Appendix 9c - LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis Document (July 18, 2007)"

This page intentionally left blank.

LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007) addresses factor analysis to establish a reasonable progress goal toward achieving natural visibility conditions in mandatory Class 1 areas. While Indiana does not have any Class 1 areas within the state, it may potentially impact visibility at nearby Class 1 areas. This factor analysis will address sulfur dioxides (SO2) and nitrogen oxides (NOx) emissions at several source categories, including electric generating units (EGUs), industrial, commercial and institutional (ICI) boilers, ammonia from agricultural operations, NOx emissions from onroad and nonroad mobile sources and reciprocating engines and turbines.

Indiana has reviewed the information contained in the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" and has listed emissions and visibility impact tables to show Indiana's contributions. Additional analyses related to each source category will be referenced but not shown in this appendix.

EGU – Page 22-38 of LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis"

Indiana's emissions were based on LADCO's Base K emissions for 2002 and projected to 2018 and are shown below in Table 1. Indiana's emission contribution to the 9-state northern Midwest region (including the states of Michigan, Minnesota, Wisconsin, Illinois, Iowa, Missouri, North Dakota and South Dakota) was 33% of SO2 emissions and 24% of NOx emissions for 2002. Indiana's contribution is projected to drop to 21% for SO2 emissions and 17% of NOx by 2018.

Table 1. Estimated Baseline Emissions from EGUs

	Emissions in 2002 (1000 tons/year)		**Projected emissions in 2018 (1000 tons/year)**	
	SO2	**Nox**	**SO2**	**Nox**
Michigan	403	164	399	100
Minnesota	116	99	86	42
Wisconsin	220	107	155	46
3-State Subtotal	*739*	*370*	*641*	*188*
Illinois	478	260	241	73
Indiana	**912**	**303**	**377**	**95**
Iowa	150	93	147	51
Missouri	305	167	281	78
North Dakota	137	72	109	72
South Dakota	13	16	12	15
9-State Total	*2,734*	*1,280*	*1,808*	*571*

Table 5.1-2 "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007)

Two sets of possible caps have been evaluated, which are termed EGU1 and EGU2:

EGU1 would establish a regional emissions cap for SO2 and NOX based on projected fuel Consumption:

- SO2 limited to 0.15 pounds per million British thermal units (lb/million-BTU) of fossil fuel consumption in the region
- NOX limited to 0.10 lb/million-BTU

EGU2 would establish regional emission caps for SO2 and NOX based on projected fuel consumption:

- SO2 limited to 0.10 lb/million-BTU
- NOX limited to 0.07 lb/million-BTU

Estimated costs for SO2 and NOx controls for each of the possible cap scenarios for the 9-State region is listed in Tables 5.1-3 and 5.1-4 of the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" document. The estimated energy and non-air environmental impacts of EGU control strategies can be found in Table 5.1-8 and estimated annual health benefits applied to the 5-state Midwest Regional Planning Organization can be found in Table 5.1-9.

Based on these possible caps, visibility impacts were determined and improvements were shown for 2018. Indiana emission reductions were combined with the other 8 state region emission reductions to determine the visibility improvements and are shown below in Table 2. Significant visibility improvements were modeled with both emission cap scenarios.

Table 2. Estimated Visibility Impacts of EGU Control Strategies					
	Estimated Visibility Improvement in 2018 (DV)				
Strategy and region	Boundary Waters	Voyageurs	Isle Royale	Seney	Average
EGU1 Emission Caps: 9-State Region					
SO2	0.77	0.35	0.84	1.01	0.74
NOX	0.18	0.24	0.15	0.12	0.17
Total	0.95	0.59	1	1.13	0.92
EGU2 Emission Caps: 9-State Region					
SO2	0.87	0.4	0.96	1.18	0.85
NOX	0.26	0.3	0.23	0.19	0.24
Total	1.13	0.69	1.18	1.37	1.09

Table 5.1-10 "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007)

Cost effectiveness of EGU control strategies for the 9-State region can be found in Table 5.1-11.

ICI– Page 39-52 of LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis"

Non-EGU point sources, such as Industrial, Commercial and Institutional (ICI) boilers was identified by source apportionment as the second largest contributor to visibility impairment to the northern Class 1 areas. Two control strategies have been constructed to address non-EGU/ICI boiler emissions. The first strategy, referred to as the ICI1, requires 40% SO2 reduction and 60% NOx reduction from 2018 baseline emissions. The second strategy was created by an ICI Workgroup and identifies SO2 and NOx emission limitations based on boiler type, size and fuel type consumed. This strategy would result in approximately 77% SO2 emission reductions and 70% reduction in NOx emissions. Table 5.2-3 of the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" document outlines the ICI Workgroup proposed emission caps for NOx and SO2 for different boiler and fuel types.

Indiana's emissions were based on LADCO's Base K emissions for 2002 and projected to 2018 and are shown below in Table 6. Indiana's emission contribution to the 9-state northern Midwest region (including the states of Michigan, Minnesota, Wisconsin, Illinois, Iowa, Missouri, North Dakota and South Dakota) was 28.4% of SO2 emissions and 21% of NOx emissions for 2002. Indiana's contribution is projected to drop to 28.3% for SO2 emissions and 20.7% of NOx by 2018.

Table 3 Estimated Point and Area Emissions from ICI Boilers

	Emissions from ICI sources in 2002 (1000 tons/year)		Projected emissions from ICI sources in 2018 (1000 tons/year)	
	SO2	**Nox**	**SO2**	**Nox**
Michigan	44.2	27	42.8	26.5
Minnesota	20.2	52.9	19.7	52.7
Wisconsin	57	34.5	54.8	33.9
3-State Subtotal	*121.5*	*114.4*	*117.2*	*113.1*
Illinois	58.9	49.5	59	48
Indiana	**108.9**	**54.2**	**105.2**	**52.5**
Iowa	32.2	16.3	30.6	16.2
Missouri	53	18.8	52.5	18.7
North Dakota	7.6	5.1	7.2	5.1
South Dakota	0.7	0.3	0.7	0.3
9-State Total	*382.8*	*258.7*	*372.3*	*253.9*

Table 5.2-1 "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007)

Estimated cost of ICI1 SO2 and NOx controls for the 9-state region can be found in Tables 5.2-5 and 5.2-6 of the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" document with the estimated cost of ICI Workgroup SO2 and NOx controls for the 9-state region can be found in Tables 5.2-7 and 5.2-8. The estimated energy and non-air environmental impact of ICI control strategies for the 9-state region can be found in Table 5.2-10 with cost effectiveness of the ICI controls found in Table 5.2-12.

Visibility improvements at nearby Class 1 areas are realized with emission reductions from ICI point and area sources, however these improvements are an order of magnitude less that those achieved from EGU emission reductions. Impacts are shown below in Table 4.

Table 4. Estimated Visibility Impacts of ICI Control Strategies							
			Estimated Visibility Improvement in 2018 (DV)				
			Boundary Waters	Voyageurs	Isle Royale	Seney	Average
ICI1	3-State	SO2	0.07	0.03	0.07	0.05	0.06
		NOX	0.07	0.05	0.03	0.02	0.04
	9-State	SO2	0.09	0.05	0.09	0.11	0.08
		NOX	0.1	0.07	0.05	0.06	0.07
ICI Workgroup	3-State	SO2	0.1	0.06	0.11	0.09	0.09
		NOX	0.1	0.06	0.03	0.03	0.05
	9-State	SO2	0.15	0.08	0.15	0.18	0.14
		NOX	0.11	0.08	0.06	0.07	0.08

Table 5.2-11 “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007)

Reciprocating Engines and Turbines – Page 53-60 of LADCO’s “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis”

Indiana’s reciprocating engines and turbine emissions were based on LADCO’s Base K emissions for 2002 and projected to 2018 and are listed below in Table 5. Indiana’s emission contribution to the 9-state northern Midwest region (including the states of Michigan, Minnesota, Wisconsin, Illinois, Iowa, Missouri, North Dakota and South Dakota) was 9% of NOx emissions for 2002. Indiana’s contribution is projected to drop to 8% of NOx emissions by 2018. Stationary internal combustion engines are projected to represent 11 % of all non-EGU point sources in 2018.

Table 5. Estimated Emissions from Reciprocating Engines and Turbines in Non-EGU Emissions in 2018						
	Nox Emissions from stationary internal Combustion sources in 2002 (tons/day)			Projected Nox from stationary internal Combustion sources in 2018 (tons/day)		
	Reciprocating Engines	Turbines	Total	Reciprocating Engines	Turbines	Total
Michigan	44.1	11.4	55.5	41.4	11.5	52.9
Minnesota	18.3	5.9	24.3	17.6	6.3	23.9
Wisconsin	8.1	1.9	10	7.2	1.9	9.2
3-State Subtotal	*70.5*	*19.2*	*89.8*	*66.2*	*19.7*	*85.9*
Illinois	112.5	14.3	126.8	110.6	15.9	126.4
Indiana	**25.1**	**1.7**	**26.8**	**23**	**1.8**	**24.7**
Iowa	26.3	1.6	27.9	25.2	1.7	26.9
Missouri	21	3.2	24.3	20.2	3.4	23.6
North Dakota	8.7	1.3	10	8.3	1.4	9.7
South Dakota	0	1	1	0	1.1	1.1
9-State Total	*264.1*	*42.5*	*306.6*	*253.6*	*44.9*	*298.4*

Table 5.3-1 “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007)

Emission reductions for candidate internal combustion control measures are found in Table 5.3-2 of the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" document. Indiana's sources with emissions of 100 tons/year or more could realize emission reductions up to 88.5% with sources with emission of 10 tons/year or more up to 87.7%. Estimated cost effectiveness of controls for internal combustion sources are found in Table 5.3-3 with cost effectiveness in terms of visibility improvement found in Table 5.3-5.

Indiana emission reductions were combined with the other 8 state region emission reductions to determine the visibility improvements and are shown below in Table 6. Visibility improvements were modeled with larger improvements seen from emission reductions from the reciprocating engines.

Table 6. Estimated Visibility Improvements from Internal Combustion Control Measures					
9-State region					
Control of sources emitting over 100 tons/year	**Boundary Waters**	**Voyageurs**	**Isle Royale**	**Seney**	**Average**
Reciprocating engines	0.074	0.053	0.036	0.044	0.052
Turbines	0.01	0.007	0.005	0.006	0.007
Total	0.084	0.06	0.041	0.05	0.059
9-State region					
Control of sources emitting over 10 tons/year	**Boundary Waters**	**Voyageurs**	**Isle Royale**	**Seney**	**Average**
Reciprocating engines	0.105	0.075	0.051	0.062	0.073
Turbines	0.017	0.012	0.008	0.01	0.012
Total	0.121	0.087	0.059	0.072	0.085

Table 5.3-4 "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007)

Ammonia from Agricultural Sources – Page 61-67 of LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis"

Agricultural sources account for an estimated 97% of ammonia emissions in the nine-state region with most of those emissions coming from livestock. Cost effectiveness for control measures for agricultural ammonia emissions in the study region is found in Table 5.4-1 of the "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" document with the estimated energy and non-air environmental impact located in Table 5.4-2. Cost effectiveness in terms of visibility improvement from agricultural ammonia emission reductions from the 9-state region can be found in Table 5.4-4.

Visibility improvements at nearby Class 1 areas are realized with 10% and 15% ammonia emission reductions and are shown below in Table 7. Indiana would not be expected to significantly impact nearby Class 1 areas due to the ground-level releases of ammonia being dispersed before reaching the surrounding Class 1 areas.

Table 7. Estimated Visibility Impacts of Agricultural Ammonia Emission Control Measures.					
Estimated visibility Improvement in 2018 (DV)					
	Boundary Waters	**Voyageurs**	**Isle Royale**	**Seney**	**Average**
10% Ammonia Reduction in the 9-state region	0.15	0.18	0.15	0.17	0.16
15% Ammonia Reduction in the 9-state region	0.23	0.27	0.23	0.26	0.25

Table 5.4-3 "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis" (July 18, 2007)

Mobile Sources – Page 68-76 of LADCO's "Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis"

Source apportionment modeling show that mobile sources contribute significantly to visibility impairment in 2018 in the northern Midwest Class I areas, despite projected NOX reductions from on-the-books Federal and state-wide programs targeting on- and non-road mobile source sectors as well as locomotives and marine engines. Potential additional control strategies were identified that could be applied on a regional level.

For on-road engines:

- Low-NOX Reflash
- Anti-Idling
- Midwest Clean Diesel Initiative (MCDI)
- Cetane Additive Program

For non-road and locomotive engines:

- Anti-Idling
- Cetane Additive Program
- MCDI

Estimated cost effectiveness and emission reduction potential from mobile sources in the 9-state region are found in Table 5.5-1. The estimated energy and non-air environmental impacts from mobile source control strategies are listed in Table 5.5-2. Cost effectiveness of mobile source controls in terms of visibility improvement can be found in Table 5.5-4.

Emission reductions resulting from the above mobile emission control strategies for the 9-state region will average less than 2% for 2012 emission projections and just over 2 % for 2018 emission projections. Resulting visibility improvements as a result of each of the emission reductions will only improve visibility by less than 0.005 deciviews with visibility impacts from the cumulative mobile emission reductions resulting in 0.04 deciview improvement.

SUMMARY

Tables 8 and 9 show the 2002 and 2018 emission summaries for the nine state region for NOx and SO2. Table 10 shows a summary of the estimate visibility impacted from each of the source category emission reductions strategies. All Class 1 areas see a bigger benefit for visibility with emission controls on EGUs followed by ammonia reduction from agricultural sources. This analysis takes into account emission reductions from sources in all nine states within the study region so visibility improvement represents a cumulative impact from the states of Indiana, Michigan, Minnesota, Wisconsin, Illinois, Iowa, Missouri, North Dakota and South Dakota.

