation Plan (FIP) proposal and the lack of specific State Implementation Plan guidance in the proposal. A FIP implies that a state has failed to meet its obligation and this is just not the case. The Kentucky CAIR SIP was approved in EPA in an October 4, 2007, Federal Register. The Division would prefer the opportunity to implement the proposed Transport Rule requirements through the SIP process; however, due to the lack of time this is not feasible. In addition, there is little specificity in this proposal on how states would develop an appropriate SIP to replace the Transport Rule FIP. EPA should provide additional SIP guidance to the states.

Incomplete Flawed Modeling

- Pursuant to the proposed Transport Rule preamble Section III.A., Summary of Proposed Rule (75 FR 45214), EPA is proposing FIPs to immediately implement the emission reduction requirements identified and quantified by EPA in this action. For some covered states, these FIPs will completely satisfy the emissions reductions requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 and 2006 PM2.5 NAAQS and the 1997 ozone NAAQS. The exception is for the 10 eastern states for which EPA has not completely quantified the total significant contribution or interference with maintenance with respect to the 1997 ozone NAAQS and the 15 states for which EPA has not completely quantified total significant contribution or interference with maintenance with respect to the 2006 PM2.5 NAAQS in which case the FIPs would achieve measurable progress towards implementing that requirement.

  The Division is concerned that EPA's modeling results are incomplete and flawed since EPA admittedly has not completely quantified the total significant contribution or interference with maintenance with regards to all existing standards. The Division recommends that EPA properly complete its analysis.

