Technical Determination of Reasonably Available Control Technology for the Control of Direct Fine Particles, Sulfur Dioxide and Oxides of Nitrogen in the Missouri Portion of the St. Louis PM2.5 Nonattainment Area.

1. $PM_{2.5}$ History & Background

1.1 $PM_{2.5}$ Standard and Designations

On July 18, 1997, the U.S. Environmental Protection Agency (EPA) revised the National Ambient Air Quality Standards (NAAQS) for particulate matter to add new standards for fine particles, using $PM_{2.5}$ as the indicator. Based on a review of the health data, the annual standard was set at a level of 15 micrograms per cubic meter and the 24-hour standard was set at a level of 65 micrograms per cubic meter. NOTE: EPA has subsequently revised the 24-hour $PM_{2.5}$ standard to 35 $\mu g/m^3$ in 2006. After a few legal challenges, the standard was eventually upheld. The final nonattainment designations for these standards occurred on April 5, 2005. The Missouri portion of the St. Louis nonattainment area included Franklin, Jefferson, St. Charles, and St. Louis Counties along with the City of St. Louis. The Illinois' portion of the St. Louiis area included the Counties of Madison, Monroe, and St. Clair, and Baldwin Township of Randolph County.

The designation of the St. Louis area as nonattainment formally initiated the planning process. Section 72(b) of the federal Clean Air Act requires states to submit implementation plans to EPA within three years after formal designation. The attainment designations for the 1997 $PM_{2.5}$ standards became final on April 5, 2005, making the implementation plans due April 5, 2008.

1.2 $PM_{2.5}$ Implementation Rule & RACT Definition

On April 25, 2007, EPA published the second phase of the Clean Air Fine Particle Implementation Rule. The rule provides specific requirements for states developing plans to address $PM_{2.5}$ nonattainment areas. The rule recognized that sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are both gases that act as precursors to fine particle formation. These gas-phase precursors participate in chemical reactions in the atmosphere to form secondary particulate matter (sulfates and nitrates). Formation of secondary particulate matter depends on numerous factors including the concentrations of precursors, the concentrations of other gases, atmospheric conditions, and relative humidity. Local analysis of monitoring data has shown that these gases both play a significant role in $PM_{2.5}$ formation in St. Louis.

The implementation rule established a comprehensive set of plan requirements for each state's $PM_{2.5}$ plan. One of these requirements is to ensure that all large stationary sources have installed Reasonably Available Control Technology (RACT). The implementation rule states that EPA has interpreted RACT to mean "the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility".

2. PM2.5 RACT - Regulatory Environment

2.1 EPA Approach

For ozone planning, EPA mandated that states evaluate all major sources of ozone precursors for reasonable controls. For moderate ozone nonattainment areas, major sources were specifically defined as sources that had the potential to emit more than one hundred tons of NO_x or Volatile Organic Compounds (VOCs) per year. The Clean Air Fine Particle Implementation Rule did not establish a precursor emission threshold for the state to review for reasonable controls. EPA reasoned that RACT can vary in different nonattainment areas based on the reductions needed for attainment as expeditiously as practicable. EPA recognized that different areas may have widely different $PM_{2.5}$ formation processes. The goal of this federal regulatory approach was to ensure that states consider and adopt RACT measures to meet the overarching requirement to attain the standard as expeditiously as practicable, while providing flexibility to the states to focus regulatory resources on those sources that have the most contribution to $PM_{2.5}$ nonattainment.

The responsibility, therefore, falls to the State to determine which measures both contribute to expeditious attainment and is reasonably available. By definition, measures that are not necessary either to meet reasonable further progress goals or to help the area attain promptly are not necessary. EPA notes in the preamble of the Clean Air Fine Particle Implementation Rule that, "As long as a state's analysis is sufficiently robust in considering potential measures to ensure selection of all appropriate RACT…., and the state provides a reasoned justification for its analytical approach, we will consider approving that state's RACT….strategy".

2.2 Attainment Date Extension

The current attainment demonstration modeling project is showing that St. Louis will not be able to attain the $PM_{2.5}$ standard by the presumed attainment deadline of 2010. In addition to the Clean Air Interstate Rule (CAIR) controls for utilities, national controls for mobile emissions, existing air quality controls in St. Louis, the Illinois multi-pollutant electric utility rule, and the SO_2 and NO_x RACT options presented here, it appears that additional local controls of specific direct $PM_{2.5}$ sources in Illinois will be necessary to meet the standard near the violating monitor. Illinois has indicated that these local controls and portions of the multi-pollutant utility controls will not be in place until 2011. Therefore, an attainment date extension to 2012 is being requested in conjunction with this plan submittal.

The Clean Air Fine Particle Implementation Rule provides that the attainment date can be extended provided states can demonstrate that it is impracticable to attain by 2009 due to the severity of the nonattainment problem and the lack of available control measures that are reasonably available. EPA will not grant an attainment date extension if the state has not considered the implementation of all reasonably available control measures and technology for local controls.

2.3 Reasonable Further Progress

To avoid delaying the implementation of controls, Congress established a requirement in the Clean Air Act that nonattainment areas make reasonable progress. In the Clean Air Fine Particle Implementation Rule EPA has determined that attaining the standard by the original attainment deadline meets this requirement. For states that cannot attain by their original attainment deadline, the Clean Air Fine Particle Implementation Rule says the plan must show that emissions will decline in a manner that represents generally linear progress from the 2002 baseline year to the attainment year.

The emission reductions achieved through the implementation of RACT controls can be used as part of the reasonable further progress demonstration. The delay in the publication of the final implementation rule by EPA precluded the use of RACT controls in Missouri to satisfy the RFP requirements. In Missouri, the development of new air quality control regulations takes a minimum of two years. Therefore, the time necessary for adoption of new regulations would not allow for compliance until after 2009.

3. RACT Review Process

3.1 Analysis of Emission Inventory

The Clean Air Fine Particle Implementation Rule requires that states review reasonable control measures for sources that emit SO_2, NO_x, and direct $PM_{2.5}$. For the state of Missouri direct PM sources, the current emission inventory and modeling analyses illustrate that additional control of direct $PM_{2.5}$ emissions will not advance the attainment of the area. This is due to the nature of the “large” sources that emit direct PM and the limited spatial impact for direct PM sources on the violating monitor in Granite City, Illinois. Further, none of the Missouri monitors exceed the standard and have not for several years. If nearby Missouri sources were impacting these monitors in and near the downtown St. Louis area, these local impacts would cause greater concentrations on monitors closer to these sources.

Nonetheless, for completeness, the department is providing a list of Missouri direct PM sources (both $PM_{2.5}$ and PM_{10}) in the St. Louis nonattainment area above 25 tons of actual PM_{10} emissions and/or above 10 tons of actual $PM_{2.5}$ emissions in 2002. The largest individual sources at each facility are identified and any controls for direct PM at each installation are included in Table 3-1. It should be noted that $PM_{2.5}$ emissions were not required to be collected in 2002 and the estimates made by the department of these emissions are likely high compared to subsequent emission inventories of the same sources. This conclusion is supported by the 2008 inventory data included in Table 3-1. Also, included in Table 3-1 is the distance to the Granite City, IL monitoring site.