Table 8. Summary of Current (2002) Emissions in the Nine States in the Study Region										
	EGU	ICI Boilers	Reciprocating Engines	Turbines	Other Point	Area Sources	Onroad Mobile Sources	Nonroad Mobile Sources	Marine, Aircraft, Railroad	Total
SO2 in 2002										
Michigan	1,103	55			107	71		19	1	1,355
Minnesota	318	23			36	33		19	8	437
Wisconsin	602	149			14	9		13	13	800
3-State Subtotal	2,023	227			156	113		51	21	2,592
Illinois	1,310	161			213	11		31	0	1,725
Indiana	**2,499**	**148**			**144**	**158**		**17**	**0**	**2,966**
Iowa	412	88			50	2		12	8	571
Missouri	835	28			227	117		12	12	1,231
North Dakota	376	21			22	142		0	3	564
South Dakota	35	1			3	50		0	1	90
9-State Total	7,489	676			813	594		123	44	9,739
NOx in 2002										
Michigan	448	45	44	11	116	49	926	205	114	1,959
Minnesota	271	26	18	6	117	126	455	208	100	1,327
Wisconsin	294	65	8	2	24	32	481	145	79	1,129
3-State Subtotal	1,013	136	71	19	256	208	1,862	557	294	4,416
Illinois	712	101	112	14	129	62	890	324	277	2,622
Indiana	**830**	**105**	**25**	**2**	**106**	**63**	**703**	**178**	**123**	**2,133**
Iowa	254	45	26	2	39	7	304	174	89	941
Missouri	458	12	21	3	63	64	602	199	133	1,555
North Dakota	196	14	9	1	7	45	75	2	46	395
South Dakota	44	1	0	1	14	14	92	2	8	176
9-State Total	3,507	413	264	42	616	462	4,529	1,437	969	12,239

Table A-1.1 “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007)

Table 9. Summary of Projected (2018) Emissions in the Nine States in the Study Region

	EGU	ICI Boilers	Reciprocating Engines	Turbines	Other Point	Area Sources	Onroad Mobile Sources	Nonroad Mobile Sources	Marine, Aircraft, Railroad	Total
SO2 in 2018										
Michigan	1,093	51			134	68		0	1	1,347
Minnesota	236	22			48	34		4	2	346
Wisconsin	426	142			15	10		0	9	601
3-State Subtotal	1,755	215			196	112		4	11	2,294
Illinois	661	155			94	13		0	0	923
Indiana	**1,033**	**138**			**152**	**153**		**3**	**0**	**1,479**
Iowa	404	83			74	3		1	2	567
Missouri	770	26			395	120		3	7	1,321
North	298	20			32	137		4	0	491
South	33	2			4	51		3	0	94
9-State Total	4,952	641			948	588		19	20	7,168
NOx in 2018										
Michigan	273	43	41	11	133	54	385	94	110	1,145
Minnesota	115	25	18	6	134	136	205	175	54	867
Wisconsin	126	64	7	2	21	35	118	69	57	500
3-State Subtotal	514	132	66	20	287	225	708	338	222	2,512
Illinois	199	96	111	16	121	73	176	154	186	1,131
Indiana	**262**	**100**	**23**	**2**	**101**	**69**	**105**	**141**	**84**	**887**
Iowa	140	44	25	2	50	9	67	141	47	525
Missouri	213	12	20	3	75	74	119	161	99	777
North Dakota	196	14	8	1	12	50	34	204	24	545
South Dakota	40	1	0	1	22	15	42	148	5	273
9-State Total	1,564	400	254	45	669	515	1,250	1,288	666	6,650

Table A-1.2 “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007)

Table 10. Estimated Visibility Impacts of Potential Control Strategies								
Strategy and Region				**Estimated visibility improvement on the 20% worst-visibility days in 2018 (deciviews)**				
				Boundary Waters	Voyageurs	Isle Royale	Seney	Average
EGU	EGU1	9-State	SO2	0.77	0.35	0.84	1.01	0.74
			NOX	0.18	0.24	0.15	0.12	0.17
	EGU2	9-State	SO2	0.87	0.4	0.96	1.18	0.85
			NOX	0.26	0.3	0.23	0.19	0.24
ICI boilers	ICI1	9-State	SO2	0.09	0.047	0.092	0.109	0.084
			NOX	0.098	0.07	0.048	0.058	0.068
	ICI Workgroup	9-State	SO2	0.145	0.075	0.148	0.176	0.136
			NOX	0.114	0.082	0.056	0.067	0.08
Reciprocating Engines and Turbines	Reciprocating engines emitting 100 tons/year or more	9-State	NOX	0.074	0.053	0.036	0.044	0.052
	Turbines emitting 100 tons/year or more	9-State	NOX	0.01	0.007	0.005	0.006	0.007
	Reciprocating engines emitting 10 tons/year or more	9-State	NOX	0.105	0.075	0.051	0.062	0.073
	Turbines emitting 10 tons/year or more	9-State	NOX	0.017	0.012	0.008	0.01	0.012
Agricultural Sources	10% reduction	9-State	NH3	0.15	0.18	0.15	0.17	0.16
	15% reduction	9-State	NH3	0.23	0.27	0.23	0.26	0.25
Mobile Sources	Low-NOX Reflash	9-State	NOX	0.008	0.009	0.012	0.012	0.01
	MCDI	9-State	NOX	0.014	0.018	0.013	0.013	0.015
	Anti-Idling	9-State	NOX	0.005	0.007	0.006	0.006	0.006
	Cetane Additive Program	9-State	NOX	0.006	0.007	0.009	0.01	0.008

Table 6.5-2 “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007)

References:

LADCO’s “Reasonable Progress for Class 1 Areas in the Northern Midwest – Factor Analysis” (July 18, 2007) http://www.ladco.org/reports/rpo/consultation/products/reasonable_progress_for_class_i_areas_in_the_northern_midwest-factor_analysis_draft_final_technical_memo_july_18_2007.pdf

This page intentionally left blank.

Appendix 9d - Discussions and Data for ArcelorMittal Burns Harbor, ESSROC - Speed and SABIC CALPUFF Results using Bondville Ammonia Monitoring Results 2003-2005

This page intentionally left blank.

Concerns with BART eligibility modeling presented to Indiana DEM by sources:

Huffman, 2009.09.11

ArcelorMittal – Burns Harbor

- **The source used the new IMPROVE eqn. for light extinction – while this is generally acceptable the impacts on the modeled light extinction appears to be much greater than would be expected by this change alone. Most of the reduction in days over the thresholds for change in light extinction was accredited to this change.**

  IDEM Response: Burns Harbor used the most current regulatory versions of CALPUFF/CALMET/CALPOST versions 5.8, Level 070623. Burns Harbor requested the use of the new IMPROVE equation upon its release. Burns Harbor included a letter, dated October, 2006 from Dr. Ivar Tombach regarding the use of CALPOST outputs with the new IMPROVE equation. Burns Harbor completed their CALPUFF modeling in mid August of 2008. U.S. EPA Region 5 forwarded an email, dated July 28, 2008 from the National Parks Service that states since Dr. Scire had posted a new version of CALPOST, NPS would no longer be recommending Dr. Tombach's new IMPROVE spreadsheet. Burns Harbor submitted their CALPUFF modeling results soon after this email release, in part due to the uncertainty of U.S. EPA approved CALPUFF version to be used for BART modeling. Therefore, IDEM reviewed and accepted the Burns Harbor results.

  The "Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data"[1] includes studies that were conducted to determine the impact of the new IMPROVE equation on light extinction compared with the old IMPROVE equation and measured values. Class 1 areas with nephelometers were analyzed. There are seven Class 1 areas within the MRPO modeling domain that have nephelometers. Modeled results on the 20% best days showed new IMPROVE equation results for light scattering was slightly lower at most Class 1 areas than the old IMPROVE equation yet would be considered conservative as the modeled results were greater than measured light scattering. A summary of the results are below in Table 1:

Table 1: Mean Light Scattering (BSP) Results for 20% Best Days

Class 1 Area	Measured BSP Value (Mm-1)	Old IMPROVE BSP value (Mm-1)	New IMPROVE BSP value (Mm-1)
Boundary Waters	5.4	7.7	6.6
Dolly Sods	15	20	19
Great Gulf	5.4	8.0	6.8
Great Smokey Mountains	15	20	20
Lye Brook	5.3	8.2	7.0
Mammoth Cave	18	22	19
Shenandoah	11	14	13

Variations in the speciation results were due to slight increases or decreases in ammonia sulfate, ammonia nitrate and organic carbon. The light scattering calculations using the new IMPROVE equation were similar to the old IMPROV

E equation results and still higher than the measured light scattering values. IDEM finds no reason to dispute the results from the new IMPROVE equation and accepts the Burns Harbor CALPUFF modeling results.

- **The source used the average annual values instead of the 20% best days for comparison. This will result in the appearance of less impact on light extinction from the source emissions. This reduction in impact may not be accurate. ("Natural visibility conditions, the 20% best days,…" - LADCO BART modeling protocol).**

  IDEM Response: Burns Harbor used 6 kilometer CALPUFF and CALMET grids, thus allowing for use of the less conservative average annual background. U.S. EPA approved the use of 20% best day annual background concentrations for MRPO states when using the MRPO 36 kilometer grid CALMET without meteorological station observational data. The more refined VISTAS 6 kilometer CALMET data used by Burns Harbor included observational data and therefore, use of the average annual background concentrations was warranted per U.S. EPA.

- **The source used background ammonia values of 0.3 ppb in January through March with 0.5 ppb the rest of the year. This does follow LADCO protocol for BART modeling but it appears very low given the source emission may travel over long stretches of agricultural land where ammonia values are likely much higher.**

  IDEM Response: As mentioned, information from the LADCO MRPO protocol was used in the modeling. The protocol was approved by U.S. EPA which included the domain seasonal ammonia values, taken from annual 2002 CAMx simulations, which represented the best available information to conduct CALPUFF modeling for the MRPO states.

  In response to this comment, IDEM conducted additional CALPUFF runs, using Bondville ammonia data collected from November 2003 through October 2005. This data was not available at the time the LADCO MRPO BART modeling protocol was created and distributed to the LADCO states in early 2006. Below in Table 2 is the comparison of the 2002 seasonal averages with the 2003 to 2005 Bondville average monitored monthly ammonia data.

Table 2 Comparison of Ammonia Concentrations (ppb) for CALPUFF modeling for ArcelorMittal

Data Source	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
CAMx 2002	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Bondville 03-05	0.43	0.57	2.16	2.31	1.69	1.45	1.5	1.7	1.58	1.81	2.17	0.57

  Comparison of the Burns Harbor CALPUFF modeling results using the MRPO background ammonia concentrations and the 2003 – 2005 Bondville data showed only slight increases in overall light extinction and the delta deciview changes. The largest light extinction change was 1.06% and the delta deciviews change was 0.084 dv at Seney. There was an increase in the number of days compared to the BART threshold using the revised ammonia background at Mingo and Seney National Wildlife Refuges, however the results when calculated using the new IMPROVE model did not change. A summary of results can be found in Appendix A. The new IMPROVE equation spreadsheet results for Burns Harbor are included.

- **The source didn't model to Dolly Sods (Q/d~40), Otter Creek, or other "eastern" Class I areas as was done in the IDEM protocol. These Class I areas are not the closest Class I**

areas but they are directly "downwind" (east) of the facilities. For example, Otter Creek (691 km) is closer and downwind of the facility than Isle Royale (700 km) which was modeled as a receptor for the source emissions. This leaves in question the actual impacts of the emissions.

IDEM Response: It was IDEM's understanding that analyzing BART-eligible sources using the Q/d method was a crude screening method that was discouraged by U.S. EPA. IDEM does understand the concern for visibility impacts on eastern Class 1 areas. Burns Harbor modeled the four nearest Class 1 areas of Seney Wilderness, Isle Royale National Park, Mammoth Cave National Park and Mingo Wilderness. IDEM modeled sixteen Class 1 areas and determined the highest visibility impacts from Burns Harbor occurred at Seney, Isle Royale, Mammoth and Mingo Class 1 areas. While Burns Harbor did impact visibility at the eastern Class 1 areas mentioned, the visibility impacts from Burns Harbor on Dolly Sods, James River Face, Linville Gorge and Shenandoah National Park were found to be much less than the impacts at the four nearest Class 1 areas. The highest number of days at the four eastern Class 1 areas modeled above the BART threshold was 4 at Dolly Sods and 3 days at Shenandoah, both occurring in 2003. All other areas were modeled at one day or none.

- **"Burns Harbor's use of a more refined 6-km grid warranted the use of the average natural background concentrations for Class I areas in the eastern United States" (rather than the 20% best days as a natural background). A smaller grid does not necessarily imply more accurate, or precise, data so there is no real justification for opting to utilize a less stringent comparison.**

  IDEM Response: Using the average annual natural background concentrations follows U.S. EPA guidance for refined CALPUFF/CALMET grid analysis and has been accepted in previous submittals throughout the country. The 20% best days was a result of MRPO using less refined grids (36 km compared to 12 km, 6 km or 4 km grid resolution and no meteorological observations blended into the CALMET files). IDEM has discouraged sources from conducting CALPUFF modeling for BART purposes using refined grids of less than a 4 kilometer grid resolution.

- **Total natural background extinction coefficients used by Burns Harbor were allocated to soils instead of distributing among sulfates, nitrates, organic and elemental carbon, coarse mass and soil (pages 4-2 through 4-4). – BH says it did not significantly affect results, however, the point of the new IMPROVE equations appears to be that it uses the speciated particulates and they impact visibility (light extinction) differently. It appears that not including the speciated particulates would limit, or hinder, the benefits gained through the use of the new IMPROVE equations.**

  IDEM Response: This issue was raised by IDEM in March of 2009 and addressed by Burns Harbor in Attachment 4 in the hardcopy of the IDEM review document submitted for review in May of 2009. Burns Harbor explained that whether allocating the total background as soils or speciated components of ammonia sulfate, ammonia nitrate, organic carbon, elemental carbon and coarse mass, the resulting background extinction values are the same. Resulting modeling showed that the allocation of the total natural background extinction coefficients did not impact the light extinction results.

- **Burn Harbor uses a grid resolution of 6 km rather than the 36 km grid from IDEM but uses the same MM5 databases from the LADCO/MWRPO 36-km CALMET database. i.e. How**

does the use of met data with a 36-km resolution with a 6-km grid improve the modeling? There do not appear to be any actual improvements gained by using a smaller grid. The improvements appear to be limited to the addition of observations in the meteorological data.

-

IDEM Response: Burns Harbor refined the CALMET data using the latest U.S. EPA approved versions of CALPUFF and CALMET (pg. 3-1 of "Source Specific BART Modeling Report: ArcelorMittal Burns Harbor LLC, August 2008). The modeling domain included the four nearest Class 1 areas and had a 6 km grid resolution. The CALPUFF and CALMET data was processed with the 6 km grid terrain and land use data as well as the hourly observations and Table 3-1 lists the CALMET user-defined field for Meteorology grid spacing (DGRIDKM) at 6 km. Initial wind fields were produced using MM5 data sets at 36 km from CENRAP and MRPO but were processed at 6 km to characterize wind flow for the area.

