APPENDIX B THE RACT DOCUMENTS FOR CARMEUSE, U.S. STEEL, DTE RIVER ROUGE AND TRENTON CHANNEL, AND EES COKE

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SO₂ RACT REVIEW Carmeuse Lime & Stone > River Rouge, MI



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Carmeuse Lime & Stone (Carmeuse) owns and operates a lime manufacturing plant in River Rouge, Michigan (River Rouge Facility), consisting of two straight rotary kilns controlled by baghouses that emit through monovents (not traditional stacks) and ancillary equipment. To support development of a State Implementation Plan (SIP) for meeting the 1-hour sulfur dioxide (SO₂) National Ambient Air Quality Standards (NAAQS) in the newly designated nonattainment area in Southeast Michigan, the Michigan Department of Environmental Quality (DEQ), Air Quality Division (AQD), requested a SO₂ Reasonably Available Control Technology (RACT) analysis for the lime kilns at the River Rouge Facility. The following submittal reflects Carmeuse's RACT analysis in response to this request. Given that Carmeuse has only had a limited amount of time or prepare this response, we may supplement our response as needed as your rulemaking process proceeds forward.

In July 2013, the DEQ provided copies of dispersion modeling input files to Carmeuse.¹ These files were used in DEQ's initial modeling analyses to assess culpability for modeled exceedances of the 1-hour SO₂ NAAQS in the Detroit area. These files, along with presentations by DEQ dispersion modelers at Southeast Michigan Council of Government (SEMCOG) meetings in 2013, demonstrated that the River Rouge Facility is not a culpable contributor to monitored exceedances of the 1-hour SO₂ NAAQS at the Southwestern High School monitor. This monitor is the only monitor in the Detroit area at which concentrations in excess of the 1-hour SO₂ NAAQS were observed during 2009-2011, which is the time period used to make a nonattainment designation for the area. Ambient SO₂ concentrations in excess of the NAAQS have not been observed near the River Rouge Facility. However, the DEQ has asked that Carmeuse reduce ambient concentrations based on a "hotspot" dispersion modeling analysis, which showed based on computer model simulations that, under a combination of worst-case meteorological conditions and worst-case emissions from the River Rouge Facility, concentrations in excess of the NAAQS may be possible. Carmeuse does not believe that RACT is applicable to a source that has not been shown to contribute to monitored SO₂ NAAQS exceedances; nevertheless, we are cooperating with this request to submit an SO₂ RACT analysis for the lime kilns at the River Rouge Facility.

¹ Email from Ms. Stephanie Hengesbach of DEQ to Ms. Stacey Rader of Carmeuse, dated July 18, 2013.

Requirements for RACT reviews are provided in the Clean Air Act and in guidance from the United States Environmental Protection Agency (USEPA). As provided in Michigan DEQ's letter requesting the RACT analysis²,

Section 172 of the federal Clean Air Act sets out basic planning requirements for areas not meeting one or more NAAQS. One such plan requirement is the application of RACT controls to existing facilities in the nonattaining area. Subrule (c)(1) of Section 172 states: "Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the National Primary Ambient Air Quality Standards." Further, the {USEPA} says RACT means devices, systems, process modification, or other apparatus or techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain the NAAQS and the social, environmental, and economic impact of such controls.

As outlined above, the sole intent of the RACT review is to establish a reduction strategies for an existing source in a nonattainment area in order to attain and maintain the NAAQS. The following analysis provides Carmeuse's evaluation of technically feasible reduction strategies and the final RACT selection.

3.1. TECHNICAL FEASIBILITY AND AVAILABILITY

For the purposes of reducing Carmeuse's contribution to modeled ambient air impacts greater than the NAAQS, (as the facility was not determined to contribute to monitored exceedances) Carmeuse analyzed the potential use of various reduction strategies for the kilns. The following resources are typically consulted when identifying potential strategies:

- EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
- Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
- Previous engineering experience with similar applications;
- Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
- Review of literature from industrial technical or trade organizations.

Entries from the RBLC and permit reviews are included in Appendix A. Table 3-1 provides a list of the reduction strategies evaluated as potential RACT for the River Rouge Facility lime kilns.

² Letter from G. Vinson Hellwig (DEQ) to Ms. Stacey Rader (Carmeuse) dated December 6, 2013.

SO ₂ Control Technologies
Inherent Dry Scrubbing
Wet Scrubbing
Semi-Wet Scrubbing
Dry Sorbent Injection
Lower Sulfur Fuels
Increased Oxygen Levels
Improved Dispersion

Table 3-1. Reduction Strategies for SO₂

3.1.1. Inherent Dry Scrubbing

Lime and limestone present in the process act as a natural scrubber for SO_2 . This inherent dry scrubbing is an integral part of the process system and is currently in use. This is the base case and will not be considered further as part of this analysis.

3.1.2. Wet Scrubbing

Wet SO₂ scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (that is, limestone, lime slurry, or other alkaline material) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent, using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the SO₂ in the flue gas to form calcium sulfite (CaSO₃) and/or calcium sulfate (CaSO₄) that is removed from the scrubber with the sludge and is disposed. Most wet scrubbing systems utilize forced oxidation to assure that only CaSO₄ sludge is produced. Wet scrubbing with lime is a technically feasible option for controlling SO₂ emissions from a lime kiln.

3.1.3. Semi-Wet Scrubbing

Spray dryer systems operate by injecting a moist sorbent into the scrubber. As the hot flue gas mixes with the sorbent, water is evaporated. This process is sometimes referred to as semi-wet scrubbing. The sorbent is normally lime or calcium hydroxide. The surfaces that are exposed to the solid sorbent react with SO_2 . Semi-wet scrubbing with lime is a technically feasible option for controlling SO_2 emissions from a lime kiln.

3.1.4. Dry Sorbent Injection

In a dry sorbent injection (DSI) system, sodium or calcium based sorbent is injected into the gas stream to react with SO_2 to form Na_2SO_4 or $CaSO_3$ which is then collected in the kiln's baghouse. Sorbent injection is an available and proven technology for SO_2 control on boilers. However, sorbent injection is not included in the RBLC database for lime kilns and Carmeuse has been unable to identify a demonstrated application of this technology on existing lime kiln operations for SO_2 reduction. The temperature profiles in lime kiln exhaust streams are different than those of a boiler; as such, the absorption processes upon which this technology is dependent could be less efficient, resulting in decreased SO_2 removal efficiencies. Consequently, there is no data available with which to establish an expected SO_2 control efficiency and corresponding RACT emission limit. Furthermore, a recent EPA supported study for cost development methodology for a DSI system indicated a target removal rate

of 70% when a baghouse system is used for boilers.³ If levels of control targeted for boilers could be achieved in a kiln, this level is still not appreciably different than the typical 60-80% reduction in SO_2 achieved through inherent dry scrubbing for the River Rouge Facility kilns. Therefore, claiming any additional control from the use of DSI in addition to the inherent dry scrubbing within a straight rotary kiln is speculative and would likely require pilot studies to assess feasibility and potential effectiveness. For all these reasons, DSI it is not a technically feasible option.

3.1.5. Lower Sulfur Fuels

One of the main sources of SO_2 emissions from a lime kiln is sulfur in the kiln's fuel. Decreasing the amount of sulfur in the fuel could potentially decrease SO_2 emissions; therefore, this is a technically feasible option.

3.1.6. Increased Oxygen Levels

Increasing oxygen levels at the burner causes a reaction between oxygen (O_2) and SO_2 to form sulfur trioxide (SO_3) which, in turn, reacts with lime to form $CaSO_4$. The $CaSO_4$ is then incorporated into the lime product, which decreases product quality in relation to customer demand. As such, this technology is not technically feasible for use in a lime kiln and will not be discussed further.

3.1.7. Improved Dispersion

As previously stated, the River Rouge facility has not been demonstrated to contribute to any monitored NAAQS exceedances. Rather, DEQ's request is based on a "hotspot" dispersion modeling analysis, which showed based on computer model simulations that, under a combination of worst-case meteorological conditions and worst-case emissions from the River Rouge Facility, concentrations in excess of the NAAQS may be possible. If Carmeuse can refine the release characteristics for the kiln stacks to improve dispersion and reduce the ambient impacts in DEQ's analysis to below the NAAQS, then use of add-on control technologies or other reduction strategies is not required. This was a reduction option specifically identified in MDEQ's RACT analysis submittal request and is a technically feasible option.

3.2. COST EVALUATION AND OTHER IMPACTS

As noted above, reducing Carmeuse's contribution to modeled ambient air impacts greater than the NAAQS (not actual monitored exceedances) is achievable through emissions reductions or using improved dispersion. Therefore, the cost evaluation for this RACT analysis is based on the current dollar value on an annualized basis in order to allow for accurate comparison of each reduction strategy. Given the brief time available to prepare the analysis, some site specific factors contributing to control costs have not been factored in (e.g., potentially severe constraints on available space at this facility for new equipment). Therefore, actual cost could potentially be higher than presented in this analysis.

3.2.1. Wet Scrubbing

There are multimedia implications to the use of wet scrubbing. The sludge from wet scrubbing creates a solid waste handling and disposal problem. This sludge must be handled in a manner that does not result in groundwater contamination. Also, the sludge disposal area needs to be permanently set aside from future

³ Sargent & Lindy LLC. *IPM Model – Revisions to Cost and Performance for APC Technologies: Dry Sorbent Injection Cost Development Methodology.* August 2010. 14 Jan. 2014. http://www.epa.gov.

surface uses since the disposed material cannot bear any weight from such uses as buildings or cultivated agriculture.

Disadvantages associated with wet scrubbing with lime also include the creation of a visible wet stack with a visible plume of water droplets, generation of particulate matter by the scrubbing process causing elevated opacity, increased water consumption, and wastewater and sludge disposal issues. Wet scrubber systems for both kilns have an annualized cost of \$6,000,000 per year, not including the cost of building and maintaining a system to handle the large amount of wastewater sludge generated by the scrubber or the cost of installing new kilns stacks after the wet scrubbers.⁴ Furthermore, space limitations specific to the River Rouge Facility could further increase installation costs and costs associated with lost revenue for temporary kiln shutdowns needed to allow for scrubber installation. Note that the costs may be reduced slightly by routing the kilns to a single control device, but such a control scenario would greatly reduce operational flexibility due to the reliance of all production on a single control device. Cost calculations for this control technology are included in Appendix B.

3.2.2. Semi-Wet Scrubbing

The process of semi-wet scrubbing forms a dry waste product that is collected in a baghouse. The performance of the semi-wet system is sensitive to operating conditions and its performance cannot be assured without additional temperature control devices. Environmental disadvantages of this system include the production of dry waste, which requires landfill disposal and water usage, in place of the lime kiln dust (LKD), a saleable product in the current kiln design.

A cost estimate was prepared to evaluate the economic feasibility of a semi-wet scrubber for the proposed kiln. Semi-wet scrubber system for both kilns have an annualized cost of \$4,700,000 per year, not including the increased cost of handling and processing the waste collected in the baghouse or the value of losing saleable LKD product. Furthermore, space limitations specific to the River Rouge Facility could further increase installation costs and costs associated with lost revenue for kiln shutdowns needed to allow for scrubber installation. Combining exhaust streams for control by a single control device will limit operational flexibility due to the reliance on a single control device to operate both kilns and is therefore not considered in this analysis. Cost calculations for this control technology are included in Appendix B.

3.2.3. Lower Sulfur Fuels

Using 2010 to 2013 data, the average sulfur content of coal used at the River Rouge facility is 1.0 % as received. Due to increasing demand for lower sulfur coal, it is becoming more difficult to guarantee availability of coal with a lower sulfur content than that currently used. Carmeuse's plant in Gary, Indiana (Buffington Plant), currently uses at coal with 0.65 % sulfur. However, this is an increase from previous agreements with the supplier to provide 0.5 % sulfur coal, and was subjected to a recent increase in price. Furthermore, low sulfur coal is often tied to higher ash contents or other downgrades in coal quality, which could increase the number of kiln shutdowns needed to remove ash rings from the kiln. The limited availability, unpredictable cost, and potential coal quality concerns associated with making a modest reduction from 1.0 % low sulfur coal to an even lower 0.65 % indicate that use of lower sulfur coal is not a reasonably available reduction strategy and will not be further evaluated as part of this RACT analysis.

⁴ The current kiln exhausts consist of monovents situated atop the baghouses. Because the wet scrubbers would be located after the baghouse, new kiln stacks would be needed.

3.2.4. Improved Dispersion

The estimated cost of installing a new stack to improve dispersion characteristics and meet the NAAQS is \$750,000/yr. Cost calculations for this reduction strategy are included in Appendix B. This cost evaluation is based on installation of a stack that would reduce the ambient impacts of DEQ's hotspot modeling analysis to levels below the NAAQS without the use of add-on controls or other reduction technologies.

3.3. ESTABLISH RACT

In order to accurately compare the costs for each reduction strategy, the cost of each option on a dollars per year basis is provided in the table below.

SO ₂ Reduction Strategy	Cost (\$/yr)
Wet Scrubbing	6,000,000
Semi-Wet Scrubbing	4,700,000
Improved Dispersion	750,000

Table 3-2. Annual Cost Comparison

In addition to higher annual cost, use of a wet scrubber will result in adverse environmental impacts, including increased opacity, generation of particulate matter, generation of sludge requiring disposal and treatment while use of the semi-wet scrubber could result in uneven performance and the generation of dry waste in place of the currently saleable LKD product. Furthermore, actual cost for the wet scrubbing systems would be higher than those presented after incorporating costs for new stacks and construction and operation of sludge processing systems. Similarly, actual costs for the semi-wet scrubbing systems would be higher than those presented after accounting for increased cost of solid waste disposal and the revenue lost from the previously saleable LKD product. Each scrubbing option could also result in additional costs or feasibility concerns due to the limited footprint available for installation of additional controls at the River Rouge Facility.

Taking all of these factor into consideration and given that the River Rouge facility is not contributing to any monitored SO₂ NAAQS violations, we propose that increased dispersion be considered RACT. Furthermore, we specifically request that any RACT requirement established as a result of this modeled hotspot include flexibility for Carmeuse to use alternative means to achieve a similar or better result than solely relying on increased dispersion should Carmeuse deem an alternative necessary.

APPENDIX A: RBLC AND PERMITS REVIEW

EPA RBLC Database and Permits Review - Kiln SO2 NSR Projects 2004 to Current

Year	Company	Facility	RBLC	Product	Fuel	Design	Project Description	Production Rate	Add-On Controls	Continuous Monitoring	Normalized SO ₂ (Ib/t lime produced)	SO₂ BACT	SO ₂ Limit / Emission Factor	Sulfuric Acid Mist Limit / Emission Factor
2012	Graymont	Pleasant Gap	PA-0283 (draft)	CaO	natural gas	vertical	Kiln 8	660 tpd lime	baghouse	SO ₂ NO _x and CO CEMS	0.8	(a) use of a vertical kiln and (b) good operating practices within the kiln	23.0 lb/hr 30 day rolling avg 500 ppmvd	
2010	Mississippi Lime	Prairie du Rocher	IL	CaO	coal coke	preheater	New preheater rotary kilns (2)	2400 tpd lime for two kilns	Baghouse	SO ₂ NO _x and CO CEMS	0.65	Inherent dry scrubbing	0.645 bs/ton lime daily 24-hr avg 32.3 lb/hr 3-hr avg each 141.5 tpy each	
2010	Vulcan	Monteno	IL	MgO	coal pet coke	preheater	Modification to install spray dryer absorber shorten the length of the kiln and install a pre-heater tower - facility has been idled	600 tpd lime	spray dryer absorber and Baghouse	SO ₂ NO _X and CO CEMS	4.3	spray dryer absorber and Baghouse	on actual k ln emissions 119 lb/hr 3-hr avg 119 lb/hr 24-hr avg 473.0 tpy	
2010	Synergy Management	White County	IN	MgO	coal pet coke	preheater	New preheater rotary kilns (2)	900 tpd lime each	Baghouse	none	2.00	proper kiln design and operation (inherent scrubbing)	2.0 lb/ton l me 3-hr avg 6 lb/mmbtu 75.0 lb/hr 3-hr avg	
2009	Graymont	Superior	WI-0250	CaO	coal pet coke	preheater	Modification to Kiln 5	650 tpd lime	Baghouse	SO ₂ NO _x and CO CEMS	1.2	use of a preheater type rotary kiln with a high temperature / membrane fabric filter Baghouse that ach eves at least 92% collection / retention of potential sulfur dioxide emissions and (b) a Usifur content limit of 2.0% (by weight)	0.62 lbs/tsf (stone) 24-hr rolling avg 33.7 lbs/hr 3-hr rolling avg	1.5000 lb/hr sulfuric acid mist
2008	Martin Marietta Magnesia Specialties	Sandusky	OH-0321	MgO	coal pet coke NG	preheater	New rotary kiln - Kiln 7	900 tpd lime 37.5 tph lime	Baghouse		1.70	no add-on controls found cost effective - Fuel sulfur content limit back calculated	1.7 lbs/t lime 279.23 tpy 12-month rolling	
2007	Mississippi Lime	Verona	KY	CaO	coal pet coke	preheater CFB	New rotary kilns (2)	840 tpd lime each	Baghouse		0.4	CFB fuel sulfur lower than tested value	12.25 lb/hr 3-hr avg 0.35 lb/t lime 30-day avg	
2007	Graymont	Pleasant Gap	Minor NSR	CaO		preheater	Modification to permit for new preheater rotary k ln - Kiln 7		Baghouse and semi wet caustic scrubber					
2006	Graymont	Superior	WI-0233	CaO	coal pet coke	preheater	New kiln - Kiln 5	650 tpd lime	Baghouse		1.24	2% sulfur in fuel - assumes 92% CE from inherent scrubbing of gas in Baghouse	0.62 lb/t stone feed 24-hr avg 33.7 lb/hr 3-hr avg	1.5 lb/hr sulfuric acid mist Acid gas HAPs controlled by reaction with lime in kiln preheater and Baghouse (92% CE)
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 1 (increase fuel S content)	600 tpd lime	Baghouse	SO ₂ CEMS	0.6	3% sulfur	14 lb/hr 3-hr avg	
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 2 (increase fuel S content)	800 tpd lime	Baghouse	SO ₂ CEMS	0.6	3% sulfur	21 lb/hr 3-hr avg	
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 3 (increase fuel S content)	1200 tpd lime	Baghouse	SO ₂ CEMS	0.7	3% sulfur	33.6 lb/hr 3-hr avg	
2006	Dakota Coal	Frannie Plant		CaO	coal pet coke	rotary	Modification to kiln (increase SO ₂ limit from 9 to 12 lb/hr and related new coal mill installation)	500 tpd lime	Baghouse	NO _x CEMS	0.58	inherent scrubbing	12 lb/hr 52.6 tpy	

EPA RBLC Database and Permits Review - Kiln SO2 NSR Projects 2004 to Current

Year	Company	Facility	RBLC	Product	Fuel	Design	Project Description	Production Rate	Add-On Controls	Continuous Monitoring	Normalized SO ₂ (Ib/t lime produced)	SO₂ BACT	SO ₂ Limit / Emission Factor	Sulfuric Acid Mist Limit / Emission Factor
2005	Chemical Lime	O'Neal Plant	AL-0220	CaO	coal	preheater	New preheater rotary kiln and modification to existing kiln (same limits for both)	1500 tpd lime		SO ₂ CEMS	1.4	not specified	2.05 lb/t lime 24-hr avg 1.4 lb/t 12-month avg 128.12 lb/hr 3-hr avg 383.25 tpy 12-month rolling	
2005	Arkansas Lime	Batesville	AR-0082	CaO	coal coke NG	preheater	New rotary preheater kiln - Kiln 3	687 tpd lime	Baghouse	O ₂ Monitor	1.13	dry scrubb ng by lime prod. 92%CE 4%S daily avg 3%S 30-day rolling avg	44.8 lb/hr 141.6 tpy	
2005	Western Lime	Port inland	MI-0383	CaO	#2 FO propane coal pet coke	preheater	New rotary preheater kiln - Kiln 1	870 tpd	Baghouse	NO _x CEMS	1.5	2.5% sulfur in fuel monthly average	60.2 lb/hr monthly basis 242 tpy 12-month rolling (hourly limit was based upon 0.83 pounds per ton of stone feed)	
2004	Graymont	Pleasant Gap	PA-0241	CaO	coal pet coke	preheater	New preheater kiln - Kiln 6	1200 tpd	Baghouse	SO ₂ CEMS	2.61	annual average fuel sulfur content of 2%	305 lb/hr 3-hr block avg 571 tpy 12-month rolling 500 ppm 1-hr avg	
2004	Graymont	Pleasant Gap	PA-0241	CaO	coal pet coke	rotary	New rotary kiln - Kiln 7	1050 tpd	Baghouse and caustic scrubber meeting 93%CE	SO ₂ CEMS	1.11	scrubber and FO limit of 0.5%S annual average fuel sulfur content of 3%	92.83 lb/hr 3-hr block avg 213 tpy 12-month rolling 500 ppm 1-hr avg	

		Page (1 of 2)
Direct Costs		
Purchased Equip	ment Costs	
	Wet Scrubber Unit	\$3,190,000
	Instrumentation (10% of EC)	\$319,000
	Sales Tax (3% of EC)	\$95,700
	Freight (5% of EC)	\$159,500
	Subtotal, Purchased Equipment Cost	(PEC) \$3,764,200
Direct Installation	n Costs (Handling and Erection included in wet scrubber cost)	
	Foundation (6% of PEC)	\$225,852
	Supports (6% of PEC)	\$225,852
	Electrical (1% of PEC)	\$37,642
	Piping (30% of PEC)	\$1,129,260
	Insulation for Ductwork (1% of PEC)	\$37,642
	Painting (1% of PEC)	\$37,642
	Subtotal, Direct Installation	n Cost \$1,693,890
Site Preparation		Not Quantified
Buildings		Not Quantified
Sludge Processing	g System	Not Quantified
Engineering and I	Design Consideration for Limited Available Footprint	Not Quantified
New Stack ¹		Not Quantified
	Total Direc	t Cost \$5,458,090
ndirect Costs		
	Engineering (8% of PEC)	\$301,136
	Construction Fee (3% of PEC)	\$112,926
	Construction and Field Expense (10% of PEC)	\$376,420
	Start-up (1% of PEC)	\$37,642
	Performance Test (1% of PEC)	\$37,642
	Total Indirec	t Cost \$865,766
	Total Direct and Indirect Costs (TDIC)	\$6,323,856
	Contingency (3% of TDIC) per CCM	\$189,716
Post Scrubber Baghouse		
	Total Direct and Indirect	t Cost \$10,000,000
		\$16,513,572

¹ The current stack for each kiln is an extension of the baghouse vents. Since the wet scrubber must be installed after the baghouse, new stacks will be required.

		Page (2 of 2
nual Costs		
Hours per Year (365 day	s per year, 24 hours per day)	8,76
Operating Labor		
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$26.15/hr)	\$14,31
	Supervisor (15% of operator)	\$2,14
	Subtotal, Operating Labor	\$16,46
Maintenance		
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$19.34/hr)	\$10,58
	Material (100% of maintenance labor)	\$10,58
	Subtotal, Maintenance	\$21,17
Variable O & M		
	Electricity	
	Pump (kW)	489.4
		\$0.0785 \$336,54
	Subtotal, Electricity	\$550,54
	Limestone Slurry	
	Amount Required (ton/yr)	91
		\$89.0 \$81,19
	· · · ·	Ş61,19
	Subtotal, Sludge Processing	Not Quantified
	· · · · · · · · · · · · · · · · · · ·	
	Subtotal, Variable O & M	\$417,74
	Total Direct Annual Costs	\$455,38
nnual Costs	of an anting any maintenance labor 0 materials)	\$71,304.2
	of operating, supervisor, maintenance labor & materials)	\$71,304.2 \$330,27
		\$165,13
Insurance (1% TCI)		\$165,13
Capital Recovery	(15 year life, 7 percent interest)	\$1,813,10
	Total Indirect Annual Cost	\$2,544,94
	Total Annualized Cost (per scrubber)	\$3,000,33
		\$6,000,67
		55
		49
	Cost Per Ton of Pollutant Removed assuming 90% removal	\$6,04
	Kiln 2	
	Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr)	58
	Pollutant Removed (tons SO ₂ /yr) assuming 90% removal Cost Per Ton of Pollutant Removed assuming 90% removal	52 \$5,72
-	Overhead (60% of sum of Administrative (2% TCI) Property Tax (1% TCI) Insurance (1% TCI)	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$26.15/hr) Subtotal, Operating Labor Maintenance Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$19.34/hr) Material (100% of maintenance labor) Subtotal, Maintenance Variable 0 & M Electricity Pump (kW) Cost (\$/kW-hr) Subtotal, Electricity Limestone Slurry Amount Required (ton/yr) Cost (\$/ton) Sludge Processing Subtotal, Sludge Processing Subtotal, Variable 0 & M Total Direct Annual Costs Overhead (60% of sum of operating, supervisor, maintenance labor & materials) Administrative (2% TCI) Property Tax (1% TCI) Insurance (15% TCI) Capital Recovery Total Annualized Cost (per scrubber) Total Annualized Cost (per scrubber) Total Annualized Cost (klin 1 and Klin 2 scrubers) Klin 1 Pollutant Emission Rate Prior to Scrubber (tons S0 2/yr) Pollutant Removed (tons S0 2/yr) assuming 90% removal Cost Per Ton of Pollutant Removed assuming 90% removal Kiln 2 Pollutant Emission Rate Prior to Scrubber (tons S0 2/yr) </td

ect Costs		Page (1 of
Purchased Equipment Costs		
	Supply Price	\$6,056,77
Direct Installation Costs		
	Installation Price	\$3,579,00
Site Preparation		Not Quantified
Buildings		Not Quantified
Engineering and Design Consideration for Limited Available Footprint		Not Quantified
Total Capital Investment (TCI)		\$9,635,78

Semi-Wet Scrubber Cost	3	Page (2 of 2)
Direct Annual Costs	r (365 days per year, 24 hours per day)	8,760
nouis per rea		6,700
Operating Lab		
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$26.15/hr)	\$14,317
	Supervisor (15% of operator) Subtotal, Operating Labor	\$2,148 \$16,465
	Subtotal, Operating Labor	\$10,403
Maintenance		
	abor (0.5 hr/shift, 3 shifts/day, 365 d/yr, \$19.34/hr).	\$10,589
<u> </u>	Material (100% of maintenance labor)	\$10,589
	Subtotal, Maintenance	\$21,177
Variable O & N	Λ	
	Electricity	
-	Pump (kW)	489.41
(Cost (\$/kW-hr)	\$0.0785
	Subtotal, Electricity	\$336,549
	Hydrated Lime (Reagent)	
	Amount Required (ton/yr)	1,276
	Cost (\$/ton)	\$250.00
-	Subtotal, Lime	\$319,056
_	Solid Waste	
	Solid Waste Processing Losses of Saleable Lime Kiln Dust (LKD)	Not Quantified Not Quantified
<u>-</u>	Subtotal, Solid Waste	Not Quantified
_	·	-
-	Subtotal, Variable O & M	\$655,605
		A c c c c c c
	Total Direct Annual Costs	\$693,247
Indirect Annual Costs		
Overhead (609	% of sum of operating, supervisor, maintenance labor & materials)	\$214,019
Administrative		\$192,716
Property Tax (\$96,358
Insurance (1%		\$96,358
Capital Recove	ery (15 year life, 7 percent interest) Total Indirect Annual Cost	\$1,057,957 \$1,657,407
	Total Annualized Cost (per scrubber)	
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers)	
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1	\$2,350,653 \$4,701,307
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1 Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr)	\$4,701,307 552
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1 Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr) Pollutant Removed (tons SO ₂ /yr) assuming 90% removal	\$4,701,307 552 497
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1 Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr) Pollutant Removed (tons SO ₂ /yr) assuming 90% removal Cost Per Ton of Pollutant Removed assuming 90% removal	\$4,701,307 552
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1 Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr) Pollutant Removed (tons SO ₂ /yr) assuming 90% removal Cost Per Ton of Pollutant Removed assuming 90% removal Kiln 2	\$4,701,307 552 497 \$4,733
1	Fotal Annualized Cost (Kiln 1 and Kiln 2 scrubbers) Kiln 1 Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr) Pollutant Removed (tons SO ₂ /yr) assuming 90% removal Cost Per Ton of Pollutant Removed assuming 90% removal	\$4,701,307 552 497

	ct Costs			
			Total Capital Investment (TCI)	\$5,600,000
Direct Annual Cos	sts			
Operat	ting Labor and	Supervision		Negligible
Mainte	enance Labor a	and Materials		Negligible
EI		Italia ta sana sa ta sana sa alao a ƙasar ƙwallon ƙ	1-1	Mogligible
Electric	city (assume ne	egligible increase in pressure drop for new stac	к)	Negligible
Electric	city (assume n	egligible increase in pressure drop for new stac	K) Total Direct Annual Costs	st \$
		egligible increase in pressure drop for new stac		
Indirect Annual Co	osts			\$0
Indirect Annual Co Genera	osts	trative (2% TCI)		\$112,000
Indirect Annual Co Genera Propert	Costs al and Adminis ty Tax (1% TCI)	trative (2% TCI)		
Indirect Annual Co Genera Propert Insuran	Costs al and Administ	trative (2% TCI)		\$112,000 \$56,000

UNITED STATES STEEL CORPORATION GREAT LAKES WORKS SO₂ Reasonably Achievable Control Technology Evaluation

Prepared for:



United States Steel Corporation Great Lakes Works

Prepared by:



CB&I Environmental & Infrastructure, Inc. 2790 Mosside Boulevard Monroeville, PA 15146

Project No. 151439 March 2014



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1.0 Executive Summary

The Reasonable Available Control Technology (RACT) analysis included an evaluation of available SO₂ controls for the following emission units at United States Steel Corporation (USS) Great Lakes Works (GLW):

- Hot Mill Reheat Ovens,
- Boiler Houses 1 and 2, and
- Related Flares

There are five (5) furnaces associated with the Hot Mill Reheat Ovens. The Hot Mill is located between Zug Island and the main USS GLW plant in the City of River Rouge. Each boiler house contains five (5) boilers and an associated flare. Boiler Houses 1 and 2 and associated flares are all located on Zug Island at the primary iron producing facility.

Add-on SO_2 controls including Dry Sorbent Injection (DSI), Spray Dryer Absorber (SDA), and wet scrubbers were all evaluated as part of the RACT analysis. Each of these add-on control devices were considered theoretically feasible. Due to the challenges associated with retrofitting a stand-alone control device at an existing source, it was concluded that a more detailed engineering analysis would be needed before each of these controls could be considered technically feasible. The cost effectiveness of each of these technologies was cost prohibitive, and was therefore rejected as RACT.

Alternative SO₂ controls including fuel switching, fuel blending, and increased dispersion were all evaluated for the RACT analysis. Each alternative control was considered technically feasible. Increased dispersion was determined to be cost prohibitive and rejected as RACT. Fuel switching and fuel blending were both considered technically feasible for Boiler House 1 and 2 and the Hot Mill Reheat Ovens. However, fuel switching was rejected because it was not considered economically feasible and would result in significant collateral impacts that must be considered, and are generally converse to implementation of RACT. Our analysis indicates that fuel switching would result in a Prevention of Significant Deterioration (PSD) significant emission increase (SER) of other pollutants at the USS GLW plant, and would not result in a "real" reduction in SO₂ emissions; and would increase emissions of other pollutants in the area. The fuel switching analysis evaluated substituting natural gas for coke oven gas (COG). If COG is not used in the Boiler Houses or Hot Strip Mill, it must be flared at the adjacent metallurgical coke plant. This does not result in any reduction in SO_2 emissions and could actually increase overall SO_2 emissions, as well as other pollutants, in the area since additional natural gas would be burned to substitute for the loss in COG, while the COG is being flared at the coke plant simultaneously. The additional COG flaring could significantly increase emissions at the adjacent coke plant for pollutants such as nitrogen oxides (NOx), thereby resulting in collateral impacts affecting ambient air quality, including possibly preventing the area from attaining the National Ambient Air Quality Standards (NAAQS) with the 1-hour NOx standard.



CB&I concluded that the most reasonable SO_2 control that was both technically and economically feasible is fuel blending. Fuel blending involves using various fuel blends to achieve an overall lower fuel sulfur level. During calendar year 2013, the average SO_2 emission rate for USS GLW's emission units subject to the RACT analysis was 0.32 lb/MMBtu. CB&I recommends that USS GLW propose an emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate of Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. This value represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. Additionally, this emissions level results in a 15% reduction of SO_2 emissions from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ and satisfies the definition of RACT. It should be noted that a short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. Further, in the event operations are interrupted due to process upsets and temporary fuel loss situations (e.g. loss of BFG), an alternate SO_2 emission limit for this operating scenario would need to be established.



2.0 Introduction

On June 11, 2011 the Michigan Department of Environmental Quality (MDEQ) submitted its recommended designations to U. S. Environmental Protection Agency (USEPA) for the new 1-hour SO₂ National Ambient Air Quality Standards (NAAQS). This included recommending that a sub-boundary in Wayne County, south of the Southwestern High School (SWHS), be designated non-attainment for this standard. As part of the SO₂ emission reduction strategy for this area, the MDEQ subsequently submitted a letter to USS GLW on December 6, 2013 requesting that a RACT analysis be completed for the hot mill reheat ovens, boiler houses 1 and 2, and related flares. In the RACT letter, MDEQ indicated that the SO₂ reduction strategies should include add-on control equipment, process modifications, fuel switching/cleaning, and increased dispersion. USS contracted with CB&I Environmental & Infrastructure, Inc. f/k/a Shaw Environmental, Inc. (CB&I) to provide assistance with conducting the RACT.