Based on other state evaluations of direct PM control, the department investigated existing emissions and controls on any sources within 10 miles of the violating monitor as part of the RACT process. To be clear, there are several other large sources within the nonattainment area at great distance from the violating monitor (>30 miles). These sources are too distant to provide any significant impact on the Granite City monitor. There are several sources within the 10 mile radius that are already controlled well (Anheuser Busch – existing ESP control on their coal-fired boilers; Procter & Gamble, Federal Mogul Friction Products, and Mallinckrodt – baghouses on all substantive fugitive or process-related emissions; Beelman River Terminals and American Commercial Terminals – water sprays and sweepers for fugitive dust control on road and storage piles; St. Louis MSD – Bissel Plant – combined scrubber for 6 sludge incinerators). The control efficiency for all these sources is well above 50 percent and, in the case of Anheuser Busch is 95 percent. Also, Washington University Medical School has permanently removed the coal-fired boilers contributing significantly to the emission total (discussed later under SO_2 RACT). The only other remaining source within the 10 mile radius is PQ Corporation. Some of the PM emissions from this source are controlled using baghouses, but the largest source (sodium silicate furnace) is uncontrolled at around 50 tons per year. The direct PM emissions from the large sources near the Granite City monitor are over 1,500 tons per year.

Therefore, the department believes that additional control of direct PM sources in Missouri is not necessary due to the limited impact of these sources on the violating monitor at Granite City, Illinois.

Therefore, the analysis provided for the remaining pollutants, SO_2 and NO_x, is the focus of this technical paper.

A review of large emission sources within the nonattainment area for these two precursor chemicals identified cement kilns, internal combustion engines, glass melting furnaces, incinerators, industrial boilers and heaters, and a primary lead smelter for RACT consideration. This list was developed based on a review of the 2002 bi-state nonattainment area point source inventory for NO_x and SO_2. This review showed that the vast majority of point source emissions are emitted from the electric generating utility boilers. In fact, the SO_2 and NO_x inventory was dominated by these boilers. The next phase of the review was to examine the largest non-utility point sources. This review showed that 98 percent of the SO_2 emissions in the nonattainment area can be accounted for by including both the electric utilities and remaining sources that reported greater than 25 tons of actual emissions in 2002. The RACT team concluded that this was a logical threshold above which individual review of RACT technology was appropriate. A similar review was conducted for the NO_x sources. The 98 percent threshold was met by including all NO_x sources that reported greater than 50 tons of actual emissions in 2002. Based on this analysis, the RACT team identified the set of SO_2 and NO_x sources that represented 98 percent of the actual point source emissions in the nonattainment area. Tables 3.2 and 3.3 identifies the SO_2 and NO_x sources, respectively under consideration for RACT in Missouri.

CNTY	FAC ID	NAME	2002 PM10 TPY	2002 PM2.5 TPY		2008 TPY PM2.5	Distance (km)
071	0003	AMERENUE-LABADIE	1022.5	692.6	Boilers 1-4 (ESP @ 98% control)	328.4	63
099	0002	RC CEMENT COMPANY	725.1	55.3	New permit (baghouses for kiln/handling); old operation (ESP kilns)	197.4	63
099	0016	AMERENUE-RUSH ISLAND	539.0	363.2	Boilers (ESP @ 98%)	179.4	64
189	0010	AMERENUE-MERAMEC	351.2	177.5	Boilers 1-4 (ESP @ 98% control)	118.8	38
510	0156	AMERICAN COMM TERMINALS	219.7	116.6	Storage Piles/Material Handling (Water Sprays/Surfactants)	30.2	**6**
183	0001	AMERENUE-SIOUX	167.6	148.9	Boilers 1-2 (ESP @ 98% control)	70.5	27
510	0040	WASHINGTON UNIV MED SCH	116.6	96.2	Boilers (old coal-fired boilers/cooling towers removed); cooling towers	2.9	**13**
099	0068	SAINT-GOBAIN CONT -PEVELY	71.5	68.2	Glass melting furnaces (no control for PM2.5)	69.3	51
510	0118	ALUMAX FOILS	61.9	51.0	Reverberatory Furnace, Foil Rolling, Cooling Tower (no PM control)	47.0	19
510	0809	PQ CORPORATION (THE)	58.6	46.9	Glass melting furnaces (no control for PM2.5)	66.6	**10**
510	0003	ANHEUSER-BUSCH	58.3	21.9	Boilers 1, 5, 8, 9 (ESP 95% Control); Cooling towers	24.4	**13**
510	0072	FEDERAL-MOGUL FRICTION PROD	55.4	33.3	Grey Iron Foundry - casting,shakeout (fabric filters)	3.0	**12**
183	0027	MEMC ELECTRONICS	48.4	40.0	Cooling Tower	4.5	47
510	0053	ST. LOUIS MSD-BISSEL	42.4	20.5	6 Incinerators (1 scrubber)	3.6	**6**
189	0021	U. S. SILICA COMPANY-PACIFIC	40.9	16.9	Silica Milling, Drying, Handling (Wet scrubbers/baghouses)	3.0	57
099	0111	CARONDELET CORPORATION	39.4	7.8	Material Handling; Casting/Molding (Enclosure; fabric filter)	0.2	51
510	0057	PROCTER & GAMBLE	35.6	9.1	Handling fugitives (baghouses)	47.4	**6**
510	0070	ASTARIS -CARONDELET	35.5	28.8	Chemical process units (Baghouse, collectors)	1.3	21
510	2565	BEELMAN RIVER TERMINALS	34.5	6.8	Storage Piles, Truck traffic, mat. handling (water sprays/sweepers)	3.5	**7**
099	0103	BUSSEN QUARRIES -ANTIRE	32.9	6.6	Fugitive dust controls (watering roads/piles, process enclosures)	0.1	44
189	0019	FRED WEBER –SOUTH STONE	31.4	3.3	Fugitive dust controls (watering, process enclosure, 1 baghouse)	0.0	32
099	0008	FRED WEBER -FESTUS STONE	30.8	3.2	Fugitive dust controls (watering, process enclosure, 1 baghouse)	0.1	60
189	1093	BODINE ALUMINUM	30.5	21.8	Reverberatory Furnace, Annealing Furnace (no PM control)	6.2	18
183	0007	FRED WEBER -O'FALLON STONE	30.2	6.5	Fugitive dust controls (watering, process enclosure, 1 baghouse)	0.0	54
189	0230	BOEING COMPANY	28.7	21.7	Boilers (old coal-fired boilers removed; baghouses on new)	0.7	20
510	0179	ITALGRANI ELEVATOR	23.5	10.5	Grain elevator/material handling (Multiple baghouses)	0.9	21
510	0017	MALLINCKRODT INC.	23.4	15.6	Chemical process units (Multiple baghouse)	13.5	**6**
189	0312	BRIDGETON LANDFILL	12.2	10.3	Flare	5.5	27
			3967.8	**2101.2**		**1228.2**	

Table 3-1: St. Louis Nonattainment Area Direct PM Sources (Missouri Only)