ESSROC-Speed

- **ESSROC did not model particulate matter (PM10) emissions.**

  IDEM Response: At the time of the initial review, IDEM was not requiring PM_{10} emissions to be modeled. However, IDEM's review of ESSROC Speed's modeling included PM_{10} emissions which ESSROC-Speed provided estimates. IDEM's CALPUFF results showed NOx, SO_2 and PM_{10} emissions did not cause visibility impacts that exceeded the subject to BART threshold in its submittal in October of 2008.

- **ESSROC modeling used 4 KM CALMET data (2001-2003) and 4 km CALPUFF grid from VISTAS but MM5 data is only available in 12 km resolution. This would limit the stated benefit *of using a smaller grid size.***

  IDEM Response: ESSROC utilized the VISTAS's 4 km sub-regional Domain 3 meteorological data, as detailed in ESSROC-Speed's "BART Applicability Analysis, Air Quality Modeling Report" Section 3.2. IDEM's review used the emissions and stack parameter data modeled by ESSROC and modeled those using IDEM's original CALPUFF model set-up to make the subject to BART determination. This was done in order to compare visibility results from the U.S. EPA approved MRPO BART modeling protocol for the Midwest states, including Indiana.

- **No cumulative impacts to Class I areas as a whole were analyzed. The source only modeled change in light extinction to Mammoth Cave. There are 11 Class I areas within 600 km of ESSROC and IDEM originally modeled impacts to 16 Class I areas in the eastern United States.**

-

  IDEM Response: ESSROC-Speed requested modeling only the nearest Class 1 area due to limited resources and amount of time to model using a more refined modeling grid domain. IDEM's review included modeling the sixteen nearby Class 1 areas and determined that the highest deciviews impact from ESSROC-Speed occurred at the Mammoth Cave Class 1 area with no other Class 1 areas beside Mammoth Cave recording delta deciview above the BART threshold. Cumulative impacts to Class 1 areas as a whole were used to determine whether a source was BART-eligible, however to make subject to BART determinations, visibility impacts on each individual Class 1 areas were analyzed.

- **Background ammonia used by ESSROC (0.3 Jan-Mar and 0.5 ppb the rest of the year) is likely too low to represent the land use around the source and the potentially impacted Class I areas.**

-

IDEM Response: As mentioned, information from the LADCO MRPO protocol was used in the modeling. The protocol was approved by U.S. EPA which included the domain seasonal ammonia values, taken from annual 2002 CAMx simulations.

IDEM has conducted further CALPUFF runs, using Bondville ammonia data collected from November 2003 through October 2005. This data was not available at the time the LADCO MRPO BART modeling protocol was created and distributed to the LADCO states in early 2006. Below in Table 3 is the comparison of the 2002 seasonal averages with the 2003 to 2005 Bondville average monthly data.

Table 3 Comparison of Ammonia Concentrations (ppb) for CALPUFF modeling for ESSROC-Speed

Data Source	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
CAMx 2002	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Bondville 03-05	0.43	0.57	2.16	2.31	1.69	1.45	1.5	1.7	1.58	1.81	2.17	0.57

Comparison of the ESSROC-Speed CALPUFF modeling results using the MRPO background ammonia concentrations and the 2003 – 2005 Bondville data showed only slight increases in overall light extinction and the largest deciviews changes. The largest light extinction change was 0.15% and the largest deciviews change was 0.015 dv at Dolly Sods. There was an increase in the number of days above the BART threshold using the revised ammonia background at Mammoth Caves, however this increase was by one day and the total days for the year remained below the BART threshold. A summary of results can be found in Appendix B.

SABIC

- **SABIC modeling used 4 KM CALMET data (2001-2003) and 4 km CALPUFF grid from VISTAS but MM5 data is only available in 12 km resolution. This would limit the stated benefit of using a smaller grid size.**

  IDEM Response: SABIC utilized the VISTAS's 4 km sub-regional Domain 3 meteorological data. IDEM's review used the emissions and stack parameter data modeled by SABIC and modeled those using IDEM's original CALPUFF model set-up to make a subject to BART determination. This was done in order to compare visibility results from the U.S. EPA approved MRPO BART modeling protocol for the Midwest states, including Indiana.

- **The source used the average annual values instead of the 20% best days for comparison. This will result in the appearance of less impact on light extinction from the source emissions. This reduction in impact may not be accurate. ("Natural visibility conditions, the 20% best days,…" - LADCO BART modeling protocol).**

  IDEM Response: SABIC used 4 kilometer CALPUFF and CALMET grids, thus allowing for use of the less conservative average annual background. U.S. EPA approved the use of 20% best day annual background concentrations for MRPO states when using the MRPO 36 kilometer grid CALMET without meteorological station observational data. The VISTAS's 4 kilometer CALMET data used by SABIC included observational data and therefore, use of the average annual background concentrations was warranted.

- **SABIC - Chose a modeling domain for refined 4 km modeling and then based the Class I areas to model to base on the domain rather than the other way around. In doing so SABIC left off Hercules Glades Class I Wilderness area and included many Class I receptors further away.**

  IDEM Response: SABIC used the pre-determined sub domain grid taken from the VISTAS BART modeling protocol and modeled all Class 1 areas within the sub domain grid. IDEM's review modeled the sixteen nearby Class 1 areas as were modeled in the initial subject to BART determination modeling. This review showed all nearby Class 1 areas would not be impacted by SABIC above the BART threshold.

- **Background ammonia used by ESSROC (0.3 Jan-Mar and 0.5 ppb the rest of the year) is likely too low to represent the land use around the source and the potentially impacted Class I areas.**
-
  IDEM Response: As mentioned, information from the LADCO MRPO protocol was used in the modeling. The protocol was approved by U.S. EPA which included the domain seasonal ammonia values, taken from annual 2002 CAMx simulations.

  IDEM has conducted further CALPUFF runs, using Bondville ammonia data collected from November 2003 through October 2005. This data was not available at the time the LADCO MRPO BART modeling protocol was created and distributed to the LADCO states in early 2006. Below in Table 4 is the comparison of the 2002 seasonal averages with the 2003 to 2005 Bondville average monthly data.

Table 4 Comparison of Ammonia Concentrations (ppb) for CALPUFF modeling for SABIC

Data Source	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
CAMx 2002	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Bondville 03-05	0.43	0.57	2.16	2.31	1.69	1.45	1.5	1.7	1.58	1.81	2.17	0.57

Comparison of the SABIC CALPUFF modeling results using the MRPO background ammonia concentrations and the 2003 – 2005 Bondville data showed only slight increases in overall light extinction and the largest deciviews changes. The largest light extinction change was 0.17% and the largest deciviews change was 0.016 dv at Sipsey Wilderness. There was an increase in the number of days above the BART threshold using the revised ammonia background at Hercules Glades Wilderness, however this increase was by one day and the total days for the year remained below the BART threshold. A summary of results can be found in Appendix C.

- **SABIC utilized the ammonia limiting technique (ALM) which does not appear to be a valid switch in CALPUFF**
-
  IDEM Response: Discussion between IDEM, EPA and Federal Land Managers, held on a conference call on September 16, 2009, brought this issue to light. IDEM understands that if the MNITRATE switch is set to 1, this option does not affect light extinction and delta deciview calculations. Review of the input file shows the MNITRATE switch in the CALPOST input file

was set to 1 and therefore the ALM option was used correctly. SABIC verified this result by email on November 11, 2009.

References:

[1] http://vista.cira.colostate.edu/improve/Publications/GrayLit/019_RevisedIMPROVEeq/RevisedIMPROVEAlgorithm3.doc

Appendix 9d - ArcelorMittal Burns HarborCALPUFF Results using Bondville Ammonia Monitoring Results 2003-2005

CALPUFF Results for Mittal - Comparing Ammonia background

	With MRPO NH3			With Bondville NH3			Difference		
	Extinction Change			Extinction Change			Extinction Change		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	11.94%	7.55%	10.58%	12.07%	7.64%	11.33%	0.13%	0.09%	0.75%
Brigantine Wild. - NJ	3.38%	5.82%	5.17%	3.45%	6.08%	5.58%	0.07%	0.26%	0.41%
Dolly Sods - WV	7.89%	5.61%	5.31%	8.31%	5.81%	5.51%	0.42%	0.20%	0.20%
Great Gulf Wild - NH	6.08%	4.47%	12.92%	6.24%	4.63%	13.59%	0.16%	0.16%	0.67%
Great Smokey Mount - TN	5.50%	5.44%	4.58%	5.60%	5.56%	4.86%	0.10%	0.12%	0.28%
Hercules - Glades Wild. - MO	10.54%	4.58%	13.77%	10.68%	4.73%	14.24%	0.14%	0.15%	0.47%
Isle Royale - MI	7.22%	13.77%	9.17%	7.32%	14.25%	9.80%	0.10%	0.48%	0.63%
James River Face - VA	2.70%	3.92%	2.73%	2.76%	4.07%	2.89%	0.06%	0.15%	0.16%
Linville Gorge - NC	4.23%	2.37%	2.34%	4.36%	2.41%	2.48%	0.13%	0.04%	0.14%
Lye Brook Wild. - VT	5.49%	5.30%	8.01%	5.67%	5.37%	8.47%	0.18%	0.07%	0.46%
Mammoth Caves - KY	10.55%	5.62%	6.66%	10.77%	5.90%	7.32%	0.22%	0.28%	0.66%
Mingo Wild. - MO	9.14%	7.23%	8.91%	9.35%	7.34%	9.27%	0.21%	0.11%	0.36%
Seney Wild. - MI	14.72%	20.36%	26.29%	15.47%	21.31%	27.35%	0.75%	0.95%	1.06%
Shenandoah N.P. - VA	4.95%	6.16%	4.68%	5.14%	6.25%	4.86%	0.19%	0.09%	0.18%
Sipsey Wild. - AL	4.12%	2.01%	3.12%	4.23%	2.06%	3.31%	0.11%	0.05%	0.19%
Voyageurs N.P. - MN	4.47%	12.21%	9.91%	4.54%	12.37%	10.29%	0.07%	0.16%	0.38%
	Largest Delta Deciview			Largest Delta Deciview			Largest Delta Deciview		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	1.128	0.728	1.006	1.14	0.736	1.073	0.012	0.008	0.067
Brigantine Wild. - NJ	0.333	0.565	0.504	0.34	0.59	0.543	0.007	0.025	0.039
Dolly Sods - WV	0.759	0.546	0.517	0.798	0.565	0.536	0.039	0.019	0.019
Great Gulf Wild - NH	0.54	0.437	1.215	0.606	0.453	1.275	0.066	0.016	0.06
Great Smokey Mount - TN	0.535	0.53	0.448	0.545	0.541	0.474	0.01	0.011	0.026
Hercules - Glades Wild. - MO	1.002	0.448	1.29	1.015	0.462	1.332	0.013	0.014	0.042
Isle Royale - MI	0.697	1.29	0.877	0.706	1.332	0.935	0.009	0.042	0.058
James River Face - VA	0.267	0.384	0.269	0.273	0.399	0.285	0.006	0.015	0.016
Linville Gorge - NC	0.414	0.234	0.231	0.427	0.238	0.245	0.013	0.004	0.014
Lye Brook Wild. - VT	0.534	0.516	0.771	0.552	0.523	0.813	0.018	0.007	0.042
Mammoth Caves - KY	1.003	0.547	0.645	1.023	0.573	0.707	0.02	0.026	0.062
Mingo Wild. - MO	0.875	0.698	0.854	0.894	0.708	0.886	0.019	0.01	0.032
Seney Wild. - MI	1.373	1.854	2.334	1.439	1.932	2.418	0.066	0.078	0.084
Shenandoah N.P. - VA	0.483	0.597	0.457	0.501	0.606	0.475	0.018	0.009	0.018
Sipsey Wild. - AL	0.404	0.199	0.307	0.414	0.203	0.325	0.01	0.004	0.018
Voyageurs N.P. - MN	0.438	1.152	0.945	0.444	1.167	0.979	0.006	0.015	0.034
	Days above 0.5 DV			Days above 0.5 DV			Days above 0.5 DV		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	1	2	4	1	3	4	0	1	0
Brigantine Wild. - NJ	0	1	1	0	1	1	0	0	0
Dolly Sods - WV	1	3	1	1	4	1	0	1	0
Great Gulf Wild - NH	1	0	2	1	0	2	0	0	0
Great Smokey Mount - TN	2	0	0	2	1	0	0	1	0
Hercules - Glades Wild. - MO	2	0	1	2	0	1	0	0	0
Isle Royale - MI	2	4	4	2	4	4	0	0	0
James River Face - VA	0	0	0	0	0	0	0	0	0
Linville Gorge - NC	0	0	0	0	0	0	0	0	0
Lye Brook Wild. - VT	1	1	4	1	1	4	0	0	0
Mammoth Caves - KY	6	1	4	7	1	4	1	0	0
Mingo Wild. - MO	5	3	2	5	3	4	0	0	2
Seney Wild. - MI	9	17	16	10	17	19	1	0	3
Shenandoah N.P. - VA	1	3	0	1	3	0	0	0	0
Sipsey Wild. - AL	0	0	0	0	0	0	0	0	0
Voyageurs N.P. - MN	0	1	1	0	1	1	0	0	0

Appendix 9d - ESSROC - Speed CALPUFF Results using Bondville Ammonia Monitoring Results 2003-2005

CALPUFF Results for ESSROC - Speed - Comparing Ammonia background

	With MRPO NH3			With Bondville NH3			Difference		
	Extinction Change			Extinction Change			Extinction Change		
Class 1 Areas	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Boundary Waters - MN	0.14%	0.67%	0.47%	0.14%	0.69%	0.54%	0.00%	0.02%	0.07%
Brigantine Wild. - NJ	1.52%	0.92%	0.59%	1.53%	0.92%	0.60%	0.01%	0.00%	0.01%
Dolly Sods - WV	1.12%	1.11%	1.93%	1.18%	1.26%	2.02%	0.06%	0.15%	0.09%
Great Gulf Wild - NH	0.95%	0.55%	0.73%	0.97%	0.55%	0.73%	0.02%	0.00%	0.00%
Great Smokey Mount - TN	1.35%	2.56%	4.58%	1.45%	2.58%	4.58%	0.10%	0.02%	0.00%
Hercules - Glades Wild. - MO	0.57%	0.49%	0.39%	0.58%	0.49%	0.39%	0.01%	0.00%	0.00%
Isle Royale - MI	0.20%	1.30%	0.79%	0.20%	1.35%	0.90%	0.00%	0.05%	0.11%
James River Face - VA	0.96%	1.51%	1.34%	1.00%	1.52%	1.35%	0.04%	0.01%	0.01%
Linville Gorge - NC	2.50%	1.43%	1.61%	2.51%	1.44%	1.61%	0.01%	0.01%	0.00%
Lye Brook Wild. - VT	1.20%	1.11%	1.61%	1.24%	1.12%	1.62%	0.04%	0.01%	0.01%
Mammoth Caves - KY	6.08%	8.21%	10.36%	6.11%	8.23%	10.50%	0.03%	0.02%	0.14%
Mingo Wild. - MO	4.05%	3.18%	1.87%	4.08%	3.22%	1.87%	0.03%	0.04%	0.00%
Seney Wild. - MI	0.74%	1.45%	0.67%	0.74%	1.47%	0.68%	0.00%	0.02%	0.01%
Shenandoah N.P. - VA	1.45%	1.90%	1.36%	1.46%	1.92%	1.37%	0.01%	0.02%	0.01%
Sipsey Wild. - AL	1.85%	1.44%	3.95%	1.86%	1.45%	3.97%	0.01%	0.01%	0.02%
Voyageurs N.P. - MN	0.11%	0.21%	0.10%	0.11%	0.21%	0.10%	0.00%	0.00%	0.00%