Attachments for

Kentucky Division for Air Quality's (KYDAQ) Comments on the

U.S. EPA's Proposed Transport Rule

Kentucky EGU SO2 and NOx

Emission Control Information and 2009 CAMD Emissions

				Table 1. EPA's Allocation Table with Added Kentucky 2009 Emissions and Control Information		Allocations (Tons)					
Plant Name	ORIS	Unit	State Name	*Added Existing SO2 Controls before 2012 unless otherwised indicated*	*Added 2009 CAMD SO2 Emissions*	2012 SO2 Allocation	2014 SO2 Allocation	*Added Existing NOx Controls before 2012 unless otherwised indicated*	Added 2009 CAMD NOx Emissions	Annual NOx Allocation	Ozone Season NOx Allocation
Big Sandy	1353	BSU1	Kentucky	Per Consent Decree Sulfur Content <= 1.75 mmBTU annual basis	8709.281	5,946	1,262	OFA,LNB	1467.714	1,635	711
Big Sandy	1353	BSU2	Kentucky	Per Consent Decree & BART, a FGD by December 31, 2015	31515.594	29,626	1,943	SCR,LNB	3401.964	1,655	727
Bluegrass Generation LLC	55164	CT1	Kentucky		0.155	0	0	Hot SCR/Dry LNB,Water Injection	11.139	0	0
Bluegrass Generation LLC	55164	CT2	Kentucky		0.024	0	0	Hot SCR/Dry LNB,Water Injection	2.063	0	0
Bluegrass Generation LLC	55164	CT3	Kentucky		0.005	0	0	Dry LNB ,Water Injection	0.439	0	0
Cane Run	1363	4	Kentucky	FGD-Scrubber	2158.231	1,930	821	SLNB	1769.939	1,724	669
Cane Run	1363	5	Kentucky	FGD-Scrubber	2099.905	1,918	918	CCVDAZ (LNB)	2020.058	1,763	684
Cane Run	1363	6	Kentucky	FGD-Scrubber	4533.98	4,801	2,039	LNCFS II	1948.222	2,497	1,086
Cooper	1384	1	Kentucky	Per Consent Decree(CD)\For BART FGD-Scrubber After 2012	4454.49	5,139	3,021	Low NOx Burner (LNB)	989.035	1,469	638
Cooper	1384	2	Kentucky	Per Consent Decree(CD)\For BART FGD-Scrubber June 2012	10704.172	850	756	LNB	2373.401	2,815	1,227
D B Wilson	6823	W1	Kentucky	FGD-Scrubber	6746.768	8,195	7,866	LNB, SCR	990	697	305
Dale	1385	1	Kentucky		954.298	744	0	LNB	238	356	155
Dale	1385	2	Kentucky		962.113	750	0	LNB	242	359	156
Dale	1385	3	Kentucky		2909.489	2,875	2,047	LNB	794	863	374
Dale	1385	4	Kentucky		2456.864	2,389	2,048	LNB	675	863	374
E W Brown	1355	1	Kentucky	Being constructed FGD-Scrubber in 2010	3452.251	2,851	795	LNB	606.277	1,346	584
E W Brown	1355	2	Kentucky	Being constructed FGD-Scrubber in 2010	6726.183	678	650	Low Nox Concentric Firing System (LNCFS) I	903.265	1,913	831
E W Brown	1355	3	Kentucky	Being constructed FGD-Scrubber in 2010	22070.924	1,525	1,463	LNCFS III	2,716	915	400
E W Brown	1355	10	Kentucky		0.246	0	0	Water Injection	3.614	0	0
E W Brown	1355	11	Kentucky		0.266	0	0	Water Injection	5.262	0	0
E W Brown	1355	5	Kentucky		0.019	0	0	Water Injection	2.375	0	0
E W Brown	1355	6	Kentucky		0.15	0	0	Water Injection (when burning fuel oil)	19.163	0	0
E W Brown	1355	7	Kentucky		0.143	2	0	Water Injection (when burning fuel oil)	12.683	0	0
E W Brown	1355	8	Kentucky		0.038	0	0	Water Injection	8.901	0	0
E W Brown	1355	9	Kentucky		0.027	0	0	Water Injection	2.319	0	0
East Bend	6018	2	Kentucky	FGD-Scrubber	1724.598	2,038	2,387	SCR/LNB	2,436	1,113	488
Elmer Smith	1374	1	Kentucky	FGD-Scrubber	2423.962	2,109	1,056	SCR/OFA	710.702	564	245
Elmer Smith	1374	2	Kentucky	FGD-Scrubber	4299.032	3,906	2,354	SNCR/LNB\OFA	2297.828	1,407	547
Ghent	1356	1	Kentucky	FGD-Scrubber	1417.925	2,221	3,653	SCR/LNCFS II	973.221	794	346
Ghent	1356	2	Kentucky	FGD-Scrubber - in May 2009	5044.319	2,101	1,813	LNCFS III	2,664.851	976	427
Ghent	1356	3	Kentucky	FGD-Scrubber - in May 2007	3188.359	3,578	3,363	SCR/LNB & OFA	1,972.329	483	195
Ghent	1356	4	Kentucky	FGD-Scrubber - in June 2008	1220.484	1,214	3,359	SCR/LNB & OFA	802.807	468	189
Green River	1357	4	Kentucky		5447.666	5,215	1,153	LNB	525.684	890	364
Green River	1357	5	Kentucky		9276.268	9,447	2,854	LNB	894.028	1,159	474
H L Spurlock	6041	1	Kentucky	WFGD-June 2009	4978.491	843	750	SCR/Modified Burner	772.795	647	283
H L Spurlock	6041	2	Kentucky	WFGD-June 2008	1304.589	1,624	1,455	SCR/LNB	1,253.289	810	354
H L Spurlock	6041	3	Kentucky	Dry Lime Scrubber	1259.842	1,270	782	SNCR	693.198	314	137