STATE	COUNTY	FACILITY ID	FACILITY NAME	2002 SO2 TPY	Unit Description
29	071	0003	AMERENUE-LABADIE	47607.8	EGU Boilers 4
29	183	0001	AMERENUE-SIOUX	45957.4	EGU Boilers 2
29	099	0003	DOE RUN COMPANY-HERCULANEUM	41840.0	Lead Smelting (Sinter Plant/Blast Furnace)
29	099	0016	AMERENUE-RUSH ISLAND	23257.8	EGU Boilers 2
29	189	0010	AMERENUE-MERAMEC	16447.5	EGU Boilers 4
29	510	0003	ANHEUSER-BUSCH INC-ST. LOUIS	6250.0	Non-EGU Boilers 4 (2 @ 99, 230, & 240 MMBTU)
29	183	0076	GENERAL MOTORS-WENTZVILLE	679.8	Non-EGU Boilers 4 (82, 3@ 248 MMBTU)
29	099	0002	RC CEMENT COMPANY	554.2	Cement Kiln (Kiln and Raw Mills)
29	510	0017	MALLINCKRODT INC.	277.0	Non-EGU Boiler (115 MMBTU)
29	099	0068	SAINT-GOBAIN CONTAINERS - PEVELY	242.8	Glass Melting Furnaces (2)
29	189	0230	MCDONNELL DOUGLAS /BOEING CO	135.7	Non-EGU Boilers 3 (all 76 MMBTU)
29	510	0809	PQ CORPORATION	74.7	Melting Furnace
29	510	0038	TRIGEN-ST. LOUIS -ASHLEY STREET	59.8	Boilers
29	510	0040	WASHINGTON UNIV MED SCHOOL	49.6	Non-EGU Boiler (93 MMBTU)
29	510	0053	ST. LOUIS MSD – BISSEL	25.4	Incinerator
17	157	157851AAA	DYNEGY – BALDWIN	26267.2	EGU Boilers 3
17	119	119090AAA	TOSCOPETRO CORP	12761.8	Refinery (Cat Cracker, Flares, Process Heaters)
17	119	119020AAE	DYNEGY – WOOD RIVER	7265.0	EGU Boilers 2
17	119	119813AAI	NATIONAL STEEL CORP - GRANITE CITY	5003.2	Steel Manufacture (Coke Ovens, Flare, other)
17	119	119050AAA	PREMCOR REFINING GROUP INC	1608.8	Refinery (Process Heaters, Boilers)
17	163	163121AAK	BIG RIVER ZINC CORP	1378.6	Zinc Smelting (Sulfuric Acid Absorber)
17	163	163121AAB	ETHYL PETROLEUM ADDITIVES INC	136.7	Refinery
COMBINED EGU TOTAL				166,803	
>25 TPY TOTAL				237,881	
>50 TPY TOTAL				237,806	
POINT SOURCE NAA TOTAL				238,104	

TABLE 3-2: St. Louis Nonattainment Area SO2 Sources Above 25 tons per year in 2002

STATE	COUNTY	FACILITY ID	FACILITY NAME	2002 NOx TPY	Unit Description
29	183	0001	AMERENUE-SIOUX	14093.2	EGU Boilers 2
29	189	0010	AMERENUE-MERAMEC	9480.9	EGU Boilers 4
29	071	0003	AMERENUE-LABADIE	7819.8	EGU Boilers 4
29	099	0002	RC CEMENT COMPANY	4954.7	Kiln and Raw Mills
29	099	0016	AMERENUE-RUSH ISLAND	3997.2	EGU Boilers 2
29	510	0003	ANHEUSER-BUSCH INC-ST. LOUIS	848.4	Non-EGU Boilers 4 (2 @ 99, 230, & 240 MMBTU)
29	183	0076	GENERAL MOTORS-WENTZVILLE	301.1	Non-EGU Boilers 4 (82, 3@ 248 MMBTU)
29	510	2378	LACLEDE GAS	218.2	6 IC Engines (2@5.91 MMBTU, 4@9.04 MMBTU) NG
29	099	0068	SAINT-GOBAIN CONT – PEVELY	187.5	Glass Melting Furnaces (2)
29	510	0809	PQ CORPORATION	181.1	Melting Furnace
29	510	0038	TRIGEN-ASHLEY STREET	178.6	Boilers
29	189	0230	BOEING CO	142.8	Non-EGU Boilers 3@76 MMBTU, 1@80 MMBTU)
29	510	0017	MALLINCKRODT INC	135.7	Non-EGU Boiler (115 MMBTU), smaller boilers
29	189	0231	CHRYSLER CORP-NORTH PLANT	104.8	Non-EGU Boiler (3@120 MMBTU ,94 MMBTU NG)
29	189	1205	ST. LOUIS MSD – MO RIVER	88.2	IC Engines (small)
29	189	1210	ST. LOUIS MSD - COLDWATER	78.4	IC Engines
29	510	0053	ST. LOUIS MSD - BISSEL	78.3	Sludge Incinerators
29	189	0217	ST. LOUIS MSD - LEMAY	52.4	Sludge Incinerator
29	183	0027	MEMC ELECTRONIC MATERIALS	50.1	Non-EGU Boilers (Small), Nitric Acid Etching
29	189	0002	CHRYSLER PLANT 1-FENTON	38.6	Natural Gas Heaters
29	189	0015	FORD MOTOR CO-HAZELWOOD	37.8	Non-EGU Boilers (3@ 60 MMBTU), Process Heaters
29	510	0023	SOLUTIA INC-QUEENY PLANT	35.2	Non-EGU Boilers (181 MMBTU) facility OB
29	189	1029	DEPAUL HEALTH -BRIDGETON	31.9	Engines (3 @ 63 MMBTU)
29	183	0009	FRED WEBER INC-NEW MELLE	28.7	Diesel Engines
29	510	0118	ALUMAX FOILS INC	27.9	NG Ovens, 3 MMBTU Boiler, Aluminum Rolling
17	157	157851AAA	DYNEGY – BALDWIN	22367.1	EGU Boilers 3
17	119	119020AAE	DYNEGY MW GEN- WOOD RIVER	2370.7	EGU Boilers 2
17	119	119090AAA	TOSCOPETRO CORP	3761.2	Refinery (Cat Cracker, Flares, Process Heaters)
17	119	119813AAI	US STEEL - GRANITE CITY	3406.5	Steel Manufacture (Coke Ovens, Flare, other)
17	119	119050AAA	PREMCOR REFINING GROUP INC	575.8	Refinery
17	163	163045ADT	ELEMENTIS PIGMENTS INC	101.6	Non-EGU Boilers (>100 MMBTU, NG)

STATE	COUNTY	FACILITY ID	FACILITY NAME	2002 NOx TPY	Unit Description
17	119	119020AAG	OLIN CORP	95.7	Non-EGU Boilers (>10,<100 MMBTU, NG)
17	119	119105AAA	UNION ELECTRIC CO	82.9	EGU Boilers >100 MMBTU, NG (7)
17	163	SCOTT AFB	SCOTT AIR FORCE BASE	70.0	Military Aircraft
17	119	119090AAI	ROXANA POWER PLANT	69.0	IC Engine (Landfill Gas)
17	163	163815AAA	US AIR FORCE/SCOTT AIR FORCE BASE	47.9	Boilers
17	119	119055AAD	HIGHLAND ELECTRIC LIGHT PLANT	33.5	IC Engines
17	119	119040ADM	PRECOAT METALS	28.8	Metal Coating (Oven)
					% Total
EGU Total				60,129	77.8%
>50 TPY Total				75,952	98.2%
>25 TPY Total				76,299	98.7%
NAA Total				77,318	

TABLE 3-3: St. Louis Nonattainment Area NOx Sources Above 25 tons per year in 2002

3.2 RACT Source Workgroup

The first RACT stakeholder meeting was held August 23, 2007, for the affected SO_2 and NO_x sources. Background and history of $PM_{2.5}$ were discussed as well as technical and economic feasibility, reasonable costs, the RACT process, and references. A RACT questionnaire was sent out to be completed by each participant. A copy of the questionnaire is included as an attachment to this document. The next RACT meetings were held over two days, September 20 & 21, 2007, to discuss with each individual stakeholder their specific concerns or issues regarding the questionnaire or their particular RACT concerns. These meetings were especially helpful for the department to better understand the specific operations of the different facilities. An additional meeting was held November 16, 2007; $PM_{2.5}$ planning efforts were reviewed, RACT findings were presented by each company and information about future steps given. Many of the sources provided sufficient technical and economic information to allow for a decision to be reached for that source. However, the information provided by a few sources (detailed below) did not allow for immediate concurrence by the program or were not sufficient to provide for a complete RACT decision.