	Largest Delta Deciview			Largest Delta Deciview			Largest Delta Deciview		
Class 1 Areas	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Boundary Waters - MN	0.014	0.068	0.047	0.014	0.069	0.054	0	0.001	0.007
Brigantine Wild. - NJ	0.151	0.091	0.058	0.152	0.091	0.059	0.001	0	0.001
Dolly Sods - WV	0.111	0.11	0.191	0.117	0.125	0.2	0.006	0.015	0.009
Great Gulf Wild - NH	0.095	0.055	0.073	0.096	0.055	0.073	0.001	0	0
Great Smokey Mount - TN	0.134	0.253	0.447	0.144	0.254	0.448	0.01	0.001	0.001
Hercules - Glades Wild. - MO	0.057	0.049	0.039	0.058	0.049	0.039	0.001	0	0
Isle Royale - MI	0.02	0.129	0.079	0.02	0.134	0.09	0	0.005	0.011
James River Face - VA	0.095	0.15	0.133	0.1	0.151	0.134	0.005	0.001	0.001
Linville Gorge - NC	0.247	0.142	0.16	0.248	0.143	0.16	0.001	0.001	0
Lye Brook Wild. - VT	0.119	0.11	0.16	0.124	0.112	0.161	0.005	0.002	0.001
Mammoth Caves - KY	0.59	0.789	0.985	0.593	0.791	0.999	0.003	0.002	0.014
Mingo Wild. - MO	0.397	0.313	0.183	0.4	0.317	0.185	0.003	0.004	0.002
Seney Wild. - MI	0.073	0.144	0.067	0.074	0.146	0.068	0.001	0.002	0.001
Shenandoah N.P. - VA	0.144	0.189	0.135	0.145	0.19	0.136	0.001	0.001	0.001
Sipsey Wild. - AL	0.183	0.143	0.388	0.184	0.144	0.39	0.001	0.001	0.002
Voyageurs N.P. - MN	0.011	0.021	0.01	0.011	0.021	0.01	0	0	0

	Days above 0.5 DV			Days above 0.5 DV			Days above 0.5 DV		
Class 1 Areas	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Boundary Waters - MN	0	0	0	0	0	0	0	0	0
Brigantine Wild. - NJ	0	0	0	0	0	0	0	0	0
Dolly Sods - WV	0	0	0	0	0	0	0	0	0
Great Gulf Wild - NH	0	0	0	0	0	0	0	0	0
Great Smokey Mount - TN	0	0	0	0	0	0	0	0	0
Hercules - Glades Wild. - MO	0	0	0	0	0	0	0	0	0
Isle Royale - MI	0	0	0	0	0	0	0	0	0
James River Face - VA	0	0	0	0	0	0	0	0	0
Linville Gorge - NC	0	0	0	0	0	0	0	0	0
Lye Brook Wild. - VT	0	0	0	0	0	0	0	0	0
Mammoth Caves - KY	2	5	3	2	5	4	0	0	1
Mingo Wild. - MO	0	0	0	0	0	0	0	0	0
Seney Wild. - MI	0	0	0	0	0	0	0	0	0
Shenandoah N.P. - VA	0	0	0	0	0	0	0	0	0
Sipsey Wild. - AL	0	0	0	0	0	0	0	0	0
Voyageurs N.P. - MN	0	0	0	0	0	0	0	0	0

Appendix 9d - SABIC CALPUFF Results using Bondville Ammonia Monitoring Results 2003-2005

CALPUFF Results for Sabic - Comparing Ammonia background

	With MRPO NH3			With Bondville NH3			Difference		
	Extinction Change			Extinction Change			Extinction Change		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	0.35%	1.65%	0.43%	0.35%	1.66%	0.44%	0.00%	0.01%	0.01%
Brigantine Wild. - NJ	1.57%	0.83%	1.17%	1.57%	0.83%	1.18%	0.00%	0.00%	0.01%
Dolly Sods - WV	0.82%	0.95%	1.14%	0.83%	0.95%	1.15%	0.01%	0.00%	0.01%
Great Gulf Wild - NH	1.01%	1.20%	1.22%	1.01%	1.20%	1.22%	0.00%	0.00%	0.00%
Great Smokey Mount - TN	1.07%	1.95%	2.93%	1.07%	1.95%	2.94%	0.00%	0.00%	0.01%
Hercules - Glades Wild. - MO	1.76%	4.67%	6.23%	1.78%	4.67%	6.23%	0.02%	0.00%	0.00%
Isle Royale - MI	1.02%	2.03%	0.89%	1.02%	2.03%	0.90%	0.00%	0.00%	0.01%
James River Face - VA	0.61%	1.49%	2.36%	0.61%	1.49%	2.37%	0.00%	0.00%	0.01%
Linville Gorge - NC	1.05%	1.80%	5.73%	1.06%	1.80%	5.75%	0.01%	0.00%	0.02%
Lye Brook Wild. - VT	1.68%	1.57%	2.54%	1.69%	1.59%	2.54%	0.01%	0.02%	0.00%
Mammoth Caves - KY	6.68%	9.52%	6.67%	6.68%	9.53%	6.69%	0.00%	0.01%	0.02%
Mingo Wild. - MO	11.93%	11.03%	6.26%	11.95%	11.04%	6.31%	0.02%	0.01%	0.05%
Seney Wild. - MI	1.45%	2.28%	1.69%	1.45%	2.28%	1.69%	0.00%	0.00%	0.00%
Shenandoah N.P. - VA	1.24%	1.40%	1.67%	1.24%	1.41%	1.68%	0.00%	0.01%	0.01%
Sipsey Wild. - AL	5.17%	1.73%	3.48%	5.34%	1.73%	3.49%	0.17%	0.00%	0.01%
Voyageurs N.P. - MN	0.16%	0.98%	0.21%	0.16%	0.98%	0.21%	0.00%	0.00%	0.00%
	Largest Delta Deciview			Largest Delta Deciview			Largest Delta Deciview		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	0.035	0.164	0.043	0.035	0.164	0.044	0	0	0.001
Brigantine Wild. - NJ	0.155	0.082	0.117	0.155	0.083	0.117	0	0.001	0
Dolly Sods - WV	0.082	0.095	0.113	0.082	0.095	0.115	0	0	0.002
Great Gulf Wild - NH	0.101	0.119	0.122	0.101	0.119	0.122	0	0	0
Great Smokey Mount - TN	0.107	0.193	0.289	0.107	0.193	0.29	0	0	0.001
Hercules - Glades Wild. - MO	0.174	0.456	0.604	0.176	0.456	0.605	0.002	0	0.001
Isle Royale - MI	0.102	0.201	0.088	0.102	0.201	0.09	0	0	0.002
James River Face - VA	0.061	0.148	0.233	0.061	0.148	0.234	0	0	0.001
Linville Gorge - NC	0.105	0.179	0.557	0.105	0.179	0.559	0	0	0.002
Lye Brook Wild. - VT	0.166	0.156	0.25	0.167	0.158	0.251	0.001	0.002	0.001
Mammoth Caves - KY	0.647	0.91	0.646	0.647	0.91	0.648	0	0	0.002
Mingo Wild. - MO	1.127	1.046	0.607	1.129	1.047	0.612	0.002	0.001	0.005
Seney Wild. - MI	0.144	0.225	0.168	0.144	0.225	0.168	0	0	0
Shenandoah N.P. - VA	0.123	0.139	0.166	0.124	0.14	0.167	0.001	0.001	0.001
Sipsey Wild. - AL	0.504	0.171	0.343	0.52	0.171	0.343	0.016	0	0
Voyageurs N.P. - MN	0.016	0.097	0.021	0.016	0.097	0.021	0	0	0
	Days above 0.5 DV			Days above 0.5 DV			Days above 0.5 DV		
Class 1 Areas	2002	2003	2004	2002	2003	2004	2002	2003	2004
Boundary Waters - MN	0	0	0	0	0	0	0	0	0
Brigantine Wild. - NJ	0	0	0	0	0	0	0	0	0
Dolly Sods - WV	0	0	0	0	0	0	0	0	0
Great Gulf Wild - NH	0	0	0	0	0	0	0	0	0
Great Smokey Mount - TN	0	0	0	0	0	0	0	0	0
Hercules - Glades Wild. - MO	0	0	0	0	0	1	0	0	1
Isle Royale - MI	0	0	0	0	0	0	0	0	0
James River Face - VA	0	0	0	0	0	0	0	0	0
Linville Gorge - NC	0	0	1	0	0	1	0	0	0
Lye Brook Wild. - VT	0	0	0	0	0	0	0	0	0
Mammoth Caves - KY	1	6	2	1	6	2	0	0	0
Mingo Wild. - MO	1	2	1	1	2	1	0	0	0
Seney Wild. - MI	0	0	0	0	0	0	0	0	0
Shenandoah N.P. - VA	0	0	0	0	0	0	0	0	0
Sipsey Wild. - AL	1	0	0	1	0	0	0	0	0
Voyageurs N.P. - MN	0	0	0	0	0	0	0	0	0

This page intentionally left blank.

Appendix 9e - Alcoa Responses to National Parks Service Comments

This page intentionally left blank.

ALCOA

Alcoa Inc.
Warrick Operations
Environmental Engineering
Fax Number: 812-853-4851

Fax

To: Ken Ritter Date: 2/3/11

Fax #: (317) 233-6865

Pages: 3

Re: NODA - CATR Comments

From: Sam Brunt

Phone: (812) 853-1519

☐ Urgent ☒ For Review ☐ Please Comment ☐ Please Reply ☐ Please Recycle

Comments: Ken,

these comments were filed with EPA regarding the Notice of Data Availability for the Clean Air Transport Rule

Sam Brunt

Alcoa Power Generating Inc – Warrick Power Plant
4700 Darlington Road
PO Box 10
Newburgh, IN 47630 USA
Tel: 812 853 1519
Fax: 812 853 4851
Samuel.Bruntz@alcoa.com

ALCOA

Feb. 3, 2011

U.S. Environmental Protection Agency
Mailcode 2822T
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Docket ID# EPA-HQ- OAR–2009--0491
Notice of Data Availability (NODA)
5 Fed. Reg. 1109 (January 7, 2011)

Dear Sir or Madam:

Alcoa Power Generating, Inc. (APGI) - Warrick Power Plant appreciates the opportunity to comment, as follows:

1.) This NODA specifically invites comment regarding existing units listed in the initial Clean Air Transport Rule (CATR) that should not have been included. The CATR, as proposed, specified that the proposed rule would be applicable for electricity generating units producing electricity for sale. APGI consists of units 1-4. Units 1-3 are industrial boilers that produce electricity, steam, and hot process water for the Alcoa Inc. – Warrick Operations primary aluminum smelter and aluminum fabrication plant. Electricity produced by these units is used for the exclusive use of Alcoa Inc., and is not sold on the grid. Unit 4 is jointly owned by APGI and Vectren. 50% of the electricity produced by this unit is sold to the grid, so it will be subject to the CATR. APGI requests that Units 1-3 be removed from the list of existing potential units, since they do not sell to the grid.

2.) APGI recommends that NODA Option 1 be used for allocating state budgets to subject units. Option 1 proportions baseline heat input for each subject unit to total statewide baseline heat input to determine the share of state budget to be allocated. APGI does have concerns with the overall CATR concept, in general. EPA seems not to have considered air quality improvements achieved by the vacated CAIR rule. The most recent air quality data indicate substantially fewer nonattainment and maintenance areas than EPA's data.

3.) Modeling of existing CAIR requirements and other OTB controls indicate no need for the nature and extent of controls as proposed in the CATR. APGI thus conditions its recommendation for Option 1 on a re-evaluation by EPA of needed pollutant reductions based on improvements the vacated CAIR rule provided.

4.) EPA has proposed a FIP rather than a SIP, followed by a FIP, as required by the CAA. Congress intended States to take the primary role in regulating stationary sources under Title I of the CAA. Title I unequivocally guarantees States the opportunity to establish a statewide program for achieving the NAAQS, and only where States fail to establish such programs does a FIP apply directly to the sources within the State.

EPA lacks statutory authority to reverse the order of the NAAQS process designed by Congress and immediately impose its program for a State's achievement of the NAAQS, unless and until a State has failed to develop and obtain approval of its own State program.

Not only does a FIP-first approach violate the CAA, it also deprives States and sources the opportunity – intended by the statutory scheme – to selectively target reductions from among the many emissions sources. It also does not allow states to consider hardware installations that have provided air quality improvements, and to find innovative, source-specific solutions to achieving emission reductions.

Especially in light of air quality improvements achieved pursuant to the vacated CAIR rule, the urgency in mandated severe emissions reductions proposed by the CATR rule FIP first approach is not warranted. APGI thus strongly encourages EPA to allow states to address the needed realistic emissions reductions through the normal SIP amendment process provided by the Clean Air Act.

Thank you for considering these comments.

Sincerely,

Samuel H. Bruntz

Samuel H. Bruntz
Senior Staff Environmental Engineer
Alcoa Inc. – Warrick Operations
Alcoa Power Generating Inc. – Warrick Power Plant
(812) 853-1519

This page intentionally left blank.

Appendix 10 - IDEM Responses to US Forest Service Comments

This page intentionally left blank.

IDEM Responses to US Forest Service Comments

Our interest in the Indiana Regional Haze SIP is due to the fact that sources in your State cause or contribute to visibility impairment in many of our Class I Wilderness areas including the Boundary Waters Canoe Area Wilderness in Minnesota, Hercules Glades Wilderness Area in Missouri, Sipsey Wilderness Area in Alabama, Caney Creek Wilderness Area and Upper Buffalo Wilderness Area in Arkansas, Great Gulf Wilderness Area in New Hampshire, Lye Brook Wilderness Area in Vermont, James River Face Wilderness Area in Virginia, and Dolly Sods and Otter Creek Wilderness Areas in West Virginia.