				Table 1. EPA's Allocation Table with Added Kentucky 2009 Emissions and Control Information		Allocations (Tons)					
Plant Name	ORIS	Unit	State Name	*Added Existing SO2 Controls before 2012 unless otherwised indicated*	*Added 2009 CAMD SO2 Emissions*	2012 SO2 Allocation	2014 SO2 Allocation	*Added Existing NOx Controls before 2012 unless otherwised indicated*	Added 2009 CAMD NOx Emissions	Annual NOx Allocation	Ozone Season NOx Allocation
H L Spurlock	6041	4	Kentucky	Dry Lime Scrubber	732.275	754	724	SNCR	495.868	393	171
H L Spurlock	6041	4	Kentucky			0	0			0	0
HMP&L Station Two Henderson	1382	H1	Kentucky	FGD-Scrubber	1774.309	1,647	959	SCR/LNB	457.849	293	114
HMP&L Station Two Henderson	1382	H2	Kentucky	FGD-Scrubber	3035.676	2,750	997	SCR/LNB	580.396	305	118
Henderson I	1372	6	Kentucky			3,842	0			401	174
J K Smith	54	GT1	Kentucky		0.237	0	0	Water Injection	27.464	0	0
J K Smith	54	GT2	Kentucky		0.083	0	0	Water Injection	8.621	0	0
J K Smith	54	GT3	Kentucky		0.322	0	0	Water Injection	39.011	0	0
J K Smith	54	GT4	Kentucky		0.742	0	0	Dry low NOX Burners/Water Injection	10.884	0	0
J K Smith	54	GT5	Kentucky		0.386	0	0	Dry low NOX Burners/Water Injection	3.510	0	0
J K Smith	54	GT6	Kentucky		0.354	0	0	Dry low NOX Burners/Water Injection	4.654	0	0
J K Smith	54	GT7	Kentucky		0.430	0	0	Dry low NOX Burners/Water Injection	6.250	0	0
Kenneth C Coleman	1381	C1	Kentucky	FGD-Scrubber	1458.403	624	1,569	LNB/Rotating Over-Fire Air (ROFA)	1,744	1,646	704
Kenneth C Coleman	1381	C2	Kentucky	FGD-Scrubber	1778.283	854	1,569	LNB/Advanced Over-Fire Air (AOFA)	1,673	1,671	715
Kenneth C Coleman	1381	C3	Kentucky	FGD-Scrubber	656.389	1,003	1,621	LNB/AOFA	1,649	1,713	733
Marshall	55232	CT1	Kentucky		0.026	0	0	Operating Hours Limitation/Water Injection whe	1.259	1	0
Marshall	55232	CT2	Kentucky		0.021	0	0	Operating Hours Limitation/Water Injection whe	0.977	1	0
Marshall	55232	CT3	Kentucky		0.021	0	0	Operating Hours Limitation/Water Injection whe	1.109	1	0
Marshall	55232	CT4	Kentucky		0.02	0	0	Operating Hours Limitation/Water Injection whe	0.96	1	0
Marshall	55232	CT5	Kentucky		0.024	0	0	Operating Hours Limitation/Water Injection whe	1.233	1	0
Marshall	55232	CT6	Kentucky		0.027	0	0	Operating Hours Limitation/Water Injection whe	1.348	1	0
Marshall	55232	CT7	Kentucky		0.022	0	0	Operating Hours Limitation/Water Injection whe	1.147	1	0
Marshall	55232	CT8	Kentucky		0.022	0	0	Operating Hours Limitation/Water Injection whe	1.095	1	0
Mill Creek	1364	1	Kentucky	FGD-Scrubber	3731.712	3,562	2,666	LNCFS II	3,126.927	2,722	1,125
Mill Creek	1364	2	Kentucky	FGD-Scrubber	4122.867	4,444	3,021	LNCFS II	2,991.642	2,648	1,069
Mill Creek	1364	3	Kentucky	FGD-Scrubber	8215.092	8,366	3,725	SCR/DRB-XCL (LNB)	777.605	621	251
Mill Creek	1364	4	Kentucky	FGD-Scrubber	8164.371	8,249	6,044	SCR/DRB-XCL (LNB)	1,010.742	704	285
Paddy's Run	1366	12	Kentucky		0	0	0		0.307	0	0
Paddys Run	1366	13	Kentucky		0.004	0	0	Dry Low NOx Burners	0.521	0	0
Paradise	1378	1	Kentucky	FGD-(Venturi Scrubber)	12974.624	13,411	3,210	SCR/OFA	2,899	1,978	803
Paradise	1378	2	Kentucky	FGD-(Venturi Scrubber)	17241.622	15,053	3,134	SCR/OFA	2,205	1,952	792
Paradise	1378	3	Kentucky	FGD-Scrubber	3589.47	3,320	9,807	SCR/OFA	3,246	3,465	1,404
R D Green	6639	G1	Kentucky	FGD-Scrubber	1792.4	1,774	1,018	LNB/Coal Reburn	2,085.026	1,530	595
R D Green	6639	G2	Kentucky	FGD-Scrubber	1302.447	1,352	1,027	LNB/Coal Reburn	1,609.412	1,505	585
Riverside Generating LLC	55198	GTG1	Kentucky		0.045	0	0	Dry Low NOx Burners/Water Injection	3.901	0	0
Riverside Generating LLC	55198	GTG2	Kentucky		0.042	0	0	Dry Low NOx Burners/Water Injection	4.690	0	0
Riverside Generating LLC	55198	GTG3	Kentucky		0.031	0	0	Dry Low NOx Burners/Water Injection	3.284	0	0