3.2.1 Summary of Stakeholder RACT Proposals

The following table summarizes the information that individual facilities provided in response to the questionnaire.

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
Chrysler 189-0231	EP020	Boiler #1, 2, & 3, in service 1998, Natural gas, all 120 MMBTU/hr	23.06			Ultra Low NO_x Burners		Not enough fuel pressure	No	
	EP021	NG Heaters and Ovens, natural gas,	66.11		1028000000 BTU/fuel unit	Flue Gas Recirculation			Yes	16,100
	EP023	Boiler #4, natural gas, 94.1 MMBTU/hr, in service 1998, low NO_x burners (28% control)	3.12		1028000000 BTU/fuel unit	Selective Catalytic Reduction		Landfill gas contains compounds that poison catalyst	No	
	EP028	Thermal Oxidizers, natural gas, 16.0 MMBTU/hr, Modified furn. or burner design (17% control)	1.43		1028000000 BTU/fuel unit	Ultra Low NO_x Burners		Not enough fuel pressure	No	
	EP029	Land fill gas combustion, 211 MMBTU/hr, Modified furn. Or burner design (66.26% control)	11.07		484000000 BTU/fuel unit	Flue Gas Recirculation			Yes	9,500 - 16,000
						Selective Catalytic Reduction			Yes	33,000
			104.79							
Chrysler 189-0002	EP017	Natural gas heaters, 210 MMBTU/hr	38.6		1026000000 BTU/fuel unit					
PQ Corporation		[EIQ was corrected] 1 1/4 inch lump coal fired, installed 1958, BACT in 1982 No written submittal, from discussion, company's verbal conclusion	3.0							

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
Doe Run Company-Herc	Blast Furnace	Sintering Process		41840	note: based on 2005 stack testing	No Analysis Provided				
Anheuser-Busch, Inc.	Boiler #1	Coal and gas fired, 230 MMBTU/hr, in service 1985, 2.57% sulfur coal, pulverized-dry bottom	381	2338.9	22870000, 1050000000 BTU/fuel unit	Wet scrubber	6100	Vendors declined to quote	No	N/A
	Boiler #5	Coal and gas fired, 240 MMBTU/hr, ESP at 95.59% (for coal, PM10) eff., 2.961% sulfur coal, put in service 1948	213.4	3066.2	23028000, 1050000000 BTU/fuel unit	Dry scrubber with New Boiler	6100	Space constraints, steam reliability, must rent boiler	Yes	3,242
	Boiler #8	Coal, biogas and natural gas fired, manufactured 1988, 99 MMBTU/hr, has ESP at 97% (for coal) eff., 0.76% sulfur coal	94.2	248.8	24450000, 719999051, 1050000000 BTU/fuel unit	Dry scrubber with Rental Boiler	6100	Space constraints, production impacts	Yes	3,074
	Boiler #9	Coal, biogas and natural gas fired, manufactured 1988, 99 MMBTU/hr, has ESP at 97% (for coal) eff., 0.76% sulfur coal	96.8	256.2	24400000, 719998275, 1050000000 BTU/fuel unit	Change to Low Sulfur coal **THIS IS A-B's RECOMMENDATION**	2700	Increases fuel costs, difficulty obtaining low sulfur coal	Yes	2,117
			785.4	5910.1						
General Motors-Wentzville	Boiler #1	82.5 MMBTU/hr, put in service 1982, 0.47% sulfur coal, bituminous, spreader stoker, FF at 99% for PM_{10}, coal or gas			25000167 BTU/fuel unit	No Analysis Provided				
	Boiler #2	248 MMBTU/hr, put in service 1982, 0.47% sulfur coal, bituminous, spreader stoker, FF at 99% for PM_{10}, coal only			25000167 BTU/fuel unit	No Analysis Provided				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
	Boiler #3	248 MMBTU/hr, put in service 1982, 0.47% sulfur coal, bituminous, spreader stoker, FF at 99% for PM_{10}, coal only			25000167 BTU/fuel unit	No Analysis Provided				
	Boiler #4	248 MMBTU/hr, put in service 1982, 0.47% sulfur coal, bituminous, spreader stoker, FF at 99% for PM_{10}, coal only			25000167 BTU/fuel unit	No Analysis Provided				
			289.4	679.8						
Mallinckrodt Inc.	Boiler #6	115.1 MMBTU/hr, 0.67 - 1% sulfur coal, bituminous, only burns coal, limits in PSD permit are 2.0 lb/MMBTU(30day rolling avg), 2.85 lb/MMBTU as max for med. sulfur coal, and 1.20 lb/MMBTU daily for low sulfur coal, has baghouse for 99% eff. for PM, put in service 1982	117.3	275.6	27752000 BTU/fuel unit	BACT Limits from 1982 Permit Fuel Switching, wet scrubbing, dry scrubbing, dry lime injection, all not feasible because of costs – range of costs provided.				
Washington University Med School	Boiler #8	93 MMBTU/hr, distillate oil/natural gas fired, per permit no. 01-05-013 revision boiler #2 and #3 will be removed or inoperable 180 days from start up of boiler #8, SO_2 emissions in 2003 were 1.81, 2004 were 0.93		49.4		Fuel Switch completed by 2003				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
MEMC Electronic Materials Inc-St Peters	EP11B5	K-35 Heating Boiler #2 (N) 12.96 MMBTU/hr, natural gas, 1996	0.87		1050000000 BTU/fuel unit					
	EP11B4	K-35 Heating Boiler #1 (S) 12.96 MMBTU/hr, natural gas, 1996	0.2		1050000000 BTU/fuel unit					
	EP11B3	L-100 Heating Boiler #4 (S) 9.36 MMBTU/hr, natural gas, 1992	1.7		1050000000 BTU/fuel unit					
	EP11B2	L-100 Heating Boiler #3 (N) 10.46 MMBTU/hr, natural gas, 1992	1.48		1050000000 BTU/fuel unit					
	EP11B1	N-60Heating Boiler #5 20.92 MMBTU/hr, natural gas, fuel oil distillate 1-4, 1974	2.85		1050000000, 1.0 BTU/fuel unit					
	2	L-100 SPD Rod Lab, 2006 Venturi scrubber @ 30% NO_x control, also a 2nd stage scrubber @ 30% NO_x control	3.45			Wet Scrubbing should be considered RACT				
	4	N-120 SPD MOD As-Cut, Packed water scrubbers, 20% NO_x control @ 100% capture eff.	5.39			Wet Scrubbing should be considered RACT				
	7	N-120 SPD MOD Etching, Packed water scrubbers, 20% NO_x control @ 100% capture eff.	19.79			Wet Scrubbing should be considered RACT				
	2L	R-120 APD Rod Lab, 30% control of NO_x	3.91							
	7L	K-45 APD Etching, Packed water scrubbers, 20% NO_x control @ 100%	5.16			Wet Scrubbing should be considered RACT				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
		capture eff.								
	11B6	N-60 Boiler #6 - natural gas, fuel oil #2, 350 Hp	0.78		1050000000, 137300000 BTU/fuel unit					
	12D-L	Diesel engine for emer. Backup > 600 Hp, fuel oil #2	0.93		137030000 BTU/fuel unit					
	12D-S	Diesel engine for emer. Backup < 600 Hp, fuel oil #2	0.66		137030000 BTU/fuel unit					
	30	L-120, N-60 CCG Lab and EPI R&D Lab Research	2.42							
	5AL	L-88 Applications Laboratory/QA, 30% NO_x control	0.54							
			50.13							
Sterling Properties / Laclede gas Building	Engine 1	Waukesha L7062GU 550 kW @ 900 rpm, natural aspirated and are equipped with heat recovery units, (HRUs), gas, stat. IC engine, installed 1969	Sum 218.19			Non selective catalytic reduction for rich burn engines with an air/fuel controller; This is the method recommended by Waukesha. Miratech Emissions Solutions makes the controls and systems which reduces NO_x by 80 percent, from 13 to 2.6 gm/bhp-hr. The installation cost of this system for all eight (8) engines is $885,515.	174.5		Yes	4,177
	Engine 2	Waukesha L7062GU 550 kW @ 900 rpm, natural aspirated and are equipped with heat recovery units, (HRUs), gas, stat. IC engine, installed 1969	All Avg 5000 hrs/yr			Replace Engines. Costs would also increase because the new engines would require different HRUs due to size/power increases. New engine costs, not including emissions controls, HRUs, freight, installation, etc., is estimated to be $3,100,000 divided by 212 ton NO_x controlled equal's $14,623 per ton. Estimated costs to place engines on the 31st floor using a crane is approximately $300,000, therefore cost per ton controlled NO_x increases appreciably				14,623