RACT is defined in the Code of Federal Regulations (40 CFR 51.100) as "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls; and (3) Alternative means of providing for attainment and maintenance of such standard. (This provision defines RACT for the purposes of \$51.341(b) only.)" Specific Federal or Michigan guidance on conducting a RACT analysis was not available for SO₂; therefore, a "Top-Down" approach similar to a Best Available Control Technology (BACT) analysis was selected. The only exception to this approach is that RACT requires sources to adopt controls that are reasonably available and thus may not be the most stringent controls that have been adopted by other similar sources such as the best available control as required in a BACT analysis. MDEQ has requested that USS evaluate enhanced dispersion in the RACT analysis; therefore, enhanced dispersion from each of the emission units was evaluated as a form of control that reduces the ground level impact of SO₂ emissions.

A source of control technology information is the RACT/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database. The RBLC is an EPA-sponsored database that lists previously EPA-approved RACT/BACT/LAER determinations. CB&I consulted this database as the first step in developing a list of the most recent RACT/BACT/LAER decisions for similar sources, including blast furnace operations and boilers of various size ranges. The results of the RBLC search are summarized in Appendix A of this analysis.

The RACT analysis includes an evaluation of available add-on SO_2 controls as well as alternative forms of emission controls for each of the requested emission units by MDEQ. A technical feasibility and cost analysis evaluation was performed to determine the suitability of each of the identified SO_2 control options as RACT.



3.0 Basis of RACT Analysis Request by MDEQ

The USEPA revised the primary NAAQS for SO_2 on June 2, 2010. The USEPA replaced the 24-hour and annual SO_2 standards, set in 1971, with a new short-term standard based on the 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum SO_2 concentration. The new level was set at 75 parts per billion (ppb). In accordance with Section 107 of the federal Clean Air Act (CAA), within one year of a new or revised NAAQS, states were to submit designation recommendations to the USEPA. The recommendations were to include the boundaries for areas to be designated as nonattainment. The USEPA issued a guidance memorandum on March 24, 2011, to direct states on the SO_2 designation process and time line.

On June 11, 2011 the MDEQ submitted its recommended designations to USEPA for the new 1-hour SO_2 NAAQS. The MDEQ recommended a sub-county boundary in Wayne County, Michigan as nonattainment and the remainder of Wayne County as unclassifiable. As part of the SO_2 emission reduction strategy, the MDEQ subsequently submitted a RACT request to USS GLW on December 6, 2013. The request stated that the RACT was limited to the following emission units at USS GLW:

- Hot Mill Reheat Ovens,
- Boiler Houses 1 and 2, and
- Related Flares

In the RACT letter, MDEQ indicated that the SO_2 reduction strategies should include add-on control equipment, process modifications, fuel switching/cleaning, and increased dispersion. Each analysis, with the exclusion of dispersion modeling, is to include an estimation in reduced annual SO_2 tons and an associated cost evaluation in dollars per ton reduced.



4.0 RACT Analysis Approach for SO₂

As previously discussed, there is no specific guidance on completing a RACT analysis for SO₂. Consequently, the "Top-Down" BACT approach was used as a guidance tool to complete the RACT analysis for USS. The "Top Down" approach starts with the top technology that has been applied to similar emissions units. To utilize the "Top-Down" approach, commercially available control options for each applicable pollutant, which in this case includes SO₂ only, are identified. Technically infeasible alternatives are then eliminated, and the remaining control options are analyzed and ranked according to control effectiveness. The top control technology is either accepted or rejected based on technical or economic infeasibility. If the top control technology is rejected, the next most stringent control technology is either accepted or rejected. The top-down approach is continued until a control technology, which is found to be both technically and economically feasible, is accepted. To select a RACT option, the following items are evaluated: cost effectiveness, environmental effects, energy impacts, and sitespecific factors. The control technology selected provides a reasonable level of control without causing adverse economic, energy, or environmental impacts. Generally, the cost effectiveness parameter is stated as either total or incremental annualized dollar cost per ton of pollutant abated. The following steps provide a general outline of the "Top-Down" process that was generally implemented for this RACT analysis. In practice, each step may not apply, and the steps may be overlapped, combined, or undertaken in a different order depending on the specific emission units and considerations involved.

Step 1 – Identify All Control Technologies

The first step in this RACT approach is to define the spectrum of process and/or add-on control alternatives that will be considered potentially applicable to the emissions unit.

Step 2 – Eliminate Technically Infeasible Options

The second step in this RACT approach is to evaluate the technical feasibility of the alternatives identified in Step 1 and to reject those which are technically infeasible based on engineering evaluation or on chemical or physical principles. Criteria that may be considered in determining technical feasibility include previous commercial state demonstrations, precedents based on previous permits, technology transfer from similar sources, and limitations imposed by existing equipment design of the emissions unit under review.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

In Step 3 the alternatives are ranked into a control hierarchy from most to least stringent. To the extent practical, this involves an assessment and documentation of the emissions control level or emissions limit achievable with each technically feasible alternative, considering the specific operating constraints of the emissions units undergoing review. Generally accepted control efficiencies or ranges of control efficiencies may be presented where detailed information for the specific emissions unit is not available.



Step 4 – Evaluate Most Effective Control Options and Document Results

If the top-ranked technically feasible control is not selected, Step 4 is to evaluate and document the cost, economic, environmental, and energy impacts of the top or most stringent technique. To reject the top alternative, it must be demonstrated that this control alternative is not the most reasonable control based on the results of the impacts analysis. If a control technology is determined to be infeasible based on high cost effectiveness, or to cause adverse economic, energy or environmental impacts (including toxic pollutant impacts) that would outweigh the benefits of the additional emissions reduction as compared to a lower ranked control, then the control technology is rejected and the next most stringent control alternative is considered in turn.

Step 5 – Select RACT

The proposed RACT is the option with the most reasonable control effectiveness that was not eliminated based on consideration of cost, economic, energy or environmental impacts.

4.1 Cost Determination Methodology

Economic analyses of RACT alternatives were performed to compare capital and annual costs in terms of cost effectiveness (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system (spray dryer absorber (SDA), for example, includes spray dryer tower, baghouse, stack, induced draft fan, support frame, ductwork, lime silo, piping, atomizer equipment, instrumentation, monitoring equipment, and installation costs). Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities.

4.1.1 Capital Costs

The capital cost estimating technique used in this analysis is based on a combination of cost data from the Coal Utility Environmental Cost (CUECost) model, the factored cost estimating technique presented in the latest USEPA guidance manual for estimating control technology costs Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, and vendor quotes. Capital cost estimates generated from CUECost were inserted into the factored cost estimate format presented in the OAQPS manual. Line item costs included in the OAQPS Control Cost Manual estimating method that were not provided in the CUECost workbook were factored from Total Capital Cost using the appropriate Control Cost Manual factor. Due to variations in the output format of CUECost, merging of the cost estimating data into OAQPS Control Cost Manual format were each slightly different for the wet scrubber, SDA, and dry sorbent injection (DSI) analysis, depending on the form that the estimates were reported in CUECost.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These include such items as reagent storage and supply piping and distributed controls. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems, and their auxiliary equipment.



Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup and performance testing, working capital, interest during construction, and allowance for funds during construction.

4.1.2 Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Like the capital costs, the annualized costs were obtained from both CUECost and the OAQPS Manual. The estimates reported by CUECost were used as the primary source, and the USEPA factors were used to fill in remaining information.

Direct annual operating costs include the costs of labor, maintenance, materials, utilities, and replacement components necessary for the operation of the control equipment. Indirect costs consist of funds allocated for overhead, property taxes, and administration.

To determine the total annualized cost, it is necessary to calculate the capital recovery factor (CRF). The CRF is defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i = the annual interest rate of the loan and

n = the equipment economic life (years).

The lifetime was assumed to be 15 years. The average interest rate was assumed to be 7 percent. CRF was therefore calculated to be 0.1098.

4.1.3 Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its potential annual pollutant emission reduction which was based on 2010 emission estimates. Cost effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical tons of pollutant removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on information contained in USEPA literature, and from engineering estimates. The cost effectiveness of each control system in units of dollars per ton of pollutant removed is described within respective sections of the RACT evaluations.



5.0 Dispersion Modeling Approach for SO₂

5.1 Dispersion Modeling Approach

In MDEQ's RACT request, one RACT option mentioned was increased dispersion of the emissions. Increased dispersion can be achieved by altering the parameters of the emission source exhaust. CB&I evaluated the increased dispersion option by altering the stack height of the emission sources in order to obtain a change in 1-hr SO₂ concentration, which is further discussed in Sections 6.1.5 and 7.1.5. USS supplied CB&I with a baseline modeling file that contained the source parameters and other modeling options as noted below. For SO₂, the 1-hour standard promulgated by USEPA in June 2010 is the 99th percentile (equivalent to the 4th highest daily maximum (H4H)) concentration averaged over three years.

5.1.1 Modeling Program

The increased dispersion evaluation was conducted using the latest version (13350) of AERMOD since this is the model used by MDEQ; as recommended by USEPA. The AERMOD model is an USEPAapproved model that was introduced to incorporate air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

5.1.2 Urban or Rural Dispersion Option

According to the modeling input files provided by USS, the land use surrounding the area is classified as rural. Therefore, the rural option was selected in the modeling analysis. Although the rural option was selected, stacks less than 150 feet high were modeled using the urban option as based on the MDEQ model.

5.1.3 Land Use and Terrain

The modeling input file obtained from USS included terrain elevations for the facility sources as well as the modeled receptor.

5.1.4 Meteorology

AERMOD requires hourly surface meteorological data and twice-daily upper air data for calculating downwind concentrations. The data required for each simulation are:

- wind speed;
- wind direction;
- dry-bulb temperature;
- cloud cover;
- ceiling height;
- station pressure; and
- vertical profiles of temperature, pressure, and relative humidity.



The meteorological data used in the analysis consisted the last five years (2009-2013) of hourly surface observations taken at a nearby National Weather Service (NWS) Station in Detroit, Michigan (14822) along with concurrent twice-daily upper air data collected at the White Lake upper air station (72632). The preprocessed data was obtained from MDEQ.

5.1.5 Receptor

The dispersion modeling was conducted for one receptor. Due to time constraints, a receptor grid or hot spots were not considered in the analysis. The SO_2 monitor located at Southwestern High School (SWHS) was the only receptor evaluated in the increased dispersion modeling analysis. The SWHS monitor is located north of the USS GLW boiler house and northeast of the USS GLW reheat ovens at approximately 326356 meters Easting and 4685546 meters northing (in North American Datum 1983 (NAD83)).

5.1.6 Sources of Emissions

The increased dispersion option was evaluated for the following sources:

- Boiler House 1 (Boilers 1-5);
- Boiler House 2 (Boilers 1-5);
- Hot Strip Mill Reheat Ovens (Furnaces 1-5).

The associated flares were not evaluated in the increased dispersion option since these flares are existing open flares. It is not feasible to increase the stack height of these flares. Additionally, it is assumed that the emissions from the flares already are greatly dispersed due to the flame temperature and flame height. No other sources (on property or offsite) were considered in this analysis.

Emission source parameters modeled are included in Sections 6.1.6and 7.1.3.



6.0 Boiler House 1 and 2 RACT

6.1 Available Control Technologies

No specific add-on SO₂ controls were identified in the RBLC search for gas-fired boilers. Although coal fired boilers have higher uncontrolled SO₂ emissions than gas-fired boilers, the gas stream was considered somewhat comparable to the sulfur gas stream concentration of sulfurized coke oven gas (COG) that is utilized in the USS GLW boiler houses. Therefore, add-on SO₂ controls for coal fired boilers were evaluated as theoretically feasible control options. Generally, there are three types of add-on SO₂ controls applicable to a coal-fired boiler: dry (i.e., DSI), semi-dry (i.e., SDA), and wet (i.e., wet scrubber). Wet scrubbers and SDAs are collectively referred to as flue gas desulfurization (FGD) units. DSI may be used in boilers by dry injection of sorbents such as hydrated lime or Trona (sodium sesquicarbonate, a naturally occurring mineral mined in Wyoming) into the duct system; however, the level of control that is achievable is not comparable to FGD control systems. FGD controls applicable to boilers include wet scrubbing or SDA technology using reagents such as limestone, lime, quicklime, sodium bicarbonate, or magnesium oxide. Each of these add-on technologies have been considered for this RACT analysis.

Other types of alternative SO_2 controls were also considered for the boiler houses including fuel switching, fuel blending, and increased dispersion. Fuel switching involves substituting a lower sulfur fuel for higher sulfur fuels. At USS GLW, the highest sulfur fuel is COG followed by blast furnace gas (BFG) and natural gas. The typical sulfur values for the various fuels utilized in the boilers and furnaces at USS are provided in Table 6-1 below.

Gaseous Fuel	Sulfur Content (lb/MMBtu)	
COG	1.43	
BFG	0.08	
Natural Gas	0.0006	

Table 6-1Typical Sulfur Values of USS Gaseous Fuels

Fuel blending, as defined in this analysis, includes using various fuel blends to achieve an overall fuel sulfur level thereby reducing the amount of SO_2 that is generated in the combustion process. Increased dispersion does not have the effect of decreasing overall SO_2 emissions, but can decrease the ground level impact of those emissions. These additional alternative controls have been included in this RACT analysis for Boilers House 1 and Boiler House 2. The pre-combustion scrubbing of BFG was not considered in



this evaluation since no existing desulfurization controls were identified in the RBLC search, other than previous BACT determinations, which eliminated this option due to technically infeasibility¹.

A comparative ranking of available SO_2 control technologies must take into consideration multiple variables including fuel sulfur content, fuel sulfur variability, add-on control percent removal capability, and the resulting composite emission rate (lb/MMBtu) in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts. Any discussion of the relative effectiveness of add on SO_2 control also must take into account the level of uncontrolled SO_2 to be handled, which is highly dependent on the sulfur content of the fuel to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of SO_2 in the flue gas, and vice-versa. This is reflected in a comparison of the resulting emission rate in units of pounds of SO_2 per MMBtu of fuel burned. Table 6-2 below provides a summary of these technologies and their associated control rankings, which are based on coal-fired boilers.

Control Technology	Typical Level of Control ²	Typical Emission Level
Wet Scrubber	80-98%	Depends of fuel sulfur levels
SDA	70-90%	Depends of fuel sulfur levels
Fuel Switching	30-90%	Depends of fuel sulfur levels
Fuel Blending	20-60%	Depends of fuel sulfur levels
DSI	25-50%	Depends of fuel sulfur levels
Increased Dispersion	NA	NA

Table 6-2 Control Ranking of SO₂ Technologies Identified for USS GLW Boilers

6.1.1 Summary of RACT/BACT/LAER Clearinghouse Information

CB&I conducted a search of the RBLC database for SO_2 controls for similar emissions units as those in the USS GLW RACT request by MDEQ. No add-on controls were identified in the RBLC search for gasfired boilers in various size ranges. In addition, no add-on controls specific to the boilers were identified in the RBLC search for the steel and iron industry under process types 81.200, 81.300, and 81.400.

The most prevalent type of control identified in the RBLC for gaseous fuel for all industry boilers is to limit the sulfur content of the fuel purchased and/or utilizing a specific type of fuel (i.e. natural gas) with a low-sulfur content. Therefore, these types of controls were evaluated as part of this RACT analysis in addition to potential add-on controls. A summary of the RBLC search is provided in Appendix A

¹ Nucor - LA BACT determination for BFG SO2 control, RBLCID LA-0239.

² AP-42 Chapter 1.1, Bituminous and Subbituminous Coal Combustion, Table 1.1-1. Control level ranges for add-on controls only



6.1.2 Spray Dryer Absorber

In a SDA control system, the combustion process exhaust stream passes through the SDA upstream of a particulate matter (PM) control device (typically a fabric filter baghouse). An alkaline lime slurry is injected in the SDA using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form in the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream. Dry byproduct is collected in the bottom of the spray dryer and in the downstream baghouse. A simplified process flow diagram (PFD) is provided in Figure 6-1 below. The alkaline lime reagent may further react with SO_2 that passes through the filter cake in the baghouse. This additional reaction in the fabric filter can also aid in the removal of additional pollutants (i.e., sulfuric acid mist (H₂SO₄ mist), hydrochloric acid (HCl), hydrogen fluoride (HF), and mercury). The collected solids are either recycled back through the process or used for other off-site applications.

This system is categorized as a "dry" or "semi-dry" system in that the end product of the SO_2 conversion reaction is a dry material. Although termed as a dry system, this air pollution control system uses water for evaporative cooling and for the SO_2 reaction. Unlike a wet scrubbing system, however, there is no liquid blow-downstream from the dry system. The "dry" system has been used in low-sulfur coal applications to effectively remove SO_2 from a gas stream with removal efficiencies from 70% to 90%.

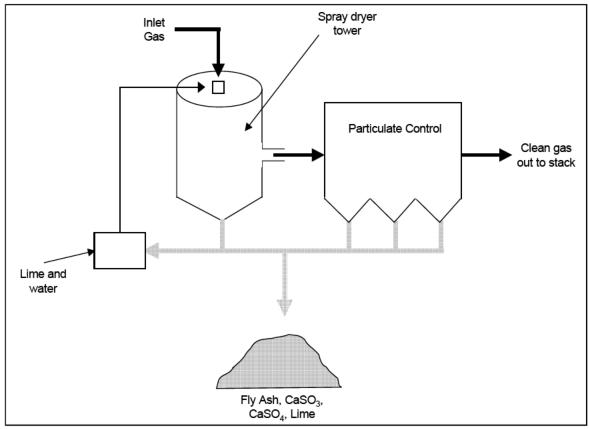


Figure 6-1 Spray Dryer Gas Desulfurization PFD



6.1.3 Dry Sorbent Injection

DSI systems remove SO_2 as well as acid gases and other acid gases through two basic steps. Step one involves injecting a powdered sorbent into the flue gas where it reacts with the SO_2 . The sorbents most commonly associated with DSI are Trona and hydrated lime. In Step 2 of the process, the compound is removed by a downstream particulate matter control device such as a baghouse similar to the SDA control. Baghouse units are generally more effective (when combined with DSI) than other particulate control devices, with respect to overall SO_2 reduction.

6.1.4 Wet Scrubber

Wet scrubber systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. Coal utility boiler wet scrubber systems typically involve the reaction of limestone (CaCO₃) or hydrated lime (Ca [OH₂]) and exhaust gas sulfur oxides in a spray absorber tower. Boiler exhaust gas enters at the bottom of the absorber tower, flows vertically through the limestone/ water spray, passes through a mist eliminator to remove re-entrained limestone slurry droplets, and then exits the tower. Ground limestone or hydrated lime in the scrubbing slurry reacts with SO_2 in the flue gas to form calcium sulfite and calcium sulfate (i.e., gypsum).

One of the main environmental issues with wet scrubber systems is that these units generate significant wastewater and wet sludge streams requiring treatment and disposal. Gypsum slurry from the reaction tank is typically treated in a series of hydroclones. Reclaimed water from the hydroclones is returned to the scrubber system and gypsum solids sent to a vacuum filtration system. Gypsum solids from the vacuum filter system may be washed to remove contaminants and then loaded into railcars or trucks for shipment as a byproduct or mixed with fly ash, if necessary, and conveyed to a landfill.



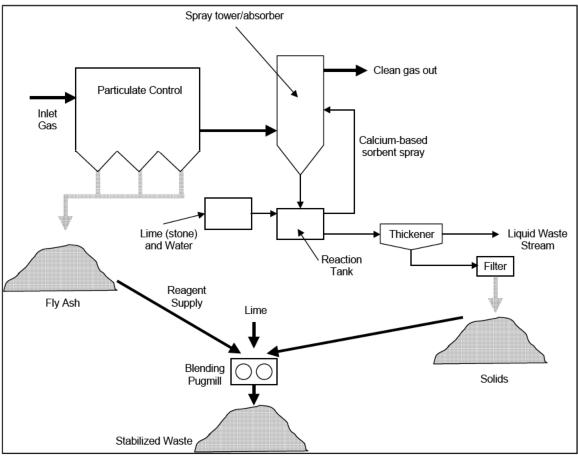


Figure 6-2 Wet Scrubber PFD

A practical issue associated with a wet scrubber system is the complexity of the system. Additional expertise is often needed in specifying, operating, and maintaining such a system, which is more like a chemical plant than a control device. Companies may need more chemical engineers, chemical laboratories, and revised operating and maintenance procedures.

6.1.5 Fuel Modifications

Two types of fuel modifications were considered for the RACT analysis. The first type of fuel modification involves fuel switching whereby higher sulfur fuels are replaced with lower sulfur fuels. The second fuel modification scenario considered was a fuel blending option. For this option, the various fuels are blended where the higher sulfur fuels are restricted to meet a total fuel sulfur blend that results in lower SO_2 emissions.

6.1.5.1 Fuel Switching

Fuel switching involves replacing higher sulfur fuels with lower sulfur fuels. In the case of Boiler House 1 and Boiler House 2, the only logical option is to evaluate eliminating or reducing coke oven gas combustion. Both boiler houses currently combust a combination of COG, BFG, and natural gas. Eliminating BFG was not considered because any BFG not combusted in the boilers would require flaring. This scenario would potentially reduce SO_2 emissions at the boiler houses and increase SO_2



emissions at the flares. Overall SO_2 emissions would likely increase in this situation due to the fact that the boilers would use more natural gas or COG in the boilers to offset the reduction in BFG, while the excess BFG is flared. Eliminating BFG would also require the installation of a new flare to accommodate the increase in BFG flaring.

Eliminating COG from the boilers fuel mixture was considered for this analysis. Currently, not all of the boilers are capable of running on natural gas. The replacement of all the fuel burners in the boilers with low-NO_x burners would be required to eliminate COG. COG is used as a stabilizer fuel for the boilers, and also has a lower nitrogen content than natural gas. The natural gas NO_x emission factor for uncontrolled boilers > 1000 MMBtu/hr is 0.28 lb/MMBtu³. Therefore, low-NO_x burners would be needed to meet the MDEQ NO_x limitation of 0.25 lb/MMBtu if natural gas was used as the only fuel. Currently, USS GLW meets this limitation by blending natural gas with other fuels, which reduces the composite nitrogen content of the fuel combusted below the MDEQ NO_x limit. In addition, new control panels would be required for each boiler. The diameter of the natural gas lines would also need to be increased to accommodate the additional natural gas flow required to offset the COG. Fuel switching has been determined as technically feasible for this application although to retrofit each of the boilers with low-NO_x burners and increase the natural gas line would require extensive modifications to the facility.

6.1.5.2 Fuel Blending Modifications

Various fuel blending scenarios were evaluated for this RACT analysis. It was assumed that USS GLW would continue to use the same fuels (i.e. COG, BFF, and natural gas) for future operations, but would utilize various composites of these fuels to lower the sulfur content of the fuel combusted on a lb/MMBtu basis. An evaluation of the historical fuel blends was examined for this exercise. During calendar year 2013, the average emission rate for USS GLW's emission units subject to this RACT analysis was 0.32 lb/MMBtu. It should be noted that a short-term emission rate would be significantly higher than the annual average emission rate observed in 2013. Fuel blending was determined to be an effective and reasonable way to reduce SO_2 emissions and is considered technically feasible.

6.1.6 Increased Dispersion

Air dispersion modeling was conducted to determine the change in concentration based on altering the stack parameters of the existing boilers. The increased dispersion option was conducted by utilizing the modeling methodology specified in Section 5.1. As mentioned in Section 5.1.5, the concentration was determined at the SWHS SO₂ monitor. A baseline model was run to determine the 1-hr SO₂ concentration (H4H) with the existing stack parameters and potential to emit (PTE) short-term emissions. A separate model was conducted for a combined stack for both boiler houses and compared to the baseline model results.

³ AP-42 Chapter 1.4, Table 1.4-1, July 1998



6.1.6.1 Baseline Model

In order to obtain the change in 1-hr SO_2 concentration (H4H) at the SWHS monitor, a baseline concentration had to be determined for each source group. The baseline model was run for Boiler House 1 and Boiler House 2 separately. The baseline modeled source parameters were supplied by USS in the modeling input file and are shown below in Table 6-3 and Table 6-4. The emissions listed in the tables correspond to the short-term SO_2 potential to emit, which was supplied to CB&I by USS.

	Baseline Boiler House 1 Model Parameters								
Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO ₂ Emission Rate (g/s)		
	7	()	()	(111)	(110.0)	()	(8,3)		
ZI1B1	Zug Island No. 1 BH Boiler No. 1	176.51	20.73	1.68	19.1058	560.93	1.642		
	Zug Island No. 1	1.5.6.1		1.60	10 10 20		1.640		
ZI1B2	BH Boiler No. 2	176.51	20.73	1.68	19.1058	560.93	1.642		
ZI1B3	Zug Island No. 1	176.51	20.73	1.68	10 2004	560.02	2 415		
ZIIB5	BH Boiler No. 3	170.31	20.75	1.08	18.3984	560.93	3.415		
711D4	Zug Island No. 1	176 51	24.69	1.69	18.3984	560.93	3.415		
ZI1B4	BH Boiler No. 4	176.51	24.09	1.68					
ZI1B5	Zug Island No. 1	176 51	24.69	1.69	18.3984	560.93	2 415		
211B3	BH Boiler No. 5	176.51	24.09	1.68	16.3984	300.93	3.415		

 Table 6-3

 Baseline Boiler House 1 Model Parameters

 Table 6-4

 Baseline Boiler House 2 Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO ₂ Emission Rate (g/s)
ZI2B1	Zug Island No. 2 BH Boiler No. 1	176.76	26.82	2.97	7.35757	560.93	2.146
ZI2B2	Zug Island No. 2 BH Boiler No. 2	176.78	26.82	2.97	7.35757	560.93	2.146
ZI2B3	Zug Island No. 2 BH Boiler No. 3	176.8	26.82	2.97	7.35757	560.93	2.146
ZI2B4	Zug Island No. 2 BH Boiler No. 4	176.82	26.82	2.97	7.35757	560.93	2.146
ZI2B5	Zug Island No. 2 BH Boiler No. 5	176.84	26.82	2.97	7.35757	560.93	2.146



Sources ZI1B1 through ZI1B5 were combined into the source group ZIB1 to obtain the total impact from all of Boiler House 1 boilers. Similarly, sources ZI2B1 though ZI2B5 were combined into the source group ZIB2 to determine the total impact form all of Boiler House 2 boilers.

6.1.6.2 Combined Stack Model

The increased dispersion option considered that all five boilers in Boiler House 1 would be combined into a common stack. Similarly, the increased dispersion option also considered that all five boilers in Boiler House 2 would be combined into a common stack (separate from Boiler House 1).

There are several structures that are nearby each of the proposed combined stacks that can influence the stack height. CB&I utilized the USEPA Building Input Profile Program (BPIP) to obtain the Good Engineering Stack Height (GEP) for the common stacks. The BPIP output file indicated that GEP stack height for both the Boiler House 1 combined stack and the Boiler House 2 combined stack should be 65 meters. It was also assumed that the combined stack for Boiler House 1 would be located centrally to the existing Boiler House 1 boiler stacks, and the combined stack for Boiler House 2 would be located centrally to the existing Boiler House 2 boiler stacks.

The baseline actual exhaust volumetric flowrate of each of the boilers (separately for each boiler house) was added together to determine the combined stack actual exhaust volumetric flowrate. The exit velocity of the combined stack was assumed to be 3,000 ft/min (15.24 m/s), which is a more realistic exit velocity than the exit velocities of the baseline model. The combined stack diameter was then calculated for each boiler house combined stack by using the volumetric flowrate and exit velocity. It was also assumed that the exhaust temperature of the combined stack would be equal to the stack temperature of the baseline model.

The stack parameters of the combined stack models are shown below in Table 6-5 and

Table 6-6. The 1-hr SO₂ concentration (H4H) was determined separately for each source group.

	Combined Stack Boiler House 1 Model Parameters									
Source ID	Description	Base Elevation	Height	Diameter	Exit Velocity	Exit Temperature	SO ₂ Emission Rate			
		(m)	(m)	(m)	(m/s)	(K)	(g/s)			
BH1	Combined Stack Boiler House 1	176.51	65	4.1605	15.24	560.93	13.529			

 Table 6-5

 Combined Stack Boiler House 1 Model Parameters



	Combined Stack Boiler House 2 Model Parameters									
Source ID	Description	Base Elevation	Height	Diameter	Exit Velocity	Exit Temperature	SO ₂ Emission Rate			
		(m)	(m)	(m)	(m/s)	(K)	(g/s)			
BH2	Combined Stack Boiler House 2	176.8	65	4.6147	15.24	560.93	10.73			

Table 6-6 Combined Stack Boiler House 2 Model Parameters

6.1.6.3 Results

The sources listed above were added into the 1-hr SO_2 model along with the SWHS monitor receptor to determine the change in impact of the combined stack over baseline. AERMOD automatically generates the H4H for the 1-hr SO_2 at the receptor for the specific source groups. The change in concentration from baseline to combined stack modeling runs is shown below in Table 6-7.

Source Group	Source Description	H4H SO ₂ 1-hr Concentration μg/m ³
ZIB1	Boiler House 1 stacks at existing stack conditions	18.24
BH1	Combined stack for Boiler House 1	4.46
	Change in Concentration	13.78
ZIB2	Boiler House 2 stacks at existing stack conditions	11.19
BH2	Combined stack for Boiler House 2	2.92
	Change in Concentration	8.27

Table 6-7 1-hr SO₂ Modeling Results Comparison Boiler House 1 and 2

As shown in the table above, combining the respective boilers in each boiler house into a common stack at GEP stack height results in a decrease in 1-hr SO₂ concentration (H4H) at the SWHS SO₂ monitor. It is important to note that the model was conducted with the potential emissions for the emission sources. The change in 1-hr SO₂ concentration at the SWHS monitor will be less if actual emissions are evaluated. However, it is assumed that a reduction over baseline would still occur if actual emissions are evaluated. Increasing dispersion by increasing stack height has been determined as technically feasible for this application although to retrofit each of the boilers to create a combined stack would require extensive modifications to the facility.

6.2 Technical Feasibility and Ranking

Although each of the add-on control technologies presents a series of challenges for implementation, all were considered theoretically feasible. A more extensive study would be needed before each of these add-on control devices could be considered technically feasible. At a minimum, this study must evaluate:



- pilings installation for support of the control device,
- evaluating the footprint of the control device units and determining available real estate, and
- increasing the capacity of the wastewater/stormwater outfalls to support the additional load from the wet scrubber

Since this is a retrofit situation, there is limited real estate available especially in and around the boiler houses. It is also CB&I's understanding that the water table is shallow in these areas. This would require extensive piling prior to construction to support the weight of these units and prevent any type of settling issues. Further, the current wastewater/stormwater outfalls are at maximum permitted and physical capacity. Additional research would be required to determine if a wet scrubber is technically feasible due to the additional load from the wastewater treatment system. The fuel switching, fuel blending, and increased dispersion options discussed previously were all considered technically feasible, although increased dispersion could require some piling to support the new stack.

Table 6-8 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness. The cost effectiveness was evaluated on a dollars per ton basis, using 2010 SO₂ emission rates as a basis, with the exception of increased dispersion which was evaluated on a dollars per reduction in ground level impact SO₂ concentration. A detailed breakdown of the costs calculations are provided in Appendix B.

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness (\$/ton) ⁴	Average Cost Effectiveness (\$/ton) ⁵		
Spray Dryer Absorber Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.026	\$34,644			
Spray Dryer Absorber Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.037	\$20, 400			
Dry Sorbent Injection Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.057	\$26,640			
Dry Sorbent Injection Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.087	\$14,890			
Wet Scrubber Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.026	\$40,747			
Wet Scrubber Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.037	\$24,848			

Table 6-8 Ranking of SO₂ Control Options

⁴ The fuel switching costs for natural gas were based on the U.S. Energy Information Administration (EIA) short-term energy outlook- released February 2014. Using the EIA costs estimates is not reasonable to estimate the cost impact for fuel switching. A more representative cost estimate would be based on the historical natural gas costs for USS, which would result in a significantly higher average cost effectiveness as shown in the adjacent column in Table 6-8.

⁵ Fuel switching costs based on average historic USS natural gas prices over the past 10 years.



*Fuel Switching Boiler House 1	Yes	No	Economic, Environmental	0.052	\$16,904	\$19,999
*Fuel Switching Boiler House 2	Yes	No	Economic, Environmental	0.063	\$12,133	\$16,168
Fuel Blending	Yes	Yes	Economic	0.40	NA	
*Increased Dispersion Boiler House 1 ⁶	Yes	No	Economic, Energy	NA	\$119,259	
*Increased Dispersion Boiler House 2 ⁷	Yes	No	Economic, Energy	NA	\$210,934	

* Fuel switching and increased dispersion do not result in reduced SO₂ emissions in the vicinity of USS GLW. Any excess COG not consumed at USS, due to fuel switching, would require flaring at the adjacent coke plant. Increased dispersion would potentially decrease the ground level impact of SO₂ emissions, but does not result in less emissions from the respective USS emission units.

6.3 Selection of RACT

Fuel switching is not economically feasible for Boiler House 1 or 2. Moreover, it does not result in any reduction of overall SO_2 emissions from the area, and could actually increase overall SO_2 emissions since additional natural gas would be burned to substitute for the loss in COG, while the COG is being flared at the adjacent coke plant simultaneously. Fuel switching could also trigger PSD permitting for certain pollutants since there could be an actual emissions increase above the PSD SER. Therefore, fuel switching was rejected as RACT.