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Riverside Generating LLC	55198	GTG4	Kentucky		0.028	0	0	Hot SCR/Dry Low NOx Burners/Water Injection	2.541	0	0
Riverside Generating LLC	55198	GTG5	Kentucky		0.028	0	0	Hot SCR/Dry Low NOx Burners/Water Injection	2.788	0	0
Robert A Reid	1383	R1	Kentucky		545.215	1,136	1,872	OFA	59.842	734	284
Robert A Reid	1383	GEN2	Kentucky		11.035	0	0		26.482	0	0
Shawnee	1379	1	Kentucky	Low Sulfur Coal	2723.855	2,830	4,216	LNB	1,436.826	1,028	420
Shawnee	1379	10	Kentucky	Low Sulfur Coal	1008.322	1,320	460	AFBC Unit	717.478	810	358
Shawnee	1379	2	Kentucky	Low Sulfur Coal	2777.381	3,120	1,093	LNB	1,451.109	1,585	648
Shawnee	1379	3	Kentucky	Low Sulfur Coal	3199.903	3,076	1,093	LNB	1,677.213	1,585	648
Shawnee	1379	4	Kentucky	Low Sulfur Coal	2767.575	2,858	1,093	LNB	1,459.477	1,585	648
Shawnee	1379	5	Kentucky	Low Sulfur Coal	3321.447	3,488	1,093	LNB	1,736.095	1,585	648
Shawnee	1379	6	Kentucky	Low Sulfur Coal	3011.688	3,107	1,093	LNB	1,342.566	1,585	648
Shawnee	1379	7	Kentucky	Low Sulfur Coal	2585.294	2,918	1,093	LNB	1,138.950	1,585	648
Shawnee	1379	8	Kentucky	Low Sulfur Coal	3018.583	3,272	1,093	LNB	1,330.452	1,585	648
Shawnee	1379	9	Kentucky	Low Sulfur Coal	3007.453	3,237	1,093	LNB	1,317.130	1,585	648
Smith Generating Facility	54	SCT10	Kentucky			0	0	SCR\Water Injection		0	0
Smith Generating Facility	54	SCT9	Kentucky			0	0	SCR\Water Injection		0	0
TVAK_KY_Coal Steam	82713	1	Kentucky			2,674	0			1,381	605
Trimble County	6071	1	Kentucky	FGD-Scrubber	1216.561	1,499	2,257	SCR/ALNB	1,110.654	599	261
Trimble County	6071	10	Kentucky		0.073	0	0	DLNB	4.566	0	0
Trimble County	6071	5	Kentucky		0.144	0	0	DLNB	6.998	0	0
Trimble County	6071	6	Kentucky		0.097	0	0	DLNB	5.628	0	0
Trimble County	6071	7	Kentucky		0.119	0	0	DLNB	5.842	0	0
Trimble County	6071	8	Kentucky		0.117	0	0	DLNB	5.949	0	0
Trimble County	6071	9	Kentucky		0.091	0	0	DLNB	5.111	0	0
Tyrone	1361	5	Kentucky		203.681	1,634	1,180	LNB	77.150	610	265
					252,013	**212,959**	**110,428**		***78,794***	**71,892**	**29,985**

Utility Information Exchange of Kentucky (UIEK)

Comments on EPA's Proposed Transport Rule

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402-2801

September 29, 2010

Mr. John Lyons, Director
Kentucky Division for Air Quality
200 Fair Oaks Lane
Frankfort, Kentucky 40601

Subject: Comments by the UIEK on U.S. EPA's Proposed Transport Rule

Dear Mr. Lyons:

I am writing on behalf of the Utility Information Exchange of Kentucky (UIEK), an organization comprising electric utilities operating in the Commonwealth of Kentucky, to relay comments on the U.S. Environmental Protection Agency's (EPA's) proposed rule to limit interstate transport of emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) (Transport Rule). The UIEK appreciates the opportunity to offer these comments as the rulemaking process for the Transport Rule begins.