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
						not including new HRUs				
	Engine 3	Waukesha L5108GSIU 800 kw @ 1200 rpm, turbocharged and are equipped with HRUs, gas, stat. IC engine, installed 1969				Selective catalytic reduction for lean-burn engines; Will require buying rich-burn engines along with all the needed emissions controls and HRUs due to increased exhaust volume, and freight, installation, etc. This would also require the injection and storage of ammonia and its added costs.				
	Engine 4	Waukesha L5108GSIU 800 kw @ 1200 rpm, turbocharged and are equipped with HRUs, gas, stat. IC engine, installed 1969				Water/steam injection; Not recommended by Waukesha because carbon/combustion chamber deposits may/can become loose and lodge between the valve faces and seats, thus over time, the valves can burn.				
	Engine 5	Waukesha L5108GSIU 800 kw @ 1200 rpm, turbocharged and are equipped with HRUs, gas, stat. IC engine, installed 1969				Pre-chamber or low-emission combustion conversions; Waukesha does not have upgrades available for these old engines.				
	Engine 6	Waukesha L5108GSIU 800 kw @ 1200 rpm, turbocharged and are equipped with HRUs, gas, stat. IC engine, installed 1969 EP01 = EU001 thru EU 006				Pre-stratified charge conversion; Offered by the aftermarket company, “Emissions Plus, Inc., but it is not recommended because of high cost of the modifications; loss of power from the engines and the HRUs would have to be changed out. Ignition timing retard; Will reduce engines power and engines would not be able to respond to load variations and demand as required. Engines would bog, voltage and frequency safeties would probably open and would lose power to all functions.				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
						Re-power to all electrical; A study was done on in Jan, 2006 to do this. The cost in 2006 dollars was $5,400,000. Factoring in a 10 percent growth, costs would increase to approximately $6,500,000. Dividing $6,500,000 by 212 tons of NO_x controlled is equal to $30,600 per ton.				30,600
Saint-Gobain Containers	EP03 and 02	Glass melting furnaces, have oxy-fuel [firing (BACT), natural gas, in service 1980	187.5	242.8	1020000000 BTU/fuel unit	ESP/semi-dry scrubber				15,000
McDonnell Douglas/ Boeing Co	CS-005-01, EU CS-005-02, 03, and 04	76.4 MMBtu/hr, dry bottom, bituminous, 0.78% sulfur, installed 1941, gas, installed in 1984, Riley stoker, Removing Equipment	142.8	135.7	1050000000, BTU/fuel unit	Removing Boilers	ALL			
RC Cement	8-B-09BK	Raw Mill Fluid Bed Furnace 2, installed 1985, 66.5 MMBtu/hr, 3.98% sulfur coal, Dry limestone injection air separators @ 50% SO_2 control efficiency	49	26.4	26600000 BTU/fuel unit					
	8-B-09AK	Raw Mill Fluid Bed Furnace 1, 3.98% sulfur coal, 66.5 MMBtu/hr, installed 1985, Dry limestone injection air separators @ 50% SO_2 control efficiency	46.9	25.3	26600000 BTU/fuel unit					
	4-K-02	Cement Kiln-Coal combustion, no “end-of process” SO_2 or	4858.2	502.5		Inherent Lime Scrubbing should be considered RACT				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
		NO_x controls								
			4954.1	554.2						
Trigen-St Louis Energy Corp	EP1	#1 combustion turbine, 66.54 MMBtu/hr, Natural gas, in service 1999	63.8	0.96	1020 BTU/fuel unit	No Analysis Provided				
	EP1.1	#1 Heat recovery boiler, 107.9 MMBtu/hr, Natural gas, in service 1999	6.85	0.05	1020 BTU/fuel unit					
	EP2	# 2 combustion turbine, 66.54 MMBtu/hr, Natural gas, in service 1999	57.99	0.89	1020 BTU/fuel unit					
	EP2.1	#2 Heat recovery steam generator, 107.9 MMBtu/hr, Natural gas, in service 1999	8.12	0.06	1020 BTU/fuel unit					
	EP6	#6 Boiler, No. 5-6 (residual) fuel oil, 404 MMBtu/hr, in service 1948, Natural gas	12.36	0.065						
	EP7	Emergency diesel generator, 8.31 MMBtu/hr, No. 2 fuel oil, in service 1999	3.14	0.54	138500000 BTU/fuel unit					
	EP5	#5 Boiler	27.05	57.26		No longer coal-fired (Construction permit issued to replace the coal-fired units at this facility).				
			179.31	59.825						
Ford Motor Company - Hazelwood	002	Boiler #2, LPG, 60 MMBtu/hr, in service 1948, fuel oil 5-6 (residual), natural gas, LPG Propane, no NO_x or SO_2 controls	4.75		150000000, 1050000000, 97500000 BTU/fuel unit	**PRODUCTION CEASED**				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
	001	Boiler #1, LPG, 60 MMBtu/hr, in service 1948, fuel oil 5-6 (residual), natural gas, LPG Propane, no NO_x or SO_2 controls	4.75		150000000, 1050000000, 97500000 BTU/fuel unit					
	017	Natural gas fired equipment, Process heaters, surface coat., 278.15 MMBtu/hr, in service 1948, natural gas, no NO_x or SO_2 controls	22.05		1050000000 BTU/fuel unit					
	018	Space Heaters, LPG, in service 1948, 22.0 MMBTU/hr, natural gas, propane, no NO_x or SO_2 controls	0.85		1050000000, 97500000 BTU/fuel unit					
	023	Big Foot space heaters, 40 MMBTU/Hr, in service 2001, natural gas, no NO_x or SO_2 controls	5.25		1050000000, BTU/fuel unit					
	024	Gas fired hot water heaters, natural gas, in service 2001, 30 MMBTU/hr, no NO_x or SO_2 controls	0.02		1050000000, BTU/fuel unit					
			37.67							
MSD - Metropolitan Sewer District Lemay Plant	EP1	Engine Stacks, propane, Digester gas, no NO_x or SO_2 controls	88.2		DG 560000000 BTU/fuel unit	VenturiPak Scrubber (particulate and VOC precursor controls)	95%		Yes	9,399