As shown in Table 6-8, CB&I recommends that USS GLW proposes to utilize fuel blending to reduce SO_2 emissions by accepting an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. A short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. Further, in the event operations is interrupted due to process upsets and temporary fuel loss situations (e.g. loss of BFG), an alternate SO_2 emission limit for this operating scenario would need to be established. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO_2 levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness and/or questionable technical feasibility.

⁶ Average cost effectiveness provided on a dollars per microgram per cubic meter (µg/m³) reduction in ground level SO₂ concentration

 $^{^{7}}$ Average cost effectiveness provided on a dollars per microgram per cubic meter ($\mu g/m^3$) reduction in ground level SO₂ concentration. Increased dispersion for Boiler House 2 results in less ambient impact reduction of SO₂.



7.0 Hot Strip Mill Reheat Ovens/Furnaces RACT

7.1 Available Control Technologies

As previously discussed, no specific add-on SO₂ controls were identified in the RBLC search for gas-fired fuels. Although coal fired boilers have higher uncontrolled SO₂ emissions than gaseous fired fuels, the gas stream was considered somewhat comparable to the sulfur gas stream concentration of COG that is utilized in the USS GLW hot strip mill reheat ovens/furnaces. Therefore, these add-on controls were evaluated as a theoretically feasible control option. Generally, there are three types of add-on SO₂ controls applicable to a coal-fired boiler: dry (i.e., DSI), semi-dry (i.e., SDA), and wet (i.e., wet scrubber). Wet scrubbers and SDAs are collectively referred to as FGD) units. DSI may be used in boilers by dry injection of sorbents such as hydrated lime or Trona into the duct system; however, the level of control that is achievable is not comparable to FGD control systems.

Other types of alternative control techniques identified for the boiler houses are also applicable to the reheat ovens/furnaces and include fuel switching, fuel blending, and increased dispersion. Fuel switching involves substituting a lower sulfur content fuel for higher sulfur content fuels. At USS GLW, the highest sulfur fuel is COG followed by BFG and natural gas. Fuel blending, as defined in this analysis, includes using various fuel blends to achieve an overall fuel sulfur level thereby reducing the amount of SO_2 that is generated in the combustion process. Increased dispersion does not have the effect of decreasing overall SO_2 emissions, but can decrease the ground level impact of those emissions. These additional non-add-on controls have been included in this RACT analysis for the reheat ovens/furnaces. The pre-combustion scrubbing of BFG was not considered in this evaluation since no existing data was identified in the RBLC database other than previous BACT determinations eliminating this option as not technically feasible.

7.1.1 Summary of RACT/BACT/LAER Clearinghouse Information

CB&I conducted a search of the RBLC database for SO2 controls for similar emissions units as those in the USS GLW RACT request by MDEQ. No add-on controls were identified in the RBLC search for gasfired ovens/furnaces in the various size ranges. Detailed information on the RBLC search is provided in Appendix A. In addition, no add-on controls specific to the furnaces were identified in the RBLC search for the steel and iron industry under process types 81.200, 81.300, and 81.400. The most prevalent type of control identified in the RBLC for gaseous fuel for all industry boilers and furnaces is to limit the sulfur content of the fuel purchased and/or utilizing a specific type of fuel (i.e. natural gas) with a low-sulfur content. Therefore, these types of controls were evaluated as part of this RACT analysis in addition to potential add-on controls. A summary of the RBLC search is provided in Appendix A.

7.1.2 Fuel Modifications

Two types of fuel modifications were considered for the RACT analysis. The first type of fuel modification involves fuel switching whereby higher sulfur fuels are replaced with lower sulfur fuels. The second fuel modification scenario considered was a fuel blending option. For this option, the various fuels



are blended where the higher sulfur fuel usage is restricted to meet a total fuel sulfur blend that results in lower SO₂ emissions.

7.1.2.1 Fuel Switching

Fuel switching involves replacing higher sulfur fuels with lower sulfur fuels. In the case of the reheat ovens/furnaces, the only logical option is to evaluate eliminating or reducing coke oven gas combustion since natural gas has the lowest sulfur content of any of the fuels utilized in the mill. The reheat ovens/furnaces in the hot strip mill combust COG and natural gas.

In order to switch the reheat ovens/furnaces to 100% natural gas, the replacement of all the fuel burners with low-NOx burners would be required. COG has a lower nitrogen content than natural gas. The natural gas NOx emission factor for uncontrolled boilers > 1000 MMBtu/hr is 0.28 lb/MMBtu. Therefore, low-NOx burners would be needed to meet the MDEQ nitrogen oxide (NOx) limitation of 0.25 lb/MMBtu assuming the reheat ovens/furnaces would strictly operate on natural gas. Currently, USS GLW meets this limitation by blending natural gas with COG, which reduces the composite nitrogen content of the fuel combusted below the MDEQ NOx limit. The diameter of the natural gas lines would also need to be increased to accommodate the additional natural gas flow required to offset the COG. To retrofit each of the reheat ovens/furnaces with low-NOx burners would require extensive engineering, labor, and production downtime of the ovens/furnaces. Substituting COG with BFG was not considered due to the low Btu value of BFG, and the fact that there is no current BFG fuel line near the hot strip mill. Therefore, the COG to BFG fuel switching alternative was not considered a technically feasible option.

7.1.2.2 Fuel Blending Modifications

Various fuel blending scenarios were evaluated for this RACT analysis. It was assumed that USS would continue to utilize the same fuels (i.e. COG and natural gas) for future operations, but would use various composites of these fuels to lower the sulfur content of the fuel combusted on a lb/MMBtu basis. An evaluation of the potential and recent historical fuel blends was examined for this exercise. During calendar year 2013, the average emission rate for USS GLW's emission units subject to this RACT analysis was 0.32 lb/MMBtu. It should be noted that a short-term emission rate would be significantly higher than the annual average emission rate observed in 2013. Fuel blending was determined to be an effective and reasonable way to reduce SO₂ emissions and is considered technically feasible.

7.1.3 Increase Dispersion

Air dispersion modeling was conducted to determine the change in concentration based on altering the stack parameters of the existing hot strip mill reheat ovens/furnaces. The increased dispersion option was conducted by utilizing the modeling methodology specified in Section 5.1. As mentioned in Section 5.1.5, the concentration was determined at the SWHS SO_2 monitor. A baseline model was run to determine the 1-hr SO_2 concentration (H4H) with the existing stack parameters and potential to emit (PTE) short-term emissions.



7.1.3.1 Baseline Model

In order to obtain the change in 1-hr SO_2 concentration (H4H) at the SWHS monitor, a baseline concentration had to be determined for the source group. The baseline modeled source parameters for the hot strip mill reheat ovens/furnaces were supplied by USS in the modeling input file and are shown below in Table 7-1. The emissions listed in the tables correspond to the short-term SO_2 potential to emit, which was supplied to CB&I by USS.

	Baseline Reneat Ovens/Furnaces Model Parameters								
Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO ₂ Emission Rate (g/s)		
HSMF1	80" HSM Slab Reheat Furnace 1	175.27	31.09	4.27	6.06932	477.59	15.731		
HSMF2	80" HSM Slab Reheat Furnace 2	175.26	31.09	4.27	6.12809	477.59	15.732		
HSMF3	80" HSM Slab Reheat Furnace 3	175.25	31.09	4.27	6.12809	477.59	15.732		
HSMF4	80" HSM Slab Reheat Furnace 4	175.23	31.09	4.27	6.12809	477.59	15.732		
HSMF5	80" HSM Slab Reheat Furnace 5	175.23	31.09	4.27	6.30447	477.59	15.732		

Table 7-1
Baseline Reheat Ovens/Furnaces Model Parameters

7.1.3.2 Combined Stack Model

The increased dispersion option considered that all five ovens/furnaces would be combined into a common stack. There are several structures that are nearby the proposed combined stack that can influence the stack height. CB&I utilized the BPIP to obtain the GEP for the common stack. The BPIP output file indicated that GEP stack height for both the reheat ovens/furnaces combined stack should be 65 meters. It was also assumed that the combined stack located centrally to the existing ovens/furnace stacks.

The baseline actual exhaust volumetric flowrate of each of the ovens/furnaces was added together to determine the combined stack actual exhaust volumetric flowrate. The exit velocity of the combined stack was assumed to be 3,000 ft/min (15.24 m/s), which is a more realistic exit velocity than the exit velocities of the baseline model. The combined stack diameter was then calculated for the combined stack by using the volumetric flowrate and exit velocity. It was also assumed that the exhaust temperature of the combined stack would be equal to the stack temperature of the baseline model.

The stack parameters of the combined stack models are shown below in Table 7-2.



	Combined Stack Reheat Ovens/Furnaces Model Parameters									
Source ID	Description	Base Elevation	Height	Diameter	Exit Velocity	Exit Temperature	SO ₂ Emission Rate			
		(m)	(m)	(m)	(m/s)	(K)	(g/s)			
FURN	Combined Stack Reheat Furnaces	175.23	65	6.0655	15.24	477.59	78.659			

Table 7-2 Combined Stack Reheat Ovens/Furnaces Model Parameters

7.1.3.3 Results

The sources listed above were added into the 1-hr SO_2 model along with the SWHS monitor receptor to determine the change in impact of the combined stack over baseline. AERMOD automatically generates the H4H for the 1-hr SO_2 at the receptor for the specific source groups. The change in concentration from baseline to combined stack modeling runs is shown below in Table 7-3.

1-III 30 ₂ I	1-hr SO ₂ modeling Results Comparison Reneat Ovens/Furnaces							
Source Group	Source Description	H4H SO ₂ 1-hr Concentration µg/m ³						
		µg∕m						
HSMF	Reheat furnaces at existing stack conditions	45.31						
FURN	Combined stack for Reheat Furnaces	14.86						
	Change in Concentration 30.45							

 Table 7-3

 1-hr SO₂ Modeling Results Comparison Reheat Ovens/Furnaces

As shown in the table above, combining the ovens/furnaces into a common stack at GEP stack height results in a decrease in 1-hr SO₂ concentration (H4H) at the SWHS SO₂ monitor. It is important to note that the model was conducted with the potential emissions for the emission sources. The change in 1-hr SO₂ concentration at the SWHS monitor will be less if actual emissions are evaluated. However, it is assumed that a reduction over baseline would still occur if actual emissions are evaluated. Increasing dispersion by increasing stack height has been determined as technically feasible for this application although to retrofit each of the ovens/furnaces to create a combined stack would require extensive modifications to the facility.

7.2 Technical Feasibility and Ranking

Although all add-on controls (i.e. SDA, DSI, and wet scrubber) have all been considered theoretically feasible, a more extensive study would be needed to conclude that each of these technologies are technically feasible. This is a retrofit situation which presents a series of challenges for add-on control equipment that require a large footprint. It is also CB&I's understanding that the water table is shallow at the USS GLW facility. This would require extensive piling prior to construction to support the weight of these units and prevent any type of settling issues. Further, the current wastewater/stormwater outfalls are at maximum permitted and physical capacity. Additional research would also be required to determine if a

wet scrubber is technically feasible due to the additional wastewater load from the wastewater treatment system. The fuel switching, fuel blending, and increased dispersion options discussed previously were all considered technically feasible for the hot mill, although increased dispersion could require some piling to support the new stack.

Table 7-4 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness. The cost effectiveness was evaluated on a dollars per ton basis, using 2010 SO₂ emission rates as a basis, with the exception of increased dispersion which was evaluated on a dollars per reduction in ground level impact concentration. A detailed breakdown of the costs calculations are provided in Appendix B.

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness (\$/ton) ⁸	Average Cost Effectiveness (\$/ton) ⁹
Spray Dryer Absorber	Potentially	No	Economic, Energy, Environmental	0.046	\$10,650	
Dry Sorbent Injection	Potentially	No	Economic, Energy, Environmental	0.101	\$8,081	
Wet Scrubber	Potentially	No	Economic, Energy, Environmental	0.046	\$10,178	
*Fuel Switching	Yes	No	Economic, Environmental	0.001	\$9,129	\$14,295
Fuel Blending	Yes	Yes	Economic	0.40	NA	
*Increased Dispersion ¹⁰	Yes	No	Economic, Energy	NA	\$82,934	

Table 7-4 Ranking of SO₂ Control Options

* Fuel switching and increased dispersion do not result in reduced SO₂ emissions in the vicinity of USS GLW. Any excess COG not consumed at USS, due to fuel switching, would require flaring at the adjacent coke plant. Increased dispersion would potentially decrease the ground level impact of SO₂ emissions, but does not result in less emissions from the respective USS emission units.

7.3 Selection of RACT

Fuel switching is not economically feasible. Further, it does not result in any reduction of overall SO_2 emissions from the area, and could actually increase overall SO_2 emissions since additional natural gas

⁸ The fuel switching costs for natural gas were based on the U.S. Energy Information Administration (EIA) short-term energy outlook- released February 2014. Using the EIA costs estimates is not reasonable to estimate the cost impact for fuel switching. A more representative cost estimate would be based on the historical natural gas costs for USS, which would result in a significantly higher average cost effectiveness as shown in the adjacent column in Table 7-4.

⁹ Fuel switching costs based on average historic USS natural gas prices over the past 10 years.

¹⁰ Average cost effectiveness provided on a dollars per microgram per cubic meter (µg/m³) reduction in ground level SO₂ concentration



would be burned to substitute for the loss in COG, while the COG is being flared at the adjacent coke plant simultaneously. Fuel switching could also trigger PSD permitting since there could be an actual increase above the SER for certain pollutants. Therefore, fuel switching was rejected as RACT.

As shown in Table 7-4, CB&I recommends that USS GLW proposes to utilize fuel blending to reduce SO_2 emissions by accepting an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. A short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. In the event operations is interrupted due to process upsets and temporary fuel loss situations (e.g. loss of natural gas), an alternate SO_2 emission limit for this operating scenario would need to be established. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO_2 levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ, and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness, and/or questionable technical feasibility.



8.0 Flare RACT

8.1 Available Control Technologies

No specific control technologies were identified for SO_2 control from flares. A search of the RBLC database did not result in any identified SO_2 controls other than limiting the sulfur content of natural gas as a supplemental fuel. USS does not have any control over the sulfur content of the natural gas available. Therefore, any type of sulfur restriction for natural gas combustion could not be guaranteed by USS since the fuel is provided by a third party utility. Further, this control would not result in a significant decrease in SO_2 emissions from flaring.

8.1.1 Increase Dispersion

The associated flares (A-1 Flare Stack and D-4 Flare Stack) were not evaluated in the increased dispersion option since these existing flares are open flares. It is not feasible to increase the stack height of these flares. Additionally, it is assumed that the emissions from the flares already are greatly dispersed due to the flame temperature and flame height.

8.2 Technical Feasibility and Ranking

The two identified controls for flaring were both considered not technically feasible. The increased dispersion option does not result in lower ground level concentrations of SO₂. In addition, limiting sulfur in the natural gas supply is not a feasible option since USS has no control over the natural gas supply and has no alternative means of purchasing natural gas from a different supplier.

Table 8-1 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness.

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness (\$/ton)
Limit sulfur content of supplemental natural gas	No	No	Economic	NA	NA
Increased Dispersion	No	No	Economic, Energy	NA	NA

Table 8-1 Ranking of SO₂ Control Options

8.3 Selection of RACT

Although there is no means to actually change the fuel blend for flaring, CB&I recommends that USS GLW propose to utilize fuel blending to reduce SO₂ emissions to an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2,



Flares, and Hot Strip Mill Furnaces. Again, a short-term average would require a considerably higher emission rate to account for process fluctuations. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO₂ levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ previous years, and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness and/or questionable technical feasibility.

APPENDIX A SUMMARY OF SO₂ CONTROL DETERMINATIONS PER USEPA'S RACT/BACT/LAER DATABASE

							THROUGHPUT		EMISSIO	N LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION 1		IMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
	THYSSENKRUPP STEEL AND STAINLESS			Z-HIGH MILL WITH MIST ELIMINATOR (LO42) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
L-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)				(SO2)		0.0006 LE	B/MMBTU	0			FURNACE (LO43).
				NATURAL GAS -FIRED ANNEALING											
	THYSSENKRUPP STEEL AND STAINLESS	;		FURNACE (LA43) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	196.4	1 MMBTU/H	(SO2)		0.0006 LE	B/MMBTU	0			FURNACE (LA43).
				2 ACID REGENERATION LINES EACH											
				WITH CAUSTIC SCRUBBERS & amp;											
	THYSSENKRUPP STEEL AND STAINLESS	;		COMMON SCR (LO72) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WIT
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	20600) T/YR	(SO2)		0.0006 LE	B/MMBTU	0			CAUSTIC SCRUBBER & COMMON SCR (LO72).
	THYSSENKRUPP STEEL AND STAINLESS			DEGREASING WITH WET SCRUBBER (LO52) (MULTIPLE EMISSION				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
AL-0230	USA, LLC	AL	08/17/2007 ACT	POINTS)		60	т/н	(SO2)		0.0006 LE	B/MMBTU	0			FURNACE (LO53).
AL 0220	THYSSENKRUPP STEEL AND STAINLESS		09/17/2007 8 share 6 CT	DEGREASING WITH WET SCRUBBER				Sulfur Dioxide		0.0000		0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
4L-0230	USA, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS) NATURAL GAS-FIRED BATCH		61	рт/н	(SO2)		0.0006 LE	B/IVIIVIBTU	0			FURNACE.
	THYSSENKRUPP STEEL AND STAINLESS			ANNEALING FURNACES (LA63,				Sulfur Dioxide							
AL-0230	USA, LLC	AL	08/17/2007 ACT	LA64)	NATURAL GAS	33.4	1 MMBTU each	(SO2)		0.0006 LE	B/MMBTU	0			
	THYSSENKRUPP STEEL AND STAINLESS		09/17/2007 8 share ACT	NATURAL GAS-FIRED PASSIVE				Sulfur Dioxide		0.0000		0			
AL-0230	USA, LLC	AL	08/17/2007 ACT	ANNEALING FURNACE (LO41) 4 CONTINUOUS HOT DIP	NATURAL GAS	27	2 MMBTU/H	(SO2)		0.0006 LE	B/IVIIVIBTU	0			
				GALVANIZING LINE (EACH LINE											
	THYSSENKRUPP STEEL AND STAINLESS	;		WITH SAME MULTIPLE EMISSION				Sulfur Dioxide							THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING
AL-0230	USA, LLC	AL	08/17/2007 ACT					(SO2)		0.0006 LE	B/MMBTU	0			WITH PRE & POST DRYERS.
				4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE											
	THYSSENKRUPP STEEL AND STAINLESS			WITH SAME MULTIPLE EMISSION				Sulfur Dioxide							
AL-0230	USA, LLC	AL	08/17/2007 ACT	POINTS)				(SO2)		0.0006 LE	B/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
	THYSSENKRUPP STEEL AND STAINLESS			MELTSHOP - LO (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH
AL-0230		AL	08/17/2007 ACT	EMISSION POINTS)		120	5 т/н	(SO2)		0.15 LE	в/т	0			ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO
	THYSSENKRUPP STEEL AND STAINLESS	;		MELTSHOP - LO (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		120	5 Т/Н	(SO2)		0.15 LE	В/Т	0			VENTED TO BAGHOUSE (LO1).
				TPH ELECTRIC ARC FURNACE WITH											
				DEC & ELEPHANT HOUSE											
	THYSSENKRUPP STEEL AND STAINLESS	;		VENTED TO BAGHOUSE 3 (LA1)				Sulfur Dioxide							THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC &
AL-0230	USA, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS)	NATURAL GAS	120	5 Т/Н	(SO2)		0.15 LE	3/Т	0			ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1).
				TPH ELECTRIC ARC FURNACE WITH											
				DEC & amp; ELEPHANT HOUSE											THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION
	THYSSENKRUPP STEEL AND STAINLESS	;		VENTED TO BAGHOUSE 3 (LA1)				Sulfur Dioxide							FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIO
AL-0230	USA, LLC	AL	08/17/2007 ACT		NATURAL GAS	120	5 Т/Н	(SO2)		0.15 LE	В/Т	0			VENTED TO COMMON BAGHOUSE.
	THYSSENKRUPP STEEL AND STAINLESS			NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	169	ЭММВТU/Н	(SO2)		0.0006 LE	B/MMBTU	0			(LA 21).
				NATURAL GAS-FIRED REHEAT											
	THYSSENKRUPP STEEL AND STAINLESS USA, LLC		08/17/2007 ACT	FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	10	ЭММВТИ/Н	Sulfur Dioxide (SO2)		0.0006 LE		0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
4L-0230	USA, LLC	AL	08/17/2007 AC1	NATURAL GAS-FIRED REHEAT	NATURAL GAS	10:		(302)		0.0006 LE	S/IVIIVIBIU	0			THIS COVERS SOZ FOR THE 3 COIL DROM FORNACES (LA24-LA26).
	THYSSENKRUPP STEEL AND STAINLESS	;		FURNACE (LA21) (MULTIPLE				Sulfur Dioxide							
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	169	9 ММВТU/Н	(SO2)		0.0006 LE	B/MMBTU	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
	THYSSENKRUPP STEEL AND STAINLESS			BAL STEAM SWEEP WITH MIST ELIMINATOR (LA66) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
AL-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		12.0	5 т/н	(SO2)		0.0006 LE	в/ммвти	0			FURNACE (LA70).
	THYSSENKRUPP STEEL AND STAINLESS	;		3 NATURAL GAS-FIRED BOILERS			1	Sulfur Dioxide	1						
AL-0230		AL	08/17/2007 ACT	WITH ULNB & amp; EGR (537-539)	NATURAL GAS	64.9	9 MMBTU each	(SO2)		0.0006 LE	B/MMBTU	0			
1 0220	THYSSENKRUPP STEEL AND STAINLESS		08/17/2007 & sheet ACT	HOT STRIP MILL (MULTIPLE	NATURAL GAS		от/н	Sulfur Dioxide (SO2)		0.006		_			THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED WALKING BEAM REHEAT FURNACES.
AL-0230	USA, LLC THYSSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	EMISSION POINTS) HCL ACID REGENERATION	INAT UNAL GAS	690		(SO2) Sulfur Dioxide	+	0.000 LE	B/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS
AL-0230	USA, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS)	NATURAL GAS	3.7	7 Т/Н	(SO2)		0.0006 LE	B/MMBTU	0			WITH CAUSTIC SCRUBBER (5-10).
	THYSSENKRUPP STEEL AND STAINLESS	5		NATURAL GAS-FIRED BATCH				Sulfur Dioxide							
AL-0230	USA, LLC	AL	08/17/2007 ACT	ANNEALING FURNACE (535)	NATURAL GAS	99	9 MMBTU/H	(SO2)		0.0006 LE	B/MMBTU	0		ļ	
			09/24/2008 ACT	COMBUSTION TURBINE	NATURAL GAS		2 ММВТИ/Н	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	15.2 LE	- 4.				

				Summa	ry of SO₂ Contr	ol Determination per EPA's	RACT/BACT/I	AER Database for Natural Gas >	250 million BTU/hr				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AL-0251	HILLABEE ENERGY CENTER	A1	09/24/2008 ACT	FUEL HEATER	NATURAL GAS	11640000 BTU	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	0	0			Contact permitting agency for emissions information.
AL-0231		AL		TOLL HEATER	NATORAL GAS	11040000 810	Sulfur Dioxide	NATONAL GAS	0	0			
AL-0251	HILLABEE ENERGY CENTER	AL	09/24/2008 ACT	EMERGENCY GENERATOR	DIESEL	600 EKW	(SO2) Sulfur Dioxide	LOW SULFUR DIESEL FUEL	0	0			Contact permitting agency for emissions information.
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	TURBINE, SIMPLE CYCLE	NATURAL GAS	170 MW	(SO2)	LOW SULFUR FUELS	0.0006 LB/MMBTU	0			
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	FUEL OIL	170 MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS - 0.05% S BY WT	0.0489 LB/MMBTU	0			
							Sulfur Dioxide						
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	BURNER, DUCT TURBINE, COMBINED CYCLE,	NATURAL GAS	315 MMBTU/H	(SO2) Sulfur Dioxide	CLEAN FUELS.	0.0006 LB/MMBTU	0.0006	lb/MMBTU		
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	NATURAL GAS	NATURAL GAS	170 MW	(SO2)	LOW SULFUR FUEL - < 0.05% S BY WT	0.0006 LB/MMBTU	0			
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	CASTRIP LMF			Sulfur Dioxide (SO2)	LOW SULFUR COKE USAGE	54 LB/H	0 36	LB/T STEEL		
							Sulfur Dioxide						
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	CASTRIP VTD BOILER CASTRIP MISCELLANEOUS DRYERS	NATURAL GAS		(SO2) Sulfur Dioxide	FUEL SPECIFICATION: NATURAL GAS	0.1 LB/H	0.0006	lb/MMBTU		
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	AND PREHEATERS	NATURAL GAS		(SO2)	FUEL SPECIFICATION: NATURAL GAS	0.0006 LB/MMBTU	0			
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	PC BOILER	PRB SUB-BIT COAL	6000 MMBTU/H	Sulfur Dioxide (SO2)	DRY FLUE GAS DESULFURIZATION (SPRAY DRY ADSORBER)	0.08 LB/MMBTU	0			LOWER LIMIT IS FOR BURNING COAL <= 0.45% BY WEIGHT SULFUR CONTENT. ALSO 480 LB/HR 24 HOUR SO2 LIMIT AT ALL TIMES
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	AUXILIARY BOILER	NATURAL GAS	555 MMBTU/H	Sulfur Dioxide (SO2)		0.0006 LB/MMBTU	0			
/11/0004	John W. Tohk JK. FOWERTERNT	7.11	11/05/2000 ((1050), (C)	EMERGENCY GENERATOR AND FIRE		555 (1111) 10/11	Sulfur Dioxide		0.0000 ES/MINDTO	0			
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	PUMP ENGINE			(SO2)	LOW SULFUR DIESEL USE FUEL SPECIFICATIONS:: NATURAL GAS	0 007 G/KW-H	0			BASED ON USE OF LOW SULFUR DIESEL USE
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	180 MW	Sulfur Dioxide (SO2)	WITH A MAXIMUM OF 2.0 GRAINS OF SULFUR PER 100 SCF	0	0			BACT is fuel specification
				TURBINE, COMBINED CYCLE, FUEL			Sulfur Dioxide	FUEL SPECIFICATIONS: DISTILLATE OIL, < 0 05% S BY					
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	OIL	FUEL OIL	180 MW	(SO2)	WT	0	0			BACT is fuel specification
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	DUCT BURNER, NATURAL GAS			Sulfur Dioxide (SO2)	CLEAN FUEL	0.2 LB/MMBTU	0.2	lb/mmbtu		
*FI -0330	PORT DOLPHIN ENERGY LLC	FI	12/01/2011 ACT	Boilers (4 - 278 mmbtu/hr each)	natural gas	0	Sulfur Dioxide (SO2)	use of natural gas	0.0006 LB/MMBTU	0			
					indianal gao		Sulfur Dioxide	use of natural gas (99% of the time) and	0.0000 EB/WWDT0	0			
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/01/2011 ACT	Power Generator Engines (3)	natural gas	0	(SO2)	low sulfur fuel oil (1% of the time)	0.16 G/KW-H	0			THE 30 DAY ROLLING AVERAGE BACT LIMIT DOES NOT
													INCLUDE STARTUP, SHUTDOWN, OR MALFUNCTION
							Sulfur Dioxide	LIME SPRAY DRYER FLUE GAS				30 DAY ROLLING	EMISSIONS. THE TON/YR LIMIT INCLUDES ALL EMISSIONS INCLUDING STARTUP, SHUTDOWN, AND
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	CBEC 4 BOILER	PRB COAL	7675 MMBTU/H	(SO2)	DESULFURIZATION	0.1 LB/MMBTU	0.1	lb/MMBTU	AVERAGE	MALFUNCTION.
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	AUXILIARY BOILER	NATURAL GAS	429.4 MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.0006 LB/MMBTU	0			
			06/17/2002 & share ACT				Sulfur Dioxide	GOOD COMBUSTION PRACTICES AND LOW	V				UNIT IS ALSO LIMITED TO FUEL WITH A MAXIMUM
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	EMERGENCY GENERATOR	DIESEL FUEL	97.73 GAL/H	(SO2) Sulfur Dioxide	SULFUR FUEL GOOD COMBUSTION PRACTICES AND LOV	0 052 LB/MMBTU	0			SULFUR CONTENT OF 0 05% (BY WT) ALSO LIMITED TO FUEL WITH A MAXIMUM SULFUR
IA-0067	WALTER SCOTT JR. ENERGY CENTER ADM CORN PROCESSING - CEDAR	IA	06/17/2003 ACT	DIESEL FIRE PUMP	DIESEL FUEL	27.8 GAL/H	(SO2) Sulfur Dioxide	SULFUR FUEL	0 052 LB/MMBTU	0			CONTENT OF 0 05% SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS
IA-0088	RAPIDS	IA	06/29/2007 ACT	DDGS COOLER		140 T/H OF DRY FEED	(SO2)		10 PPMVD	0			LADEN WITH SO2.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	14	06/29/2007 ACT	INDIRECT-FIRED DDGS DRYER	NATURAL GAS	93.7 MMBTU/H	Sulfur Dioxide (SO2)		6 PPMVD	0			
	ADM CORN PROCESSING - CEDAR						Sulfur Dioxide						SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS
IA-0088	RAPIDS	IA	06/29/2007 ACT	GERM DRYERS AND COOLERS		15 T/H	(SO2)	WET SCRUBBER BURN LOW-SULFUR DIESEL FUEL. 0.05%	10 PPMVD	0			LADEN WITH SO2.
	ADM CORN PROCESSING - CEDAR						Sulfur Dioxide	BY WEIGHT OR LESS NOT TO EXCEED THE					
IA-0088	RAPIDS	IA	06/29/2007 ACT	FIRE PUMP	DIESEL #2	540 HP	(SO2)	NSPS REQUIREMENT. LIMITED THE HYDROGEN SULFIDE	0.17 G/B-HP-H	0			
								CONCENTRATION OF THE BOIGAS					
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	WASTEWATER TREATMENT PLANT (WWTP) ANAEROBIC DIGESTER		1500 SCFM OF BIOGAS	Sulfur Dioxide (SO2)	PRODUCED TO 200 PPMV (24-HOUR ROLLING AVERAGE).	0 023 LB/MMBTU	0			

				Summa	rv of SO ₂ Contr	ol Determinat	ion per EPA's	RACT/BACT/L	AER Database for Natural Gas >	250 million BTU/hr				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
														SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2. THE CO2 SCRUBBER CONTROLS THE FERMENTATION TANKS, VEAST PROPAGATORS AND BEERWELLS. THE NCG SCRUBBER CONTROLS THE NITROGEN STRIPPER AND DISTILLATION COLUMN. THE PERCENT REDUCTION LIMIT APPLIES ACROSS BOTH OF THE SCRUBBER INDIVIDUALLY. THE CONCENTRATION LIMIT APPLIES TO THE OUTLET OF THE RTO, WHICH
	ADM CORN PROCESSING - CEDAR			FERMENTATION, DISTILLATION AND				Sulfur Dioxide	CO2 SCRUBBER AND DISTILLATION NCG					IS AFTER THE SCRUBBERS. THE LIMITS ARE WRITTEN AS 90 %
IA-0088	RAPIDS	IA	06/29/2007 ACT	DEHYDRATION		840000	GAL/H	(SO2)	SCRUBBER	90 % REDUCTION	(0		REDUCTION OR 10 PPMV.
	ADM CORN PROCESSING - CEDAR			NATURAL GAS BOILER (292.5				Sulfur Dioxide						
IA-0088	RAPIDS	IA	06/29/2007 ACT	MMBTU/H)	NATURAL GAS	292.5	5 MMBTU/H	(SO2)	NATURAL GAS FUEL ONLY	0.0006 LB/MMBTU	(0		
	ADM CORN PROCESSING - CEDAR							Sulfur Dioxide	BURN LOW-SULFUR DIESEL FUEL. 0.05%					
IA-0088	RAPIDS	14	06/29/2007 ACT	EMERGENCY GENERATOR	DIESEL	1500	кw	(SO2)	BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17 G/B-HP-H		h		
IA-0088	INAFID3		00/23/2007 ,Ac1	EMERGENCI GENERATOR	DILGLE	1500		(302)		0.17 0/8-07-01				TON PER YEAR LIMIT IS THE SUM OF EMISSIONS FROM BOTH
														ALCOHOL LOADOUT FLARES AND CORRESPONDS TO A PLANTWIDE
	ADM CORN PROCESSING - CEDAR							Sulfur Dioxide	FUEL FIRED IN THE FLARE IS LIMITED TO					LOADOUT LIMIT OF 752,325,000 GALLONS OF ETHANOL PER 12-
IA-0088	RAPIDS	IA	06/29/2007 ACT	ALCOHOL RAIL LOADOUT		12000	GAL/MIN	(SO2)	NATURAL GAS AND BIOGAS	0.0025 LB/MMBTU	0	b		MONTH ROLLING PERIOD.
				TURBINES, COMBUSTION, NAT GAS				Sulfur Dioxide	LOW SULFUR FUEL. ALTERNATE LIMIT FOR	R				
IN-0092	WHITING CLEAN ENERGY, INC.	IN	07/20/2000 ACT	(2) W/DUCT BURNER	NATURAL GAS	1735	5 ММВТU/Н	(SO2)	EACH CT	6 LB/MMBTU	0	D		
									GOOD COMBUSTION PRACTICES AND LOW	v				
									SULFUR FUEL					
									(0 8 % BY WT SULFUR). PERMIT LIMITS					
									TOTAL SO2					
									FROM COMBUSTION TURBINES AND DUCT					
				TURBINES, COMBUSTION, NATURAL				Sulfur Dioxide	BURNERS TO 22 8	PPM @ 15%			-	
IN-0092	WHITING CLEAN ENERGY, INC.	IN	07/20/2000 ACT	GAS (2)	NATURAL GAS	1735	5 MMBTU/H	(SO2)	LB/H.	150 02	150) PPM @ 15% C	02	
IN-0092	WHITING CLEAN ENERGY, INC.	INI	07/20/2000 ACT	GENERATORS, STEAM, NATURAL GAS (2) W/DUCT BURNERS	NATURAL GAS	001	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0.2 LB/MMBTU	0.7	2 LB/MMBTU		
111-0092	WHITING CLEAN ENERGY, INC.		07/20/2000 &IIDSP,ACT	GAS (2) W/DOCT BORNERS	NATURAL GAS	021		(302)	LOW SULFUR NATURAL GAS: < 007% S BY		0.2			
								Sulfur Dioxide	WT (2 GR/100					
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	DUCT BURNER, NATURAL GAS, (4)	NATURAL GAS	300	ммвти/н	(SO2)	SCF), GOOD COMBUSTION PRACTICE.	0 001 LB/MMBTU	0.001	1 LB/MMBTU		
			57,27,2002 dilb3p,re1			500		(002)	LOW SULFUR NATURAL GAS: 0 007 % S BY	-	0.001	2.23/101010		
				TURBINE, COMBINED CYCLE,				Sulfur Dioxide	WT (2 GR/100					
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT		NATURAL GAS	1490.5	ммвти/н	(SO2)	SCF), GOOD COMBUSTION PRACTICE	0.0028 LB/MMBTU	(b		
							· · ·		LOW SULFUR NATURAL GAS: < 0.007 % S	1 1				
									BY WT (2					
				TURBINES, SIMPLE CYCLE, NATURAL				Sulfur Dioxide	GR/100 SCF), GOOD COMBUSTION					
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	GAS, (4)	NATURAL GAS	1490.5	5 MMBTU/H	(SO2)	PRACTICES.	0.0028 LB/MMBTU	(0		
									LOW SULFUR NATURAL GAS: < .007 %S BY					
				TURBINE, COMBINED CYCLE AND				Sulfur Dioxide	WT (2 GR/100			1		
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	DUCT BURNER, NAT GAS	NATURAL GAS	1490.5	5 MMBTU/H	(SO2)	SCF), GOOD COMBUSTION PRACTICE.	4.4 LB/H	(D	1	