Comment 1: The Schedule for Meeting Phase I Emission Caps Beginning In 2012 is Unreasonable.

Assuming the final Transport Rule is promulgated less than a year from now (EPA's current schedule is Spring of 2011), Phase I of the program would allow only about 6-9 months to implement the new emission budgets, establish emission trading programs and make the needed investments to comply with the new emission caps. Having these new emission caps, state budgets and allowance allocations in 2012 creates major logistical challenges for the electric power sector and for the states that must implement the programs.

While the EPA claims that Phase I will require little investment in the way of new controls, its assumption is predicated upon high-level modeling and not the actual physical, contractual and financial constraints at electric generating facilities during such a short time frame. In reality, implementation of further reductions by a utility will require an engineering analysis for each generating unit, and any analysis must be based on promulgated targets. Until a final rule is in hand, a utility can only establish the framework for securing funding and procurement of the project.

EPA also claims that switching to lower-sulfur coals to meet SO_2 emission caps is possible by 2012. However, implementation of a fuel switch will require existing contracts to be ended and new contracts obtained. Ending existing contracts often results in negotiation and litigation over several months or even years. New contracts, if obtainable, often take several months to plan and procure. In addition, many units without add-on controls already use as much low-sulfur coal as the existing equipment can handle to meet Title IV emission targets. Switching entirely to or using a greater percentage of low-sulfur western coals, like Powder River Basin sub-bituminous coal, would require changes to coal handling and processing equipment, as well as particulate control equipment. These types of changes may require permitting, including consideration of possible impacts to emissions of newly-regulated greenhouse gases. The environmental review, permitting, design, procurement and construction required for these projects could not be completed by 2012.

Comment 2: Retrofit Emission Control Projects Cannot Be Completed in Time for Phase II in 2014.

States like Kentucky that are most reliant on coal for electric power generation face the major portion of the compliance burden for limiting SO_2 emissions under the Transport Rule. The SO_2 caps in 2014 for sources in Kentucky are significantly more stringent than those in 2012. These caps would require most of the coal-fired units in the state without add-on controls to install flue gas desulfurization (FGD) systems, switch to natural gas or retire early.

EPA assumes that it takes only 27 months to build an FGD system. However, a typical FGD project takes much longer to complete if you consider the entire scope from conceptual design to commercial operation. For example, it took TVA approximately five years to install the Paradise Fossil Plant Unit 3 FGD system from conceptual design to commercial operation. Also, it should be noted that utilities have already installed FGD on the units where it is most cost-effective. The remaining uncontrolled units tend to be older and smaller with corresponding space limitations. This schedule may not be achievable at sites with little available space and other retrofit challenges.

In addition, most utilities in the South and East will be effectively required to install scrubbers over the same period of time. With multiple utilities installing scrubbers at many different units over the exact same time frame, supply shortages of materials, skilled labor and engineering talent could drive up costs and lengthen the timeline for project completion. And unit outages for control installations must be staggered to avoid peak demand seasons and ensure reliability of the power supply.

Finally, the pollution control project exemption was overturned by the courts, adding pre-construction permitting requirements to many FGD project schedules. With the pollution project exemption gone, FGD projects, especially in conjunction with installation of selective catalytic reduction (SCR), will often exceed prevention of significant deterioration (PSD) significance threshold(s) for sulfuric acid mist (SAM) and require a PSD pre-construction permit. The time required to develop a permit application, obtain a permit, and add SAM mitigation equipment could add several months to the overall project schedule.

Comment 3: Many Older Coal-fired Units will be Idled or Retired.