BART analyses

Comment:
RPO coordination
On page 35 the quote "The Uniform Rate is achieved and exceeded at all MANE-VU Class I sites" from "Recent MANE-VU Projections of Visibility for 2018." Do these projections include the latest predictions in emissions from Indiana sources? It appears that with some sources modeling out of being subject-to-BART the 2018 emissions from Indiana may be greater than what was predicted by MANE-VU in 2008. The possibility that the RPOs assumed greater emission reductions in their Class I area analysis (Section 7.0) are highlighted on page 69 (Section 9.2) – "The analyses show no reductions from Indiana sources, **beyond the BART rule**, are necessary to meet the reasonable progress goals of the areas analyzed at this time." (emphasis added). It is not clear what reductions from Indiana other States considered part of the BART rule and how these could differ from the reductions proposed in this Regional Haze SIP.

IDEM Response:
IDEM has added the megawatt capacities for the Indiana coal fired units listed in Table 10 to demonstrate the size of these units. This table highlights the BART-eligible units and notes which units were included in the MANEVU "ask" list, described in Section 7.9. IDEM has added a more detailed description of the data presented in Table 10 and an explanation of the assumptions made for each column in the table. A discussion of the implications of the various modeling scenarios and the best current information available regarding Indiana electric generating units controls and the legal enforceability of these controls has been added. In addition, two tables in Appendix 10a show a comparison between IDEM's projected controls and EPA and LADCO's modeling scenarios for SO_2 and NO_x controls.

Cumulative Haze impacts
On page 49 – Table 15 - it appears that when considered cumulatively (the sum of modeled days over the 0.5 dv threshold for all the Class I areas modeled – 15 (Seney) + 6 (Mammoth Cave) + 4 (Mingo) + 4 (Isle Royale) = 29 days) Burns Harbor would still be subject to BART. As the facility impacts haze at so many Class I areas we feel Indiana should address the cumulative impact of the facility and consider ArcelorMittal Burns Harbor subject to BART.

IDEM Response:
IDEM appreciates the USFS's comment and position on this issue. However, a consistence approach is preferred. Representatives from EPA Region 5, the EPA Headquarters and the states of Ohio, Michigan, Wisconsin and Minnesota favor the approach of summing up days for each

individual Class 1 area instead of counting all modeled receptors at all the Class 1 areas modeled. A summary of responses from these respondents on the question of using cumulative or individual Class 1 area days above the BART threshold for BART determinations is attached in Appendix 10b.

Comment:
Please adjust permitted emissions to the highest actual emissions when there is a significant difference for facilities not subject to BART.
Page 53 – Table 18 is an example of our concern when revised modeling results in facilities no longer being considered subject to BART done by the three facilities (Burns Harbor, ESSROC and SABIC) in Indiana. When the "highest actual" emission rates are significantly lower than the "potential" emission rates and the lower rates are used as justification to avoid subject to BART designation, the lower rates need to be incorporated into a federally enforceable permit condition. The NO_x emissions for the highest emitting day and potential emissions in Table 18 are similar but the SO_2 differences are significant. Reduction in permitted, potential emissions to the actual highest emissions would ensure that the facility's (ESSROC) emissions remain consistent with the "not subject to BART" determination. Most importantly, it will ensure that the facility has a minimal impact on regional haze in Class I areas.

IDEM Response:
IDEM appreciates the USFS's comment and position on this issue. However, average 24-hour actual emission rates from the highest emitting day are permitted according to the BART Rule and have been accepted by U.S. EPA and IDEM for use in the CALPUFF model.

Comment:
SABIC
We recommend that IDEM accepts the permit modification from SABIC to remove the oil burning provision from Part 70 Operating Permit. This will ensure long-term visibility improvements from this current status at the plant.

IDEM Response:
IDEM has accepted the permit modification request from SABIC to remove the oil burning provisions from its Part 70 Operating Permit. The all references to fuel oil were removed from the emission unit description of the boiler, identified as BW-Boiler with ID No. 09-0001, on 08/2008 through Minor Source/Significant Permit Modification Nos. 129-26621-00002/129-26650-00002.

Alcoa
Comment:
Emission reductions from Boiler 1, a not-subject-to-BART unit, could be achieved through Reasonable Progress as part of the Regional Haze Rule, and as such are not necessarily better than what would be achieved under the rule.

IDEM Response:
IDEM's approach to BART reductions has been to follow guidance from various parts of the regional haze program. In the 1999 Regional Haze Regulations, Subpart P – Protection of Visibility, it states that reductions must be surplus to required emission reductions up to the baseline date. The established baseline date is 2002. The year 2002 has been used by various states, RPOs, and the EPA regional haze modeling guidance. It is also specified by the Lydia Wegman November 18, 2002 memo, "2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$ and Regional Haze Programs."

The BART Rule, 70 FR 128, 39143, states that "(2) The EPA does not believe that anything in the CAA or relevant case law prohibits a State from considering emissions reductions required to meet other CAA requirements when determining whether source by source BART controls are necessary to make reasonable progress." and "(3)…in lieu of BART programs be based on emissions reductions 'surplus to reductions resulting from measures adopted to meet requirements as of the baseline date of the SIP.' The baseline date for regional haze SIPs is 2002…" This is extracted from a discussion justifying the use of CAIR, a program used for other purposes, to substitute for BART. Therefore, it is our belief that emission reductions from Boiler 1 as part of the BART alternative proposed by Alcoa is acceptable under the rule.

Comment:
There is no apparent reason why the SO_2 controls on Boilers 2 and 3 cannot achieve 92 percent or greater efficiency with wet FGD. Please explain and justify the need to operate this control equipment at 90 percent. Include this as part of the five-factor analysis.

IDEM Response:
Alcoa used the 92% reduction level for the BART control analysis for Boilers 2 and 3. The alternative to BART proposal was to control Boiler 1 at 91% and Boiler 2 and 3 at 90%, which still results in an overall improvement in visibility degradation. The actual modifications performed to the boilers were not extensive enough to trigger the 92% removal efficiency level requirements, as required in the re-construction criteria set forth in the NSPS for industrial boilers.

Comment:
The need to allow for increased sulfur content in coke above 3 percent has not been seen in previous BART determinations. Additional information about the need to use higher sulfur coke is needed. An analysis including cost comparisons and dollar per deciview comparisons between the proposed and alternative BART are needed as part of the five-factor analysis for the BART determination.

IDEM Response:
Sulfates are the main contributors, at approximately 0.188 dv. Contributions due to other species are less than 0.01 dv. Therefore, any add-on controls for these pollutants will result in insignificant improvements in visibility. Due to insignificant impact from vents (0.013 dv), Alcoa did not perform the 5-step analysis for these sources. Further, these sources are subject to 40 CFR 63, Subpart LL, Maximum Achievable Control Technology (MACT). In order to comply with these standards, Alcoa follows work practices which minimize emissions escaping roof vents.

Sulfur dioxide from potlines can be controlled by lowering sulfur content in the anode grade coke and/or by installing wet scrubbers. Alcoa presently limits sulfur at ≤ 2%. From a market study, Alcoa has concluded that a supply of coke below 3% sulfur cannot be ensured beyond 2013, the year when the BART controls will be needed. Therefore it proposes ≤ 3% sulfur coke as BART and ≤ 3.5% sulfur coke as alternative BART. The 3.5% sulfur limit in the coke translates into 2.919% sulfur in the baked anode composite, the practice Alcoa follows to measure the sulfur content.

The installed and annual costs of wet scrubbers on potlines are estimated at $300 million and $55 million respectively. Modeling shows that SO_2 scrubbers on potlines can improve visibility by 0.138 dv. This improvement will be achieved at a cost/benefit ratio equal to $398 million/dv. Also, there are severe space and access limitations at the facility that would complicate the installation.

Comment:
A five factor analysis is needed for the Alcoa facility to accurately determine if SNCR or SCR technology for NO_x control is feasible. Stating the costs and the assumption that these controls would not be cost effective without information, or data, to support the statement does not meet the needs, or intent, of a five factor analysis. Similar analysis is needed for PM controls on Boilers 2-4.

IDEM Response:
The NOx controls are significantly tighter than NSPS limits (0.38 lb/MMBtu vs. 0.70 lb/MMBtu), which are the "required" controls referenced. In regard to PM, Alcoa provided information regarding the cost of adding a baghouse on each unit, at IDEM's request.

Alcoa evaluated fabric filtration for Boiler 4 , the installation cost on a $ / dv basis was shown to be unreasonable. PM emissions from Boiler 4 would be higher than the BART level of control of 0.015 lb./mm Btu, which is the NSPS for a new utility boiler. However, the alternative to BART emission reductions provided by Boiler #1 offsets the PM emissions that would exceed the BART alone level from Boiler 4, and would therefore meet the regional haze rule requirements.

<u>Impact of Adding Baghouses for Units 2, 3, and 4</u>
Based on information provided by another utility where baghouse control was installed, the capital cost for a baghouse on a 2830 mm Btu/hr. boiler was $49.7 mm. Assuming baghouse capital costs are proportional to heat input, the capital cost for the baseline heat inputs for the BART eligible boilers is estimated to be:

Boiler 2: 1364.41 mm Btu/hr. Estimated baghouse capital cost would be

(1364.41/2830) X $49.7 mm = $23.96 mm

Boiler 3: 1323.51 mm Btu/hr. Estimated baghouse capital cost would be

(1323.51/2830) X $49.7 mm = $23.24 mm

Boiler 4: 2845.79 mm Btu/hr. Estimated baghouse capital cost would be

(2845.79/2830) X $49.7 mm = $49.98 mm

Airflow for boiler 2: 347,149 scfm

Airflow for boiler 3: 335,372 scfm

Airflow for boiler 4: 796,416 scfm

Assuming the lowest emission rate a baghouse vendor will guarantee is 0.005 grains /scf, filterable PM emissions would be:

Boiler 2: (0.005 grains/scf) X (347,149 scf/min) X (60 min. /hr.) X (1 lb. /7000 grains) = 14.88 lbs./hr.

Boiler 3: (0.005 grains/scf) X (335,149 scf/min) X (60 min. /hr.) X (1 lb. /7000 grains) = 14.36 lbs./hr.

Boiler 4: (0.005 grains/scf) X (796,416 scf/min) X (60 min. /hr.) X (1 lb. /7000 grains) = 34.13 lbs./hr.

On an annualized basis, the filterable PM emissions would be 128.07 tons from boilers 2 and 3 combined, and 149.49 tons/yr. from boiler 4.

Because the baghouses will be upstream of wet scrubbers, the assumed baghouse vendor guarantee emissions is conservative because it does not take into account the added filterable PM from the scrubbers.

BART for filterable PM for all 3 boilers was electrostatic precipitators and SO2 scrubbers.

BART was proposed at 0.03 lb./mm Btu for boilers 1 and 2, and 0.015 lb./mm Btu for boiler #4.

BART annual filterable PM emissions would thus be:

Boiler 2: (0.03 lb./mm Btu) X (1364.41 mm Btu/hr.) X (8760 hrs/yr.) X (1 ton/2000 lbs.) = 179.28 tons/yr.

Boiler 3: (0.03 lb./mm Btu) X (1323.51 mm Btu/hr.) X (8760 hrs/yr.) X (1 ton/2000 lbs.) = 173.91 tons/yr.

Boiler 4: (0.015 lb./mm Btu) X (2845.79 mm Btu/hr.) X (8760 hrs/yr.) X (1 ton/2000 lbs.) = 186.97 tons/yr.

Detailed engineering would have to take into consideration the available real estate for installation of baghouses, removal of the precipitators or routing the exhaust gases in series through the precipitators, baghouses then downstream pollution removal equipment, present boiler and pollution control equipment configurations, ash handling from the ash removed by the baghouses, etc. Those factors would increase the capital cost assumptions used above.

For the \$/ton and \$/dv improvement derived below, and the present prevailing economic conditions, Alcoa Power Generating Inc. – Warrick Power Plant does not understand the usefulness of performance of such a study.

Assuming an annualized cost of 11% of the assumed capital costs, the annualized cost on a \$/ton difference between the alternative to BART proposal and baghouses would be:
Boilers 2 and 3: 11% of \$47.2 mm = \$5,192,000 / yr.

BART emissions: 353.19 tons/yr.

Baghouse: 128.07 tons/yr.

Baghouse additional removal: (353.19 – 128.07) tons/yr. = 225.12 tons/yr.

\$ / ton impact: \$5,192,000 / 225.12 tons/yr. = \$23,063.26 / ton

Boiler 4: 11% of \$49.98 mm = \$5,497,800 / yr.

BART emissions: 186.97 tons/yr.

Baghouse: 149.49 tons/yr.

Baghouse additional removal: (186.97 – 149.49) tons/yr. = 37.48 tons/yr.

\$ / ton impact: \$5,497,800 / 37.48 tons/yr. = \$146,686.23 / ton

Baseline visibility impact, filterable PM, boilers 2 and 3: 0.027 dv, based on 2003 (See revised table 5-2 in the BART determination report).

The assumed baghouse outlet emissions would result in a filterable PM reduction of:

Baseline: 635.02 lbs/hr.

Baghouse: 63.37 lbs./hr.

Reduction: [(635.02 – 63.37)/635.02] X 100 = 90.02%

A reduction of 90.02% in the visibility impact would represent a dv impact reduction of:

0.027 dv X (90.02/100) = 0.024 dv

The annualized cost for baghouses on a \$/dv basis would thus be:

\$(5,192,000 + 5,497,800) / 0.024 dv = \$445 mm / dv

The above 11% of capital assumption does not consider such operating costs as increased pressure drop represented by the baghouse, possible de-rating of the boiler, and the baghouse being upstream of a wet scrubber. The above cost estimates are thus low, but still show that the extra cost represented by baghouses is unreasonable both from a \$/ton and \$/dv basis.

Long-term Strategy

Comment:
Necessary smoke management regulations and techniques for prescribed burning on National Forest land appear to be covered in IC 13-17-9 and 326 IAC 4-1 and the associated information in Appendix 6. However, it may be beneficial to formalize these regulations in an Indiana Smoke Management Plan/Program per EPA's Interim Air Quality Policy on Wildland and Prescribed Fires (April 23, 1998). The Forest Service will work with the State to help develop this SMP in the future.