				Summa	ry of SO ₂ Contr	ol Determinat	ion per EPA's	RACT/BACT/LA	ER Database for Natural Gas >	> 250 million B	TU/hr	-			
							THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
															IDENTIFIED AS (EU-001) SHALL BE LIMITED AS FOLLOWS:
															LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE SO2 EMISSIONS DURING STARTUPS, SHUTDOWNS, AND OTHER FLARING EVENTS. THE PERMITTEE WILL USE METHANOL, RATHER THAN COAL OR PET COKE, AS THE FEEDSTOCK IN EACH GASIFIER DURING STARTUP CONDITIONS REQUIRING SYNGAS FLARING, THEREBY REDUCING EMISSIONS OF SULFUR DIOXIDE AT THE SYNGAS HYDROCARBON FLARE. DURING A PLANNED SHUTDOWN OF A GASIFIER, THE PERMITTEE SHALL ROUTE THE CONTENTS OF EACH GASIFIER UNIT (GASIFIER VESSEL, QUENCH CHAMBER, SCRUBBER VESSEL) DURING INITIAL DEPRESSURIZATION TO ONE OF THE WET SULFURIC ACID (WSA) PLANTS. THE PERMITTEE SHALL REDUCE GASIFIER FEED RATES SUCH THAT ALL SYNGAS CAN BE PROCESSED THROUGH ONE GAS TREATMENT TRAIN PRIOR TO A SCHEDULED GAS TREATMENT TRAIN OUTAGE. THIS LIMITS THE AMOUNT OF SYNGAS THAT WILL HAVE TO BE SENT TO THE SYNGAS HYDROCARBON FLARE.
								Cultur Disuida							THE PERMITTEE SHALL HAVE WRITTEN PROCEDURES FOR THE ABOVE
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	SYNGAS HYDROCARBON FLARE	SYNGAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	A FLARE MINIMIZATION PLAN	0		0			OPERATIONS AND THE PERMITTEE SHALL TRAIN THE OPERATORS ON THESE PROCEDURES. EMISSION LIMITS: NONE
								Sulfur Dioxide							(3) THE SO2 EMISSIONS FROM THE ACID GAS FLARE, IDENTIFIED AS (EU-002) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE EMISSIONS DURING FLARING EVENTS. THE PERMITTEE SHALL INVESTIGATE THE ?ROOT CAUSE? OF MALFUNCTION EVENTS THAT CAUSE GASES TO BE SENT TO A FLARE AND DETERMINE WHETHER THERE ARE ADDITIONAL PREVENTATIVE MEASURES THAT CAN BE IMPLEMENTED TO MINIMIZE RE-OCCURRENCE OF THESE EVENTS. SUCH IDENTIFIED MEASURES SHALL BE
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ACID GAS FLARE	ACID GAS	0 27	MMBTU MMBTU/H,	(SO2) Sulfur Dioxide	FLARE MINIMIZATION PLAN	0		0			IMPLEMENTED AND DOCUMENTED.
*IN-0166	INDIANA GASIFICATION, LLC	IN		TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	EACH	(SO2)	USE OF NATURAL GAS OR SNG	0.0006	ММВТU/Н	0			ļ
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT		NATURAL GAS		EACH	Sulfur Dioxide (SO2)	RECTISOL ACID GAS REMOVAL SYSTEM	3.17	LB/H	0			EMISSION LIMIT 1 IS FOR EACH RTO.
*IN-0166	INDIANA GASIFICATION, LLC	IN			NATURAL GAS AND SNG		MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF CLEAN BURNING GASEOUS FUEL	0.0006	LB/MMBTU	0			EMISSION LIMIT IS FOR EACH BURNER.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	N 15	PPM SULFUR	0			EMISSION LIMIT: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION. EMISSION LIMITS: EACH EMERGENCY GENERATOR SHALL NOT
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	N 15	PPM SULFUR	0			EMISSION LIMITS: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN		TWO (2) WET SULFURIC ACID PLANTS	STPD	800	STPD	Sulfur Dioxide (SO2)	PEROXIDE SCRUBBER	0.25	LB/T ACID PRODUCED	0			EMISSION LIMIT IS FOR EACH UNIT.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ZLD SPRAY DRYER		5.6	MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	USE OF A CLEAN BURNING GASEOUS FUE LEAK DETECTION AND REPAIR (LDAR)	EL O		0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FUGITIVE LEAKS FROM PIPING		c)	(SO2)	PROGRAM	0		0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	SPACE HEATERS	NATURAL GAS	1	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	о			LIMIT IS FOR EACH HEATER
-	MAGNETATION LLC			COKE BREEZE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS		MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES		LB/MMBTU	0			
	MAGNETATION LLC			EMERGENCY GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF NATRUAL GAS AND GOOD COMBUSTION PRACTICES		G/KW-H	0			

	r	Γ	1	Summa	ry of SO ₂ Control Determinat	tion per EPA's	RACT/BACT/L	AER Database for Natural Gas > 2	50 million B	TU/hr		1	_	
						THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION USE OF NATUAL GAS AND GOOD	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FIRE WATER PUMP	NATURAL GAS 30	0 НР	(SO2)	COMBUSTION PRACTICES	0.0015	G/KW-H	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM	16	5 Т/Н	Sulfur Dioxide (SO2)		0.0005	LB/MMBTU	0			
114-0107			04/10/2013 @1030,ACT	GROUND LIMESTONE/DOLOMITE	10.	5 1/11	Sulfur Dioxide	USE OF NATURAL GAS AND GOOD	0.0005		0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	ADDITIVE SYSTEM AIR HEATER	NATURAL GAS 1	9 MMBTU/H	(SO2)	COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE HOOD EXHAUST	NATURAL GAS 43	6 MMBTU/H	Sulfur Dioxide (SO2)		21.68	LB/H	0			LIMIT ONE: 7.1 PPMV WET AT 20% O2 NOTE: 0.089 LB SO2/TON PELLETS * 450 TONS/HR = 40.1 LB/HR SO2
				FURNACE WINDBOX EXHAUST			Sulfur Dioxide	GSA DRY SCRUBBER AND BAGHOUSE						LIMIT ONE: 5.0 PPMV WET AT 15% O2
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	(WBE)	NATURAL 43	6 MMBTU/H	(SO2)	CE016	19.61	LB/H	0			NOTE: 0.048 LB SO2/TON PELLETS * 450 TONS/HR = 21.6 LB/HR SO2
10.0174	PORT HUDSON OPERATIONS	1.0	01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 2	NATURAL GAS 30	6 T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.04	LB/H	0			
LA-0174			01/25/2002 @1059,AC1	TOWEL MACHINE NO. 6 YANKEE	1017E 073 30	0 170	Sulfur Dioxide		0.04	LOJII				
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	AIRCAP EXHAUST	30	6 T/D	(SO2)	NATURAL GAS AS FUEL	0.02	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1	2 8	1 MM LB/D	Sulfur Dioxide (SO2)		105.91	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV @ 8% O2.
				TOWEL MACHINE NO. 6 TAD			Sulfur Dioxide							
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	EXHAUST 1	NATURAL GAS 30	6 T/D	(SO2) Sulfur Dioxide	NATURAL GAS AS FUEL	0.07	' LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2	3 9	6 MM LB/D	(SO2)		143.23	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV AT 8% O2.
14.0174			01/25/2002 8 share ACT		2.2		Sulfur Dioxide		0.22		0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1	33	2 MM LB BLS/D	(SO2) Sulfur Dioxide	WET SCRUBBER	9.22	LB/H	U			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2	2 2	5 MM LB BLS/D	(SO2)	WET SCRUBBERS	6.24	LB/H	0			
14-0174	PORT HUDSON OPERATIONS	١۵	01/25/2002 ACT	LIME KILN NO. 1	34	0 T/D	Sulfur Dioxide (SO2)	WET SCRUBBERS AND OPTIMAL MUD WASHING	3 26	LB/H	0			
6/101/4							Sulfur Dioxide	WET SCRUBBERS AND OPTIMAL MUD	5.20					
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2	27	0 T/D	(SO2)	WASHING	2.59	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS 98	7 ММВТИ/Н	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS	5126	LB/H	5.19	LB/MMBTU		
							Sulfur Dioxide							
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 2	NAT GAS 65.	5 MMBTU/H	(SO2)	FIRING NATURAL GAS ADD-ON: WET SCRUBBER.	0.26	LB/H	0.004	lb/MMBTU		
								P2: FUEL CAN BE EITHER WOOD WASTE						
14 0174			01/25/2002 ACT	COMPINIATION DOLLED NO. 1	WOOD WASTE / NAT GAS 459.	5 MMBTU/H	Sulfur Dioxide	OR NATURAL GAS.	22.22	U.D./L	0.72	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 AC1	COMBINATION BOILER NO. 1	NAT GAS 459.		(SO2) Sulfur Dioxide	USE OF LOW SULFUR NATURAL GAS, 1.8	37.37	цв/п	0.73	LB/IVIIVIBTU		
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	GAS TURBINES - 187 MW (2)	200	6 MMBTU/H	(SO2)	GRAINS PER 100 SCF	10.1	LB/H	0			
							Sulfur Dioxide	USE OF LOW SULFUR PIPELINE NATURAL					ANNUAL	*TPY LIMIT FOR ALL 3 HEATERS. AGGREGATE HEAT INPUT IS LIMITED TO 14,250 MM BTU/YR. ONLY 2 OF THE 3 HEATERS ARE ALLOWED TO
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	FUEL GAS HEATERS (3)	1	9 MMBTU/H	(SO2)	GAS AND GOOD COMBUSTION PRACTICES	0 008	LB/H	0.0004	LB/MMBTU		OPERATE AT ANY GIVEN TIME.
14.0102			05/05/2005 8 about 65				Sulfur Dioxide	GOOD ENGINE DESIGN AND PROPER	0.61	1.0./11	0.00		ANNUAL	
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DIESEL FIRED WATER PUMP			(SO2)	OPERATING PRACTICES USE OF LOW SULFUR NATURAL GAS, 1.8	0.61	LB/H	0.05	G/B-HP-H	AVERAGE	OPERATING TIME = 52 HR/YR
							Sulfur Dioxide	GRAINS					ANNUAL	
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DUCT BURNERS (2)	75	9 MMBTU/H	(SO2) Sulfur Dioxide	PER 100 SCF FUELED BY NATURAL GAS OR SUBSTITUTE	3.8	LB/H	0.005	lb/MMBTU	AVERAGE	
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	SHIFT REACTOR STARTUP HEATER	NATURAL GAS 34.	2 MMBTU/H	(SO2)	NATURAL GAS (SNG)	0.02	LB/H	0			
14.0221			05/22/2000 8 share 6 CT	GASIFIER STARTUP PREHEATER			Sulfur Dioxide	FUELED BY NATURAL GAS OR SUBSTITUTE	0.02	1.0.41	0			
LA-0251	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	BURNERS (5)	NATURAL GAS 3	5 MMBTU/H	(SO2) Sulfur Dioxide	NATURAL GAS (SNG)	0.02	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	ACID GAS FLARE	NATURAL GAS 0 2	7 MMBTU/H	(SO2)	NO ADDITIONAL CONTROL	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	FIRE WATER DIESEL PUMPS (3)	DIESEL 57	5 HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
2. 5251		<u></u>		HYDROCARBON/GASIFIERS			Sulfur Dioxide		0.01					
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	STARTUP FLARE	NATURAL GAS 487 5	5 MMBTU/H	(SO2) Sulfur Dioxide	NO ADDITIONAL CONTROL	1303.99	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	METHANATION STARTUP HEATERS	NATURAL GAS 56.	9 MMBTU/H	(SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.03	LB/H	0			
							Sulfur Dioxide	FUELED BY NATURAL GAS OR SUBSTITUTE			-			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	AUXILIARY BOILER	NATURAL GAS 938.	3 MMBTU/H	(SO2) Sulfur Dioxide	NATURAL GAS (SNG)	0.28	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	THERMAL OXIDIZERS (2)	NATURAL GAS 40.	9 MMBTU/H	(SO2)	NO ADDITIONAL CONTROL	22.92	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY		06/22/2009 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	DIESEL 134	1 HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
LA-0231		ыл 	00/22/2003 QHUSP,ACT		134	I III LACII	(SO2) Sulfur Dioxide	CONTEL WITH 40 CIN 00 SUDPANT III	0.01		0		+	
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	WET SULFURIC ACID PLANTS (2)	200	0 T/D	(SO2)	HYDROGEN PEROXIDE SCRUBBERS	13.8	LB/H	0			

LA-0238 ALLI LA-0238 ALLI LA-0245 HYD	FACILITY NAME LIANCE REFINERY LIANCE REFINERY LIANCE REFINERY DROGEN PLANT	FACILITY STATE	PERMIT ISSUANCE DATE 07/10/2009 ACT 07/10/2009 ACT 07/10/2009 ACT	PROCESS NAME FCCU FEED HEATER CO BOILERS (2) FCCU REGEN VENT - SU/SD	PRIMARY FUEL REFINERY GAS	THROUGHPUT 181.7 MMBTU/H	POLLUTANT	AER Database for Natural Gas >		EMISSION	STANDARD	STANDARD	STANDARD LIMIT AVERAGE	
LA-0238 ALLI LA-0238 ALLI LA-0245 HYD	LIANCE REFINERY LIANCE REFINERY	LA LA LA LA	07/10/2009 ACT	CO BOILERS (2)	REFINERY GAS			CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	EMISSION LIMIT	EMISSION	TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0238 ALLI	LIANCE REFINERY	LA LA LA				101.7 101010/11	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	4.79	LB/H	0			
LA-0238 ALLI	LIANCE REFINERY				REFINERY GAS	831.3 MMBTU/H EACH	Sulfur Dioxide	COMPLY WITH 40 CFR 60 SUBPART J	1286	I D /U	0			
LA-0245 HYD		LA LA	07/10/2009 ACT		REFINERT GAS		Sulfur Dioxide				0			
	DROGEN PLANT	LA		OPERATIONS SMR Heaters (EQT0400 and		89000 BBL/D	(SO2) Sulfur Dioxide	COMPLY WITH 40 CFR 60 SUBPART J Limit maximum H2S concentration in fuels	1286	lb/H	0			
LA-0248 DIRI			12/15/2010 ACT	EQT0401)	Fuel Gas	1055 MMBTU/H	(SO2)	to 60 ppmv (annual average)	16.7	LB/H	0			
	RECT REDUCTION IRON PLANT	14	01/27/2011 ACT	DRI-111 - DRI Unit #1 Acid Gas Absorption Vent		30624 scfm	Sulfur Dioxide (SO2)	BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO-CAT Redox process, for the removal of H2S. Nucor will install a redox catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.		18/H	0			The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively.
							Sulfur Dioxide							The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively. BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO CAT Redox process, for the removal of H2S. Nucor will install a redox
LA-0248 DIRI	RECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-211 - DRI Unit #1 Acid Gas Absorption Vent		30624 scfm	(SO2)		0.58	LB/H	0			catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.
LA-0248 DIRI	RECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-106 - DRI Unit No. 1 Upper Seal Gas Vent		1765 acfm	Sulfur Dioxide (SO2)		0.02	lb/H	0			Sulfur dioxide BACT was determined to treat the spent reducing gas being sent to the Reformer as combustion fuel. The seal gas is removed before the spent reducing gas is treated for SO2 control, and so no additional control is feasible for the seal gas.
														Sulfur dioxide BACT was determined to treat the spent reducing gas being sent to the Reformer as combustion fuel. The seal gas is
LA-0248 DIRI	RECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-206 - DRI Unit No. 2 Upper Seal Gas Vent		1765 acfm	Sulfur Dioxide (SO2)		0.02	LB/H	0			removed before the spent reducing gas is treated for SO2 control, and so no additional control is feasible for the seal gas.
				DRI-108 - DRI Unit #1 Reformer	Iron Ore and		Sulfur Dioxide	BACT is selected to be the removal of hydrogen sulfide from the top gas fuel through acid gas scrubbing. This technology was identified as the most stringent control method of the available technologies, and has the added benefit or slightly reducing energy demand at the reformer. Nucor will install and acid gas scrubbing system for top gas prior to its use as fuel in the reformer. BACT for natural gas is to purchase natural gas containing no more than 2000 grains of	F					Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels. Sweet natural gas is often cited as an alternative to other fuels due to the very low sulfur content of this fuel The reformer also burns top gas from the shaft furnace, which contains a small portion of hydrogen sulfide originating from sulfur compounds in the iron ore, as well as any sulfur that was in the natural gas converted into reformer gas. Once combusted, this hydrogen sulfide converts directly to SO2. Because sulfur is rarely introduced into a combustion reaction other than as a component of the fuel, Nucor evaluated both fuel treatment for the removal of hydrogen sulfide and other sulfur compounds, as well as flue gas desulfurization (FGD) for the removal of SO2 from the products of

					1 2	<u> </u>			AER Database for Natural Gas > 3		0/11				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	1 THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
															Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide
									BACT is selected to be the removal of hydrogen sulfide from the top gas fuel through acid gas scrubbing. This technology was identified as the most stringent control method of the available						Emissions from Stationary Sources. Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels. Sweet natural gas is often cited as an alternative to other fuels due to the very low sulfur content of this fuel The reformer also burns top gas from the shaft furnace, which contains a small portion of hydrogen sulfide originating from sulfur
									technologies, and has the added benefit of slightly reducing energy demand at the reformer. Nucor will install and acid gas scrubbing system for top gas prior to its	F					compounds in the iron ore, as well as any sulfur that was in the natural gas converted into reformer gas. Once combusted, this hydrogen sulfide converts directly to SO2. Because sulfur is rarely introduced into a combustion reaction other than as a component of
									use as fuel in the reformer. BACT for natural gas is to purchase natural gas						the fuel, Nucor evaluated both fuel treatment for the removal of hydrogen sulfide and other sulfur compounds, as well as flue gas
A-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	Iron ore and Natural Gas	12168 Bi	illion Btu/yr	Sulfur Dioxide (SO2)	containing no more than 2000 grains of Sulfur per MM scf.	3.16	LB/H	0.002	lb/mmbtu		desulfurization (FGD) for the removal of SO2 from the products of combustion in the flue gas.
				DRI-109 - DRI Unit #1 Package Boiler				Sulfur Dioxide	Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other						Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct
_A-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	Flue Stack	Natural Gas	1760 Bi	illion Btu/yr	(SO2)	potential fuels. Emissions of SO2 are usually attributable	0.09	LB/H	0			sampling by the facility
				DRI-209 - DRI Unit #2 Package Boiler				Sulfur Dioxide	to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other						Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct
A-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	Flue Stack GE 7EA COMBUSTION TURBINE -	Natural Gas	1760 Bi	illion Btu/yr	(SO2) Sulfur Dioxide	potential fuels.	0.09	LB/H	0			sampling by the facility EMISSIONS LIMITS APPLY TO EACH CT WHEN FIRING NATURAL GAS
MD-0031	CHALK POINT	MD	04/01/2005 ACT	NG, SC ONLY	NATURAL GAS	85 M	IW	(SO2) Sulfur Dioxide	USE OF LOW SULFUR FUELS	6.3	LB/H	0			AND OPPORATING IN SIMPLE CYCLE MODE OPERATION OF EACH HEATER SHALL NOT EXCEED 1500 HR/12-
MD-0031	CHALK POINT	MD	04/01/2005 ACT	(2) NATURAL GAS FUEL HEATERS GE 7EA COMBUSTION TURBINE -	NATURAL GAS	10 M	IMBTU/H	(SO2) Sulfur Dioxide	USE OF LOW SULFUR FUELS	0 056	LB/H	0		NOT AVAILABLE	MONTH PERIOD EMISSION LIMIT APPLIES TO EACH CT WHEN FIRING FUEL OIL AND
MD-0031	CHALK POINT	MD	04/01/2005 ACT	FO, SC ONLY		85 M	IW	(SO2)	USE OF LOW SULFUR FUELS	60.3	LB/H	0			OPPERATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	NATURAL GAS	196 M	IW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	11	LB/H	0			LIMIT APPLIES TO UNIT 4 WITH FIRING NG WITH OR WITH OUT DUCT FIRING AND OPPORATING IN COMBINED CYCLE MODE LIMIT APPLIES TO UNIT 4 WHEN FIRING 0.05 WT% SULFUR FUEL OIL WITH OUT DUCT FIRING AND OPPORATING IN EITHER COMBINED OR
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		196 M	IW	Sulfur Dioxide (SO2)		92	LB/H	0			SIMPLE CYCLE MODE, FIRING LIMITED TO 250 H/YR IN SIMPLE CYCLE AND 720 H/YR IN COMBINED CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	NATURAL GAS	196 M	IW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	11	LB/H	0			LIMIT APPLIES TO UNIT 4 FIRING NG WITH OUT DUCT FIRING AND OPPORATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		196 M	IW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	106	LB/H	0			LIMIT APPLIES TO UNIT 5 WHEN FIRING 0.05 WT% SULFUR FUEL OIL WITH OUT DUCT FIRING AND OPPORATING IN EITHER COMBINED OR SIMPLE CYCLE MODE, FIRING LIMITED TO 250 H/YR IN SIMPLE CYCLE AND 720 H/YR IN COMBINED CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC		196 M	ıw	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	12	LB/H	0			LIMIT APPLIES TO UNIT 4 FIRING NG WITH OUT DUCT FIRING AND OPPORATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	AUXILARY BOILER - NG		60 M	IMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, USE OF CLEAN FUEL	0.34	LB/H	0 01	lb/mmbtu	CALCULATED	EMISSION LIMIT APPLIES TO AUXILARY BOILER WHEN FIRING NATURAL GAS
MD-0032	DICKERSON	MD	11/05/2004 EST	AUXILARY BOILER - FO	NATURAL GAS	60 M	IMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, USE OF CLEAN FUELS	3.1	LB/H	0 05	LB/MMBTU	CALCULATED	EMISSION LIMIT APPLIES TO AUXILARY BOILER WHEN FIRING FUEL OIL
	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	NATURAL GAS	196 M	IW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS		LB/H	0			LIMIT APPLIES TO UNIT 5 WITH FIRING NG WITH OR WITH OUT DUCT FIRING AND OPPORATING IN COMBINED CYCLE MODE
	KALKASKA GENERATING, INC	MI	02/04/2003 ACT		NATURAL GAS		IMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL.		LB/MMBTU	0.003	lb/mmbtu		Emissions are from each duct burner.
	BLACK DOG GENERATING PLANT	MN	01/12/2001 ACT	TURBINE, COMBINED CYCLE	NATURAL GAS	290 M		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL LIMITED TO 0 004 GR/DSCF, USING 12-MONTH ROLLING AVG.	0	,	0	,		
								Sulfur Dioxide	LOW SULFUR FUEL-PIPELINE QUALITY NATURAL GAS; SULFUR CONTENT OF FUEL LESS THAN 0 004 GR/DSCF USING 12-MO ROLLING AV; PRIMARY EMISSION LIMIT						

					.					//				
				Summa	ry of SO ₂ Contr	ol Determinat	ion per EPA's	RACT/BACT/L	AER Database for Natural Gas >	250 million BTU/hr	STANDARD	STANDARD	STANDARD LIMIT AVERAGE	E
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	EMISSION LIMIT	EMISSION LIMIT UNIT	TIME CONDITION	POLLUTANT COMPLIANCE NOTES
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, LARGE	DIESEL FUEL	1850	НР	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.59 G/B-HP-H	0			
				INTERNAL COMBUSTION ENGINE,				Sulfur Dioxide						
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	SMALL COMBUSTION TURBINE, LARGE 2	DIESEL FUEL	290) HP	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	0.14 G/B-HP-H	0			
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	EACH	NATURAL GAS	182	7 ММВТИ/Н	(SO2) Sulfur Dioxide	LOW SULFLUR FUEL	0.05 % S BY WT	0)		LIMIT APPLIES TO OIL SULFUR CONENT
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	DUCT BURNER, 2 EACH	NATURAL GAS	800) ММВТИ/Н	(SO2)	LOW SULFUR FUEL	0.8 GR/100SCF	0		NOT AVAILABLE	LIMIT IS FOR SULFUR CONTENT OF NG
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE, 2 EACH	NATURAL GAS	1910	5 ММВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8 GR/100SCF	0			LIMIT IS FOR SULFUR CONENT OF NG
								Sulfur Dioxide			0.001			
IVIN-0054 I	MANKATO ENERGY CENTER	IVIN	12/04/2003 ACT	BOILER, COMMERCIAL	NATURAL GAS	70	MMBTU/H	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	0 001 LB/MMBTU	0.001	LB/MMBTU		
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	TUNNEL FURNACE INDURATING FURNACE - WASTE	NATURAL GAS	205	5 Т/Н	(SO2) Sulfur Dioxide		1 PPM	0)		
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	GAS	NATURAL GAS	624	1 т/н	(SO2)	WET SCRUBBER	3.3 PPM@15%02	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	PROCESS HEATERS	NATURAL GAS	600	5 ММВТИ/Н	Sulfur Dioxide (SO2)	LIMITED TO NATURAL GAS	0.0029 LB/T	0			
				ELECTRIC ARC FURNACE/MELT				Sulfur Dioxide						
MN-0070 r	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	SHOP INDURATING FURNACE - HOOD		205	5 Т/Н	(SO2) Sulfur Dioxide		0.15 LB/T	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	EXHAUST DIESEL FIRE WATER PUMPS (&It500	NATURAL GAS	624	1 SHORT T/H	(SO2) Sulfur Dioxide	WET SCRUBBER	7.8 PPM@15%02	0			LIMITED TO 500 HOURS DER YEAR (12 MONTH ROLLING SUM) SUI FUR
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	HP)				(SO2)	LIMITED SULFUR IN FUEL; LIMITED HOURS	0.05 %	0			LIMITED TO 500 HOURS PER YEAR (12 MONTH ROLLING SUM) SULFUF CONTENT OF FUEL SO2 EMISSIONS
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	EMERGENCY POWER GENERATION - DIESEL	DIESEL			Sulfur Dioxide (SO2)	LIMITED HOURS, LIMITED SULFUR IN FUEL	0.05 %	0			LIMITED TO 500 HOURS PER YEAR (12 MONTH ROLLING AVERAGE); SULFUR LIMIT FOR FUEL LIMITS SO2 EMISSIONS.
(GEORGIA PACIFIC CORPORATION,				512022		T BLS/H, each	Sulfur Dioxide						
	MONTICELLO MILL GEORGIA PACIFIC CORPORATION,	MS	07/09/2003 ACT	SMELT DISSOLVING TANKS (4)	NA	36.	5 tank	(SO2) Sulfur Dioxide	SCRUBBERS ON EACH TANK	6.5 LB/H	0			ALSO, 0.2 LB/T AIR-DRIED PULP
MS-0075	MONTICELLO MILL	MS	07/09/2003 ACT	LIME KILN	NATURAL GAS	200) ММВТU/Н	(SO2)	SCRUBBER	12.4 LB/H	0			
	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	NCG THERMAL OXIDIZER (BACK-UP)	NATURAL GAS	7.	5 ММВТИ/Н	Sulfur Dioxide (SO2)	SCRUBBER	0 045 LB/H	0.006	LB/MMBTU	CALCULATED	
	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	RECOVERY BOILER NO. 1	BLACK LIQUOR	861 4	1 MMBTU/H	Sulfur Dioxide (SO2)		408.33 LB/H	0			7.0 LBS SO2 / TON AIR-DRIED PULP
	GEORGIA PACIFIC CORPORATION,							Sulfur Dioxide	SULFUR LIMIT ON FUELS BURNED. SEE					DISCONTINUATION OF NO. 6 FUEL OIL. MAXIMUM OF 1% SULFUR CONTENT IN THE USED OIL BURNED. MAXIMUM USEAGE RATE FOR THE VOLUME OF ON-SITE GENERATED USED OIL THAT CAN BE
MS-0075	MONTICELLO MILL	MS	07/09/2003 ACT	COMBINATION BOILER	SCRAP WOOD	917.4	1 ММВТИ/Н	(SO2)	NOTE	2335.5 LB/H	0 26	LB/MMBTU		BURNED.
	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	POWER BOILER - NG	NATURAL GAS	76	5 ММВТИ/Н	Sulfur Dioxide (SO2)		0.46 LB/H	0.0006	LB/MMBTU		
(GEORGIA PACIFIC CORPORATION,							Sulfur Dioxide						
IVIS-0075 I	MONTICELLO MILL	MS	07/09/2003 ACT	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	1 MMBTU/H	(SO2) Sulfur Dioxide		408.33 LB/H	0			7 LB SO2 / T AIR-DRIED PULP.
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	LADLE PREHEATER	NATURAL GAS	48	3 MMBTU/H	(SO2) Sulfur Dioxide		346.59 LB/T	0)		
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNI REHEAT FURNACE	NATURAL GAS	133	3 MMBTU/H	(SO2)		0.0006 LB/MMBTU	0)		
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII REHEAT FURNACE	NATURAL GAS	143	3 ММВТИ/Н	Sulfur Dioxide (SO2)		0.0006 LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII BILET POST-HEATER	NATURAL GAS	61	3 MMBTU/H	Sulfur Dioxide (SO2)		0.0006 LB/MMBTU	0			
						0.0		Sulfur Dioxide						
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	CUT-OFF TORCHES	NATURAL GAS			(SO2) Sulfur Dioxide		2.25 LB/T	0			
NJ-0043 L	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	AUXILIARY BOILER	NATURAL GAS	200) ММВТИ/Н	(SO2) Sulfur Dioxide	NONE	0.8 LB/H	0.004	lb/mmbtu		BASIS OF LIMIT IS STATE.
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DUCT BURNER (3)	NATURAL GAS	250	5 ММВТИ/Н	(SO2)	NONE LISTED	0.2 LB/MMBTU	0.2	LB/MMBTU		
NJ-0043 L	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE WITH DUCT BURNER	NATURAL GAS	3207	2 MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0 004 LB/MMBTU	0.8	PPM @ 15% O2		
	LIBERTY GENERATING STATION	L. L	03/28/2002 ACT	EMERGENCY GENERATOR	DISTILLATE OIL			Sulfur Dioxide (SO2)	SULFUR IN OIL LIMITED TO 0.05% BY WEIGHT.	0.8 LB/H	0			
NJ-0043 L	LIBERTY GENERATING STATION	NI	03/28/2002 ACT	COMBINED CYCLE TURBINE (3)	NATURAL GAS	296	1 MMBTU/H	Sulfur Dioxide (SO2)	ONLY USE NATURAL GAS WITH SULFUR CONTENT 0.8%	0 004 LB/MMBTU	0.8	PPM @ 15% O2	,	BASIS OF LIMIT IS STATE
								Sulfur Dioxide			0.0		-	
	LIBERTY GENERATING STATION HARRAH'S OPERATING COMPANY,	NJ	03/28/2002 ACT	DIESEL FIRE PUMP	DISTILLATE OIL	3.5	5 MMBTU/H	(SO2) Sulfur Dioxide	NONE	1 LB/H	0			
NV-0049 I		NV	08/20/2009 ACT	BOILER - UNIT HA08	NATURAL GAS	8 3	7 ММВТИ/Н	(SO2)	FUEL IS LIMITED TO NATURAL GAS.	0.0006 LB/MMBTU	0.0006	LB/MMBTU	ļ	
1	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	NATURAL GAS	41.6	1 ММВТИ/Н	Sulfur Dioxide (SO2)	LIMITING THE FUEL TO NATURAL GAS ONLY.	0.0007 LB/MMBTU	0.0007	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH OF THE THREE UNITS.