Utilities have many older, smaller coal-fired units that may not be economical to control and continue to operate in light of anticipated future air, water, and waste regulatory requirements. TVA is evaluating plans to idle a portion of its coal-fired fleet, including units in Kentucky. Other utility companies operating in Kentucky have also announced that they are evaluating thousands of megawatts of coal-fired capacity for possible retirement. In many cases, gas-fired generating units will be required to replace the lost capacity. These new cleaner units will in effect be constructed in lieu of constructing controls on some of the idled or retired units. If constructed on the same site as the retired units, where emissions netting is available, the project duration from air permitting to commercial operation would be approximately three years. Gas-fired units at greenfield sites would take significantly longer to complete.

Comment 4: The Proposed Transport Rule Does Not Allow Banked CAIR Emission Allowances to Carry Forward Into the New Trading Program.

In the interim Clean Air Interstate Rule (CAIR) program, EPA currently allows power plants to reduce SO_2 and NO_x emissions more than required in a given year and save, or "bank," these emission allowances for use in a later compliance year. Emissions banking allows companies to comply at a lower overall cost, because very high cost reductions and expensive pollution control equipment can be delayed until the most optimal time by using banked allowances. More importantly, banking provides a net environmental benefit, because more emission reductions and, hence, environmental improvement occurs sooner.

Under the proposed Transport Rule, EPA has eliminated the use of previously-banked SO_2 allowances after 2011. As a consequence, the market price of SO_2 allowances has dropped to nearly zero, and the SO_2 market has been effectively eviscerated. Elimination of the SO_2 and NO_x allowance banks is unfair to utilities that installed controls early to bank allowances and planned, as the CAIR rule allowed, to use those banked allowances to provide time for completion of additional control installations for future lower CAIR allocation levels. Utilities that added controls and aggressively reduced emissions will be penalized and lose the value of accumulated allowances, while those who delayed controls and relied on purchased allowances will be rewarded. This elimination will also reduce confidence in and hinder any cap-and-trade features of the final Transport rule and any future cap-and-trade programs.

EPA should allow banked SO_2 and NO_x emission allowances to carry over into the Transport Rule trading program. The allowances carried over should never expire, but even a 2016 expiration date would provide significant benefits and partially mitigate the unreasonable timeframes described above. If EPA does not allow CAIR allowances to carry over, EPA should incentivize minimal use of

CAIR allowances and base allocations in part on bank balances at the end of the CAIR program.

Comment 5: The Transport Rule Provides No Certainty Regarding Future Reduction Requirements for SO_2 and NO_x Under Later EPA Rules

EPA noted in the proposed Transport Rule that it plans to further revise the rule and tighten the utility SO_2 and NO_x emissions caps in future rulemakings to meet its new fine particle and ozone standards. Without knowing what levels of reductions will ultimately be required and by when, the investment planning process for the current proposed rule is completely untenable. The risk of stranded or unnecessary pollution control costs increases dramatically. Such uncertainty also increases the probability that coal-fired power plant units will be prematurely retired to avoid these investment and rate recovery risks.

Comment 6: EPA's Economic and Cost Effectiveness Analysis of the Proposed Rule is Flawed.

The preamble to the Transport Rule states that, "*EPA cannot assume in its base case analysis that the reductions required by CAIR will continue to be achieved.*" So the emission reduction benefits of CAIR are not included in the base case, resulting in higher emissions assumed in the base years. At the same time, however, the preamble says that, "*Units with advanced controls (e.g., scrubber, SCR) that were not required to run for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules were allowed in IPM to decide on the basis of economic efficiency whether to operate those controls.*" It appears that the emission control equipment that electric utility companies have already installed to comply with CAIR, or are currently constructing for that reason, are included in the base case.

EPA cannot have it both ways. The base case must either assume a world where CAIR never existed or continue to assume that CAIR controls and reductions are in place. To assume that CAIR controls exist in the base case and that the only costs associated with the Transport Rule are operating & maintenance costs (or allowance costs) significantly underestimates the cost impacts of the rule. The costs to comply with the Transport Rule are not costs incurred in lieu of CAIR; they are costs incurred in addition to the capital expenditures made as a result of CAIR.