We request that Indiana provide language in your SIP linking the Regional Haze and New Source Review programs, including continued FLM coordination for these programs. Currently, there is no mechanism in the SIP to ensure that the emissions from new stationary sources or major modifications of existing sources will make reasonable progress toward the national visibility goal (40 CFR 51.307). This could be especially important for emissions from new sources that were not anticipated in 2018 emission inventories. Please describe how new and expanded sources of air emissions will be reviewed to ensure they don't jeopardize reasonable progress goals set by Class I Areas owner states.

IDEM Response:
Please see the IDEM Response to National Parks Service Comments in Appendix A for IDEMs response regarding the Long Term Strategy comment related to linking the Regional Haze and New Source Review programs in the SIP and the mechanism in the SIP to ensure that the emissions from new stationary sources or major modifications of existing sources will make reasonable progress toward the national visibility goal (40 CFR 51.307).

This page intentionally left blank.

Appendix 10 - IDEM Responses to US Forest Service Comments Cover Letter

This page intentionally left blank.

USDA United States Department of Agriculture | Forest Service | Monongahela National Forest | 200 Sycamore Street
Elkins, WV 26241
304-636-1800

File Code: 2580
Date: December 22, 2010

Ken Ritter
Air Programs Branch
IDEM Office of Air Quality
100 North Senate Avenue
Indianapolis, IN 46204-2251

Dear Mr. Ritter,

On November 6, 2010 the State of Indiana submitted a draft State Implementation Plan (SIP) describing your proposal to improve regional haze impacts at mandatory Class I areas across your region. We appreciate the opportunity to work closely with your State through the initial evaluation, development, and now, subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I Wilderness areas.

The Forest Service provided informal comments on IDEM's BART analyses to Mark Derf on September 22, 2009 to which IDEM provided responses on February 9, 2010. We will not reiterate those comments again in this letter. This letter acknowledges that the U.S. Forest Service has received and conducted a substantive review of your proposed Regional Haze SIP including the Best Available Retrofit Technology (BART) designations. Please note that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the ability to approve the document. The Forest Service's participation in Indiana's administrative process does not waive any legal defenses or sovereignty rights it may have under the laws of the United States, including the Clean Air Act and its implementing regulations.

I have attached comments to this letter from the perspective of a Federal Land Manager. I look forward to your response required by 40 CFR 51.308(i)(3). For further information, please contact air resources management specialist Edward Huffman (elhuffman@fs.fed.us, (304) 636-1800 ext. 192).

Again, we appreciate the opportunity to work closely with the State of Indiana. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

/s/ Debra J. Tenney (for):
CLYDE N. THOMPSON
Forest Supervisor

cc: John Summerhays - R5 E

US Forest Service comments on the Indiana Regional Haze SIP (December 2010)

Our interest in the Indiana Regional Haze SIP is due to the fact that sources in your State cause or contribute to visibility impairment in many of our Class I Wilderness areas including the Boundary Waters Canoe Area Wilderness in Minnesota, Hercules Glades Wilderness Area in Missouri, Sipsey Wilderness Area in Alabama, Caney Creek Wilderness Area and Upper Buffalo Wilderness Area in Arkansas, Great Gulf Wilderness Area in New Hampshire, Lye Brook Wilderness Area in Vermont, James River Face Wilderness Area in Virginia, and Dolly Sods and Otter Creek Wilderness Areas in West Virginia.

BART analyses

RPO coordination

On page 35 the quote "The Uniform Rate is achieved and exceeded at all MANE-VU Class I sites" from "Recent MANE-VU Projections of Visbility for 2018." Do these projections include the latest predictions in emissions from Indiana sources? It appears that with some sources modeling out of being subject-to-BART the 2018 emissions from Indiana may be greater than what was predicted by MANE-VU in 2008. The possibility that the RPOs assumed greater emission reductions in their Class I area analysis (Section 7.0) are highlighted on page 69 (Section 9.2) – "The analyses show no reductions from Indiana sources, **beyond the BART rule**, are necessary to meet the reasonable progress goals of the areas analyzed at this time." (emphasis added). It is not clear what reductions from Indiana other States considered part of the BART rule and how these could differ from the reductions proposed in this Regional Haze SIP.

Cumulative Haze impacts

On page 49 – Table 15 - it appears that when considered cumulatively (the sum of modeled days over the 0.5 dv threshold for all the Class I areas modeled – 15 (Seney) + 6 (Mammoth Cave) + 4 (Mingo) + 4 (Isle Royale) = 29 days) Burns Harbor would still be subject to BART. As the facility impacts haze at so many Class I areas we feel Indiana should address the cumulative impact of the facility and consider ArcelorMittal Burns Harbor subject to BART

Please adjust permitted emissions to the highest actual emissions when there is a significant difference for facilities not subject to BART.

Page 53 – Table 18 is an example of our concern when revised modeling results in facilities no longer being considered subject to BART done by the three facilities (Burns Harbor, ESSROC and SABIC) in Indiana. When the "highest actual" emission rates are significantly lower than the "potential" emission rates and the lower rates are used as justification to avoid subject to BART designation, the lower rates need to be incorporated into a federally enforceable permit condition. The NO_x emissions for the highest emitting day and potential emissions in Table 18 are similar but the SO_2 differences are significant. Reduction in permitted, potential emissions to the actual highest emissions would ensure that the facility's (ESSROC) emissions remain consistent with the "not subject to BART" determination. Most importantly, it will ensure that the facility has a minimal impact on regional haze in Class I areas.

SABIC

We recommend that IDEM accepts the permit modification from SABIC to remove the oil burning provision from Part 70 Operating Permit. This will ensure long-term visibility improvements from this current status at the plant.

Alcoa

Emission reductions from Boiler 1, a not-subject-to-BART unit, could be achieved through Reasonable Progress as part of the Regional Haze Rule, and as such are not necessarily better than what would be achieved under the rule.

There is no apparent reason why the SO_2 controls on Boilers 2 and 3 cannot achieve 92 percent or greater efficiency with wet FGD. Please explain and justify the need to operate this control equipment at 90 percent. Include this as part of the five-factor analysis.

The need to allow for increased sulfur content in coke above 3 percent has not been seen in previous BART determinations. Additional information about the need to use higher sulfur coke is needed. An analysis including cost comparisons and dollar per deciview comparisons between the proposed and alternative BART are needed as part of the five-factor analysis for the BART determination.

A five factor analysis is needed for the Alcoa facility to accurately determine if SNCR or SCR technology for NO_x control is feasible. Stating the costs and the assumption that these controls would not be cost effective without information, or data, to support the statement does not meet the needs, or intent, of a five factor analysis. Similar analysis is needed for PM controls on Boilers 2-4.

Long-term Strategy

Necessary smoke management regulations and techniques for prescribed burning on National Forest land appear to be covered in IC 13-17-9 and 326 IAC 4-1 and the associated information in Appendix 6. However, it may be beneficial to formalize these regulations in an Indiana Smoke Management Plan/Program per EPA's Interim Air Quality Policy on Wildland and Prescribed Fires (April 23, 1998). The Forest Service will work with the State to help develop this SMP in the future.

We request that Indiana provide language in your SIP linking the Regional Haze and New Source Review programs, including continued FLM coordination for these programs. Currently, there is no mechanism in the SIP to ensure that the emissions from new stationary sources or major modifications of existing sources will make reasonable progress toward the national visibility goal (40 CFR 51.307). This could be especially important for emissions from new sources that were not anticipated in 2018 emission inventories. Please describe how new and expanded sources of air emissions will be reviewed to ensure they don't jeopardize reasonable progress goals set by Class I Areas owner states.

This page intentionally left blank.

Appendix 10a - SO_2 and NOx Credits for Projected Best Available Retrofit Technology

SO_2 CREDITS FOR PROJECTED BEST AVAILABLE RETROFIT TECHNOLOGY

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			SO_2	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected SO_2_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2
A B Brown Generating Station	1	250	Dual Alkali FGD	SCR+FGD	250	250		250	250		250	250		250	250		250	250		250	250
A B Brown Generating Station	2	250	Dual Alkali FGD	SCR+FGD	250	250		250	250		250	250		250	250		250	250		250	250
Alcoa Allowance Management Inc	1	144	Wet Limestone FGD (2008)	LNB w/SOFA	144			144			144			144			144			144	
Alcoa Allowance Management Inc	2	144	Wet Limestone FGD (2008)	LNB w/SOFA	144			144			144			144			144			144	
Alcoa Allowance Management Inc	3	144	Wet Limestone FGD (2008)	LNB w/SOFA	144			144			144			144			144			144	
Alcoa Allowance Management Inc	4	300	Wet Limestone FGD (2008)	SCR	300			300		FGD	300	300	FGD	300	300	FGD	300	300	FGD	300	300
Bailly Generating Station	7	160	Wet Limestone	SCR+FGD	160	160		160	160		160	160		160	160		160	160		160	160
Bailly Generating Station	8	320	Wet Limestone	SCR+FGD	320	320		320	320		320	320		320	320		320	320		320	320
Cayuga*	1	500	Wet Limestone (2008 - 95%)	FGD+LNB w/SOFA	500	500		500	500	SCR	500	500	SCR	500	500	SCR	500	500	SCR	500	500
Cayuga*	2	495	Wet Limestone (2008 - 95%)	FGD+LNB w/SOFA	495	495		495	495	SCR	495	495	SCR	495	495	SCR	495	495	SCR	495	495
Clifty Creek*	1	217	(FGD Scheduled after 2014)	FGD+SCR		217			217		217	217		217	217					217	
Clifty Creek*	2	217	(FGD Scheduled after 2014)	FGD+SCR		217			217		217	217		217	217					217	
Clifty Creek*	3	217	(FGD Scheduled after 2014)	FGD+SCR		217			217		217	217		217	217					217	
Clifty Creek*	4	217	(FGD Scheduled after 2014)	FGD+SCR		217			217		217	217		217	217					217	
Clifty Creek*	5	217	(FGD Scheduled after 2014)	FGD+SCR		217			217		217	217		217	217					217	
Clifty Creek*	6	217	(FGD Scheduled after 2014)	FGD		217	SCR		217	SCR	217	217	SCR	217	217	SCR			SCR	217	
Dean H Mitchell Generating Station	11	125	Shut Down	LNB	125			125			125			125			125			125	
Dean H Mitchell Generating Station	4	125	Shut Down	Comb. Optimization	125			125			125		SCR	125			125		SCR	125	
Dean H Mitchell Generating Station	5	125	Shut Down	Comb. Optimization	125			125			125		SCR	125			125		SCR	125	
Dean H Mitchell Generating Station	6	110	Shut Down	LNB	110			110			110		SCR	110			110		SCR	110	
Edwardsport	7-1	40	Unit will retire in 2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			SO_2	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected SO_2_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2
Edwardsport	7-2	40	Unit will retire in 2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		
Edwardsport	8-1	40	Unit will retire in 2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		
F B Culley Generating Station	2	90	Wet Limestone	FGD+LNB	90	90		90	90		90	90	SNCR	90	90		90	90	SNCR	90	90
F B Culley Generating Station	3	270	Wet Limestone	FGD+SCR	270	270		270	270		270	270		270	270		270	270		270	270
Frank E Ratts	1SG1	122	U.S. EPA settlement, plant-wide from 2009 levels 42% reduction - 2012, 58% - 2014	LNB							122		SCR	122			122		SCR	122	
Frank E Ratts	2SG1	121	U.S. EPA settlement, plant-wide from 2009 levels 42% reduction - 2012, 58% - 2014	LNB									SCR						SCR		
Gibson*	1	630	Wet Limestone	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	2	630	Wet Limestone	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	3	630	Wet Limestone	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	4	622	Wet Limestone	SCR+FGD	622	622		622	622		622	622		622	622		622	622		622	622
Gibson	5	620	Wet Limestone	SCR+FGD	620	620		620	620		620	620		620	620		620	620		620	620
Harding Street Station (EW Stout)	50	109		SNCR																	
Harding Street Station (EW Stout)	60	109		SNCR																	
Harding Street Station (EW Stout)*	70	435	Wet Limestone	SCR	435		FGD	435	435	FGD	435	435	FGD	435	435	FGD	435	435	FGD	435	435
IPL Eagle Valley Generating Station	3	43																			

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			SO_2	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
				IPM Existing	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected SO_2_CONTROL		SO_2	SO_2		SO_2	SO_2		SO_2	SO_2		SO_2	SO_2		SO_2	SO_2		SO_2	SO_2
IPL Eagle Valley Generating Station	4	56		LNB w/SOFA																	
IPL Eagle Valley Generating Station	5	62		LNB w/SOFA																	
IPL Eagle Valley Generating Station	6	99		LNB w/SOFA																	
Merom	1SG1	507	upgrade FGD-90% 2012, upgrade to 95% 2014	SCR+FGD	507	507		507	507		507	507		507	507		507	507		507	507
Merom	2SG1	493	upgrade FGD-90% 2012, upgrade to 95% 2014	SCR+FGD	493	493		493	493		493	493		493	493		493	493		493	493
Michigan City Generating Station	12	469		SCR									Hg Control						Hg Control		
Petersburg	1	232	Wet Limestone	FGD+LNB	232	232		232	232		232	232	SCR	232	232		232	232	SCR	232	232
Petersburg	2	407	Wet Limestone	FGD+SCR	407	407		407	407		407	407		407	407		407	407		407	407
Petersburg	3	510	Wet Limestone	FGD+SCR	510	510		510	510		510	510		510	510		510	510		510	510
Petersburg	4	545	Wet Limestone	FGD+LNB	545	545		545	545	SCR	545	545	SCR	545	545		545	545	SCR	545	545
R Gallagher*	1	140	Shut down by 2/1/12 or Convert to NG 1/1/13	LNB							140			140			140			140	
R Gallagher*	2	140	Dry Sorbent Technology 1/1/11	LNB							140			140			140			140	
R Gallagher*	3	140	Shut down by 2/1/12 or Convert to NG 1/1/13	LNB							140			140			140			140	
R Gallagher*	4	140	Dry Sorbent Technology 1/1/11	LNB																	
R M Schahfer Generating Station	14	431		SCR							431		Hg Control	431					Hg Control	431	
R M Schahfer Generating Station	15	472		LNB									Hg Control	472					Hg Control	472	