NY-0086 RAVENSWOOD GEN NY-0086 RAVENSWOOD GEN NY-0086 RAVENSWOOD GEN BIOMASS ENERGY, I BIOMASS ENERGY, I OH-0269 POWER OH-0307 SOUTH POINT BIOM	GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	NY NY ОН ОН ОН	09/07/2001 ACT 09/07/2001 ACT 09/07/2001 ACT 01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT	PROCESS NAME TURBINE WITHOUT DUCT BURNER (NATURAL GAS) TURBINE WITHOUT DUCT BURNER (KEROSENE) DUCT BURNER AUXILIARY BOILER, FUEL OIL	PRIMARY FUEL PRIMARY FUEL NATURAL GAS KEROSENE NATURAL GAS FUEL OIL #2 NATURAL GAS WOOD NATURAL GAS	THROUGHPUT 250 251 64 22 24 17	tion per EPA's THROUGHPUT UNIT 0 MW 4 MMBTU/H 7 MMBTU/H 7 MMBTU/H 5 MMBTU/H	POLLUTANT Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide	AER Database for Natural Gas > 2 CONTROL METHOD DESCRIPTION LOW SULFUR FUEL04% LOW SULFUR FUEL (0.04%) LOW SULFUR FUEL (0.04%)	EMISSION LIMIT 1 0.0071 LB/MMBTU 0.0071 LB/MMBTU 0.0071 LB/MMBTU 0.0071 LB/MMBTU 2.84 LB/H	STANDARD EMISSION LIMIT 0 0 0 0 0 0.0125 LB/MMBTU	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
NY-0086 RAVENSWOOD GEN NY-0086 RAVENSWOOD GEN NY-0086 RAVENSWOOD GEN BIOMASS ENERGY, I BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 OH-0269 POWER OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-0307 UMATILLA GENERA' OR-043 L.P. OR-0443 L.P. OR-0187 GRAYS FERRY COGE	GENERATING STATION GENERATING STATION GENERATING STATION GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	NY NY ОН ОН ОН ОН	09/07/2001 ACT 09/07/2001 ACT 09/07/2001 ACT 01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT	TURBINE WITHOUT DUCT BURNER (NATURAL GAS) TURBINE WITHOUT DUCT BURNER (KEROSENE) DUCT BURNER AUXILIARY BOILER, FUEL OIL AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	NATURAL GAS KEROSENE NATURAL GAS FUEL OIL #2 NATURAL GAS WOOD	250 250 64 22 24 17	0 MW 0 MW 4 MMBTU/H (HHV) 7 MMBTU/H 7 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2)	LOW SULFUR FUEL04% LOW SULFUR FUEL (0.04%)	0.0071 LB/MMBTU 0 044 LB/MMBTU 0.0071 LB/MMBTU 2.84 LB/H	0 0 0 0.0125 LB/MMBTU	CALCULATED	
NY-0086 RAVENSWOOD GEN NY-0086 RAVENSWOOD GEN BIOMASS ENERGY, I DH-0269 OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER OH-0269 POWER OH-0269 POWER OH-0307 SOUTH POINT BIOM OR-0037 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI UMATILLA GENERA' UMATILLA GENERA' OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0045 TURNER ENERGY COGE PA-0187 GRAYS FERRY COGE	GENERATING STATION GENERATING STATION GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	NY NY ОН ОН ОН	09/07/2001 ACT 09/07/2001 ACT 01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT 04/04/2006 ACT	TURBINE WITHOUT DUCT BURNER (KEROSENE) DUCT BURNER AUXILIARY BOILER, FUEL OIL AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7)	KEROSENE NATURAL GAS FUEL OIL #2 NATURAL GAS WOOD	250 64 22 24 17	0 MW 4 MMBTU/H (HHV) 7 MMBTU/H 7 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%)	0 044 LB/MMBTU 0.0071 LB/MMBTU 2.84 LB/H			
NY-0086 RAVENSWOOD GEN BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER OH-0269 POWER OH-0269 POWER OH-0307 SOUTH POINT BIOM OR-0037 KLAMATH FALLS CO OR-0037 COB ENERGY FACILI UMATILLA GENERAL UNATILLA GENERAL OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	GENERATING STATION GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	NY ОН ОН ОН ОН	09/07/2001 ACT 01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 01/05/2006 ACT 04/04/2006 ACT	(KEROSENE) DUCT BURNER AUXILIARY BOILER, FUEL OIL AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	NATURAL GAS FUEL OIL #2 NATURAL GAS WOOD	64- 22 24 17	4 MMBTU/H (HHV) 7 MMBTU/H 7 MMBTU/H	(SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2)		0.0071 LB/MMBTU 2.84 LB/H			
BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER OH-0269 POWER OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-0043 L.P. UMATILLA GENERA' L.P. OR-0043 L.P. OR-0043 L.P. OR-0045 TURNER ENERGY CGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	он он он он	01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT 04/04/2006 ACT	AUXILIARY BOILER, FUEL OIL AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	FUEL OIL #2 NATURAL GAS WOOD	22 ² 24 17	7 MMBTU/H 7 MMBTU/H	(SO2) Sulfur Dioxide (SO2) Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%)	2.84 LB/H			
BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER OH-0269 POWER OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POIN	GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT GY, LLC-SOUTH POINT IOMASS GENERATION IOMASS GENERATION	он он он он	01/05/2004 ACT 01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT 04/04/2006 ACT	AUXILIARY BOILER, FUEL OIL AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	FUEL OIL #2 NATURAL GAS WOOD	22 ² 24 17	7 MMBTU/H 7 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide (SO2)		2.84 LB/H			
BIOMASS ENERGY, I OH-0269 POWER BIOMASS ENERGY, I OH-0269 POWER OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-00307 COB ENERGY FACILI UMATILLA GENERA' OR-0043 L.P. UMATILLA GENERA' L.P. OR-0043 L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	GY, LLC-SOUTH POINT	ОН	01/05/2004 ACT 01/05/2004 ACT 04/04/2006 ACT 04/04/2006 ACT	AUXILIARY BOILER, NATURAL GAS WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	NATURAL GAS	24	7 MMBTU/H	Sulfur Dioxide (SO2)					ADDITIONAL LIMITS FOR FUEL OIL: 0.50% BY WEIGHT.
OH-0269 POWER BIOMASS ENERGY, I BIOMASS ENERGY, I OH-0269 POWER OH-0307 SOUTH POINT BIOM OR-0307 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0045 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE	GY, LLC-SOUTH POINT	ОН	01/05/2004 ACT 04/04/2006 ACT 04/04/2006 ACT	WOOD FIRED BOILERS (7) WOOD FIRED BOILERS (7)	WOOD WOOD	17		(SO2)		0.45 1.5 /11			0.33 T/YR IS TOTAL FOR AUXILIARY BOILER, ALL FUELS
OH-0269 POWER OH-0307 SOUTH POINT BIOM OR-00307 SOUTH POINT BIOM OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	IOMASS GENERATION	ОН	04/04/2006 ACT 04/04/2006 ACT	WOOD FIRED BOILERS (7)	WOOD		5 MMBTU/H	Sulfur Dioxide		0.15 LB/H	0.6 LB/MMBTU	WITH NATURAL GAS	LIMITS ARE FOR NATURAL GAS, EXCEPT: 0.33 T/YR IS TOTAL FOR AUXILIARY BOILER, ALL FUELS
OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-00307 SOUTH POINT BIOM OR-0037 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI UMATILLA GENERA' OR-0043 L.P. UMATILLA GENERA' OR-0043 L.P. OR-0045 TURNER ENERGY COGE PA-0187 GRAYS FERRY COGE	IOMASS GENERATION	ОН	04/04/2006 ACT 04/04/2006 ACT	WOOD FIRED BOILERS (7)	WOOD				DRY SODIUM BICARBONATE INJECTION	22.121.0/11			
OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-0037 SOUTH POINT BIOM OR-0039 COB ENERGY FACILI UMATILLA GENERA' UMATILLA GENERA' OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0043 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	IOMASS GENERATION	ОН	04/04/2006 ACT			21		(SO2)	SYSTEM OR SPRAY DRYER ADSORBER	22.13 LB/H	0.087 LB/MMBTU		LIMITS ARE FOR EACH OF 7 BOILERS
OH-0307 SOUTH POINT BIOM OH-0307 SOUTH POINT BIOM OR-0037 SOUTH POINT BIOM OR-0039 COB ENERGY FACILI UMATILLA GENERA' UMATILLA GENERA' OR-0043 L.P. OR-0043 L.P. OR-0043 L.P. OR-0043 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	IOMASS GENERATION	ОН	04/04/2006 ACT			24		Sulfur Dioxide	SPRAY DRYER ADSORBER OR DRY SODIUM			FACILITY	
OH-0307 SOUTH POINT BIOM OR-0037 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI UMATILLA GENERA UMATILLA GENERA I.P. UMATILLA GENERA OR-0043 L.P. OR-0046 TURNER ENERGY CO PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	IOMASS GENERATION			AUXILIARY BOILER	NATURAL GAS	510	8 MMBTU/H	(SO2) Sulfur Dioxide	BICARBONATE INJECTION SYSTEM	22.13 LB/H	0.087 LB/MMBTU	FACTOR	LIMITS ARE FOR EACH OF THE 7 BOILERS.
OR-0037 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI UMATILLA GENERA OR-0043 L.P. UMATILLA GENERA L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE		ОН	04/04/2006 ACT			24	7 ММВТU/Н	(SO2)		0.15 LB/H	0.6 LB/MMSCF		AUXILIARY BOILER USING NATURAL GAS.
OR-0037 KLAMATH FALLS CO OR-0039 COB ENERGY FACILI UMATILLA GENERA OR-0043 L.P. UMATILLA GENERA L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE		он	04/04/2006 ACT					Sulfur Dioxide				MAXIMUM SULFUR CONTENT OF	
OR-0039 COB ENERGY FACILI UMATILLA GENERAT OR-0043 L.P. UMATILLA GENERAT OR-0043 L.P. OR-0046 TURNER ENERGY COGE PA-0187 GRAYS FERRY COGE				AUXILIARY BOILER	FUEL OIL #2	22	7 ММВТU/Н	(SO2)		2.84 LB/H	0.5 % BY WEIGHT	OIL	AUXILIARY BOILER USING NUMBER 2 FUEL OIL
OR-0039 COB ENERGY FACILI UMATILLA GENERAT OR-0043 L.P. UMATILLA GENERAT OR-0043 L.P. OR-0046 TURNER ENERGY COGE PA-0187 GRAYS FERRY COGE								Sulfur Dioxide				WHILE BURNING DISTILLATE	SEE FACILITY NOTES FOR RESTRICTIONS TO S CONTENT
UMATILLA GENERA OR-0043 L.P. UMATILLA GENERA L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	S COGENERATION	OR	12/29/2000 ACT	AUXILIARY BOILER	NAT GAS	40	0 ММВТU/Н	(SO2)	RESTRICTIONS ON S CONTENT OF FUEL	0.8 LB/MMBTU	0.8 LB/MMBTU	FUEL	OF FUEL.
OR-0043 L.P. UMATILLA GENERA L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	CILITY, LLC	OR	12/30/2003 ACT	DUCT BURNERS, NATURAL GAS, (4)	NATURAL GAS	654	4 ММВТU/Н	Sulfur Dioxide (SO2)	CLEAN FUEL	0.2 LB/MMBTU	0.2 LB/MMBTU		Limit does not apply during startup, shut down, or emergency conditions
UMATILLA GENERA OR-0043 L.P. OR-0046 TURNER ENERGY CE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	ERATING COMPANY,	OR	05/11/2004 ACT	DUCT BURNERS	NATURAL GAS	27	2 MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	86 NG/J	0.2 LB/MMBTU		Limit does not apply during startup, shutdown, or emergency conditions
OR-0043 L.P. OR-0046 TURNER ENERGY CO PA-0187 GRAYS FERRY COGE		-											
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	ERATING COMPANY,	OR	05/11/2004 ACT	TURBINE, COMBINED CYCLE & amp; DUCT BURNER, NAT GAS (2)	NATURAL GAS	200	7 ММВТU/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: < 0.8% S BY WEIGHT	8000 PPMW	0		
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE								Sulfur Dioxide		% SULFUR			
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	Y CENTER, LLC	OR	01/06/2005 ACT	ELECTRICAL POWER GENERATION COMBUSTION TURBINE, COMBINED	NATURAL GAS	3450744	8 MMBTU/YR	(SO2) Sulfur Dioxide	USE OF NATURAL GAS GOOD COMBUSTION PRACTICE, LOW	0.8 CONTENT	0	NUT AVAILABLE	SO2 EMISSION LIMIT SET BY NSPS GG.
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	OGEN PARTNERSHIP	РА	03/21/2001 ACT	CYCLE, NATURAL GAS	NATURAL GAS	151	5 ММВТU/Н	(SO2)	SULFUR FUEL	0.0008 LB/MMBTU	0		PERMIT LIMIT FOR TURBINE AND HRSG.
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	OGEN PARTNERSHIP	РА		COMBUSTION TURBINE, COMBINED CYCLE, FUEL OIL	#2 FUEL OIL	151	5 ММВТИ/Н	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0 203 LB/MMBTU	0		
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE		DA.	02/21/2001 8 share ACT			111		Sulfur Dioxide	GOOD COMBUSTION PRACTICE, LOW				
PA-0187 GRAYS FERRY COGE PA-0187 GRAYS FERRY COGE	JGEN PARTNERSHIP	PA	03/21/2001 ACT	AUXILIARY BOILER, NATURAL GAS	NATURAL GAS	111	9 MMBTU/H	(SO2) Sulfur Dioxide	SULFUR FUEL GOOD COMBUSTION PRACTICE, LOW	0.0008 LB/MMBTU	0.0008 LB/MMBTU		
PA-0187 GRAYS FERRY COGE	OGEN PARTNERSHIP	РА	03/21/2001 ACT	AUXILIARY BOILER, FUEL OIL	#2 FUEL OIL	111	9 MMBTU/H	(SO2)	SULFUR FUEL	0 215 LB/MMBTU	0.215 LB/MMBTU		
	OGEN PARTNERSHIP	PA	03/21/2001 ACT	COMBUSTION TURBINE, SIMPLE CYCLE, NATURAL GAS	NATURAL GAS	13	5 MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0.0008 LB/MMBTU	о		PERMIT LIMIT FOR OPERATION OF TURBINE ONLY.
		PA	03/21/2001 ACT	COMBUSTION TURBINE, SIMPLE CYCLE. FUEL OIL	#2 FUEL OIL	10	5 MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0 203 LB/MMBTU	0		PERMIT LIMIT FOR OPERATION OF TURBINE ONLY.
PA-0260 DELTA POWER PLA				OIL FIRED TURBINES (6) (COMBINED		13		Sulfur Dioxide					
i I	PLANT	РА	01/03/2008 ACT	CYCLE) OIL FIRED TURBINES (6) (SIMPLE	OIL	11 24	4 T/H GAL/H	(SO2) Sulfur Dioxide		0 051 LB/MMBTU	0		
PA-0260 DELTA POWER PLAN	PLANT	PA	01/03/2008 ACT	CYCLE)	OIL	11 2	4 T/H GAL/H	(SO2)		0 051 LB/MMBTU	0		
PA-0260 DELTA POWER PLAN		РА		GAS FIRED TURBINES (6) (SIMPLE CYCLE)	NG	1174	0 GAL/H	Sulfur Dioxide (SO2)	SCR	0 003 LB/MMBTU	0		
	Mar 11 7 1			GAS FIRED TURBINES (60				Sulfur Dioxide					
PA-0260 DELTA POWER PLAN		PA	01/03/2008 ACT	(COMBINED CYCLE) TURBINES, COMBINED CYCLE,	NG	1124	0 GAL/H	(SO2) Sulfur Dioxide		0 003 LB/MMBTU	0		
SC-0061 COLUMBIA ENERGY		sc	04/09/2001 ACT	NATURAL GAS (2)	NATURAL GAS	17	0 MW (EACH)	(SO2)	LOW SULFUR FUELS	4.9 LB/H	0		
SC-0061 COLUMBIA ENERGY	PLANT		04/09/2001 ACT	BOILERS, NATURAL GAS (2)	NATURAL GAS	35	MMBTU/H 0 (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	0.63 LB/H	0.0018 LB/MMBTU		
SC-0061 COLUMBIA ENERGY	PLANT RGY LLC	SC	04/09/2001 ACT	BOILERS, FUEL OIL (2)	NO. 2 FUEL OIL	35	0 MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	21 LB/H	0 06 LB/MMBTU		
SC-0061 COLUMBIA ENERGY	PLANT RGY LLC RGY LLC	sc sc		HOT WATER HEATERS (2)	NATURAL GAS	1	1 MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	3.5 LB/MMBTU	3.5 LB/MMBTU		
	PLANT RGY LLC RGY LLC RGY LLC	SC	04/09/2001 &nhsp-ACT	TURBINES, COMBINED CYCLE,	DISTILLATE FUEL		-	Sulfur Dioxide			3.5 26/101010		
SC-0061 COLUMBIA ENERGY	PLANT RGY LLC RGY LLC RGY LLC RGY LLC			DISTILLATE FUEL OIL (2)	OIL	17	0 MW (EACH)	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	99 LB/H	0		
SC-0071 HWY 21 SOUTH	PLANT RGY LLC RGY LLC RGY LLC RGY LLC RGY LLC	sc sc				17	0 MW	(SO2)	COMBUSTION OF LOW SULFUR FUELS	1 1 1	I		
COLUMBIA ENERGY SC-0071 HWY 21 SOUTH	PLANT RGY LLC RGY LLC RGY LLC RGY LLC RGY LLC RGY LLC RGY CENTER I-26 & US	sc sc	04/09/2001 ACT 04/09/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, (2) BOILERS, AUXILIARY, NATURAL GAS,	NATURAL GAS	1/1	- 1	Sulfur Dioxide	COMBUSTION OF LOW SULFUR FUELS	4.9 LB/H	0		

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND EMISS LIMIT U
	COLUMBIA ENERGY CENTER I-26 & US							Sulfur Dioxide					
SC-0071	COLUMBIA ENERGY CENTER I-26 & US	SC	04/09/2001 ACT	BOILER, AUXILIARY, FUEL OIL, (2) TURBINE, COMBINED CYCLE, FUEL	FUEL OIL		MMBTU/H	(SO2) Sulfur Dioxide	COMBUSTION OF LOW SULFUR FUELS		lb/MMBTU	0.0616	LB/MMB
SC-0071	HWY 21 SOUTH	SC	04/09/2001 ACT	OIL, (2)	FUEL OIL	170	MW	(SO2) Sulfur Dioxide	COMBUSTION OF LOW SULFUR FUELS	99	LB/H	0	
SC-0091	COLUMBIA ENERGY CENTER	SC	07/03/2003 ACT	BOILER, FUEL OIL	NO. 2 FUEL OIL	550	ММВТU/Н	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	0.06	lb/MMBTU	0 06	LB/MMB
SC-0091		SC	07/03/2003 ACT	BOILER, NATURAL GAS	NATURAL GAS	550	MMBTU/H	(SO2)	LOW SULFUR FUEL	0.0018	LB/MMBTU	0.0018	LB/MMB
SC-0128	NUCOR STEEL CORPORATION (DARLINGTON PLANT)	SC	12/29/2006 ACT	REHEAT FURNACE NO.2	NATURAL GAS	180	ММВТИ/Н	Sulfur Dioxide (SO2)	FUEL SPECIFICATION AND GOOD COMBUSTION PRACTICES.	0.0006	lb/mmbtu	0	
TX-0293	GREGORY POWER FACILITY	ТХ	06/16/1999 ACT	FIRE WATER PUMP ENGINE, EPN106				Sulfur Dioxide (SO2)	FUEL OIL SHALL CONTAIN NO MORE THAN 0 3 WT %S	0.1	LB/H	0	
17-0293	GREGORT POWER FACILITY		00/10/1999 & 1050, AC1	(2) COMBUSTION TURBINES, NO				Sulfur Dioxide	PIPELINE QUALITY NAT GAS, CONTAINING NO MORE THAN 3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100				
TX-0293	GREGORY POWER FACILITY	тх	06/16/1999 ACT	DUCT BURN, EPN 101&102	NAT GAS	185	MW, EA	(SO2)	DSCF 12 MO ROLLING AV PIPELINE QUALITY NAT GAS, CONTAINING NO MORE THAN	15.7	LB/H	0	
TX-0293	GREGORY POWER FACILITY	тх	06/16/1999 ACT	(2) COMBUSTION TURBINES, W/DUCT BURN, EPN101&102	NAT GAS	185	MW, EA	Sulfur Dioxide (SO2)	3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100 DSCF 12 MO ROLLING AV		LB/H	0	
TX-0293	GREGORY POWER FACILITY	тх	06/16/1999 ACT	(2) AUX PACKAGE BOILERS, EPN103 &104	NAT GAS	405	MMBTU/H	Sulfur Dioxide (SO2)	FIRED WITH PIPELINE QUALITY NAT GAS	3.4	LB/H	0.0084	LB/MMB
TX-0293	GREGORY POWER FACILITY	ТХ	06/16/1999 ACT	DIESEL GENERATOR, EPN105	DISTILLATE FUEL			Sulfur Dioxide (SO2)	FUEL OIL SHALL CONTAIN NO MORE THAN 0 3 WT %S	2.3	LB/H	0	
TX-0297	EXXON-MOBIL BEAUMONT REFINERY	тх	03/14/2000 ACT	(3) COMBUSTION TURBINES W/DUCT BURN, 61STK001-003	NAT GAS		MW, EA TURBINE	Sulfur Dioxide (SO2)	FIRING NAT GAS	1.41	LB/H	0	
TX-0297	EXXON-MOBIL BEAUMONT REFINERY	тх	03/14/2000 ACT	BOILER 23, 56STK_023	NAT GAS	1121	MMBTU/H	Sulfur Dioxide (SO2)	FIRING NAT GAS AND REFINERY FUEL GAS	31.73	LB/H	0.028	LB/MMB
TX-0310		тх	01/06/1999 ACT	BOILER, B108	NAT GAS	264	ММВТU/Н	Sulfur Dioxide (SO2)	NONE INDICATED	0.16	LB/H	0.0006	LB/MMB
TX-0310	THE GOODYEAR TIRE & RUBBER BEAUMONT	тх	01/06/1999 ACT	(4) GAS TURBINES, UNITS 1-4, W/OUT DUCT BURNER	NAT GAS	5	MW, EA	Sulfur Dioxide (SO2)	FIRING NAT GAS	0.04	LB/H	0	
TX-0310	THE GOODYEAR TIRE & RUBBER BEAUMONT	ТХ	01/06/1999 ACT	(4) GAS TURBINES, UNITS 1-4, W/DUCT BURNERS	NAT GAS	5	MW, EA	Sulfur Dioxide (SO2)	FIRING NAT GAS	0.1	LB/H	0	
TX-0369	UCC SEADRIFT OPERATIONS	тх	10/20/1999 ACT	COGEN STACK, COMBINED GT/HRSG&DB, 1180	NAT GAS	38.7	мw	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS	23.43	LB/H	0	
TX-0369	UCC SEADRIFT OPERATIONS	ТХ	10/20/1999 ACT	COGEN STACK, TURBINE ONLY	NAT GAS		мw	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS		LB/H	0	
TX-0369	UCC SEADRIFT OPERATIONS	тх	10/20/1999 ACT	COGEN STACK, PEAK LOAD - COMBINED GT/HRSG&DB, 1180	NAT GAS	44.5	MMBTU/H	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS FUEL FOR THE HRSGU DUCT BURNERS IS	24.62	LB/H	0	
TX-0369	UCC SEADRIFT OPERATIONS	тх	10/20/1999 ACT	COGEN STACK, HRSG&DB ONLY	NAT GAS	279.3	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED TO PIPELINE QUALITY NATURAL GAS CONTAINING NO MORE THAN 10 GR S/100 DSCF.	8.55	LB/H	0.031	lb/MMB
TX-0371	CORPUS CHRISTI ENERGY CENTER	ТХ	02/04/2000 EST	(3) TURBINE/HRSG NOS 1-3, CU1-3	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT	48.35	LB/H	0	
TX-0371	CORPUS CHRISTI ENERGY CENTER	тх	02/04/2000 EST	(3) AUXILIARY BOILERS 1-3, AB1-3 ANNUAL TOTALS FOR TURBINES	NAT GAS	315	MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS.	9.4	LB/H	0 03	lb/MMB
TX-0371	CORPUS CHRISTI ENERGY CENTER	ТХ	02/04/2000 EST	& AUXILIARY BOILERS	GASEOUS FUEL			(SO2) Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS.	189.3	T/YR	0	
TX-0373	ODESSA PETROCHEMICAL PLANT	ТХ	10/24/2002 ACT	F BOILER STACK, EYFBLRST	NAT GAS	370	ММВТИ/Н	(SO2) Sulfur Dioxide	LOW S FUEL GASES	0.22	LB/H	0.0005	LB/MMB
TX-0373	ODESSA PETROCHEMICAL PLANT	ТХ	10/24/2002 ACT	C BOILER STACK, EY003ST	NAT GAS	320	ммвти/н	(SO2)	NONE INDICATED	0.19	LB/H	0.0006	LB/MMB
TX-0383	FORNEY PLANT	тх	03/06/2000 ACT	(6) DUCT BURNERS (ALONE)	NAT GAS	550	MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	FIRING LOW SULFUR PIPELINE NAT GAS	33.72	LB/H	0 06	LB/MMB
TX-0383	FORNEY PLANT	ТХ	03/06/2000 ACT	(6) BLACK START GENERATORS	NAT GAS			(SO2)	NONE INDICATED	0.13	LB/H	0	
TX-0383	FORNEY PLANT	ТХ	03/06/2000 ACT	EMERGENCY DIESEL GENERATOR	DISTILLATE			Sulfur Dioxide (SO2)	NONE INDICATED	5.14	LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
B/MMBTU		
B/MMBTU		
B/MMBTU		
,		THE TEST METHODS ARE METHOD 6 OR METHOD 6C.
		SO2 EMISSION LIMIT IN LB/MMBTU CALCULATED BY
	EACH UNIT	DIVIDING THE HOURLY EMISSION LIMIT BY THE THROUGHPUT.
B/MMBTU	EACH UNIT	
		SO2 STANDARD EMISSIONS CALCULATED BY DIVIDING
B/MMBTU	CALCULATED	THE HOURLY EMISSION LIMIT BY THE THROUGHPUT. STANDARD EMISSIONS CALCULATED FROM HOURLY
B/MMBTU	SEE NOTES	EMISSION AND RATED HEAT INPUT.
B/MMBTU		
B/IVIIVIBIU	CALCULATED	
		SO2 STANDARD EMISSIONS REQUIRED IN LB/MMBTU,
B/MMBTU	EACH, CALCULATED	CALCULATED FROM MAXIMUM ALLOWABLE RATES IN LB/H AND HEAT INPUT CAPACITY.
B/MMBTU	CALCULATED, SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT,
	CALCULATED,	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT
B/MMBTU	SEE NOTE EACH,	RATING AND HOURLY EMISSION LIMIT. HOURLY EMISSION LIMIT ONLY FOR THE DUCT BURNER
B/MMBTU	CALCULATED	ONLY.