Because the capital costs spent for CAIR compliance are ignored in the base case, the costs to comply with the Transport Rule in the control cases are artificially low. This approach results in more controls being considered "highly cost effective" and, thus, exaggerates the air quality benefits of the rule. In addition, it penalizes states that have these controls in place, because it artificially lowers their allocations of allowances in future years as a result of too many reductions being considered highly cost effective.

Comment 7: Emission Budgets Should Not Be Based on Years with Depressed Economic Activity.

EPA's technical support documents indicate that 2012 SO_2 and NOx budgets are set at the lower of recent historical actual emissions or projected emissions at the state level. For SO_2 the historical 12-month emission period was the last quarter of 2008 and the first three quarters of 2009. For NO_x EPA notes this period was not used because of low utilization during that period.

Coal-fired generation and emissions were significantly depressed during the 2008-2009 historical period used because of the economic recession, unusually low natural gas prices, and other factors. This historical time period should not be used by EPA, because it is not representative of normal coal-fired generation levels. EPA should use the average 3-year period of 2006-2008, which is more representative of historical generation.

Comment 8: EPA Should Clearly State That the Final Transport Rule Satisfies the Requirements of BART and Defers Section 126 Findings.

In developing the CAIR rule, EPA took the position that States adopting the CAIR cap-and-trade program for SO_2 and NO_x would be allowed to consider the participation of EGUs in this program as equivalent to the application of best available retrofit technology (BART) controls (i.e., the CAIR=BART presumption) for those pollutants. This position was based on modeling done by EPA to demonstrate that CAIR emissions reductions as modeled produce significantly greater visibility improvements than source-specific BART. In the proposed Transport Rule, EPA does not create any such presumption equating the Transport Rule to BART.

Since EPA appropriately determined that compliance with CAIR exceeded the visibility improvements that would result from BART, and since the Transport rule will reduce SO_2 and NO_x emissions below CAIR levels, EPA should include in the Transport Rule a provision that treats EGU compliance with the Transport Rule as equivalent to the application of Regional Haze BART controls.

Additionally, in developing CAIR, EPA set forth its general view of the approach it expected to take in responding to any section 126 petition that might be submitted relying on the same record as CAIR. Under that approach, as long as an upwind state remained on track to comply with CAIR, EPA would defer making the Section 126 findings. In the proposed Transport Rule, EPA does not discuss how petitions under Section 126 will be handled.

EPA should set forth a position in the Transport Rule that, as long as an upwind state remains on track with compliance with the Transport Rule, EPA will defer making Section 126 findings. This would avoid a de novo review by EPA of petitions filed by states that would lead to uncertainty for the regulated community and consume EPA and state resources for no environmental benefit.

Comment 9: EPA's "Adjustments" to Reported NOx Emissions to Account for Controls is Unreasonable and Unjustified.

To develop NO_x budgets, EPA "adjusted" historical emissions from units equipped with SCR systems to account for year-round operation of the controls. EPA asserts that they assumed SCR systems can achieve at least 90% removal, down to a floor of 0.06 lb/MMBtu, year round. However, if a unit reported an historical ozone-season NO_x emission rate lower than the assumed floor, EPA used that lower emission rate. But if a unit reported an historical emission rate higher than the assumed floor, EPA adjusted the emission rate by assuming 90% removal or 0.06 lb/MMBtu. These downward adjustments are unreasonable and unjustified. Incentives exist in most cases to emit at the lowest reasonably achievable NO_x emission rate, and if a given unit reports NO_x emissions at rates above 0.06 lbs/MMBtu, it is likely that that unit cannot physically and consistently operate at a lower rate year round. In addition, degradation of catalyst reactivity over time, variations in unit design, and other factors can make it impossible for a unit to repeat its best short-term performance on a year-after-year basis.

If you have any comments or questions, feel free to call me at 423-751-2005 or Jerry Purvis at 859-744-4812.

Sincerely,

Tom Waddell

Tom Waddell
Chairman, Air Committee
Utility Information Exchange of Kentucky