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			SO_2	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected SO_2_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2
R M Schahfer Generating Station	17	361	Wet Limestone	SCR	361		FGD+LNB	361	361	FGD+LNB	361	361	FGD+LNB	361	361		361			361	
R M Schahfer Generating Station	18	361	Wet Limestone	LNB	361		FGD+LNB	361	361	FGD+LNB	361	361	FGD+LNB	361	361		361			361	
Rockport*	MB1	1300	FGD 12/31/17 TR allowances < CAIR 2012 and 2014	LNB w/OFA			FGD		1300	FGD		1300	FGD+SCR	1300	1300	FGD		1300	FGD+SCR	1300	1300
Rockport*	MB2	1300	FGD 12/31/17 TR allowances < CAIR 2012 and 2014	LNB w/OFA			FGD		1300	FGD		1300	FGD+SCR	1300	1300	FGD		1300	FGD+SCR	1300	1300
State Line Generating Station (IN)	3	187																			
State Line Generating Station (IN)	4	303					SCR			SCR			SCR+Hg Control			SCR			SCR (-Hg Control)		
Tanners Creek*	U1	140	Burn only coal with no more than 1.2 lb/MMBtu annual average	OFA																	
Tanners Creek*	U2	140	Burn only coal with no more than 1.2 lb/MMBtu annual average	OFA																	
Tanners Creek*	U3	200	Burn only coal with no more than 1.2 lb/MMBtu annual average	OFA									FGD+SCR		140				FGD+SCR		140
Tanners Creek*	U4	500	Burn only coal with no more than 1.2% sulfur content annual average	OFA																	
Wabash River Gen Station*	1	85	IGCC																		
Wabash River Gen Station*	2	85	Shut Down 9-30-09	LNB	85			85													
Wabash River Gen Station*	3	85	Shut Down 9-30-09	LNB	85			85					SNCR						SNCR		
Wabash River Gen Station*	4	85		LNB																	
Wabash River Gen Station*	5	95	Shut Down 9-30-09	LNB	95			95					SNCR						SNCR		
Wabash River Gen Station*	6	318	TR allocation in 2014 < CAIR	LNB									FGD+SCR		318				FGD+SCR		318

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			SO_2	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected SO_2_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe SO_2	EPA Credit for Control(s) in MWe SO_2	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe SO_2	LADCO Credit for Control(s) in MWe SO_2
Whitewater Valley	1	34.77		LNB																	
Whitewater Valley	2	62.8	Other	LNB																	
					10,800	9,463		10,800	13,220		12,810	13,520		15,882	13,978		11,077	11,496		15,882	11,954
					IDEM Base Case	EPA Basecase		IDEM 2010	EPA 2010		IDEM 2015	EPA 2015		IDEM 2020	EPA 2020		IDEM 2012	LADCO 2012		IDEM 2018	LADCO 2018

NO_X CREDITS FOR PROJECTED BEST AVAILABLE RETROFIT TECHNOLOGY

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			NOx	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected NO_x_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x
A B Brown Generating Station	1	250	Selective Catalytic Reduction	SCR+FGD	250	250		250	250		250	250		250	250		250	250		250	250
A B Brown Generating Station	2	250	Selective Catalytic Reduction	SCR+FGD	250	250		250	250		250	250		250	250		250	250		250	250
Alcoa Allowance Management Inc	1	144	Low NO_x Burner Technology w/ Overfire Air	LNB w/SOFA	144	144		144	144		144	144		144	144		144	144		144	144
Alcoa Allowance Management Inc	2	144	Low NO_x Burner Technology w/ Overfire Air	LNB w/SOFA	144	144		144	144		144	144		144	144		144	144		144	144
Alcoa Allowance Management Inc	3	144	Low NO_x Burner Technology w/ Overfire Air	LNB w/SOFA	144	144		144	144		144	144		144	144		144	144		144	144
Alcoa Allowance Management Inc	4	300	Low NO_x Burner Selective Catalytic Reduction	SCR	300	300		300	300	FGD	300	300	FGD	300	300	FGD	300	300	FGD	300	300
Bailly Generating Station	7	160	Overfire Air / Selective Catalytic Reduction (2008)	SCR+FGD	160	160		160	160		160	160		160	160		160	160		160	160
Bailly Generating Station	8	320	Overfire Air / Selective Catalytic Reduction	SCR+FGD	320	320		320	320		320	320		320	320		320	320		320	320
Cayuga*	1	500	Low NO_x Burner Technology w/ Separated OFA	FGD+LNB w/SOFA						SCR		500	SCR		500	SCR		500	SCR		500
Cayuga*	2	495	Low NO_x Burner Technology w/ Separated OFA	FGD+LNB w/SOFA						SCR		495	SCR		495	SCR		495	SCR		495
Clifty Creek*	1	217	Overfire Air Selective Catalytic Reduction	FGD+SCR	217	217		217	217		217	217		217	217		217	217		217	217
Clifty Creek*	2	217	Overfire Air Selective Catalytic Reduction	FGD+SCR	217	217		217	217		217	217		217	217		217	217		217	217
Clifty Creek*	3	217	Overfire Air Selective Catalytic Reduction	FGD+SCR	217	217		217	217		217	217		217	217		217	217		217	217
Clifty Creek*	4	217	Overfire Air Selective Catalytic Reduction	FGD+SCR	217	217		217	217		217	217		217	217		217	217		217	217
Clifty Creek*	5	217	Overfire Air Selective Catalytic Reduction	FGD+SCR	217	217		217	217		217	217		217	217		217	217		217	217
Clifty Creek*	6	217	Overfire Air	FGD			SCR		217	SCR		217	SCR		217	SCR		217	SCR		217
Dean H Mitchell Generating Station	11	125	Shut Down	LNB	125			125			125			125			125			125	
Dean H Mitchell Generating Station	4	125	Shut Down	Comb. Optimization	125			125			125		SCR	125			125		SCR	125	
Dean H Mitchell Generating Station	5	125	Shut Down	Comb. Optimization	125			125			125		SCR	125			125		SCR	125	
Dean H Mitchell Generating Station	6	110	Shut Down	LNB	110			110			110		SCR	110			110		SCR	110	
Edwardsport	7-1	40	2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			NO_x	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected NO_x_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x
Edwardsport	7-2	40	2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		
Edwardsport	8-1	40	2012, IGCC will replace all the units in 2012				Retire			Retire			Retire			Retire			Retire		
F B Culley Generating Station	2	90	Low NO_x Burner Technology (Dry Bottom only)	FGD+LNB	90	90		90	90		90	90	SNCR	90	90		90	90	SNCR	90	90
F B Culley Generating Station	3	270	Low NO_x Burner Technology (Dry Bottom only) Selective Catalytic Reduction	FGD+SCR	270	270		270	270		270	270		270	270		270	270		270	270
Frank E Ratts	1SG1	122	Low NO_x Burner Technology (Dry Bottom only) OFA-2008	LNB							122		SCR	122	122		122		SCR	122	122
Frank E Ratts	2SG1	121	Low NO_x Burner Technology (Dry Bottom only) OFA-2008	LNB									SCR		121				SCR		121
Gibson*	1	630	LNB w/ Overfire Air Selective Catalytic Reduction	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	2	630	Low NO_x Burner Technology w/ Overfire Air Selective Catalytic Reduction	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	3	630	Low NO_x Burner Technology w/ Overfire Air Selective Catalytic Reduction	SCR+FGD	630	630		630	630		630	630		630	630		630	630		630	630
Gibson*	4	622	Low NO_x Burner Technology w/ Overfire Air Selective Catalytic Reduction	SCR+FGD	622	622		622	622		622	622		622	622		622	622		622	622
Gibson	5	620	Low NO_x Burner Technology w/ Overfire Air Selective Catalytic Reduction	SCR+FGD	620	620		620	620		620	620		620	620		620	620		620	620
Harding Street Station (EW Stout)	50	109	LNB w/ Separated OFA Selective Non-catalytic Reduction	SNCR	109	109		109	109		109	109		109	109		109	109		109	109
Harding Street Station (EW Stout)	60	109	LNB w/ Separated OFA Selective Non-catalytic Reduction	SNCR	109	109		109	109		109	109		109	109		109	109		109	109
Harding Street Station (EW Stout)*	70	435	LNB w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	SCR	435	435	FGD	435	435	FGD	435	435	FGD	435	435	FGD	435	435	FGD	435	435
IPL Eagle Valley Generating Station	3	43																			

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			NOx	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
				IPM Existing	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected NO_x_CONTROL		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x
IPL Eagle Valley Generating Station	4	56	Low NOx Burner Technology w/ Separated OFA	LNB w/SOFA	56	56		56	56		56	56		56	56		56	56		56	56
IPL Eagle Valley Generating Station	5	62	Low NOx Burner Technology w/ Separated OFA	LNB w/SOFA	62	62		62	62		62	62		62	62		62	62		62	62
IPL Eagle Valley Generating Station	6	99	Low NOx Burner Technology w/ Separated OFA	LNB w/SOFA	99	99		99	99		99	99		99	99		99	99		99	99
Merom	1SG1	507	Selective Catalytic Reduction Low Nox Burner Technology w/ Overfire Air	SCR+FGD	507	507		507	507		507	507		507	507		507	507		507	507
Merom	2SG1	493	Selective Catalytic Reduction Low NO_x Burner Technology w/ Overfire Air		493			493			493			493			493			493	
Michigan City Generating Station	12	469	Selective Catalytic Reduction	SCR	469	469		469	469		469	469	Hg Control	469	469		469	469	Hg Control	469	469
Petersburg	1	232	Low NO_x Burner Technology w/ Closed-coupled/Sep. OFA	FGD+LNB									SCR		232				SCR		232
Petersburg	2	407	LNB w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	FGD+SCR	407	407		407	407		407	407		407	407		407	407		407	407
Petersburg	3	510	LNB w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	FGD+SCR	510	510		510	510		510	510		510	510		510	510		510	510
Petersburg	4	545	Low NO_x Burner Technology w/ Closed-coupled/Sep. OFA	FGD+LNB						SCR		545	SCR		545				SCR		545
R Gallagher*	1	140	Shut down by 2/1/12 or Convert to NG 1/1/13	LNB	140	140		140	140		140			140			140			140	
R Gallagher*	2	140	Low NO_x Burner Technology w/ Overfire Air	LNB	140	140		140	140		140	140		140	140		140	140		140	140
R Gallagher*	3	140	Shut down by 2/1/12 or Convert to NG 1/1/13	LNB	140	140		140	140		140			140			140			140	
R Gallagher*	4	140	Low NO_x Burner Technology w/ Overfire Air	LNB	140	140		140	140		140	140		140	140		140	140		140	140
R M Schahfer Generating Station	14	431	Overfire Air Selective Catalytic Reduction	SCR	431	431		431	431		431	431	Hg Control	431	431		431	431	Hg Control	431	431
R M Schahfer Generating Station	15	472	LNB (Dry Bottom only) A 35% efficient stratified overfire air system was added in 2008	LNB	472	472		472	472		472		Hg Control	472			472		Hg Control	472	

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			NOx	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected NO_x_CONTROL	IPM Existing	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe NO_x	EPA Credit for Control(s) in MWe NO_x	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe NO_x	LADCO Credit for Control(s) in MWe NO_x
R M Schahfer Generating Station	17	361	LNB w/ Closed-coupled/Separated	SCR	361	361	FGD+LNB	361	361	FGD+LNB	361	361	FGD+LNB	361	361		361	361		361	361
R M Schahfer Generating Station	18	361	LNB w/ Closed-coupled/Separated	LNB	361	361	FGD+LNB	361	361	FGD+LNB	361	361	FGD+LNB	361	361		361	361		361	361
Rockport*	MB1	1300	LNB (Dry Bottom only) (SCR 12/31/17)	LNB w/OFA			FGD			FGD			FGD+SCR	1300	1300	FGD			FGD+SCR	1300	1300
Rockport*	MB2	1300	Technology (Dry Bottom only) (SCR 12/31/19)	LNB w/OFA			FGD			FGD			FGD+SCR	1300	1300	FGD			FGD+SCR	1300	1300
State Line Generating Station (IN)	3	187																			
State Line Generating Station (IN)	4	303	Overfire Air		303		SCR	303		SCR	303		SCR+Hg Control	303		SCR	303		SCR (-Hg Control)	303	
Tanners Creek*	U1	140	Low NO_x Burner Technology (Dry Bottom only) A 30% efficient SNCR will be in place in 2010. SNCR will operate year round	OFA	140			140			140			140			140			140	
Tanners Creek*	U2	140	Low NO_x Burner Technology (Dry Bottom only) A 30% efficient SNCR will be in place in 2010. SNCR will operate year round	OFA																	
Tanners Creek*	U3	200	Low NO_x Burner Technology (Dry Bottom only) A 30% efficient SNCR will be in place in 2010. SNCR will operate year round	OFA	140			140			140		FGD+SCR	140	140		140		FGD+SCR	140	140
Tanners Creek*	U4	500	Overfire Air	OFA																	
Wabash River Gen Station*	1	85	IGCC																		
Wabash River Gen Station*	2	85	Shut Down 9-30-09	LNB																	
Wabash River Gen Station*	3	85	Shut Down 9-30-09	LNB									SNCR						SNCR		
Wabash River Gen Station*	4	85	Low NO_x Burner Technology w/ Overfire Air	LNB	85	85		85	85		85	85		85	85		85	85		85	85
Wabash River Gen Station*	5	95	Shut Down 9-30-09	LNB									SNCR						SNCR		
Wabash River Gen Station*	6	318	Low NO_x Burner Technology w/ Separated OFA	LNB									FGD+SCR		318				FGD+SCR		318

INDIANA COAL-FIRED UNITS				EPA IPM 3.0 2006 runs												LADCO Round 5 Runs					
BART-eligible Units *MANEVU Ask			NOx	2009 + Projected Compared to IPM Existing			2009 + Projected Compared to IPM 2010 Retrofit			2009 + Projected Compared to IPM Retrofit 2015			2009 + Projected Compared to IPM 2020 Retrofit			2009 + Projected Compared to LADCO 2012 Retrofit			2009 + Projected Compared to LADCO 2018 Retrofit		
				IPM Existing	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2010 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2015 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	IPM 2020 Retrofit	IDEM Credit for Control(s) in MWe	EPA Credit for Control(s) in MWe	LADCO 2012 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe	LADCO 2018 Retrofit	IDEM Credit for Control(s) in MWe	LADCO Credit for Control(s) in MWe
FACILITY_NAME	UNIT ID	Capacity MWe	2009 + Projected NO_x_CONTROL		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x		NO_x	NO_x
Whitewater Valley	1	34.77	Low NO_x Burner Technology w/ Separated OFA Ammonia Injection Overfire Air	LNB	34.77	34.77		34.77	34.77		34.77	34.77		34.77	34.77		34.77	34.77		34.77	34.77
Whitewater Valley	2	62.8	Low NO_x Burner Technology w/ Separated OFA Ammonia Injection Overfire Air	LNB	62.8	62.8		62.8	62.8		62.8	62.8		62.8	62.8		62.8	62.8		62.8	62.8
					12,981	**11,420**		**12,981**	**11,637**		**13,103**	**12,425**		**15,703**	**15,958**		**13,103**	**11,880**		**15,703**	**15,958**
					IDEM Base Case	**EPA Basecase**		**IDEM 2010**	**EPA 2010**		**IDEM 2015**	**EPA 2015**		**IDEM 2020**	**EPA 2020**		**IDEM 2012**	**LADCO 2012**		**IDEM 2018**	**LADCO 2018**

Appendix 10b - BART Analyses Cumulative Haze Impacts E-mails

This page intentionally left blank.