								/ /.						
							THROUGHPUT		AER Database for Natural Gas > 2		EMISSION EN	MISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT LIN	MIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
K-0383	FORNEY PLANT	тх	03/06/2000 ACT	FIREWATER PUMP ENGINE	DISTILLATE			(SO2)	NONE INDICATED	0.51 LB/H	0			
(-0383	FORNEY PLANT	тх	03/06/2000 ACT	(6) TURBINES	NAT GAS	169.8	3 MW	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE NAT GAS	26.41 LB/H	0			HOURLY EMISSION LIMIT ONLY FOR THE SIMPLE-CYCLE TURBINE.
X-0383	FORNEY PLANT	тх	03/06/2000 ACT	(6) COMBINED TURBINE & amp; DUCT BURNER	NAT GAS	169.8	B MW	Sulfur Dioxide (SO2)	LOW SULFUR PIPELINE NAT GAS FUEL SWEET, NATURAL GAS WITH NO	289.73 T/YR	0			ANNUAL LIMIT ONLY FOR COMBINED TURBINE AND DUCT BURNER. EMISSION LIMIT REQUIRED IN STANDARDIZED UNITS.
0296		TV	02/26/2002 & physic CT	TURBINES AND DUCT BURNERS (3		102		Sulfur Dioxide	MORE THAN 5.0 GRAINS (HOURLY AVERAGE) AND 0.2 GRAIN TOTAL S PER	12 6 1 9/4				
-0386	AMELLA ENERGY CENTER	тх	03/26/2002 ACT	EACH0	NATURAL GAS	1030	OMW (TOTAL)	(SO2) Sulfur Dioxide	100 DSCF (ANNUALLY)	13.6 LB/H	0			
-0386	AMELLA ENERGY CENTER	тх	03/26/2002 ACT	AUXILIARY BOILER	NATURAL GAS	15	5 MMBTU/H	(SO2)		0 843 LB/H	0.005 LB/N	MMBTU		
-0416	SHELL OIL DEER PARK	тх	11/24/1999 ACT	BOILER, PHENOL/ACETONE PLANT	NATURAL GAS	35	7 ММВТU/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (5.0 GR/100 DSCF) LOW SULFUR FUEL. NATURAL GAS - 0.25	5.11 LB/H	0.014 LB/№	MMBTU	CALCULATED	
0419	CHANNEL ENERGY FACILITY	тх	03/22/2000 ACT	TURBINE, COMBINED CYCLE, AND DUCT BURNER (3)	NATURAL GAS	180	лw	Sulfur Dioxide (SO2) Sulfur Dioxide	GR/100 SCF SULFUR, REFINERY GAS - 0.473 GR/100 SCF SULFUR.	31.4 LB/H	0			
-0419	CHANNEL ENERGY FACILITY	тх	03/22/2000 ACT	BOILER, AUXILIARY, (3)	NATURAL GAS	380	О ММВТИ/Н	(SO2)	LOW SULFUR FUEL, NATURAL GAS - 0 25 GR/100 SCF SULFUR LOW SULFUR FUEL: NATURAL	6.23 LB/H	0.016 LB/N	MMBTU		
-0419	CHANNEL ENERGY FACILITY	тх	03/22/2000 ACT	BOILER, AUXILIARY, (3) PROCESS GAS	NATURAL GAS	380) mmbtu/h	Sulfur Dioxide (SO2)	GAS/REFINERY GAS = 0.473 GR/100 SCF SULFUR	6.23 LB/H	0.016 LB/№	MMBTU		
0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	тх	10/08/2003 ACT	TURBINE AND DUCT BURNER (3)	NATURAL GAS	664	4 MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION AND SWEET NATURAL GAS	37.06 LB/H	0			
	TEXAS PETROCHEMICALS HOUSTON	T) (Sulfur Dioxide	GOOD COMBUSTION AND SWEET					
-0469	FACILITY	TX	10/08/2003 ACT	AUXILLARY STEAM BOILER (2) 2 WESTINGHOUSE 501F TURBINES	NATURAL GAS	664	4 MMBTU/H	(SO2)	NATURAL GAS	4.99 LB/H	0			
0470		T) (42/02/2004 Bishes ACT	WITH 2 735MMBTU/H DUCT				Sulfur Dioxide						
-0479	DOW TEXAS OPERATIONS FREEPORT	TX	12/02/2004 ACT	2 WESTINGHOUSE 501F TURBINES WITH 2 735MMBTU/H DUCT	NATURAL GAS NATURAL GAS AND OTHER PROCESS	/3:	5 MMBTU/H	(SO2) Sulfur Dioxide	BURN CLEAN NATURAL GAS	40.14 LB/H	0			
-0479	DOW TEXAS OPERATIONS FREEPORT	ТХ	12/02/2004 ACT	MAINTENANCE)	FUELS NATURAL GAS,	73	5 MMBTU/H	(SO2)		40.14 LB/H	0			
0479	DOW TEXAS OPERATIONS FREEPORT	тх	12/02/2004 ACT	COMBUSTION VIA FOUR GAS-FIRED STEAM BOILERS TURBINES FIRING FUEL OIL AND	OFFGAS, SYNGAS, CELL HYDROG	410	О ММВТИ/Н	Sulfur Dioxide (SO2)	BURN CLEAN NATURAL GAS FIRING LOW SULFUR PIPELINE-QUALITY	5.41 LB/H	0			
					FUEL OIL/NATURAL			Sulfur Dioxide	NATURAL GAS AND FUEL OIL WILL					
0482	COBISA GREENVILLE	тх	06/03/2005 ACT	SCENARIO 1, CASE 2	GAS			(SO2)	CONTROL SO2 AND H2SO4 EMISSIONS. FIRING LOW SULFUR PIPELINE-QUALITY	683.4 LB/H	0			
				TURBINES AND DUCTS FIRING				Sulfur Dioxide	NATURAL GAS AND FUEL OIL WILL					
0482	COBISA GREENVILLE	тх	06/03/2005 ACT	NATURAL GAS - SCENARIO 1, CASE 1	NATURAL GAS	550	D MMBTU/H	(SO2)	CONTROL SO2 AND H2SO4 EMISSIONS. FIRING LOW SULFUR PIPELINE-QUALITY	211.2 LB/H	0			
-0482	COBISA GREENVILLE	тх	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 4, CASE 1	NATURAL GAS	82	5 mmbtu/h	Sulfur Dioxide (SO2)	NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	205 LB/H	0			
				TURBINES FIRING FUEL OIL AND	FUEL OIL#2/NATURAL			Sulfur Dioxide	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL					
0482	COBISA GREENVILLE	тх	06/03/2005 ACT		GAS	82	5 ММВТИ/Н	(SO2)	CONTROL SO2 AND H2SO4 EMISSIONS.	584.1 LB/H	0			
-0487	COBISA GREENVILLE	тх	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 2, CASE 1		55) MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	211.4 LB/H	0			
0402			50,03/2003 @IDSp,ACT	TURBINES FIRING FUEL OIL AND	FUEL	550			FIRING LOW SULFUR PIPELINE-QUALITY	211.+ LD/11				
0482	COBISA GREENVILLE	тх	06/03/2005 ACT	DUCTS FIRING NATURAL GAS - SCENARIO 3, CASE 2 TURBINES FIRING FUEL OIL AND	OIL#2/NATURAL GAS FUEL	550	О ММВТU/Н	Sulfur Dioxide (SO2)	NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS. FIRING LOW SULFUR PIPELINE-QUALITY	680 LB/H	0			
				DUCTS FIRING NATURAL GAS -	OIL#2/NATURAL			Sulfur Dioxide	NATURAL GAS AND FUEL OIL WILL					
0482	COBISA GREENVILLE	тх	06/03/2005 ACT	SCENARIO 2, CASE 2	GAS	550) ММВТU/Н	(SO2)	CONTROL SO2 AND H2SO4 EMISSIONS. FIRING LOW SULFUR PIPELINE-QUALITY	699.9 LB/H	0			
-0482	COBISA GREENVILLE	тх	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 3, CASE 1	NATURAL GAS	55() ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	231.5 LB/H	0			
-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	RECYCLE ETHANE CRACKING FURNACE				Sulfur Dioxide (SO2)		1.12 LB/H	0			
	BASF ETHYLENE/PROPYLENE CRACKER		02/03/2006 ACT	FIRE WATER PUMP ENGINE (2)				(SO2) Sulfur Dioxide (SO2)		1.12 LB/H	0			
								Sulfur Dioxide						
0511	BASF ETHYLENE/PROPYLENE CRACKER	ТХ	02/03/2006 ACT	BOILER (2)		425.4	4 MMBTU/H	(SO2)		12.1 LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANI EMIS LIMIT
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	FRESH FEED CRACKING HEATER				(SO2)		1.61	LB/H	C)
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	DP FEED HEATER				Sulfur Dioxide (SO2)		0.22	LB/H	C)
				DP REACTOR REGENERATION				Sulfur Dioxide					
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	IX	02/03/2006 ACT	HEATER				(SO2) Sulfur Dioxide		0.07	LB/H	C C)
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	ТХ	02/03/2006 ACT	AUXILARY BOILER GTG HRSG UNIT 1 GE FRAME 6B				(SO2)		1.24	LB/H	C)
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	310.4 MMBTU/H DUCT BURNER (WITH SCR) GTG HRSG UNIT 2 GE FRAME 6B		310.4	MMBTU/H	Sulfur Dioxide (SO2)		4.46	LB/H	С)
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	310.4 MMBTU/HR DUCT BURNER (WITH SCR)		310.4	MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		4.46	LB/H	с)
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	тх	02/03/2006 ACT	GROUND FLARE				(SO2)		165.8	LB/H	C)
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	тх	08/18/2006 EST	FLARE PILOTS ONLY				Sulfur Dioxide (SO2)		0 002	LB/H	C)
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	тх	08/18/2006 EST	FLARE-MSS				Sulfur Dioxide (SO2)		0.01	LB/H	0	
	AIR PRODUCTS HYDROGEN, STEAM,							Sulfur Dioxide					
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	ТХ	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	(SO2) Sulfur Dioxide		0.92	LB/H	C)
TX-0526	AND ELECTRICITY PRODUCTION MOUNTAIN CREEK STEAM ELECTRIC	тх	08/18/2006 EST	REFORMER FURNACE STACK Simple Cycle Gas Turbines 1 & amp;	STEAM	1373	MMBTU/H	(SO2) Sulfur Dioxide		7.3	LB/H	C)
TX-0583	STATION	тх	01/12/2011 ACT	2	Natural Gas	0		(SO2)		64	LB/H	C)
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, DUCT BURNER	NATURAL GAS	1937	MMBTU/H	Sulfur Dioxide (SO2)		2.08	LB/H	C)
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE , FUEL OIL	DISTILLATE FUEL OIL	2080	ммвти/н	Sulfur Dioxide (SO2)		98.9	LB/H	C)
				BOILER, TANGENTIALLY-FIRED, UNIT	Г			Sulfur Dioxide	LOW SULFUR FUELS AND GOOD			0.0014	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	4	NATURAL GAS	2350	MMBTU/H	(SO2) Sulfur Dioxide	COMBUSTION PRACTICES. LOW SULFUR FUEL AND GOOD	14	T/YR	0.0014	LB/MME
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, AUXILIARY TURBINE, NATURAL GAS, NO DUCT	NATURAL GAS	99	MMBTU/H	(SO2) Sulfur Dioxide	COMBUSTION PRACTICES.	0.1	LB/H	0.001	. LB/MME
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BURNER FIRING	NATURAL GAS	1937	MMBTU/H	(SO2) Sulfur Dioxide		1.74	LB/H	C)
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	DUCT BURNERS	NATURAL GAS	385	MMBTU/H	(SO2)		0.2	lb/mmbtu	0.2	LB/MME
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT 3	NATURAL GAS	1150	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	14	T/YR	0.0028	
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	NATURAL GAS	90	MMBTU/H	Sulfur Dioxide (SO2)	CEMS AND GOOD COMBUSTION PRACTICES		LB/H		
								Sulfur Dioxide	WET OR DRY SCRUBBER AND GOOD				,
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	(SO2) Sulfur Dioxide	COMBUSTION PRACTICES 0 5% S AND WET OR DRY SCRUBBER.	9.1	LB/H	C)
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	RESIDUAL OIL	90	MMBTU	(SO2) Sulfur Dioxide	GOOD COMBUSTION PRACTICES .5% S FUEL AND GOOD COMBUSTION	9.5	LB/H	C)
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	(SO2)	PRACTICES	45.4	LB/H	C)
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 15		1150	TBLS/D	Sulfur Dioxide (SO2)		60	PPMDV @ 8% O2	C)
	LONGVIEW FIBRE PAPER AND							Sulfur Dioxide	FACILITY WILL HAVE A FEDERAL LIMIT OF SO2 REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. BACT IS NO FURTHER		PPMDV @ 8%		
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 18		1200	TBLS/D	(SO2)	CONTROL APPLICATION.	60	02	c)
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 15		1150	TBLS/D	Sulfur Dioxide (SO2)		12	T/YR	C)
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 18		1200	T BLS/D	Sulfur Dioxide (SO2)		4	T/YR	0)
	LONGVIEW FIBRE PAPER AND						-	Sulfur Dioxide					
	LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 19		2000	T BLS/D	(SO2) Sulfur Dioxide		16	T/YR	C	,
WA-0303	PACKAGING, INC LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 22		1950	T BLS/D	(SO2) Sulfur Dioxide		31	T/YR PPMDV @ 10	C)
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	LIME KILNS 1 AND 2	ļ	140	T CAO/D EACH	(SO2)		20	% 02	c)
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 3		240	T CAO/D	Sulfur Dioxide (SO2)		20	PPMDV @ 10% O2	C)

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
		Pipeline quality natural gas only
.B/MMBTU		
B/MMBTU	EACH UNIT	
B/MMBTU		
.B/MMBTU		
		EMISSION LIMITS ARE FOR 1 OF 2 BOILERS

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND EMISS LIMIT (
W/A 0202	LONGVIEW FIBRE PAPER AND	14/4	11/01/2006 & phone ACT	POWER BOILERS 12 AND 13			MMBTU/H, EA	Sulfur Dioxide		100	PPMDV @ 7%	0.24	
WA-0303	PACKAGING, INC LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	POWER BUILERS 12 AND 15		444	IVIIVIDTO/T, EA	(SO2) Sulfur Dioxide		100	PPMDV @ 7%	0 24	LB/MMB
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 20	FUEL OIL	900	MMBTU/H	(SO2)	LOW-SULFUR FUEL	100		0 25	LB/MMB
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 16	FUEL OIL	525	MMBTU/H	Sulfur Dioxide (SO2)		250	PPMDV @ 7% O2	0 59	LB/MMB
-	LONGVIEW FIBRE PAPER AND							Sulfur Dioxide			PPMDV @ 7%		
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 17	FUEL OIL	591	MMBTU/H	(SO2)	LOW SULFUR FUEL FACILITY WILL HAVE A LIMIT ON SO2	250	02	0 59	LB/MMB
	LONGVIEW FIBRE PAPER AND							Sulfur Dioxide	REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. WITH THIS NEW BASELINE FOR POTENTIAL SO2, BACT IS NO FURTHER		PPMDV @ 8%		
WA-0303	PACKAGING, INC LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	RECOVERY FURNACE 19		2000	T BLS/D	(SO2) Sulfur Dioxide	CONTROL.	60	O2 PPMDV @ 8%	0	
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 22		1950	T BLS/D	(SO2)		120	02	0	<u> </u>
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	COGEN 23	NATURAL GAS	695	MMBTU/H	Sulfur Dioxide (SO2)	ONLY PIPELINE QUALITY NATURAL GAS MAY BE USED AS FUEL	0.25	lb/mmbtu	0	
	LONGVIEW FIBRE PAPER AND							Sulfur Dioxide			PPMDV @		
WA-0303	PACKAGING, INC LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	LIME KILN 4		250	T CAO/D	(SO2) Sulfur Dioxide		20	10% O2 PPMDV @	0	
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 5		325	T CAO/D	(SO2)		20	10% 02	0	
WI-0244	APPLETON COATED COMBINED LOCKS MILL	wi	06/19/2007 ACT	BOILER B05 (#11) NATURAL GAS / DISTILLATE OIL FIRED BOILER	NATURAL GAS, DISTILLATE OIL	285	MMBTU/H	Sulfur Dioxide (SO2)	SYNTHETIC MINOR. RESTRICTION ON DISTILATE FUEL OIL SULFUR CONTENT AND USAGE TO KEEP SO2 < 40 TPY. LOW SULFUR FUEL; AVERAGE SULFUR CONTENT OF FUEL	0 365	lb/MMBTU	0	
MI-0357	KALKASKA GENERATING, INC	МІ	02/04/2003 ACT	TURBINE, COMBINED CYCLE, (2)	NATURAL GAS	605	MW	Sulfur Oxides (SOx)	CONTENT OF FUEL IS 0.75 GR/100 SCF. THE UNIT SHALL COMBUST ONLY LOW-	5.2	LB/H	0	
NV-0049		NV	08/20/2009 ACT	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	DIESEL OIL	1232	НР	Sulfur Oxides (SOx)	SULFUR DIESEL OIL WITH A SULFUR CONTENT LESS THAN 0 05%.	0.0004	LB/HP-H	0.0004	LB/HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC. HARRAH'S OPERATING COMPANY,	NV	08/20/2009 ACT	BOILER - UNIT FL01 SMALL INTERNAL COMBUSTION	NATURAL GAS	14 34	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	lb/MMBTU	0.0006	LB/MMB
NV-0049	INC.	NV	08/20/2009 ACT	ENGINE (<600 HP) - UNIT FL12	DIESEL OIL	536	НР	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0021	LB/HP-H	0.0021	LB/HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT BA01	NATURAL GAS	16.8	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0042	LB/MMBTU	0.0042	LB/MMB
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT BA03	NATURAL GAS		MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.		lb/mmbtu	0.0006	LB/MMB
NV-0049	HARRAH'S OPERATING COMPANY, INC. HARRAH'S OPERATING COMPANY,	NV	08/20/2009 ACT	BOILER - UNIT CP01	NATURAL GAS	35.4	ММВТU/Н	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	lb/mmbtu	0.0006	LB/MMB
NV-0049	INC. HARRAH'S OPERATING COMPANY,	NV	08/20/2009 ACT	BOILER - UNIT CP03	NATURAL GAS	33.48	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	lb/MMBTU	0.0006	lb/mmb
NV-0049	INC. HARRAH'S OPERATING COMPANY,	NV	08/20/2009 ACT	BOILER - UNIT CP26	NATURAL GAS	24	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	lb/mmbtu	0.0006	LB/MMB
NV-0049	INC.	NV	08/20/2009 ACT	BOILER - UNIT IP04 BOILERS - UNITS CC004, CC005,	NATURAL GAS	16.7	ММВТU/Н	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	lb/mmbtu	0.0006	LB/MMB
	MGM MIRAGE MGM MIRAGE	NV NV	11/30/2009 ACT 11/30/2009 ACT	AND CC006 AT CITY CENTER TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS		MMBTU/H MMBTU/H	Sulfur Oxides (SOx) Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS ONLY. LIMITING THE FUEL TO NATURAL GAS ONLY.		lb/mmbtu lb/mmbtu		LB/MMB
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	DIESEL EMERGENCY GENERATORS - UNITS CC009 THRU CC015 AT CITY CENTER	DIESEL OIL	3622	НР	Sulfur Oxides (SOx)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03% BY WEIGHT.		LB/HP-H	0.0002	LB/HP-H
			,,,,,,,,,, _	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW						0.0002	-,	0.0002	
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	YORK	NATURAL GAS	2	MMBTU/H	Sulfur Oxides (SOx)	LIMITING FUEL TO NATURAL GAS ONLY.	0.0006	lb/mmbtu	0.0006	LB/MMB

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
B/MMBTU		
		EITHER POWER BOILERS 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN IS OPERATED.
		THE AMOUNT OF DISTILLATE FUEL OIL BURNED IN THIS BOILER MAY NOT EXCEED 215,400 GALLONS PER MONTH, AVERAGED OVER 12 CONSECUTIVE MONTHS, ONCE THE ORIGINAL CONTENTS OF THE FUEL OIL TANK HAS BEEN TOTALLY CONSUMED. MAY NOT EXCEED 127,290 GALLONS PER MONTH, AVERAGED OVER 12 CONSECUTIVE MONTHS, FOR THE ORIGINAL SUPPLY OF DISTILLATE OIL. NATURAL GAS LIMIT OF 0.001 LBS/MMBTU
		Pound per hour limit is for each turbine and duct burner. Ton per year limit is for both turbines combined.
в/нр-н		
B/MMBTU		
в/нр-н		
B/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
B/MMBTU		
в/нр-н		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
B/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
В/НР-Н		EMISSION LIMIT 2 APPLIES TO EACH UNIT.

				6					250	T 11/1-1				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	Summa	PRIMARY FUEL THROUG	THROUGHP		AER Database for Natural Gas > 2			STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
				BOILER - UNIT MB090 AT				LIMITING THE FUEL TO NATURAL GAS						
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	MANDALAY BAY BOILERS - UNITS BE102 THRU BE105	NATURAL GAS	4.3 MMBTU/H	Sulfur Oxides (SOx)	ONLY LIMITING THE FUEL TO NATURAL GAS	0.0006	5 LB/MMBTU	0.0006	lb/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	AT BELLAGIO	NATURAL GAS	2 MMBTU/H	Sulfur Oxides (SOx)	ONLY LIMITING THE FUEL TO NATURAL GAS	0.0006	5 LB/MMBTU	0.0006	lb/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILER - UNIT BE111 AT BELLAGIO	NATURAL GAS	2.1 MMBTU/H	Sulfur Oxides (SOx)	ONLY AND GOOD COMBUSTION PRACTICES	0.0048	BLB/MMBTU	0.0048	lb/mmbtu		
				SMALL INTERNAL COMBUSTION ENGINE - UNIT EX012 AT				SULFUR CONTENT IN THE FUEL IS LIMITED						
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	EXCALIBUR BOILERS - UNITS CC026, CC027 AND	DIESEL OIL	350 HP	Sulfur Oxides (SOx)	TO 500 PPM. LIMITING THE FUEL TO NATURAL GAS	0.0004	1 LB/HP-H	0.0004	LB/HP-H		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	CC028 AT CITY CENTER	NATURAL GAS	44 MMBTU/H	Sulfur Oxides (SOx)		0.0007	IB/MMBTU	0.0007	lb/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	NATURAL GAS	2 MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY	0 005	5 LB/MMBTU	0.005	lb/mmbtu		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
			10/00/0000 0 1 1007	TURBINE, COMBINED CYCLE, DUCT										
OR-0039	COB ENERGY FACILITY, LLC	OR	12/30/2003 ACT	BURNER, NAT GAS, (4)	NATURAL GAS	1150 MW	Sulfur Oxides (SOx) Sulfur, Total	LOW SULFUR FUEL: < 0.8 % S BY WT. LIME SPRAY DRYER FLUE GAS	0		0			Limit is low sulfur fuel. No emission rate limit. Costs are the same as those for SO2. Cost
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	CBEC 4 BOILER	PRB COAL	7675 MMBTU/H	Reduced (TRS)	DESULFURIZATION	0 001	L LB/MMBTU	0			effectiveness was not calculated.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 2		668 T/D	Sulfur, Total Reduced (TRS)		0.12	2 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 81 MM LB/D	Sulfur, Total Reduced (TRS) Sulfur, Total	UPGRADE BLOX SYSTEM	4.53	3 LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 96 MM LB/D	Reduced (TRS)	UPGRADE BLOX SYSTEM	6.13	B LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
I A-0174	PORT HUDSON OPERATIONS	IA	01/25/2002 ACT	BLEACH PLANT NO. 1		1024 T/D	Sulfur, Total Reduced (TRS)		0.19) LB/H	0			
							Sulfur, Total				0.022			ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32 MM LB BLS/D	Reduced (TRS) Sulfur, Total		0.84	1 LB/H	0.032	LB/T BLS	CALCULATED	FIRED. ADDITIONAL EMISSION LIMIT USED TO CALCULATE
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 25 MM LB BLS/D		WET SCRUBBER	0.63	B LB/H	0.032	LB/T BLS	CALCULATED	STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340 T/D	Sulfur, Total Reduced (TRS)		3.5	5 LB/H	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270 T/D	Sulfur, Total Reduced (TRS) Sulfur, Total		2.81	l lb/h	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	987 MMBTU/H	Reduced (TRS)		0.48	B LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 3		623 T/D	Sulfur, Total Reduced (TRS)		0.11	L LB/H	0			
	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GAS	459.5 MMBTU/H	Sulfur, Total Reduced (TRS)			5 LB/H	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 15		1150 TBLS/D	Sulfur, Total Reduced (TRS)		17.5	PPMDV @ 8% 5 O2	0			ASSUME ALL TRS IS H2S
	LONGVIEW FIBRE PAPER AND						Sulfur, Total	NO FURTHER CONTROL APPLICATION IS EITHER		PPMDV @ 8%				
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 18		1200 TBLS/D	Reduced (TRS)	FEASIBLE OR ECONOMICALLY JUSTIFIABLE.	17.5	5 02	0			ASSUME ALL TRS IS H2S
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 15		1150 TBLS/D	Sulfur, Total Reduced (TRS)		67	7 T/YR	0			ASSUME ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 18		1200 T BLS/D	Sulfur, Total Reduced (TRS)		67	7 T/YR	0			ASSUME ALL TRS IS H2S.
VA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 19		2000 T BLS/D	Sulfur, Total Reduced (TRS)		114	1 T/YR	0			ASSUME ALL TRS IS H2S.
VA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 22		1950 T BLS/D	Sulfur, Total Reduced (TRS)		0.0168	B LB/T BLS	0			ASSUME THAT ALL TRS IS H2S.
VA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILNS 1 AND 2		140 T CAO/D EAC	Sulfur, Total Reduced (TRS)		20	PPMDV @) 10% O2	0			ASSUME ALL TRS IS H2S.
	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 3		240 T CAO/D LAC	Sulfur, Total Reduced (TRS)			PPMDV @ 10% O2	0			ASSUME THAT ALL TRS IS H2S.
WV-0205	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 19		2000 T BLS/D	Sulfur, Total Reduced (TRS)	FURTHER CONTROL IS EITHER INFEASIBLE OR NOT ECONOMICALLY JUSTIFIABLE.	10	PPMDV @ 8%				ASSUME ALL TRS IS H2S
	LONGVIEW FIBRE PAPER AND		11/01/2000 XIIDSP,ACT	ACCOVENT ONWACE 13		2000 1 813/0	Sulfur, Total	CONOMICALLI JUJIII IADLE.		PPMDV @ 8%	0			ASSOME ALL TIG IS THES
	PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 22		1950 T BLS/D	Reduced (TRS) Sulfur, Total			B O2 PPMDV @	0			ASSUME THAT ALL TRS IS H2S.
NA-0303	PACKAGING, INC LONGVIEW FIBRE PAPER AND	WA	11/01/2006 ACT	LIME KILN 4		250 T CAO/D	Reduced (TRS) Sulfur, Total		20	0 10% O2 PPMDV @	0			ASSUME ALL TRS IS H2S
WA-0303	PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 5		325 T CAO/D	Reduced (TRS)		20	10% 02	0			ASSUME ALL TRS IS H2S

AL-0230 USA	FACILITY NAME														
THY: NL-0230 USA	FACILITY NAME						THROUGHPUT				EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
L-0230 USA		FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME Z-HIGH MILL WITH MIST	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
	SSENKRUPP STEEL AND STAINLESS			ELIMINATOR (LO42) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
THY	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)				(SO2)		0.0006	lb/mmbtu	0			FURNACE (LO43).
THY.				NATURAL GAS -FIRED ANNEALING											
AL-0230 USA	SSENKRUPP STEEL AND STAINLESS		09/17/2007 8 sheet ACT	FURNACE (LA43) (MULTIPLE EMISSION POINTS)	NATURAL GAS	100	4 MMBTU/H	Sulfur Dioxide (SO2)		0.0000	lb/mmbtu	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA43).
L-0230 USA	4, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	196.4		(502)		0.0006	LB/IVIIVIBIU	0			FURNACE (LA43).
THY: AL-0230 USA	YSSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBERS & amp; COMMON SCR (LO72) (MULTIPLE EMISSION POINTS)	NATURAL GAS	2060	D T/YR	Sulfur Dioxide (SO2)		0.0006	lb/mmbtu	0			THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WIT CAUSTIC SCRUBBER & COMMON SCR (LO72).
				DEGREASING WITH WET SCRUBBER											
	SSENKRUPP STEEL AND STAINLESS			(LO52) (MULTIPLE EMISSION				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	POINTS)		6	рт/н	(SO2)		0.0006	lb/mmbtu	0			FURNACE (LO53).
THY	SSENKRUPP STEEL AND STAINLESS			DEGREASING WITH WET SCRUBBER				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS)		6	т/н	(SO2)		0.0006	lb/MMBTU	0			FURNACE.
				NATURAL GAS-FIRED BATCH											
AL-0230 USA	SSENKRUPP STEEL AND STAINLESS	A1	08/17/2007 ACT	ANNEALING FURNACES (LA63, LA64)	NATURAL GAS	33.	4 MMBTU each	Sulfur Dioxide (SO2)		0,0006	lb/mmbtu	0			
	SSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ,Act	NATURAL GAS-FIRED PASSIVE	NATONAL GAS	55.4	+ INIVIBIO Each	Sulfur Dioxide		0.0000	LB/IVIIVIBTO	0			
AL-0230 USA		AL	08/17/2007 ACT	ANNEALING FURNACE (LO41)	NATURAL GAS	27.	2 MMBTU/H	(SO2)		0.0006	LB/MMBTU	0			
				4 CONTINUOUS HOT DIP											
TIN				GALVANIZING LINE (EACH LINE				Cultur Disuida							
AL-0230 USA	SSENKRUPP STEEL AND STAINLESS	ΔΙ	08/17/2007 ACT	WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0,0006	lb/mmbtu	0			THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING WITH PRE & POST DRYERS.
12 0230 03/1	,		00/17/2007 dilb3p;//e1	4 CONTINUOUS HOT DIP				(302)		0.0000	LB/INIVIDIO	0			WITT HE GT OST DIVIENS.
				GALVANIZING LINE (EACH LINE											
	SSENKRUPP STEEL AND STAINLESS			WITH SAME MULTIPLE EMISSION				Sulfur Dioxide							
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	POINTS)			-	(SO2)		0.0006	lb/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
тнү	SSENKRUPP STEEL AND STAINLESS			MELTSHOP - LO (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH
	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		12	5 т/н	(SO2)		0.15	LB/T	0			ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO
	SSENKRUPP STEEL AND STAINLESS			MELTSHOP - LO (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		12	5 Т/Н	(SO2)		0.15	LB/T	0			VENTED TO BAGHOUSE (LO1).
THY: AL-0230 USA	YSSENKRUPP STEEL AND STAINLESS A, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	12	5 Т/Н	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1).
				TPH ELECTRIC ARC FURNACE WITH											
				DEC & amp; ELEPHANT HOUSE											THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION
	SSENKRUPP STEEL AND STAINLESS			VENTED TO BAGHOUSE 3 (LA1)				Sulfur Dioxide							FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIC
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS) NATURAL GAS-FIRED REHEAT	NATURAL GAS	12	5 Т/Н	(SO2)		0.15	LB/T	0			VENTED TO COMMON BAGHOUSE.
тнү	SSENKRUPP STEEL AND STAINLESS			FURNACE (LA21) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	16	Э ММВТИ/Н	(SO2)		0.0006	LB/MMBTU	0			(LA 21).
				NATURAL GAS-FIRED REHEAT											
	SSENKRUPP STEEL AND STAINLESS		08/17/2007 ACT	FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	10	эммвти/н	Sulfur Dioxide (SO2)		0.0000	lb/mmbtu	0			
AL-0230 USA	4, LLC	AL	08/17/2007 & HDSP, ACT	NATURAL GAS-FIRED REHEAT	NATURAL GAS	10:		(302)		0.0008		0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
тнү	SSENKRUPP STEEL AND STAINLESS			FURNACE (LA21) (MULTIPLE				Sulfur Dioxide							
AL-0230 USA	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	16	Э ММВТU/Н	(SO2)		0.0006	lb/mmbtu	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
T 1 N	SSENKRUPP STEEL AND STAINLESS			BAL STEAM SWEEP WITH MIST ELIMINATOR (LA66) (MULTIPLE				Sulfur Dioxide							
	A, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		12	5 Т/Н	(SO2)		0.0006	lb/mmbtu	n			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA70).
	SSENKRUPP STEEL AND STAINLESS		, ,	3 NATURAL GAS-FIRED BOILERS	1		1	Sulfur Dioxide		2.0000	,				· · · · ·
	A, LLC	AL	08/17/2007 ACT	WITH ULNB & amp; EGR (537-539)	NATURAL GAS	64.	9 MMBTU each	(SO2)		0.0006	lb/MMBTU	0			
	SSENKRUPP STEEL AND STAINLESS		00/47/2007 0	HOT STRIP MILL (MULTIPLE				Sulfur Dioxide		0.0	D / A A A 3	-			THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED
	A, LLC (SSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	EMISSION POINTS) HCL ACID REGENERATION	NATURAL GAS	69	рт/н	(SO2) Sulfur Dioxide		0 006	lb/mmbtu	0			WALKING BEAM REHEAT FURNACES. THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS
	A, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS)	NATURAL GAS	3.7	7 т/н	(SO2)		0.0006	lb/mmbtu	0			WITH CAUSTIC SCRUBBER (5-10).
	SSENKRUPP STEEL AND STAINLESS			NATURAL GAS-FIRED BATCH	-		1	Sulfur Dioxide							

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT
									COMBUSTION OF LOW SULFUR FUELS NO FUEL > 0.5% BY				
	PINE BLUFF ENERGY LLC - PINE BLUFF			TURBINE, COMBINED CYCLE,				Sulfur Dioxide	WEIGHT				
AR-0026	ENERGY CENTER PINE BLUFF ENERGY LLC - PINE BLUFF	AR	05/05/1999 ACT	NATURAL GAS	NATURAL GAS	170	MW	(SO2) Sulfur Dioxide	SULFUR. COMBUSTION OF LOW SULFUR FUELS (<	0.0006	lb/MMBTU	0	
AR-0026	ENERGY CENTER	AR	05/05/1999 ACT	BOILER, NATURAL GAS	NATURAL GAS	362	MMBTU/H	(SO2)	0 05% BY WT S)	0.0006	LB/MMBTU	0.0006	lb/mmbtu
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	BOILER, FUEL OIL	DISTILLATE FUEL OIL	346	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUELS: < .05% BY WT S	0 052	LB/MMBTU	0.052	LB/MMBTU
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	DISTILLATE OIL	170	MW	Sulfur Dioxide (SO2)	COMBUSTION OF LOW S FUELS: 0.5% BY WT S	0.0497	lb/mmbtu	0	
HN-0020	PINE BLUFF ENERGY LLC - PINE BLUFF	AN	03/03/1999 &IIDsp,ACT		DISTILLATE OIL	170		Sulfur Dioxide	W15	0.0487	LB/IVIIVIBTO	0	
AR-0026	ENERGY CENTER	AR	05/05/1999 ACT	DUCT BURNER	NATURAL GAS	315	MMBTU/H	(SO2) Sulfur Dioxide	CLEAN FUEL	0.0006	lb/MMBTU	0.0006	lb/MMBTU
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, LADLE METALLURGY		225	т/н	(SO2)	LOW SULFUR COKE USE.	0 076	LB/T	0	
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	PROCESS HEATERS	NATURAL GAS			Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0.0006	lb/mmbtu	0.0006	LB/MMBTU
							- 4.1	Sulfur Dioxide	LOW SULFUR COKE/SCRAP				
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, ELECTRIC ARC		225	т/н	(SO2) Sulfur Dioxide	MANAGEMENT.	1.5	LB/T	0	
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	REHEAT FURNACE LADLE PREHEAT & DRYOUT	NATURAL GAS	225	MMBTU/H	(SO2) Sulfur Dioxide	CLEAN FUELS	0.0006	lb/MMBTU	0.0006	lb/MMBTU
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	STATIONS	NATURAL GAS	225	т/н	(SO2)	CLEAN FUEL	0.0006	lb/mmbtu	0.0006	LB/MMBTU
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	BOILER, NATURAL GAS, (2)	NATURAL GAS	122	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATION: NATURAL GAS.	0.006	lb/mmbtu	0.006	LB/MMBTU
HN-0037		AN	10/03/2001 &IDSP,ACT	TURBINE, COMBINED CYCLE,		122		Sulfur Dioxide	TOLL SPECIFICATION. NATORAL DAS.	0 000	LB/IVIIVIBTO	0.000	LB/IVIIVIBIO
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	NATURAL GAS TURBINE, COMBINED CYCLE, FUEL	NATURAL GAS	185	MW	(SO2) Sulfur Dioxide	FUEL SPECIFICATION: LOW SULFUR FUELS.	0 006	lb/MMBTU	0	
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	OIL	FUEL OIL	185	MW	(SO2)	FUEL SPECIFICATION: LOW SULFUR FUELS.	0.05	LB/MMBTU	0	
FL-0251	OKEELANTA CORPORATION SUGAR MILL	FL	10/29/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	211	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS	0		0	
	OKEELANTA CORPORATION SUGAR			,				Sulfur Dioxide	FUEL SPECIFICATIONS: LOW SULFUR				
FL-0251	MILL	FL	10/29/2001 ACT	BOILER, FUEL OIL	FUEL OIL	211	MMBTU/H	(SO2)	(0 05% S BY WT)	0		0	
NI 0005	PSEG LAWRENCEBURG ENERGY	IN	06/07/2004 Bullion ACT	TURBINE, NATURAL GAS,		476.6		Sulfur Dioxide	LOW SULFUR NATURAL GAS (LESS THAN 2		1.5.41		
IN-0085	FACILITY PSEG LAWRENCEBURG ENERGY	IN	06/07/2001 ACT	COMBINED CYCLE FOUR	NATURAL GAS	476.6	MMBTU/H	(SO2) Sulfur Dioxide	G/DSCF). EMISSION LIMIT IS FOR EACH CT LOW SULFUR NATURAL GAS (LESS THAN	11	LB/H	0	
IN-0085	FACILITY	IN	06/07/2001 ACT	AUXILIARY BOILER, NATURAL GAS	NATURAL GAS	124.6	MMBTU/H	(SO2) Sulfur Diovido	%0.8 BY WEIGHT)	0 006	lb/MMBTU	0.006	lb/MMBTU
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	GAS TURBINES, 3	NATURAL GAS	1799	MMBTU/H EACH	Sulfur Dioxide (SO2)		2	LB/H	0	
								Sulfur Dioxide					
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	HRSG, UNIT 6	NATURAL GAS	300	MMBTU/H	(SO2)	GOOD COMBUSTION PRACTICES	0.2	LB/H	0.0007	lb/MMBTU
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	HRSGS, UNITS 7-1, 7-2	NATURAL GAS	166	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.1	LB/H	0.0006	LB/MMBTU
								Sulfur Dioxide					
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU FEED HEATER	REFINERY GAS	181.7	MMBTU/H	(SO2) Sulfur Dioxide	COMPLY WITH 40 CFR 60 SUBPART J	4.79	LB/H	0	
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	CO BOILERS (2)	REFINERY GAS	831.3	MMBTU/H EACH		COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0	
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU REGEN VENT - SU/SD OPERATIONS		89000	BBL/D	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0	
MI-0368	MICHIGAN PAPERBOARD COMPANY	MI	09/08/2004 ACT	BOILER	FUEL OIL	185	MMBTU/H	Sulfur Dioxide (SO2)		280	LB/H	1 51	LB/MMBTU
0500								Sulfur Dioxide					
MN-0039	MINNESOTA CORN PROCESSORS	MN	08/08/2000 ACT	BOILER, NATURAL GAS	NATURAL GAS	237.4	MMBTU/H	(SO2) Sulfur Dioxide	FUEL LIMITED TO NATURAL GAS ONLY FUEL LIMITED TO NATURAL GAS OR	0.4	LB/H	0.0017	lb/mmbtu
MN-0039	MINNESOTA CORN PROCESSORS	MN	08/08/2000 ACT	CORN GLUTEN DRYER	NATURAL GAS	39	MMBTU/H	(SO2)	PROCESS GAS	15	LB/H	0	
MN-0076	BLANDIN PAPER/RAPIDS ENERGY CENTER	MN	09/18/2008 ACT	BOILER	NATURAL GAS	280	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS ONLY	0		0	
								Sulfur Dioxide					
NC-0073	BRIDGESTONE FIRESTONE	NC	06/28/2001 ACT	BOILERS, (2)	NATURAL GAS DISTILLATE FUEL	121	MMBTU/H	(SO2) Sulfur Dioxide	FUEL OIL < 0.5 % S BY WT LOW SULFUR OIL (NO PERCENTAGES	2.3	lb/MMBTU	2.3	lb/MMBTU
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER- DISTILLATE OIL	OIL	99	MMBTU/H	(SO2) Sulfur Dioxido	GIVEN)	5 021	LB/H	0.0507	lb/mmbtu
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	FUEL GAS HEATER	NATURAL GAS	16	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 069	LB/H	0.0043	LB/MMBTU
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER	NATURAL GAS		MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 514	1.5.41		LB/MMBTU

nillion B	ſU/hr	Γ	1	
AISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
1MBTU	0			
IMBTU	0.0006	lb/mmbtu		
имвти	0.052	lb/mmbtu		
1MBTU	0			
1MBTU	0.0006	lb/mmbtu		
	0			
IMBTU	0.0006	lb/mmbtu		
	0			
IMBTU	0.0006	lb/mmbtu		
IMBTU	0.0006	lb/mmbtu		
IMBTU	0.006	lb/mmbtu		
IMBTU	0			
IMBTU	0			
	0		see notes	BACT is pipeline natural gas. State BACT, Rule 62- 296.406 FAC
	0		see notes	BACT is low sulfur fuel. State BACT, rule 62- 296.406 FAC
1	0			
IMBTU	0.006	lb/mmbtu		
	0			THE EMISSION LIMIT IN STANDARD UNITS WAS
				CALCULATED FROM THE HOURLY EMISSION LIMIT IN THE PERMIT AND THE HRSG'S THROUGHPUT; 0.2 LB/H /
	0.0007	lb/mmbtu		300 MMBTU/HR THE EMISSION LIMIT IN STANDARD UNITS WAS
1	0.0006	lb/mmbtu		CALCULATED FROM THE HOURLY EMISSION LIMIT IN THE PERMIT AND THE SOURCE'S THROUGHPUT; 0.1 LB/H / 166 MMBTU/HR
	0			
	0			
	0			
I	1 51	lb/mmbtu	CALCULATED	NO SIMILAR SIZED UNITS IDENTIFIED IN RBLC WITH CONTROL REQUIREMENTS FOR SO2.
I	0.0017	lb/mmbtu		
	0			
	0			NO EMISSION LIMITS AVAILABLE
IMBTU		lb/mmbtu		
1		LB/MMBTU		
	0.0043	lb/mmbtu		
	0.0043	lb/mmbtu		