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
MSD - Metropolitan Sewer: District Cold Water Creek Plant	EP1 twice	Internal combustion engines, 16.9 MMBTU/hr, in service 1965, natural gas, digester gas, no NO_x or SO_2 controls	78.4		1000000000, 650000000 BTU/fuel unit	Membrane WESP (additional particulate and VOC precursor controls)	98%		Yes	10,832
MSD - Metropolitan Sewer District: Bissell Plant	EP18	Pump station boilers(2), natural gas, 10.0 MMBTU/hr(sum), natural gas, no NO_x or SO_2 controls	1.5	0.009	1050000000 BTU/fuel unit	Ionizing Wet Scrubber (additional particulate and VOC precursor controls)	98%	Space limitations	No	9,753
	EP4	Incinerator #3 W/New scrubber, 2.5 MMBTU/hr, sludge incinerator, Venturi scrubber (90% PM_{10} control), Impingement tray scrubber (90% PM_{10} control)	22.53	17.1		Cloud Chamber Scrubber (additional particulate and VOC precursor controls)	98%		Yes	11,222
	EP5	Incinerator #4, 2.5 MMBTU/hr, sludge incinerator, Venturi scrubber (67% SO_2 control), Impingement tray scrubber (90% PM_{10} control)	7.87	1.55		Venturi Scrubber serves as RACT for particulates				
	EP6	Incinerator #5, 2.5 MMBTU/hr, sludge incinerator, Venturi scrubber (99% NO_x and SO_2 control), Impingement tray scrubber (90% NO_x and SO_2 control)	28.87	6.1		Venturi Scrubber serves as RACT for particulates				
	EP7	Incinerator #6, 2.5 MMBTU/hr, sludge incinerator, Venturi scrubber (90% NO_x and SO_2 control),	16.35	0.66		Venturi Scrubber serves as RACT for particulates				

Summary of RACT Information Provided by Individual Companies

Company	Unit	Specifications	2002 NO_x (TPY)	2002 SO_2 (TPY)	BTU/unit	Technology	Reduction (TPY)	Feasibility Issues	Tech/ Feas?	Cost ($/ton)
		Impingement tray scrubber (90% NO_x and SO_2 control)								
			77.12	25.419						
MSD - Metropolitan Sewer District Lemay Plant	EP1	Sludge Incinerator, 8.39 MMBTU/hr, Venturi scrubber (99.29% SO_2 controls), Impingement tray scrubber (99% SO_2 control)	51.58			Venturi Scrubber serves as RACT for particulates				

3.3 NO_x Findings

Several facilities indicated that they had reduced NO_x emissions or were planning changes at their facilities that will result in emission reductions. Coal-fired boilers at Washington University have been replaced with boilers that are natural gas-fired. Construction permits would be required to switch back to coal, therefore, no additional steps need to be taken to assure that these changes are permanent and enforceable. This physical change at this facility is sufficient to meet the RACT requirement for this source. Also, the Boeing Company has removed the coal-fired boilers that were in operation in 2002. The removal of these units satisfies the RACT requirement for Boeing.

The department and MEMC have signed a consent agreement to continue to operate their scrubbers for the control of NO_x from their acid bath/etching process. This agreement can be found in Appendix C. The agreement codifies the existing NOx control processes for the facility and is sufficient to satisfy the RACT requirement for MEMC.

St. Gobain Containers has installed oxy-fuel firing on both glass melting furnaces at the Pevely location. This technique is the best available NOx control option for melting furnaces and is considered RACT for St. Gobain Containers.

Sterling Properties (formerly Laclede Gas) provided an extensive document detailing the cost of control for their eight (8) natural gas fired internal combustion engines. The controls that were considered were non-selective catalytic reduction (NSCR), selective catalytic reduction (SCR), replacement of existing engines, water/steam injection, re-powering all engines to electric, and engine upgrades to low emission. The department concurred with the finding that NSCR and SCR were not feasible due to space constraints and overall cost of control for SCR. The NSCR technology is designed to use residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NOx using a catalyst. The lowest cost option was NSCR with a cost of $4,177 per ton reduced, but this was precluded due to the space constraints of the operation. The replacement of engines was $14,623 per ton and was eliminated due to the high cost of control. Water/steam injection to reduce NOx is not supported by the manufacturer of the engines (Waukesha) and there are no engine upgrades available for the types of engines at this facility. The re-powering to electric would cost over $6,000,000 and would result in a unit control cost of $30,600 per ton. Therefore, the department concluded that no NOx control options were available for this facility and the RACT requirement is met without additional control.

Chrysler Corporation provided documentation that specified a cost of $33,000 per ton for SNCR technology applied to the landfill gas-fired boilers at Chrysler. The cost per ton of control was strongly influenced by the small amount of NOx emissions occurring from the boilers. The department concluded that no additional NOx control was necessary to satisfy the RACT requirement for this source. In the same manner, the lack of emission reductions at Ford Motor Company from the three 60 MMBTU boilers (<40 TPY) and the similarity to the sources in the Chrysler Corporation and other analyses led to the conclusion that no additional NOx control was necessary to satisfy RACT. This finding is due to excessive cost per ton of add-on control technology for NOx; well above $10,000 per ton.

NO_x Emissions from the Buzzi Unicem cement kiln in Jefferson County (previously RC Cement) are expected to decrease appreciably between 2002 and 2009. This facility has received a permit to replace their existing long wet kilns with preheater / precalciner configuration. In 2002 the total NO_x emissions for the two raw mills and the kiln was 4,955 tons. The permit for the new plant limits NO_x emissions to 3,315 tons per year, an expected minimum reduction of approximately 1650 tons. The new permitted emission rate for this facility was 3.0 pounds of NO_x per ton of cement clinker produced. The new permit was issued to Buzzi Unicem as a minor permit because they were able net out of major review. This emission rate, however, is comparable to the Best Available Control Technology (BACT) findings of two previous permits. For the previously permitted projects, BACT was found to be 2.8 and 3.0 pounds of NOx per ton of clinker. Because the emission rate of the new permit is comparable, and because the emissions from this plant will be reduced by a minimum of 1650 tons of NO_x per year, the RACT team has concluded that this new permit can be considered RACT for this facility.

NOx control on the engines located at the St. Louis Metropolitan Sewer District (MSD) facilities was also examined. These engines were evaluated for control using NSCR and SCR. The cost per ton of NOx removed for SCR was calculated as $9,152. The department concluded that no additional control was necessary to satisfy the RACT requirement for these engines.

The remaining non-utility boilers in the RACT evaluation group have undergone multiple RACT analyses for the ozone plans completed by the department. This group has recently undergone that evaluation for the 2007 ozone plan. This group has been previously controlled, is required to comply with 10 CSR 10-5.510 Control of Emissions of Nitrogen Oxides, and has satisfied the requirement for RACT. General Motors, Trigen – Ashley Street Station, and Mallinckrodt are the facilities in this group.

The four facilities owned by Ameren (Labadie, Rush Island, Sioux, and Meramec) are included in the Clean Air Interstate Rule (CAIR). Further, as noted in Table 3-1, all the boilers owned by Ameren include electrostatic precipitator controls at 98 percent effectiveness. The existing controls for NOx on these units include low NOx burners and overfire air along with a computerized firing control system at Labadie and Rush Island. The current emission rates (2008 average) at each facility are as follows in pounds per million British Thermal Unit heat input (lb/MMBTU):

Labadie – 0.11 lb/MMBTU NOx and 0.70 lb/MMBTU SO2
Meramec – 0. 15 lb/MMBTU NOx and 0.64 lb/MMBTU SO2
Rush Island – 0.10 lb/MMBTU NOx and 0.68 lb/MMBTU SO2
Sioux – 0.28 lb/MMBTU NOx and 1.80 lb/MMBTU SO2

It should be noted that Ameren is testing urea injection for additional NOx control at the Sioux plant and has long used low sulfur subbituminous western coal at its units. Further, to address potential controls required under CAIR, the utility is retrofitting the Sioux plant with flue gas desulfurization (FGD) technology to be completed by the end of 2010. Further, the utility meets current CAIR NOx requirements with existing controls. Based on the current and future control requirements under CAIR, the facilities will satisfy the RACT requirement for NOx and SO2.