BART Analyses - Cumulative Haze Impacts

Below is a summary of responses to the question of using cumulative or individual Class 1 area days above the BART threshold for BART determinations. Respondents included representatives from EPA Region 5, EPA Headquarters and from the states of Ohio, Michigan, Wisconsin and Minnesota. All states appear to favor the approach of summing up days for each individual Class 1 area instead of counting all modeled receptors at all the Class 1 areas modeled. States desire a constant approach to this

---

EPA Region 5 and EPA Headquarter Responses

Hello Mark, Sept. 5, 2008

Just FYI. I had some discussions with Wisconsin last week about the single vs multiple Class I area determination question you asked back in June. I forwarded to them the communications I had sent to you, attached below. We further had some conversations with Tim Allen with the FWS and he stated that he's not seen the guidance interpreted that way. In the work he's seen, analysis done for Subject to BART has been single Class I area only. However, for BART determination work, they are advising a multiple Class I area analysis. I don't see the logic in that but that's what being done apparently. Of course, the bottom line on this is that States can be as conservative as they feel is needed. Maybe with the 0.5 dv threshold, additional conservatism is warranted.

I don't know if this will have any impact on your work but wanted to share it with you.

Randy.

P.S. Guess we'll see you on the 11th regarding Alcoa. We should probably talk briefly before the meeting.

Randy Robinson
USEPA Region 5
312 353-6713

06/17/2008 12:45 PM

To: "DERF, MARK" MDERF@idem.IN.gov
Randall Robinson/R5/USEPA/US@EPA
Cc:

Subject RE: Re: Fw: BART question

Very helpful. Thanks for passing along to Todd and getting back to me so quick. Enjoy the rest of your week off. Take care.

From: Robinson.Randall@epamail.epa.gov
[mailto:Robinson.Randall@epamail.epa.gov]
Sent: Tuesday, June 17, 2008 1:40 PM
To: DERF, MARK
Subject: Fw: Re: Fw: BART question

Hi Mark,

I'm out this week but am trying to keep up with emails. I sent an email to Todd Hawes last week with your question. Below is his reply. The BART guidelines may provide additional support. I've retouched base with Todd regarding your latest email.

Randy

Randy Robinson
USEPA Region 5
312 353-6713

-----Forwarded by Randall Robinson/R5/USEPA/US on 06/17/2008 12:39PM

To: Randall Robinson/R5/USEPA/US@EPA
From: Todd Hawes/RTP/USEPA/US
Date: 06/12/2008 12:20PM
Subject: Re: Fw: BART question

As I recall, the protocol recommended the methodology described below in Mark's email in order to be conservative. That is entirely up to the state, so we would be fine with summing up the days. In addition to the Q&A, the BART Guidelines do provide some support for modeling multiple Class I areas (70 FR 39126, also see footnote 36). The Q&A, if I remember correctly, was advising to look at ALL receptors modeled, so if there are receptors on more than one Class I area, you would throw out the highest 7 days from the entire universe of receptors. Even if there is double counting, it is up to the state to determine if it wants to use that level of conservatism. We did not specify a position on double counting. I hope this is helpful.
Randall Robinson/R5/USEPA/US

-----Forwarded by Randall Robinson/R5/USEPA/US on 06/11/2008 7:27PM

To: Todd Hawes/RTP/USEPA/US
From: Randall Robinson/R5/USEPA/US@EPA
Date: 06/12/2008 12:20PM
Subject: Fw: BART question

Hello Todd,

I'm out of the office this week and next but wanted to get some information to Indiana. I haven't looked at the guidance in a while but my recollection is the characterization they provide below is correct. That is, you sum the days, for impacts at any Class I area. Is that correct? If so, I guess their approach would be conservative if they are doublecounting days. Lastly, is there any other guidance, beyond the Q and A to send to them.

Thanks for your help.

Randy
Randy Robinson
USEPA Region 5
312 353-6713

-----Forwarded by Randall Robinson/R5/USEPA/US on 06/11/2008 05:22PM
To: Randall Robinson/R5/USEPA/US@EPA
From: "DERF, MARK" <MDERF@idem.IN.gov>
Date: 06/10/2008 12:05PM
Subject: BART question

Need a quick clarification for our BART modeling. Using the MRPO BART modeling protocol and determining the output from Kirk Baker's software, Indiana has determined whether sources are subject to BART by adding the number of days for all the 16 Class 1 areas modeled for each year and comparing the 98th percentile. This approach has come under scrutiny from one of our BART sources. They are viewing their results in a slightly different way. They are only looking at the nearest Class 1 area and basing their results on that area only. For instance, they have 6 days over 0.5 DV at Mammoth Cave and 3 days over 0.5 DV at Mingo in 2003 but are only counting the 6 days at Mammoth Cave. I contacted them and said that I wanted additional information to show the days that the high days occurred at Mammoth and Mingo to determine if there were 9 different days over 0.5 DV for both Class 1 areas which would make them subject to BART or if there was double counting where impacts were over 0.5 DV at both Class 1 areas for the same day.

We had emailed each other about a similar situation on Dec 15, 2005 and Nov. 29, 2006. Your December email provided a Q & A Part 1 document with reference to this question. I wanted to provide this document to the source (or updated guidance if available). As the guidance reads in Question/Response #24, the highest modeled delta-DV for each day should be used for all modeled receptors, regardless of location. The modeled receptors represent those in all the Class 1 areas.

Is this your understanding of the guidance? I guess IN's approach is a little conservative in that some days could be over 0.5 DV for more than one Class 1 area and we would count them more than once towards the determination of subject to BART. It looks like if the source considers the highest delta-DV from all modeled receptors for each day, that meets guidance for BART.

Let me know if you need me to explain better. Thanks.

Mark Derf
Office of Air Quality
Indiana Department of Environmental Management Indianapolis, IN 46206
Phone: 317 233-6870
Fax: 317 233-2342
mderf@idem.in.gov

Mark
We have interpreted the federal regulation as each Class I Area. Thus, the count starts over at each Class I area. In your case, we would have counted Class I area "A" as 6 and Class I area "B" as 3. BWCA and VOYA (in Minnesota) are adjacent to one another and we still interpreted it this way (although the end-result would not change were we to use your approach). I've never before heard of a State using a compilation of all receptors at all Class I areas to make a subject-to-BART determination, so this is a new concept to me.
Margaret

-----Original Message-----
From: DERF, MARK [mailto:MDERF@idem.IN.gov]
Sent: Thursday, June 19, 2008 1:28 PM
To: Abigail Fontaine; James G Haywood; Matthew Johnson; Michael A Majewski; Scott Leopold; McCourtney, Margaret; dana.thompson@epa.state.oh.us; Sarah.Vanderwielen@epa.state.oh.us; Carolina.Prado@epa.state.oh.us; david.brown@dnr.iowa.gov
Subject: BART question

Indiana has received three separate BART exemption modeling analysis. One source had conducted a more refined analysis at 4 km using the VISTAS protocol. The issue is the results showed that there were 6 days modeled over 0.5 DV at the nearest Class I area and 3 additional days over 0.5 DV at the next closest Class I area. Both areas are within 300 kms of the source. The source is arguing that since this is a refined analysis, the only results that matter are those at the most affected (closest) Class I area. Indiana has summed all modeled Class I receptors with impacts over 0.5 DV to make subject to BART determinations, based on Kirk's CALPOST output files. In that case, the source would have 9 days over 0.5 DV for one year. The source says that it should only be 6 days over.

Randy Robinson and Todd Hawes have replied with references to 70 FR39126 and also footnote 36. I haven't found any specific citation in the BART modeling guidelines and Appendix Y that directly address this issue so I wanted to get other opinions or see if anyone else had run up against this issue. The source points out that in accepted modeling protocols in other states, there is language that mentioned a given Class I area or the relevant Class I area. I tend to think that for exemption modeling, if a source is trying to demonstrate they are not subject to BART, the threshold should include all modeled receptors below the 98th percentile of 0.5 DV.

If anyone has any thoughts, I would appreciate it. Thanks.

Mark Derf
Office of Air Quality
Indiana Department of Environmental Management
Indianapolis, IN 46206
Phone: 317 233-6870
Fax: 317 233-2342
mderf@idem.in.gov

Ohio's Response **June 23, 2008**

Mark:

It has been Ohio's understanding, for at least the last couple of years, that what governs is the number of days above threshold at any single Class I area. The aggregate of all the days at all the downwind Class I areas has nothing to do with anything. Two or three years ago, Kirk provided an analysis that seemed to indicate the aggregate over multiple areas was, in fact, pertinent. To me, and I think to Bill, that was a totally outlandish interpretation. After we got the question clarified and resolved, I'm sure we decided that only the most-impacted single area governs.

-- Dana

>>> "DERF, MARK" <MDERF@idem.IN.gov> 6/19/2008 2:28 pm >>>
Indiana has received three separate BART exemption modeling analysis.
One source had conducted a more refined analysis at 4 km using the VISTAS protocol. The issue is the results showed that there were 6 days modeled over 0.5 DV at the nearest Class I area and 3 additional days over 0.5 DV at the next closest Class I area. Both areas are within 300 kms of the source. The source is arguing that since this is a refined analysis, the only results that matter are those at the most affected
(closest) Class I area. Indiana has summed all modeled Class I receptors with impacts over 0.5 DV to make subject to BART determinations, based on Kirk's CALPOST output files. In that case, the source would have 9 days over 0.5 DV for one year. The source says that it should only be 6 days over.

Randy Robinson and Todd Hawes have replied with references to 70 FR
39126 and also footnote 36. I haven't found any specific citation in the BART modeling guidelines and Appendix Y that directly address this issue so I wanted to get other opinions or see if anyone else had run up against this issue. The source points out that in accepted modeling protocols in other states, there is language that mentioned a given Class I area or the relevant Class I area. I tend to think that for exemption modeling, if a source is trying to demonstrate they are not subject to BART, the threshold should include all modeled receptors below the 98th percentile of 0.5 DV.

If anyone has any thoughts, I would appreciate it. Thanks.

Mark Derf
Office of Air Quality
Indiana Department of Environmental Management Indianapolis, IN 46206
Phone: 317 233-6870
Fax: 317 233-2342
mderf@idem.in.gov

We get people trying to color outside the box, too, on BART issues. We have little guidance to go on, so I'll be interested to hear what you determine...

Jim Haywood
Senior Meteorologist
Michigan Department of Environmental Quality
Phone: (517) 241-7478
Fax: (517) 335-3122
E-mail: HaywoodJ@michigan.gov

>>> "DERF, MARK" <MDERF@idem.IN.gov> 06/19/2008 2:28:17 PM >>>
Indiana has received three separate BART exemption modeling analysis.
One source had conducted a more refined analysis at 4 km using the VISTAS protocol. The issue is the results showed that there were 6 days modeled over 0.5 DV at the nearest Class I area and 3 additional days over 0.5 DV at the next closest Class I area. Both areas are within 300 kms of the source. The source is arguing that since this is a refined analysis, the only results that matter are those at the most affected
(closest) Class I area. Indiana has summed all modeled Class I receptors with impacts over 0.5 DV to make subject to BART determinations, based on Kirk's CALPOST output files. In that case, the source would have 9 days over 0.5 DV for one year. The source says that it should only be 6 days over.

Randy Robinson and Todd Hawes have replied with references to 70 FR
39126 and also footnote 36. I haven't found any specific citation in the BART modeling guidelines and Appendix Y that directly address this issue so I wanted to get other opinions or see if anyone else had run up against this issue. The source points out that in accepted modeling protocols in other states, there is language that mentioned a given Class I area or the relevant Class I area. I tend to think that for exemption modeling, if a source is trying to demonstrate they are not subject to BART, the threshold should include all modeled receptors below the 98th percentile of 0.5 DV.

If anyone has any thoughts, I would appreciate it. Thanks.

Mark Derf
Office of Air Quality
Indiana Department of Environmental Management Indianapolis, IN 46206
Phone: 317 233-6870
Fax: 317 233-2342
mderf@idem.in.gov

Wisconsin's Response **June 19, 2008**

Hi Mark...

Just a thought, are you basing your results on the CALPUFF 36 km runs? If the source is using the 4 km met data they get to compare their results to the annual average and not the 20% "worst days" we have to use.

Mike

From: DERF, MARK [mailto:MDERF@idem.IN.gov]
Sent: Thu 6/19/2008 1:28 PM
To: Abigail Fontaine; James G Haywood; Matthew Johnson; Majewski, Michael A - DNR; Scott Leopold; Margaret McCourtney; dana.thompson@epa.state.oh.us; Sarah.Vanderwielen@epa.state.oh.us; Carolina.Prado@epa.state.oh.us; david.brown@dnr.iowa.gov
Subject: BART question

Indiana has received three separate BART exemption modeling analysis. One source had conducted a more refined analysis at 4 km using the VISTAS protocol. The issue is the results showed that there were 6 days modeled over 0.5 DV at the nearest Class I area and 3 additional days over 0.5 DV at the next closest Class I area. Both areas are within 300 kms of the source. The source is arguing that since this is a refined analysis, the only results that matter are those at the most affected(closest) Class I area. Indiana has summed all modeled Class I receptors with impacts over 0.5 DV to make subject to BART determinations, based on Kirk's CALPOST output files. In that case, the source would have 9 days over 0.5 DV for one year. The source says that it should only be 6 days over.

Randy Robinson and Todd Hawes have replied with references to 70 FR 39126 and also footnote 36. I haven't found any specific citation in the BART modeling guidelines and Appendix Y that directly address this issue so I wanted to get other opinions or see if anyone else had run up against this issue. The source points out that in accepted modeling protocols in other states, there is language that mentioned a given Class I area or the relevant Class I area. I tend to think that for exemption modeling, if a source is trying to demonstrate they are not subject to BART, the threshold should include all modeled receptors below the 98th percentile of 0.5 DV.

If anyone has any thoughts, I would appreciate it. Thanks.

Mark Derf
Office of Air Quality
Indiana Department of Environmental Management
Indianapolis, IN 46206
Phone: 317 233-6870
Fax: 317 233-2342
mderf@idem.in.gov