3.4 SO2 Findings for Non-boilers

The first group includes PQ Corporation, St. Gobain Containers, Buzzi Unicem (previously River Cement), and the St. Louis Metropolitan Sewer District. PQ Corporation revised the emission inventory for SO2 because this facility does not use sulfur containing fining agents to clarify its glass. The emission factors utilized in 2002 included the use of these agents and were incorrect. The emission change results in less than 10 tons per year of SO2 from this facility. The RACT team visited St. Gobain Containers and toured the Pevely facility. The source of the sulfur in the St. Gobain process is largely from the introduction of sodium sulfate, which is used as a fining agent to help remove small air bubbles from the molten glass. St. Gobain estimated that fluidized gas desulfurization (FGD) will cost about $15,000 per ton SO2 reduced. Based on a review of the literature and the cost information provided by the company the meeting, the RACT team concluded that the cost of FGD is not reasonable.

Buzzi Unicem currently operates two long dry process cement kilns in Selma, Missouri. The company has been issued permits to replace these kilns with a new state of the art preheater/precalciner kiln system which is currently under construction. The kiln environment itself produces control of SO_2 due to its highly alkaline internal environment at temperatures that promote scrubbing of SO_2 and the formation of stable sulfates in the clinker. The literature indicates that this control is approximately 95 percent effective and River Cement recommended that the reasonable control for this process is inherent scrubbing. The RACT team has reviewed this recommendation and did not find additional control of SO2 warranted beyond the inherent scrubbing of the kiln system.

The St. Louis Metropolitan Sewer District operates five multiple hearth sewage sludge incinerators at their Bissell Point plant in St. Louis City. The gases from these units report to a venture / impingement tray scrubber for particulate control prior to being discharged through a common stack. The SO_2 emissions from these processes are of moderate amounts, and the RACT team has concluded that additional equipment to control SO_2 emissions would not be reasonable because of costs.

The Doe Run Company operates a primary lead smelter in Herculaneum, Missouri. 10 CSR 10-6.260, Restriction of Emission of Sulfur Compounds currently limits SO2 emissions from the Doe Run Herculaneum facility to 20,000 pounds per hour. This facility operates an acid plant that converts strong acid gases from the front end of their sintering process into sulfuric acid, but the overall efficiency is relatively poor. Even with the acid plant in operation, base year emissions utilized in the attainment demonstration were over 40,000 tons per year for Doe Run sources. Because Doe Run’s emissions are quite high, it is evident that the installation and operation of an SO2 scrubbing system would be cost effective on a per ton basis. Although the cost per ton would be reasonable, the overall capital costs of a scrubbing system for the gas streams at this facility would be considerable. In an effort to significantly reduce emissions from the plant and allow for continued operation of the facility, 10 CSR 10-6.260 was amended to establish a tiered approach which required an emission limit of twenty-five thousand one hundred (25,100) tons SO2 per year in the attainment year of 2012 as RACT. Then, the emission limit will be reduced to sixteen thousand three-hundred-fifty (16,350) tons SO2 per year in 2014, and zero (0) tons SO2 per year in 2017. Doe Run is considering a plant to manufacture lead using a proprietary leaching and electrowinning process to replace the primary lead smelting operation at Herculaneum. This new process would completely eliminate SO2 emissions.

3.5 Boiler Source Group – SO_2

As noted in the NOx RACT discussion, Washington University and Boeing Company have eliminated the coal-fired boilers at these two facilities and new construction permits would be required for operation of boilers not fired by natural gas. Therefore, no additional consideration of SO2 RACT is necessary for these facilities. The industrial boiler group that includes Anheuser Busch, Mallinckrodt, and General Motors – Wentzville is the single group that will require additional negotiation/discussion to resolve SO_2 control. There are several technical issues with this group that we must consider: the physical capacity of the boilers, calculation of emissions from these boilers, the current operation of each source including coal type/sulfur content, other states' and Missouri's regulation of these sources, and RACT recommendations from this group of sources. The boiler capacities are presented in Table 1 for boilers that burn coal in the St. Louis nonattainment area. This information is important due to the historical methodology used to limit emissions from industrial boilers. The limits are usually expressed in pounds per million British Thermal Units (lb/MMBTU). In addition, as boiler size increases emission limits decrease with typical thresholds at 100 MMBTU/hr and 250 MMBTU/hr.

TABLE 1

Facility	Facility ID	Unit ID	Capacity (MMBTU/hr)
Anheuser Busch	510-0003	Boiler #1	230
Anheuser Busch	510-0003	Boiler #5	240
Anheuser Busch	510-0003	Boiler #8	99
Anheuser Busch	510-0003	Boiler #9	99
Mallinckrodt	510-0017	Boiler #6	115.1
General Motors	183-0076	Boiler #1	82.5
General Motors	183-0076	Boiler #2	248
General Motors	183-0076	Boiler #3	248
General Motors	183-0076	Boiler #4	248

Typically smaller boilers have higher emission rates on a per-MMBTU basis, but this is not currently the situation with these boilers located in St. Louis.

The second issue is the calculation of emissions from all these boilers. During the 2002 base year, all the boilers used an emission factor for coal combustion listed in the EPA emission factor guidance [AP-42]:

$$\rightarrow 38*S \text{ (lb } SO_2 \text{ / ton coal)},$$

where S is the sulfur content of the coal.

Therefore, compliance with any SO_2 limit in lb/MMBTU could be calculated with only the sulfur and heat content of the coal burned in the boiler during an appropriate averaging time unless stack testing is required. During the development for the boiler SO_2 RACT regulation, Anheuser Busch proposed to use a total sulfur conversion in the fuel from its boilers to SO_2 instead of this emission factor. This calculation is conservative in that it does not assume any sulfur compounds in the ash from the boiler and all the sulfur is emitted in the form of sulfur dioxide.

Third, annual operational parameters for coal-firing of these boilers are summarized in Table 2 for the 2002-2006 (including coal sulfur content, lb SO_2/MMBTU, and total SO_2 emissions).

TABLE 2

Unit ID	Min S Content	Max S Content	Min lb per MMBTU	Max lb per MMBTU	Min Emission (TPY)	Max Emission (TPY)
AB #1	2.48%	2.61%	4.083	4.297	2,338.9	2,707.6
AB #5	2.44%	2.96%	4.034	4.951	2,638.1	3,066.2
AB #8	0.76%	1.20%	1.163	1.860	248.8	389.0
AB #9	0.74%	1.18%	1.132	1.838	238.9	362.8
MA #6	0.67%	0.72%	0.941	1.184	250.3	282.7
GM 1-4	0.47%	0.68%	0.714	1.033	431.8	761.3

It should be noted that the Anheuser Busch boilers can be fired by a variety of fuels including natural gas, biogas, fuel oil, coal, or wood. This means that the overall emissions reported for any given year are potentially higher or lower depending on the use of these non-coal fuels which are significantly cleaner.

Fourth, there are regulations in neighboring states, as well as the previous regulation in the St. Louis nonattainment area, that restrict coal-fired non-utility boiler SO_2 emissions. The Missouri regulation is contained in 10 CSR 10-6.260 – Restriction of Emissions of Sulfur Compounds. This rule previously limited the sulfur content of indirect heating sources (boilers) to two percent sulfur during the months of October – March and four percent from April – September, using a monthly average. In addition, there is a provision in the rule that restricts emissions which cause or contribute to concentrations exceeding the NAAQS. The RACT team assumes the first provision of the regulation was developed to help maintain compliance with the SO_2 NAAQS in the late 1970s or early 1980s. Table 3 contains a summary of current rules in surrounding states for non-utility boilers. These rules establish a baseline for consideration since none of these states have finalized SO_2 RACT evaluations for the particulate matter standard.

TABLE 3

State	Rule Citation	Description/ Applicability	Compliance Limit/ Timeframe
Illinois	Title 35(B)(I)(c)(C)214.141	All boilers in the St. Louis metro area (burning solid fuel)	1.8 lb/MMBTU 1-hour
Illinois	Title 35(B)(I)(c)(D)214.161	All boilers (burning distillate oil/diesel)	0.3 lb/MMBTU 1-hour
Oklahoma	Title 252:100-31-25(a)(3)	New fuel-burning equipment (solid fuel-	1.2 lb/MMBTU 24-hour

		fired)	
Oklahoma	Title 252:100-31-25(a)(2)	New fuel-burning equipment (liquid fuel-fired)	0.8 lb/MMBTU 3-hour
Nebraska	Tile 129 Chapter 24 (001)	Existing fossil fuel burning equipment	2.5 lb/MMBTU 2-hour
Kentucky	Title 401 – 61:015 Appendix B	Existing boilers in Class I Counties(100 MMBTU/hr) solid fuel	1.8 lb/MMBTU 24-hour
Kentucky	Title 401 – 61:015 Appendix B	Existing boilers in Class I Counties(200 MMBTU/hr) solid fuel	1.3 lb/MMBTU 24-hour
Kentucky	Title 401 – 61:015 Appendix B	Existing boilers in Class I Counties(100 MMBTU/hr) liq. Fuel	1.2 lb/MMBTU 24-hour
Kentucky	Title 401 – 61:015 Appendix B	Existing boilers in Class I Counties(200 MMBTU/hr) liq. Fuel	0.9 lb/MMBTU 24-hour
Tennessee	Chapter 1200-3-14.02 Table 1	Fuel burning installations (<1000 MMBTU/hr) Class I counties	1.6 lb/MMBTU 1-hour
Tennessee	Chapter 1200-3-14.02 Table 2	Fuel burning installations Class IV counties (Coal)	4.0 lb/MMBTU 1-hour

The most relevant limit for the St. Louis, Missouri RACT evaluation is the existing Illinois limit of 1.8 lb SO_2/MMBTU for Illinois portion of the St. Louis nonattainment area. In addition to these limits, it is important to note that the average Missouri utility boiler emission rate is currently 0.67 lb SO_2/MMBTU (pre-Clean Air Interstate Rule).

Two of the three companies in this group provided a RACT recommendation for consideration by staff. General Motors did not provide a RACT recommendation for consideration of their four coal-fired boilers. The Mallinckrodt proposed recommendation did not include any additional control equipment or fuel switching for control. The cost of any additional control for the Mallinckrodt proposal was well above $10,000 per ton SO_2 reduced. Anheuser Busch proposed a 40 percent reduction in emissions by relying on fuel switching at a cost of nearly $2,000 per ton reduced. However, the cost of installation of scrubbers (95 percent control) on all four boilers was $2,900 per ton reduced.

The department did not choose a technology-based standard (e.g. installation of dry scrubbers on all boilers that have a certain capacity) because a standard on some boilers that would not be economically feasible would be imposed. Therefore, the necessary decision was setting of the limit and averaging time to achieve RACT for these boilers. Several relevant data exist to help with this decision: the limit on Illinois boilers of 1.8 lb/MMBTU using a 1-hour average, the high cost per ton for scrubber installation for the Mallinckrodt boilers, the current utility emission rate of 0.67 lb/MMBTU using an annual average, the current emission rates at boilers except Anheuser-Busch within the St. Louis nonattainment area, and the capability of the Anheuser-Busch boilers to burn lower sulfur fuel.

Based on these data, the RACT team recommended the following emission limit for boilers, 1.0 lb SO_2/MMBTU with a 30-day rolling average (EPA standard practice for long-term standards). During the April 2009 Missouri Air Conservation Commission meeting, the commission adopted the proposed regulation, 10 CSR 10-5.570 Control of Sulfur Emissions From Stationary Boilers, to establish this limit for boilers greater than 50 MMBTU in the St. Louis nonattainment area. This rule also provided a twelve month rolling SO_2 tonnage cap for applicable boilers at Anheuser Busch of 3,050 tons. This limit was designed to allow maximum flexibility for the facility to comply with the regulation and still meet the requirements of RACT. The overall cost to comply with this regulation for Anheuser Busch (based on current fuel cost estimates) was over $6 million. This represents an extremely large financial commitment and provides over 4,000 tons of SO_2 emission reductions in the St. Louis area from the 2012 projected emissions for the facility.

Outside the scope of the new boiler regulation, Trigen has received a permit to decommission the two major coal-fired boilers at the Ashley Street Station (Boiler #5 and #6). When this decommissioning is effective, the boilers at this station will not be required to meet the limits of the boiler regulation due to the use of low-sulfur fuels. Therefore, Trigen will meet the RACT requirements for non-utility boilers.

4.0 Conclusion

The SO_2 and NO_x RACT evaluations identified several sources that would need to limit emissions or codify existing requirements to meet the requirement for reasonable control. Two regulations to limit SO_2 emissions were finalized by the department and are included as part of this plan submittal (primary lead smelting and non-utility boilers). A consent agreement was finalized to codify the use of a NO_x scrubbing system at MEMC's nitric acid bath/etching source. The total amount of SO_2 reduced by these regulations is over 20,000 tons per year in 2012. Further, the reductions will increase to over 40,000 tons per year in future years based on the regulatory strategy adopted by the department. Further, the NO_x emission reductions resulting from the installation of a new preheater/precalciner kiln system at Buzzi Unicem (previously River Cement) will amount to over 3,000 tons per year. The resultant emission reductions and costs associated with those reductions are substantial, but will help reduce overall PM concentrations in the St. Louis area. In conjunction with the IEPA control evaluations and regional/national control measures, these strategies will enable the St. Louis area to attain the NAAQS in 2012.

Attachment

St. Louis PM2.5 Nonattainment Area

RACT Questionnaire

1.) Facility Name?

OVERVIEW

2.) Please provide a brief overview or orientation regarding your process. What is the capacity? Is this capacity limited by permit? What fuels are burned? Do you have the capability to blend or switch fuels? How are the emissions generated? Are there any special considerations that make your process unique? Is there a control device currently in operation at your facility? If so, have you determined its cost of operation and its control efficiency?

3.) Since 2002, have there been any major changes at your facility? Have you installed any emission controls, changed the process, or changed the way that the equipment is operated? Have you accepted permit or other limits that may affect the RACT determination?

TECHNOLOGIES AND COSTS

4.) List the potential emission control technologies (including those suggested in our original meeting invitation letter) in order of effectiveness, and eliminate any technically unfeasible options.

What are the estimated annualized costs associated with each technology? Annual operating costs consist of the financial requirements to operate the control system and include impacts to heat rate (efficiency losses), overhead, maintenance, outages, labor, raw materials, and utilities.

ASSOCIATED CONSIDERATIONS

5.) Are there any issues that are of special consideration when evaluating the various technologies? For instance, are costs significantly higher because there is no room for a new control device, or are there certain chemicals or catalysts that are not compatible with your product?