				Summary of SO ₂ Co	ontrol Determin	ation per EPA'	s RACT/BACT	/LAER Databa	se for Natural Gas > 100 million	BTU/hr & < 2!	50 million B	TU/hr	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAN EMIS LIMIT
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	EMERGENCY GENERATOR	DIESEL FUEL	49	ммвти/н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.45	LB/H	0	
								Sulfur Dioxide					
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NAT GAS)	NATURAL GAS	118	MMBTU/H	(SO2) Sulfur Dioxide	NONE LISTED	0.1	LB/H	0.0008	lb/MMI
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NO. 2 OIL)	NATURAL GAS	84.4	MMBTU/H	(SO2)	LOW SULFUR FUEL- 0.05% BY WEIGHT	4.3	lb/H	0.051	LB/MM
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NAT GAS)	NATURAL GAS	134	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0007	LB/MMI
								Sulfur Dioxide					
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NAT GAS)	NATURAL GAS	152	MMBTU/H	(SO2)	NONE LISTED LIMITED OPERATING HOURS FOR NO. 2	0.1	LB/H	0.0007	LB/MMI
								Sulfur Dioxide	OIL; FUEL SULFUR LIMIT OF 0 05% BY				
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NO. 2 OIL)	NAT GAS	241.6	MMBTU/H	(SO2)	WEIGHT. LIMITED OPERATING HOURS FOR NO. 2	12.4	lb/H	0.0513	LB/MMI
								Sulfur Dioxide	OIL, FUEL SULFUR LIMIT OF 0 05% BY				
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NO. 2 OIL)	NAT GAS	230.8	MMBTU/H	(SO2)	WEIGHT. LIMITED OPERATING HOURS FOR NO. 2	11.9	lb/H	0.0516	LB/MMI
								Sulfur Dioxide	OIL; FUEL SULFUR LIMIT OF 0 05% BY				
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NO. 2 OIL)	NAT GAS	204.2	MMBTU/H	(SO2) Sulfur Diovido	WEIGHT.	10.5	lb/H	0.0514	LB/MMI
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NATURAL GAS)	NATURAL GAS	84.4	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.001	LB/MM
				BOILER 1 (LASALOCID OIL & amp;				Sulfur Dioxide	LIMITED OPERATING HOURS FOR NO. 2 OIL; NO. 2 OIL LIMITED TO 0.05% SULFUR BY				
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	NO. 2 OIL COMBINED)	NATURAL GAS	35.5	MMBTU/H	(SO2) Sulfur Dioxide	WEIGHT.	2.8	lb/H	0.079	LB/MMI
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	AUXILIARY BOILER	NATURAL GAS	200	MMBTU/H	(SO2)	NONE	0.8	LB/H	0.004	LB/MMI
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DUCT BURNER (3)	NATURAL GAS	256	ММВТИ/Н	Sulfur Dioxide (SO2)	NONE LISTED	0.2	lb/mmbtu	0.2	LB/MM
115 0045		10		COMBINED CYCLE TURBINE WITH		230		Sulfur Dioxide		0.2	LD/ININDIO	0.2	20/11/11
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DUCT BURNER	NATURAL GAS	3202	MMBTU/H	(SO2) Sulfur Dioxide	NONE LISTED SULFUR IN OIL LIMITED TO 0.05% BY	0 004	lb/MMBTU	0.8	PPM @
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	EMERGENCY GENERATOR	DISTILLATE OIL	14.1	MMBTU/H	(SO2)	WEIGHT.	0.8	LB/H	0	
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE (3)	NATURAL GAS	2964	ММВТИ/Н	Sulfur Dioxide (SO2)	ONLY USE NATURAL GAS WITH SULFUR CONTENT 0.8%	0.004	lb/mmbtu	0.8	PPM @
113-0043	LIDERT I GENERATING STATION	10	03/20/2002 @1030,ACT		INATOINAL GAS	2504		Sulfur Dioxide		0 004	LD/IVIIVID10	0.0	TTIVI @
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DIESEL FIRE PUMP	DISTILLATE OIL	3.5	MMBTU/H	(SO2) Sulfur Dioxide	NONE	1	lb/H	0	
OH-0241	MILLER BREWING COMPANY - TRENTON	ОН	05/27/2004 ACT	BOILER (2), NO. 6 FUEL OIL	NO. 6 FUEL OIL	238	MMBTU/H	(SO2)		1.6	LB/MMBTU	1.6	LB/MM
011 02 44	MILLER BREWING COMPANY -	0.1	05/27/2004 Bullion ACT			220		Sulfur Dioxide		1.0		1.0	
OH-0241	TRENTON MILLER BREWING COMPANY -	ОН	05/27/2004 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	238	MMBTU/H	(SO2) Sulfur Dioxide		1.6	lb/MMBTU	1.6	LB/MMI
OH-0241	TRENTON	ОН	05/27/2004 ACT	BOILER (2), COAL FIRED	COAL	238	MMBTU/H	(SO2) Sulfur Dioxide		1.6	lb/MMBTU	1.6	LB/MM
OH-0241	MILLER BREWING COMPANY - TRENTON	ОН	05/27/2004 ACT	BOILER (2), NO. 2 FUEL OIL	NO. 2 FUEL OIL	238	MMBTU/H	(SO2)		1.6	lb/mmbtu	1.6	LB/MM
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	он	01/27/1999 ACT	ELECTRIC ARC FURNACE (EAF) NO. 7, P905		85	т/н	Sulfur Dioxide (SO2)	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) AND SO2 CONTROLS (NOT FEASIBLE)	5.95	LB/H	0	
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	он	01/27/1999 ACT	ELECTRIC ARC FURNACE (EAF) NO. 9, P907		165	т/н	Sulfur Dioxide (SO2)	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) AND SO2 CONTROLS (NOT FEASIBLE)	11.55	LB/H	0	
OH-0245	REPUBLIC TECHNOLOGIES	ОН	01/27/1999 ACT	BLOOM REHEAT FURNACE	NATURAL GAS	196.2	MMBTU/H	Sulfur Dioxide (SO2)		0.12	LB/H	0.0006	LB/MMI
	REPUBLIC TECHNOLOGIES			LADLE METALLURGY FACILITY				Sulfur Dioxide	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) & FLUE GAS DESULFURIZATION. LOOKED AT ADD-ON CONTROLS (WET SCRUBBER, SPRAY DRYEF ABORPTION AND				
OH-0245		ОН	01/27/1999 ACT	(LMF), P123				(SO2) Sulfur Dioxido	DRY SORBENT INJECTION)	525	LB/3 H PERIOD	0	
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	ОН	10/08/2009 ACT	AUXILIARY BOILER	NATURAL GAS	150	MMBTU/H	Sulfur Dioxide (SO2)		0.09	LB/H	0.6	LB/MM
	+			*						•			•

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
B/MMBTU		
B/MMBTU		
B/MMBTU		BASIS OF LIMIT IS STATE.
B/MMBTU		
PM @ 15% O2		
PM @ 15% O2		BASIS OF LIMIT IS STATE
B/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
B/MMBTU		
B/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
B/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
B/MMBTU		
		Additional limit: 318.84 T/YR
B/MMCF		

				Summary of SO. Co	ntrol Determin	ation ner FPA	'ε ΒΔΓΤ/ΒΔΓΤ	/I AFR Databa	se for Natural Gas > 100 million	BTII/br & < 2	50 million B	RTH/br			
							THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
															ADDITIONAL LIMITS: 0.184 LB/MMBTU HEAT INPUT AS A 24-HOUR ROLLING AVERAGE; 0.2400 LB/MMBTU HEAT INPUT, AS 3-HR AVERAGE
														HEAT INPUT AS A 30-DAY	
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	ОН	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	519:	1 MMBTU/H	Sulfur Dioxide (SO2)	WET FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	1246	5 LB/H	0.15	LB/MMBTU	ROLLING AVERAGE	THESE LIMITS ARE FOR EACH OF 2 BOILERS; TOTAL EMISSIONS ARE TIMES 2.
OH-0336	CAMPBELL SOUP COMPANY	он	12/14/2010 ACT	Boilers (3)	Natural Gas		ס	Sulfur Dioxide (SO2) Sulfur Dioxide		0.0006	EB/MMBTU	C		NUMBER 2 OIL	
OH-0336	CAMPBELL SOUP COMPANY	ОН	12/14/2010 ACT	Bolier (3)	Number 2 fuel oil	3246593	3 GAL/YR	(SO2)		0.35	5 T/YR	0.0015	LB/MMBTU	STANDARD	
*OH-0354	KRATON POLYMERS U.S. LLC	ОН	01/15/2013 ACT	Two 249 MMBtu/H boilers	Natural Gas	249	9 MMBtu/H	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0 05 % sulfur.	11.24	T/YR	1.6	LB/MMBTU	BURNING DISTILLATE OIL	Netted out for SO2 by replacing old coal/oil-fired boilers.
		01						Sulfur Dioxide							
OK-0045	REDBUD POWER PLT	ОК	08/15/2001 ACT	BOILER, AUXILIARY	NATURAL GAS	20) ММВТU/Н	(SO2) Sulfur Dioxide	PIPELINE QUALITY NATURAL GAS FUEL LOW SULFUR FUEL - PIPELINE QUALITY	0.0006	5 LB/MMBTU	0.0006	LB/MMBTU		
OK-0045	REDBUD POWER PLT	ОК	08/15/2001 ACT	TURBINE, COMBINED CYCLE, (4)	NATURAL GAS	1698	B MMBTU/H	(SO2)	NATURAL GAS SULFURIC ACID MIST, USE LOW SULFUR	0 005	LB/MMBTU	C)	Not Available	
									FUELS (<0 05 %S) EMISSION LIMITTION						
SC-0049	SKYGEN	SC		SIMPLE COMBUSTION TURBINES, 3, NG/NO. 2 FUEL FIRED	NATURAL GAS	17:	1 MW	Sulfur Dioxide (SO2)	FOR NO. 2 FUELS	11	LB/H	C)		
									LOW SULFUR FUELS (<0.05 %SO2) EMISSION LIMITS - 1.1 LB/H NG, 99 LB/H						
									NO. 2						
SC-0049	SKYGEN	sc		SIMPLE COMBUSTION TURBINES, 3, NG/NO. 2 FUEL FIRED	NATURAL GAS	17'	1 MW	Sulfur Dioxide (SO2)	ALTERNATE LIMITS - 1.65 T/YR - NG, 24.75 T/YR NO. 2		LB/H NG	(
				THREE NATURAL GAS FIRED				Sulfur Dioxide							
SC-0049	SKYGEN	SC	12/02/1999 ACT	BOILERS (UTILITY)	NATURAL GAS	230) MMBTU/H	(SO2)	LOW SULFUR FUELS LOW SULFUR FUELS (<0.05 %SO2)	0.0006	5 LB/MMBTU	0.0006	EB/MMBTU		
								Cultur Disuida	EMISSION LIMITS - 1.1 LB/H NG,99 LB/H NO. 2						
SC-0049	SKYGEN	sc		SIMPLE COMBUSTION TURBINES, 3, NO. 2 FUEL OIL	NATURAL GAS	17:	1 MW	Sulfur Dioxide (SO2)	ALTERNATE LIMITS - 1.65 T/Y - NG 24.75 T/Y NO. 2	99	B/H	C)		
															SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL
								Cultur Disuida	FUEL SPEC: SULFUR CONTENT OF FUEL						USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000.
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #2 (NAT GAS)	NATURAL GAS	183	3 ММВТU/Н	Sulfur Dioxide (SO2)	SHALL NOT EXCEED 0.2% BY WEIGHT.	C)	C)	NOT AVAILABLE	WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
															SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL
									FUEL SPEC: SULFUR CONTENT OF FUEL						USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000.
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #2 (FUEL OIL)	NO.2 FUEL OIL	183	3 ММВТU/Н	Sulfur Dioxide (SO2)	SHALL NOT EXCEED 0.2% BY WEIGHT.	C)	C)	NOT AVAILABLE	WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
															SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING
									FUEL SPEC: SULFUR CONTENT OF FUEL						NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000.
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #50-1 (NAT GAS)	NATURAL GAS	221	5 MMBTU/H	Sulfur Dioxide (SO2)	SHALL NOT EXCEED 0.2% BY WEIGHT.	0		(WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
								(/							SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING
									FUEL SPEC: SULFUR CONTENT OF FUEL						NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000.
TN 0090	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #50-1 (FUEL OIL)		221	5 MMBTU/H	Sulfur Dioxide	SHALL NOT						WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL
110003			55/05/2001 &IID5P,ACI	OTTELL BOILEN #30-1 (FUEL OIL)	NO.2 FUEL OIL	22:		(SO2)	EXCEED 0.2% BY WEIGHT.		, 				OIL). The facility must meet compliance with production
TN-0146	FLORIM, USA, INC.	TN	12/20/2000 ACT	GAS-FIRED KILNS	NATURAL GAS	12	5 MMBTU/H	Sulfur Dioxide (SO2)	COATED BAGHOUSE, HYDRATED CALCIUM MEDIUM.		LB/MMBTU	0.266	LB/MMBTU		limits and recordkeeeping requirements to demonstrate compliance with emission limits.
		1	, , , , , , , , , , , , , , , , , , ,	-			-, -		FUEL SWEET, NATURAL GAS WITH NO						
									MORE THAN 5.0 GRAINS (HOURLY AVERAGE) AND 0.2						
TX-0386	AMELLA ENERGY CENTER	тх		TURBINES AND DUCT BURNERS (3 EACH0	NATURAL GAS	1020) MW (TOTAL)	Sulfur Dioxide (SO2)	GRAIN TOTAL S PER 100 DSCF (ANNUALLY)	12 6	5 LB/H				
								Sulfur Dioxide					<u> </u>		
TX-0386	AMELLA ENERGY CENTER ATOFINA PETROCHEMICALS PORT	тх		AUXILIARY BOILER TURBINE, COMBINED CYCLE, W/	NATURAL GAS	15	5 MMBTU/H	(SO2) Sulfur Dioxide		0 843	B LB/H	0.005	LB/MMBTU		
TX-0414	ARTHUR COMPLEX	тх			NATURAL GAS	39	эмw	(SO2)	LOW SULFUR FUEL	2.27	' LB/H	C)	ļ	
TX-0414	ATOFINA PETROCHEMICALS PORT ARTHUR COMPLEX	тх	04/22/1999 ACT	SUPPLEMENTAL BOILER	NATURAL GAS	22	7 ММВТU/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.61	LB/H	0.0027	LB/MMBTU	CALCULATED	

				Summary of SO ₂ Co	ontrol Determin	ation per EPA	s RACT/BACT	/LAER Databa	se for Natural Gas > 100 million I	BTU/hr & < 2	50 million B	TU/hr	
BBI CID							THROUGHPUT				EMISSION	STANDARD EMISSION	ST/ EN
RBLCID	FACILITY NAME ATOFINA PETROCHEMICALS PORT	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME TURBINE, COMBINED CYCLE & amp;	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIN
TX-0414	ARTHUR COMPLEX	тх	04/22/1999 ACT	DUCT BURNER, UNIT 1	NATURAL GAS	39	MW	(SO2)	LOW SULFUR FUEL	2.27	LB/H	0	
								Sulfur Dioxide					
TX-0499	SANDY CREEK ENERGY STATION	тх	07/24/2006 ACT	PULVERIZED CAOL BOILER	COAL	8185	MMBTU/H	(SO2)		2456	LB/H	0	
-		-						Sulfur Dioxide					
TX-0499	SANDY CREEK ENERGY STATION	ТХ	07/24/2006 ACT	AUXILLARY BOILER	NATURAL GAS	175	MMBTU/H	(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0499	SANDY CREEK ENERGY STATION	тх	07/24/2006 ACT	PLANT-EMISSION CAP				(SO2)		3585	T/YR	0	
			.,,,,,,					Sulfur Dioxide	GOOD COMBUSTION PRACTICES. LOW				
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER - NO 6 FUEL OIL	FUEL OIL #6	150	MMBTU/H	(SO2)	SULFUR FUELS.	78.5	LB/H	0 52	LB/M
								Sulfur Dioxide	GOOD COMBUSTION PRACTICES. LOW				
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER NATUAL GAS	NATURAL GAS	150	MMBTU/H	(SO2)	SULFUR FUELS.	0.1	LB/H	0.001	LB/M
VA 0270			03/31/2003 EST			150	NANADTU	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	70 5	1.0/11	0.52	10/14
VA-0270	VCU EAST PLANT	VA	03/31/2003 ES1	BOILER - DISTILLATE	FUEL OIL #2	150	MMBTU	(SU2) Sulfur Dioxide	GOOD COMBUSTION PRACTICES. LOW	/8.5	LB/H	0 53	LB/IVI
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER - OIL OR GAS	GAS OR OIL	150	ммвти	(SO2)	SULFUR FUELS.	196.3	T/YR	0	
			,.,.,				-	Sulfur Dioxide					
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, NATURAL GAS, (3)	NATURAL GAS	150.6	MMBTU/H	(SO2)	LOW SULFUR FUEL	0.1	LB/H	0.0007	LB/M
								Sulfur Dioxide					
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, #6 FUEL OIL, (3)	# 6 FUEL OIL	150.6	6 MMBTU/H	(SO2)	FUEL SULFUR LIMIT: < 0.5% S BY WT	78.5	LB/H	0 52	LB/M
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, #2 FUEL OIL, (3)	NO. 2 FUEL OIL	150.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMITS: <0.5% S BY WT.	79 5	LB/H	0.5	LB/M
VA-0278	VCO LAST FLANT	VA	03/31/2003 &IIDSP,ACI	AUXILLIARY NAT. GAS FIRED BOILER	NO. 2 FOLL OIL	150.0		Sulfur Dioxide		78.5	LB/II	0.5	LB/IVI
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	(B25, S25)	NATURAL GAS	229.8	ммвти/н	(SO2)	NATURAL GAS	0.0006	LB/MMBTU	0	
								i i	FUEL SULFUR CONTENT LIMIT (0 003 WT.				
								Sulfur Dioxide	% S)				
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	DIESEL BOOSTER PUMP (B27, S27)	DIESEL FUEL OIL	265	6 HP	(SO2)	GOOD COMBUSTION PRACTICES	0.54	LB/H	0	
								Sulfur Dioxide	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR (0.003 WT. % S) DIESEL FUEL				
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	MAIN FIRE PUMP (DIESEL ENGINE)	DIESEL FUEL OIL	460	НР	(SO2)	OIL		LB/H	0	
WI 0220			10/13/2004 ((103)),/(01	B63, S63; B64, S64 - NATURAL GAS	DIEGEETOLEOIE	400		Sulfur Dioxide		0.54	20/11	<u> </u>	
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	STATION HEATER 1 AND 2	NATURAL GAS	0.75	ММВТИ/Н	(SO2)	NATURAL GAS	0.0004	LB/H	0	
				SUPER CRITICAL PULVERIZED COAL				Sulfur Dioxide	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30				
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173 07	ИМВТИ/Н	(SO2)	DAY AVG.	0.1	LB/MMBTU	0	
			-, , ,,, .					()			, .		
								Sulfur Dioxide					
WV-0023	MAIDSVILLE	wv	03/02/2004 ACT	BOILER, PC	PULVERIZED COAL	6114	MMBTU/H	(SO2)	WET LIMESTONE FORCED OXIDATION	917	LB/H	0.15	LB/M
100000		1407	02/02/2004 0 share 4 07					Sulfur Dioxide			1.0.(1)		
WV-0023	MAIDSVILLE	WV	03/02/2004 ACT	AUXILIARY BOILER	NATURAL GAS	225	MMBTU/H	(SO2) Sulfur Dioxide	LOW SULFUR NATURAL GAS FUEL SULFUR CONTENT LIMITED TO 0.05% BY	0 004	LB/H	0	
WV-0023	MAIDSVILLE	wv	03/02/2004 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	85	НР	(SO2)	WEIGHT	3.3	LB/H	0	
	-		, , ,		-			Sulfur Dioxide	SULFUR CONTENT IN THE FUEL LIMITED	0.0			
WV-0023	MAIDSVILLE	wv	03/02/2004 ACT	EMERGENCY GENERATOR	DIESEL	1801	HP	(SO2)	TO 0 05% BY WEIGHT	6.5	LB/H	0	

DARD SION AIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
0			
0			
0			
0			
0 52	lb/mmbtu		
0.001	lb/mmbtu		
0 53	lb/mmbtu		
0		NOT AVAILABLE	
0.0007	lb/mmbtu	calculated	
0 52	lb/mmbtu	calculated	
0.5	lb/mmbtu	calculated	
0			
0			'ULTRA LOW SULFUR DIESEL FUEL'
0			
0		NOT AVAILABLE	(LIMIT IS FOR EACH UNIT)
			POLLUTANT LIMITS INCLUDE STARTUP / SHUTDOWN AND ATOMIZER CHANGEOUT. PERMITTEE MAY ONLY USE ACTUAL HOURS OF OPERATION WHEN DETERMINING TIME AVERAGED EMISSIONS. WHEN CONDUCTING MAINTENANCE ON CONTROL SYSTEM (ROUTINE ATOMIZER CHANGEOUT): 3491 8 POUNDS PER HOUR ON A 3-HOUR AVERAGE AND 1508.9 POUNDS PER HOUR ON A 24-HOUR AVERAGE. CONTROLLED EMISSIONS: SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 621 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 3-HOUR PERIOD AND SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 589 POUNDS PER HOUR AVERAGED OVER ANY
0			CONSECUTIVE 24-HOUR PERIOD IN SETTLEMENT AGREEMENT OF APPEAL NO. 04-03-AQB, EXHIBIT B
0.15	lb/mmbtu	3 HOUR ROLLING	HAS A SO2 LIMIT OF 0.095 LB/MMBU, WHICH WAS NOT AGREED BY THE WVDEP AND NOT CONSIDERED AS BACT.
0			LIMITED TO USE OF NATURAL GAS AND 3,000 HOURS OF OPERATION PER YEAR
0			
0			LIMITED TO 500 HOURS OF OPERATION A YEAR

				Summary of SO ₂ Cor	ntrol Determina	ation per EPA's RACT/BACT	/LAER Databas	e for Gaseous Fuel > 100 million	n BTU/hr & < 250 million	BTU/hr			
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAG TIME CONDITION	E POLLUTANT COMPLIANCE NOTES
0037	KENAI REFINERY	АК	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1410	NATURAL GAS*	36.5 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0	500) PPM @ 15% 0	ASSUMED @	ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV					EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S TOGETHER. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. LIMITS ARE PROVIDED BASED ON FUEL CONTENT (SEE POLLUTION PREVENTION DESCRIPTION). ESTIMATED EMISSIONS ARE 21.7 T/YR, BUT THIS IS NOT A LIMIT. ADDITIONAL LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF
-0037	KENAI REFINERY	АК	03/21/2000 ACT	CRUDE HEATER, H101B	NATURAL GAS*	165 MMBTU/H	Sulfur Dioxide (SO2)	H2S. GAS, 168 PPMV H2S.	0	(0		FOR EQUIPMENT FIRED ON REFINERY GAS, AND 500 PPM SO2 FOR EQUIPMENT NOT FIRED ON REFINERY GAS.
-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H201	NATURAL GAS*	31.8 MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 SO IT IS NOT SUBJECT TO BACT-PSD.	0	(D		ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
K-0037	KENAI REFINERY	АК	03/21/2000 ACT	POWERFORMER PREHEATER, H202	NATURAL GAS*	51 MMBTU/H	Sulfur Dioxide	SOURCE IS NOT SUBJECT TO FUEL LIMITATIONS UNDER BACT-PSD BECAUSE IT WAS INSTALLED PRIOR TO 1975.	0)		ESTIMATED EMISSIONS ARE 6.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
							Sulfur Dioxide	SOURCE WAS INSTALLED PRIOR TO 1975 AND IS					ESTIMATED EMISSIONS ARE 3.7 T/YR, BUT THIS IS
(-0037	KENAI REFINERY	АК	03/21/2000 ACT	POWERFORMER PREHEATER, H203	NATURAL GAS*	27.9 MMBTU/H	(SO2)	THEREFORE NOT SUBJECT TO PSD.	0	(0		NOT AN EMISSION LIMIT. EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
K-0037	KENAI REFINERY	АК	03/21/2000 ACT	POWERFORMER REHEATER, H204	NATURAL GAS*	53.8 MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT FUEL LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR, NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0				FOR H2S AND SO2. ESTIMATED SO2 EMISSIONS ARE 7.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
		AK	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS	NATURAL GAS*	38.9 MMBTU/H	Sulfur Dioxide	FUEL SULFUR LIMITS AS FOLLOWS IS CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0				EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 5.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	KENAI REFINERY	АК	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS	NATURAL GAS*	38 MMBTU/H	Sulfur Dioxide	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.					EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. ESTIMATED EMISSIONS OF SO2 ARE 5 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
	KENAI REFINERY	AK	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1410		50.9 MMBTU/H		THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR;) REFINERY GAS, 168 PPMV H2S.					ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
	KENAI REFINERY	АК	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1400	NATURAI GAS*	50.9 MMBTU/H		THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR;) REFINERY GAS, 168 PPMV H2S.					ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.

				Summary of SU ₂ Cor	troi Determina	ation per EPA's RACI/BACI	LAER Databas	e for Gaseous Fuel > 100 million	BTU/hr & < 250 million B	TU/hr	1	1	
						THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGI TIME	E
CID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION FUEL SULFUR CONTENT LIMITS AS	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								FOLLOWS: DIESEL					
								FUEL, 0.35% SULFUR; NATURAL GAS,					
								0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01%					ESTIMATED EMISSIONS WHEN BURNING LPG, NG, OR DIESEL, ARE 10.1 T/YR, BUT THIS IS NOT AN
				DUCT BURNER FOR STEAM			Sulfur Dioxide	SULFUR; REFINERY				ASSUMED 15%	
37	KENAI REFINERY	AK	03/21/2000 ACT	GENERATION, E-1400	NATURAL GAS*	36.5 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	0	500	0 PPM @ 15% O	2 02	SO2.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH FOR SO2 AND H2S. EMISSION LIMIT IS A
								FUEL, 0.35% SULFUR; NATURAL GAS,					PRORATED CONCENTRATION OF THE FOLLOWING; 230 MB
								0 01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01%					H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF
							Sulfur Dioxide	SULFUR; REFINERY					SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION
37	KENAI REFINERY	AK	03/21/2000 ACT	REFINERY FLARE, J 801	NATURAL GAS*	1 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	0	(0		LIMIT. THIS SOURCE IS SUBJECT TO NSPS FOR SO2.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL					
								FUEL, 0.35% SULFUR; NATURAL GAS,					
								0 01% SULFUR;					
)37	KENAI REFINERY	AK	03/21/2000 ACT	ELECTRIC GENERATOR CAT 3412, EG704	DIESEL	4.8 MMBTU/H	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	(0		ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
-			. ,		-			FUEL SULFUR CONTENT LIMITS AS				1	
								FOLLOWS: DIESEL					
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					
				STEWART-STEVENSON GENERATOR,			Sulfur Dioxide	LPG, 0.01% SULFUR; REFINERY GAS, 168					ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS
37	KENAI REFINERY	AK	03/21/2000 ACT	EG801	DIESEL	6.1 MMBTU/H	(SO2)	PPMV H2S. FUEL SULFUR CONTENT LIMITS AS	500 PPM	(0		NOT AN EMISSION LIMIT.
								FOLLOWS: DIESEL,					
								0 35% SULFUR; NATURAL GAS, 0.01%					
							Sulfur Dioxide	SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV					ESTIMATED EMISSIONS ARE 0.1 T/YR SO2, BUT THIS
037	KENAI REFINERY	AK	03/21/2000 ACT	NORTH CATERPILLAR, P605A	NATURAL GAS	5.6 MMBTU/H	(SO2)	H2S.	500 PPM	(0		IS NOT AN EMISSION LIMIT.
								FUEL SULFUR CONTENT LIMITS AS					
								FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS,					
								0 01% SULFUR;					
027	KENAI REFINERY	АК	03/21/2000 ACT	SOUTH CATERPILLAR, P605B	NATURAL GAS	830 HP	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	(0		ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
57			05/21/2000 &1105p,AC1	SOUTH CATERPILLAR, POUSB	NATORAL GAS	630 HP	(302)	FUEL SULFUR CONTENT LIMITS AS	300 PPW	(
								FOLLOWS: DIESEL,					
								0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG,					
							Sulfur Dioxide	0 01% SULFUR; REFINERY GAS, 168 PPMV					ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS
37	KENAI REFINERY	АК	03/21/2000 ACT	NORTH CUMMINS, P708A	DIESEL	290 HP	(SO2)	H2S.	500 PPM	(0		NOT AN EMISSION LIMIT.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL,					
								0 35% SULFUR; NATURAL GAS, 0.01%					
							Sulfur Diovida	SULFUR; LPG,					ESTIMATED EMISSIONS ARE O 2 T/VD DUT THIS IS
037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CUMMINS, P708B	DIESEL	290 HP	Sulfur Dioxide (SO2)	0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	(D		ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
				,			· ·	FUEL SULFUR CONTENT LIMITS AS					
								FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01%					
								SULFUR; LPG,					
				UPPER TANK FARM CAT 3412DT,			Sulfur Dioxide	0 01% SULFUR; REFINERY GAS, 168 PPMV					ESTIMATED EMISSIONS ARE 0 5 T/YR, BUT THIS IS
037	KENAI REFINERY	AK	03/21/2000 ACT	P708C	DIESEL	660 HP	(SO2)	H2S. NONE INDICATED. SOURCE IS NOT	500 PPM	(0		NOT AN EMISSION LIMIT.
								SUBJECT TO BACT-					
0.0-			02/24/2000 0 1				Sulfur Dioxide	PSD BECAUSE IT WAS INSTALLED PRIOR TO					ESTIMATED EMISSIONS ARE 7.4 T/YR, BUT THIS IS
037	KENAI REFINERY	AK	03/21/2000 ACT	HOT OIL HEATER, H609	NATURAL GAS*	56 MMBTU/H	(SO2)	1975.	0	(U		NOT AN EMISSION LIMIT. EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FUEL SULFUR CONTENT LIMITS AS					FOR SO2 AND H2S. EMISSIONS LIMITS ARE A
								FOLLOWS: DIESEL					PRORATED CONCENTRATION OF; 230 MG H2S/DSCF
				1				FUEL, 0.35% SULFUR; NATURAL GAS,			1		AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED
								0 01% SULFUR;					OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE

							THROUGHPUT		EM	AISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
CID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
				REACTION FURNACE BURNER,				Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS 168						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS
37	KENAI REFINERY	АК	03/21/2000 ACT	H1101	NATURAL GAS*	5.2	2 MMBTU/H	(SO2)	PPMV H2S.	0		0			ALSO SUBJECT TO NSPS FOR SO2.
27			03/24/2020 8 share 6 CT					Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV	500	0004				ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS
037	KENAI REFINERY	АК	03/21/2000 ACT	COOLING TOWER CAT, P719C	NATURAL GAS	1	1 MMBTU/H	(SO2) Sulfur Dioxide	H2S.	500	PPM	0			NOT AN EMISSION LIMIT. ESTIMATED EMISSIONS ARE 14.4 T/YR, BUT THIS IS
037	KENAI REFINERY	АК	03/21/2000 ACT	SULFUR RECOVERY UNIT		19.3	3 LTPD	(SO2)	NONE INDICATED	0		0			NOT AN EMISSION LIMIT.
0037	KENAI REFINERY	АК	03/21/2000 ACT	TAIL GAS BURNER, H1105	NATURAL GAS*		2 ММВТU/Н	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 3 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
027	KENAI REFINERY	AK	03/21/2000 ACT	#4 REHEATER STARTUP BURNER, H1106	NATURAL GAS*		9 ммвти/н	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
037	KENAI REFINERY	АК	03/21/2000 ACT	PRIP ABSORBER FEED FURNACE, H1201/1203	NATURAL GAS*	10.4	4 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
								Sulfur Dioxide	NONE INDICATED AS SOURCE WAS INSTALLED PRIOR TO						SOURCE IS NOT SUBJECT TO PSD REQUIREMENTS BECAUSE IT WAS INSTALLED PRIOR TO 1975. ESTIMATED EMISSIONS ARE 18.4 T/YR, BUT THIS IS
037	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101A	NATURAL GAS*	140	0 MMBTU/H	(SO2)	1975 AND IS NOT SUBJECT TO BACT-PSD.	0		0			NOT AN EMISSION LIMIT.
0027	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER REHEATER, H205	NATUDAL CAS*	19 9	8 ммвти/н	Sulfur Dioxide (SO2)	A PRORATED CONCENTRATION OF THE FOLLOWING FUEL LIMITS IS CONSIDERED BACT: DIESEL FUEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			COMBINED EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S. ESTIMATED EMISSIONS OF SO2 ARE 6.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ADDITIONAL EMISSION LIMITS ARE: A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	KENAI REFINERY	АК	03/21/2000 ACT	HYDROCRACKER FRACTIONATER REBOILER, H403	NATURAL GAS*		0 ММВТU/Н	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISTION SOL EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE 6.6 T/YR. SOURCE IS ALSO SUBJECT TO NSPS. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
037	KENAI REFINERY	АК	03/21/2000 ACT	RESIDUAL OIL HEATER, H612	NATURAL GAS*	22.	2 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT IS LIMITED AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION FOR SO2 AND H2S IS COMBINED. ESTIMATED SO2 EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. EMISSION UMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
7500	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H701	NATURAL GAS*	26 51	5 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO 1975.						CONTROLS NOT INDICATED. ESTIMATED EMISSIONS ARE
1037			03/21/2000 &Π05β;ACI	TINED STEAM GENERATOR, H/U1	INATURAL GAS*	30 5		(SO2) Sulfur Dioxide	1975. NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO	0		0			4.8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ESTIMATED EMISSIONS ARE 4 8 T/YR, BUT THIS IS

			Summary of SO ₂ Cor	itroi Determina	ition per EPA's	5 KACI/BACT/	LAEK Databas	e for Gaseous Fuel > 100 million	в i U/nr & < 250 million B	i U/nr			1
						THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGI TIME	
LCID FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION FUEL SULFUR EONTENT LIMITS AS	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								FOLLOWS: DIESEL					
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					
								LIQUIFED PETROLEUM GAS, 0.01%					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
0037 KENAI REFINERY	AK	02/21/2000 8 shas ACT	NATURAL GAS SUPPLY HEATER, H704		2	MMBTU/H	Sulfur Dioxide	SULFUR; REFINERY	500 PPM	0			WITH H2S. ESTIMATED EMISSIONS OF SO2 ARE 0.1
	AK	03/21/2000 ACT	H704	NATURAL GAS*	2		(SO2)	GAS, 168 PPMV H2S. FUEL SULFUR CONTENT LIMITS AS	500 PPW	0			T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
								FOLLOWS: DIESEL					
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					
								LIQUIFIED PETROLEUM GAS, 0.01%					
0037 KENAI REFINERY	АК	03/21/2000 ACT	FIRED STEAM GENERATOR, H801	NATURAL GAS*	33	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
		03/21/2000 & 103p, ACT	TIRED STEAM GENERATOR, HOUT		JE		(502)	FUEL SULFUR CONTENT LIMITS AS	50011101	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL					WITH H2S. EMISSION LIMIT IS A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								LIQUIFIED PETROLEUM GAS, 0.01%					ESTIMATED SO2 EMISSIONS ARE 1 5 T/YR, BUT THIS
037 KENAI REFINERY	АК	03/21/2000 :ACT	PRIP RECYCLER H2 FURNACE. H1202	NATURAL CAS*	11 7	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	0	0			IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	AK	05/21/2000 &IIDSP,ACT	PRIP RECICLER HZ FURNACE, HIZUZ	NATORAL GAS	11.2		(302)	FUEL SULFUR CONTENT LIMITS AS	0	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL					WITH H2S. EMISSION LIMIT IS A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								LIQUIFIED PETROLEUM GAS, 0.01%					ESTIMATED EMISSIONS OF SO2 ARE 12.0 T/YR, BUT
037 KENAI REFINERY	АК	03/21/2000 ACT	VACUUM TOWER HEATER, H1701	NATURAL GAS*	01	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	0	0			THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
		03/21/2000 & 103p,ACT	VACOOM TOWER TREATER, HITOI		51		(502)	FUEL SULFUR CONTENT LIMITS AS	0	0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND
								FOLLOWS: DIESEL					H2S. EMISSION LIMITS ARE A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE
								LIQUIFED PETROLEUM GAS, 0.01%					HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4
0037 KENAI REFINERY	АК	03/21/2000 ACT	HOT GLYCOL HEATER, H802	NATURAL GAS*	10.8	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	0	0			T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
		03/21/2000 & 103p, ACT	HOT GETCOL HEATEN, HOUZ		10.8		(502)		0	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FUEL SULFUR CONTENT LIMITS AS					FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE
								FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS,					8.5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS. EMISSION LIMITS
								0 01% SULFUR;					ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF
0037 KENAI REFINERY	АК	03/21/2000 :ACT	HYDROCRACKER STABILIZER REBOILER, H404	NATURAL GAS*	64.4	ММВТИ/Н	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0	0			AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
							()	FUEL SULFUR CONTENT IS LIMITED					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								ACCORDING TO THE FOLLOWING: DIESEL FUEL, 0.35% SULFUR;					FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER
								NATURAL					THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE
								GAS, 0.01% H2S; LPG, 0.01% SULFUR;					HOURS. ESTIMATED SO2 EMISSIONS ARE 0.2 T/YR,
037 KENAI REFINERY	АК	03/21/2000 ACT	#1 REHEATER STARTUP BURNER, H1102	NATURAL GAS*	1.65	ммвти/н	Sulfur Dioxide (SO2)	REFINERY GAS, 168 PPMV H2S.	о	0			BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	1											1	EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL					FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3
								FUEL, 0.35% SULFUR; NATURAL GAS,					HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
							Sulfur Diovida	0 01% SULFUR;					ESTIMATED SO2 EMISSIONS ARE 0 2 T/YR, BUT THIS
0037 KENAI REFINERY	АК	03/21/2000 ACT	#2 REHEATER STARTUP BURNER, H1103	NATURAL GAS*	1.15	MMBTU/H	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	o	0			IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	1							FUEL SULFUR CONTENT LIMITS AS					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS,					WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF
								0 01% SULFUR;					AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED
							Culfue Disside	LIQUIFIED PETROLEUM GAS, 0.01%					OVER 3 HOUR. ESTIMATED EMISSIONS OF SO2 ARE 0.1
0037 KENAI REFINERY	АК	03/21/2000 ACT	#3 REHEATER STARTUP BURNER, H1104	NATURAL GAS*	1 05	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	o	0			T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	1	.,						Limit concentration of hydrogen sulfide in					
0074 ENDICOTT PRODUCTION FACILITY	АК	07/29/2011 ACT	Combustion of Fuel	Fuel Gas	43000) hn	Sulfur Dioxide (SO2)	the fuel no more than 1,000 parts per million by volume	1000 PPMV	0			
	7.00	0772072011 @IDSP,ACI		1 461 943	43000	קיין	Sulfur Dioxide	Concentration of hydrogen sulfide in fuel		0			
0074 ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion	Fuel Gas	8717	hp	(SO2)	gas shall not excced 1,000 ppmv	1000 PPMV	0			

				Summary of SO ₂ Co	ntrol Determination per EPA'	s RACT/BACT/	'LAER Databas	e for Gaseous Fuel > 100 million	BTU/hr & < 2		STU/hr	STANDARD	STANDARD LIMIT AVERAGE	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	EMISSION LIMIT	EMISSION LIMIT UNIT	TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT			0 MMscf/day	Sulfur Dioxide (SO2)	Limit concentration of hydrogen sulfide in fuel gas to 1000 ppmv.	1000) PPMV	0			
				Flares			Sulfur Dioxide				0			
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion	Fuel Gas 9	8 MMBTU/H	(SO2) Sulfur Dioxide	Limit content of hydrogen sulfide Limit hydrogen sulfide in fuel gas to no	1000) PPMV	0			
AK-0074	ENDICOTT PRODUCTION FACILITY	АК	07/29/2011 ACT	Combustion	Fuel Gas 540	0 hp	(SO2)	more than 1000 ppmv	1000) PPMV	0			No costs accessisted because the Department determined Cood
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	Fuel Gas Combustion by Burners	Fuel Gas 8	2 MMBTU/H	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			No costs associated because the Department determined Good Combustion Practices as BACT
AK-0077	NORTHSTAR PRODUCTION FACILITY	АК	06/26/2012 ACT	Combustion of Fuel Gas by ICEs	Fuel Gas 218	0 kW	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			
				Combustion of Fuel Gas by Turbines			Sulfur Dioxide	H2S content of fuel gas shall not exceed						
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	< 25 MW	Fuel Gas 2	4 MW	(SO2) Sulfur Dioxide	300 ppmv at any time H2S content of fuel gas shall not exceed	300) PPMV	0			
AK-0077	NORTHSTAR PRODUCTION FACILITY	АК	06/26/2012 ACT	Flaring of Fuel Gas	Fuel Gas 66 REFINERY FUEL	0 MMscf/yr	(SO2)	300 ppmv at any time	300) PPMV	0			
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DISTILLATE HYDROTREATER CHARGE HEATER	GAS OR NATURAL	5 MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
				DISTILLATE HYDROTREATER	REFINERY FUEL GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPLITTER REBOILER	GAS 11	7 ММВТU/Н	(SO2)	S LIMITED TO 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
					REFINERY FUEL GAS AND GASES		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TANK FARM THERMAL OXIDIZER	FROM TANKS NATURAL GAS OR		(SO2)		35	5 PPMV	0			CONCENTRATION OF THE REFINERY FUEL GAS.
					REFINERY FUEL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	THERMAL OXIDIZER	GAS		(SO2)	35 PPM SULFUR LIMIT IN FUEL. ALL GASES DISCHARGED FROM THE	35	5 PPMV	0			CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFER PIT NOS. 1 AND 2			Sulfur Dioxide (SO2)	SULFUR PITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.		5 LB/H	0		NOT AVAILABLE	
				CATALYTIC REFORMING UNIT	REFINERY FUEL GAS AND NATURAL		Sulfur Dioxide							THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CHARGE HEATER	GAS 12 REFINERY FUEL	2 MMBTU/H	(SO2)	SULFUR LIMITED TO 35 PPM IN FUEL.	35	5 PPMV	0		NOT AVAILABLE	UNIT.
				TRUCK AND RAIL CAR LOADING	GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTATION
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	RACK THERMAL OXIDIZERS	GAS 12. REFINERY FUEL	3 MMBTU/H	(SO2)		35	5 PPMV	0			OF THE REFINERY FUEL GAS. THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET
47.0046		47	04/14/2005 & phone ACT	CATALYTIC REFORMING UNIT	GAS AND NATURAL GAS 19		Sulfur Dioxide	S LIMITED TO 35 PPM.	25		0			CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	INTERHEATER NO. 1	REFINERY FUEL	2 MMBTU/H	(SO2)	S LIWITED TO 55 PPWI.	55	5 PPMV	0		NOT AVAILABLE	
A7-0046	ARIZONA CLEAN FUELS YUMA	Δ7	04/14/2005 ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 2	GAS OR NATURAL GAS 12	9 MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
12 00 10					REFINERY FUEL									
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT DEBUTANIZER REBOILER	GAS OR NATURAL GAS 23.	2 MMBTU/H	Sulfur Dioxide (SO2)	S LIMIT OF 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
				BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR	REFINERY FUEL GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CHARGE HEATER	GAS 31	1 MMBTU/H	(SO2)	35 PPM SULFUR LIMIT ON FUEL BURNED.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
1				BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR	REFINERY FULE GAS OR NATURAL		Sulfur Dioxide	SULFUR LIMIT OF 35 PPM IN FUEL						THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	INTERHEATER	GAS 32 REFINERY FUEL	8 MMBTU/H	(SO2) Sulfur Dioxide	BURNED.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS. THIS LIMIT IS FOR SULFUR, AS H2S, AND IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	VACUUM CRUDE CHARGE HEATER	GAS OR NG 10	1 MMBTU/H	(SO2)		35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROCRACKER UNIT CHARGE HEATER	REFINERY FUEL GAS OR NG 7	0 MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	THIS LIMIT FOR SULFUR, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
				HYDROCRACKER UNIT MAIN	REFINERY FUEL		Sulfur Dioxide				-			THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	FRACTIONATOR HEATER NAPHTHA HYDROTREATER CHARGE		1 MMBTU/H	(SO2) Sulfur Dioxide	S LIMITED TO 35 PPM.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS. THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HEATER	GAS OR NG 21. REFINERY FUEL	4 MMBTU/H	(SO2)	S LIMITED TO 35 PPM	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
				BUTANE CONVERSION UNIT	GAS AND NATURAL		Sulfur Dioxide	SULFUR LIMITED TO 35 PPM IN FUEL						THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	ISOSTRIPPER REBOILER	GAS 22 NATURAL GAS OR	2 MMBTU/H	(SO2)	BURNED.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS. THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	ATMOSPHERIC CRUDE CHARGE HEATER	REFINERY FUEL GAS 34	6 MMBTU/H	Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	5 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROGEN REFORMER HEATER	REFINERY FUEL GAS OR NATURAL GAS 143	5 MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM	35	5 PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.

									e for Gaseous Fuel > 100 million					
							THROUGHPUT				EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL REFINERY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT		CONDITION	POLLUTANT COMPLIANCE NOTES
Z-0046 A	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPRAY DRYER HEATER	GAS OR NATURAL GAS	2	4 MMBTU/H	Sulfur Dioxide (SO2)		35 PPMV	0			HIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET ONCENTRATION OF THE REFINERY FUEL GAS.
.Z-0046 A	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY UNITS 1 AND 2				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR RECOVERY UNITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33.5 LB/H	0		TI NOT AVAILABLE PI	HE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVEF
								Sulfur Dioxide	ALL GASES DISCHARGED FROM THE TAIL GAS TREATMENT UNIT MUST BE ROUTED TO THE SULFUR RECOVERY PLANT				Т. Т.	HE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVEF
Z-0046 A	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TAIL GAS TREATMENT UNIT				(SO2)	THERMAL OXIDIZER	33.5 LB/H	0		NOT AVAILABLE	
				SULFUR RECOVERY PLANT	REFINERY FUEL GAS OR NATURAL			Sulfur, Total						
AZ-0046 A	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	THERMAL OXIDIZER	GAS	10	00 MMBTU/H	Reduced (TRS)		0 089 LB/H	0		NOT AVAILABLE	
				SULFUR RECOVERY PLANT	REFINERY FUEL GAS OR NATURAL			Sulfur Dioxide					т	HE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVEF
AZ-0046 A	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	THERMAL OXIDIZER	GAS	10	0 ММВТU/Н	(SO2)		33.5 LB/H	0		NOT AVAILABLE	
7 0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DELAYED COKING UNIT CHARGE HEATER NOS. 1 AND 2	REFINERY FUEL GAS OR NATURAL GAS	90	.5 MMBTU/H	Sulfur Dioxide (SO2)	FUEL LIMITED TO 35 PPM S.	35 PPMV	0			HIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET ONCENTRATION OF THE REFINERY FUEL GAS.
			04/14/2003 killsp,Act		0.03			Sulfur Dioxide	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT LESS THAN 0.10 GR/DSCF (160 PPMV) H2S		0			
.A-0123 B	BATON ROUGE REFINERY	LA	04/26/2002 ACT	FRACTIONATOR FURNACE		36	60 MMBTU/H	(SO2)	IN FUEL.	12.47 LB/H	0.035 LB	B/MMBTU	CALCULATED	
								Sulfur Dioxide	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT OF LESS THAN 0.10 GR/DSCF (160 PPMV)				CALCULATED USING	
A-0123 B	BATON ROUGE REFINERY	LA	04/26/2002 ACT	HYDROFINER FURNACE 1		15	0 MMBTU/H	(SO2)	H2S IN FUEL.	5.1 LB/H	0.034 LB	B/MMBTU		MISSION LIMIT 1 IS 5.10 LB/H.
								Sulfur Dioxide	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT OF LESS THAN 0.10 GR/DSCF (160 PPMV)				CALCULATED USING	
A-0123 B	BATON ROUGE REFINERY	LA	04/26/2002 ACT	HYDROFINER FURNACE 2		19	7 MMBTU/H	(SO2)	H2S IN FUEL.	6.93 LB/H	0.035 LB	B/MMBTU	THROUGHPUT	
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	CRUDE HEATER (2)	NAT & REFINERY GAS	281	MMBTU/H .1 (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	11.25 LB/H	0.0044 LB	3/MMBTU	EACH, CALCULATED	
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON CHARGE	NAT & REFINERY GAS	69	.4 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.78 LB/H	0 04 LB	3/MMBTU	CALCULATED	
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON STRIPPER REBOILER		62	.1 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2.49 LB/H	0 04 LB	3/MMBTU	CALCULATED	
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	DEASPHALTING HEATER	NAT & REFINERY GAS	22	1 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	8.85 LB/H	0 04 LB	3/MMBTU	CALCULATED	
A 0140 I	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	MARINE LOADING VAPOR COMBUSTOR		5000	00 BBL	Sulfur Dioxide (SO2)	NONE INDICATED	0.13 LB/H	0			
A-0145 L				HGO HYDROCARBON CHARGE				Sulfur Dioxide		0.13 LB/11	0			
.A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HEATER	NAT & REFINERY	98	.8 MMBTU/H	(SO2) Sulfur Dioxide	LOW SULFUR FUELS	3.95 LB/H	0 04 LB	3/MMBTU	CALCULATED	
.A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	BOILER NO. 1	GAS	35	60 MMBTU/H	(SO2)	USE OF LOW SULFUR FUEL	11.21 LB/H	0.032 LB	B/MMBTU		
.A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HF ALKYLATION MAIN FRACTIONATOR REBOILER	NAT & REFINERY GAS	268	.6 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	10.75 LB/H	0 04 LB	3/MMBTU	CALCULATED	
.A-0149 L	OUISIANA REFINING DIVISION	IA	10/21/1999 ACT	HGO HYDROCARBON STRIPPER REBOILER	NAT & REFINERY GAS	-	/8 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	3.13 LB/H	0.04 B	3/MMBTU	CALCULATED	
					0.0			Sulfur Dioxide	AMINE BASED SCRUBBER (CLAUS/MDEA) AND THERMAL	5.15 60/11		PMV @ 0%	SI O	ULFUR RECOVERY UNIT EMISSIONS FROM THERMAL XIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A AP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNIT #3				(SO2)	OXIDIZER	56.86 LB/H	60 EX	CESS AIR		/YR (60 PPMV) ULFUR RECOVERY UNIT EMISSIONS FROM THERMAL
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNITS NO. 1 AND NO. 2				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA)AND THERMAL OXIDIZER.	56.86 LB/H		PMV @ 0% (CESS AIR	EMISSION CAP,	XIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A AP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 /YR (60 PPMV)
A-0149 I	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	COKER HEATER		241	.1 MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	9.64 LB/H	0.04 I B	3/MMBTU		
						241		Sulfur Dioxide			5 04 Lb	.,		HERE IS AN EMISSION CAP FOR MAXIMUM SO2
A-0149 L	OUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR PLANT NO. 3 FUGITIVES PIPESTILL, COKER,				(SO2)	LIMIT CONCENTRATION OF H2S IN FUEL	0.07 LB/H	0		E	MISSIONS
				HYDROCRACKING, & amp; LIGHT				Sulfur Dioxide	GAS TO NSPS SUBPART J LIMIT OF 160					
A-0206 B	BATON ROUGE REFINERY	LA	02/18/2004 ACT	ENDS FURNACES				(SO2)	PPMV (0.01 GR/DSCF) LIMIT CONCENTRATION OF H2S IN FUEL	0 034 LB/MMBTU	0.034 LB	3/MMBTU		
A-0206 B	BATON ROUGE REFINERY	LA	02/18/2004 ACT	PIPESTILL, COKER, CAT COMPLEX, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034 LB/MMBTU	0.034 LB	3/MMBTU		

					1		.,	se for Gaseous Fuel > 100 million	-		-,	1		
						THROUGHPU	т		EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION LIMIT CONCENTRATION OF H2S IN FUEL	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	REFORMING, HYDROFINING, & HEAVY CAT FURNACES			Sulfur Dioxide (SO2)	GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	lb/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	FEED PREPARATION FURNACES F-30 & F-31		352 MMBTU/H	Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	lb/mmbtu	0.1778	LB/MMBTU		
1 1 0 2 0 6	BATON ROUGE REFINERY	LA	02/18/2004 ACT	CRU REGENERATOR VENT		329 UNITS/YR	Sulfur Dioxide (SO2)	GOOD ENGINEERING DESIGN AND PROPER OPERATION	0.99	LB/H				
LA-0206	BATON ROUGE REFINERT		02/18/2004 ,AC1	POWERFORMING & amp; LIGHT		529 UNITS/TK	Sulfur Dioxide	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160	0.88	цруп				
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	ENDS FURNACES			(SO2)	PPMV (0.01 GR/DSCF)	0.1778	lb/MMBTU	0.1778	B LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING 2 & amp; EAST LIGHT ENDS FURNACES			Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	lb/mmbtu	0.1778	LB/MMBTU		
				NAPHTHA HYDROTREATER REACTOR CHARGE HEATER (5-08), KHT REACTOR CHARGE HEATER (9- 08), & HCU TRAIN 1&2										
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	REACTOR CHARGE HEATERS (11-08 & 12-08)	REFINERY FUEL GAS		Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0)		
				NAPHTHA HYDROTREATER STRIPPER REBOILER HEATER (6-08) & KHT STRIPPER REBOILER	REFINERY FUEL		Sulfur Dioxide							
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HEATER (10-08)	GAS REFINERY FUEL		(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	()		
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	BOILER NO. 1 (16-08)	GAS	525.7 MMBTU/H	(SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV)		
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	SRU THERMAL OXIDIZER NOS. 1 & 2 (18-08 & 19-08)	NATURAL GAS	63.7 MM BTU/H EA	Sulfur Dioxide (SO2)	SEE NOTES	93.41	PPMVD				OXYGE AUTOM DEGAS SULFUF THE SR STORAG THERM
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	DIESEL		Sulfur Dioxide (SO2)		0.02	MAX LB/H	(USE OF
				A & B CRUDE HEATERS (1-08										
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	& 2-08) & COKER CHARGE HEATER (15-08)	GAS		Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	(
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN REFORMER FURNACE FLUE GAS VENT (48-08)	PURGE GAS	1412.5 MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL GAS	25	PPMV AS H2S	()		
۱۵-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	PLATFORMER HEATER CELLS NO. 1- 3 (7A-08, 7B-08, & amp; 7C-08) & amp; HCU FRACTIONATOR HEATER (13-08)	REFINERY FUEL GAS		Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S				
				A & B VACUUM TOWER	REFINERY FUEL		Sulfur Dioxide							
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HEATERS (3-08 & amp; 4-08)	GAS	155.2 MMBTU/H EA.	(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS VENTURI WET GAS SCRUBBER W/	25	PPMV	()		
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	FCCU REGENERATOR VENT (86-74) MARINE VAPOR COMBUSTOR (55- 08) & amp; MARINE LOADING			(SO2) Sulfur Dioxide	ADDITION OF CAUSTIC SOLUTION	25	PPMV@0%02	(
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	VAPOR COMBUSTOR (107-90)		50000 BBL/H EA.	(SO2)	COMPLY WITH 40 CFR 60.18.	0		()		NO EM
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	REFINERY FUEL GAS	9.6 MM BTU/H	Sulfur Dioxide (SO2)		0.2	MAX LB/H	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN PLANT FLARE (52-08)	H2 PLANT FEED GAS	2472 MMBTU/H	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18	0.01	MAX LB/H	(
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	STARTUPS/SHUTDOWNS - SRU			Sulfur Dioxide (SO2)	FOLLOW WRITTEN SOP, MINIMIZE DURATION AND FREQUENCY, PROPERLY DOCUMENT ALL SU/SD	0		()		NO EM
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (94-43 & 94-45)	REFINERY FUEL GAS	354 MMBTU/H EA	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	9.43	LB/H)		
	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FLARE 1-5 (15-77, 12-81, 2004-5A, 2004-5B & amp; 2005-38)			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE) AS FUELS AT FLARE TIP.						NO EM

50 million B	STU/hr		1	
EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
lb/mmbtu	0.034	lb/mmbtu		
20,1111010	0.001	20,1111010		
lb/MMBTU	0.1778	lb/MMBTU		
LB/H	0			
lb/MMBTU	0.1778	lb/mmbtu		
lb/MMBTU	0.1778	lb/mmbtu		
PPMV AS H2S	0			
PPMV AS H2S	0			
PPMV	0			
PPMVD	0			OXYGEN ENRICHMENT AND SULFUR SHEDDING PROCEDURES WITH AUTOMATED CONTROLS WITHIN THE SRU; EXCESS SRU CAPACITY; DEGASSING THE LIQUID SULFUR PRODUCT UPSTREAM OF THE SULFUR PIT TO <= 15 PPMV H2S; RECYCLING SULFUR PIT VENTS TO THE SRU INLET; PROPER OPERATING PRACTICES FOR SOUR WATER STORAGE; OVERALL SULFUR CONVERSION EFFICIENCY OF 99.9%; THERMAL OXIDIZER CONVERSION EFFICIENCY OF 99.5%
MAX LB/H	0			USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS.
PPMV	0			
PPMV AS H2S	0			
PPMV AS H2S	0			
PPMV	0			
PPMV@0%02	0			
	0			NO EMISSION LIMITS AVAILABLE
MAX LB/H	0			
MAX LB/H	0			
	0			NO EMISSION LIMITS AVAILABLE
LB/H	0			
	0			NO EMISSION LIMITS AVAILABLE

									n BTU/hr & < 250 million B			
						THROUGHPUT				STANDARD STAND/ EMISSION EMISSI		
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME SRU THERMAL OXIDIZERS (99-3, 99-	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION CONTROL DEVICE - COMPLY WITH 40 CFR	1 LIMIT 1 UNIT		NIT CONDITION	POLLUTANT COMPLIANCE NOTES
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	4, 2005-39, 2007-4)		50 MMBTU/H	(SO2)	60 SUBPART J	250 PPMVD	0		
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FCCU REGENERATOR (16-77)			Sulfur Oxides (SO)	() WET SCRUBBER	176.12 LB/H	50 PPMV	7 DAY ROLLIN AVERAGE	G
								USE OF PIPELINE QUALITY NATURAL GAS				
				MVR THERMAL OXIDIZER NO. 1 (94-			Sulfur Dioxide	OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV				
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	8)		240 MMBTU/H	(SO2)	(ANNUAL AVERAGE).	3.3 LB/H	0		
							Sulfur Dioxide	FUELED BY NATURAL GAS OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAI	L			
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	ARU FLARE (2008-36)	PROCESS FUEL GAS		(SO2)	AVERAGE)	0	0		NO EMISSION LIMITS AVAILABLE
								USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S				
0242			14/47/2000 Bullion ACT		REFINERY FUEL		Sulfur Dioxide	CONCENTRATION LESS THAN 100 PPMV				
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS/REBOILERS	GAS		(SO2)	(ANNUAL AVERAGE). USE OF PIPELINE QUALITY NATURAL GAS	0	0		NO EMISSION LIMITS
							Culfue Diavid-	OR PROCESS FUEL GASES WITH AN H2S				
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (2008-1 - 2008-9)	PROCESS FUEL GAS		Sulfur Dioxide (SO2)	CONCENTRATION LESS THAN 10 PPMV (ANNUAL AVERAGE).	0	0		NO EMISSION LIMITS
								USE OF PIPELINE QUALITY NATURAL GAS				
				MVR THERMAL OXIDIZER NO. 2	REFINERY FUEL		Sulfur Dioxide	OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV				
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	(2008-38)	GAS	200 MMBTU/H	(SO2)	(ANNUAL AVERAGE).	0.45 LB/H	0		
								USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S				
0212	ST. CHARLES REFINERY		11/17/2000 8 phone ACT	HEATERS (04.21 Same: 04.20)	REFINERY FUEL		Sulfur Dioxide	CONCENTRATION LESS THAN 100 PPMV	0	0		
-0213	ST. CHARLES REFINERY		11/17/2009 ACT	HEATERS (94-21 & amp; 94-29)	GAS		(SO2)	(ANNUAL AVERAGE). USE OF PIPELINE QUALITY NATURAL GAS	0	0		NO EMISSION LIMITS AVAILABLE
							Sulfur Diovido	OR REFINERY FUEL GASES WITH AN H2S				
-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	CPF HEATER H-39-03 & H-39- 02 (94-28 & 94-30)	REFINERY FUEL GAS		Sulfur Dioxide (SO2)	CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0	0		NO EMISSION LIMITS
								FUELED BY NATURAL GAS AND/OR				
								REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE) OR PROCESS				
0212			11/17/2000 8 phone ACT	BOILERS (2008-10, 2008-11, 2008-	REFINERY FUEL		Sulfur Dioxide	FUEL GAS WITH H2S <= 10 PPMV (ANNUAL	L	0		
-0213	ST. CHARLES REFINERY		11/17/2009 ACT	40)	GAS	715 MMBTU/H EA	(SO2)	AVERAGE) FUELED BY NATURAL GAS OR REFINERY	0	0		NO EMISSION LIMITS AVAILABLE
0212	ST. CHARLES REFINERY		11/17/2009 ACT	DHT HEATERS (4-81, 5-81)	REFINERY FUEL GAS	70 MMBTU/H EA	Sulfur Dioxide (SO2)	FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0	0		NO EMISSION LIMITS AVAILABLE
-0215	ST. CHARLES REFINENT		11/17/2009 &IIDSP,ACT	DHT HEATERS (4-61, 5-61)	GAS		(302)	FUELED BY NATURAL GAS OR REFINERY	0	0		
0212			11/17/2009 ACT	HEATER F-72-703 (7-81)	REFINERY FUEL GAS	633 MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0	0		NO EMISSION LIMITS AVAILABLE
-0215	ST. CHARLES REFINERY		11/17/2009 &IIDSP,ACT	HEATER F-72-705 (7-61)	GAS	055 1011010/11	(302)	FUELED BY NATURAL GAS AND PROCESS	0	0		
0212	ST. CHARLES REFINERY		11/17/2009 ACT	THERMAL OXIDIZERS (2008-32, 2008-33, 2008-34)	PROCESS FUEL GAS	15 MMBTU/H EA	Sulfur Dioxide (SO2)	FUEL GAS WITH H2S <=10 PPMV (ANNUAL AVERAGE)		0		NO EMISSION LIMITS AVAILABLE
-0215	ST. CHARLES REFINERT		11/17/2009 &IIDSP,ACT	2008-55, 2008-54)	PROCESS FUEL GAS		Sulfur Dioxide	AVERAGE)	PPMDV @ 0%	PPMDV @	0%	
<-0095	ARDMORE REFINERY	ОК	09/03/2003 ACT	SULFUR RECOVERY UNIT		130 LT/D	(SO2) Sulfur Dioxide	SCOT UNIT	250 02	250 02		limit is fuel H2S content limit, no emission rate
<-0095	ARDMORE REFINERY	ок	09/03/2003 ACT	HOT OIL HEATERS			(SO2)	LOW SULFUR FUEL	160 S02 PPMDV	0	see note	limit.
(-0095	ARDMORE REFINERY	ок	09/03/2003 ACT	FUGITIVE EQUIPMENT LEAKS			Sulfur Dioxide (SO2)	LEAK DETECTION AND REPAIR	0	0		No emission rate limit, just leak detection and control.
0000			5,55,2005 Gilbap,Aci									
A-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	DELAYED COKER UNIT, HEATER	REFINERY GAS	116 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.71 LB/H	0.023 LB/MMBT	Calculated usi U heat input	ng Best available technology (BAT) review done.
									2.71 20/11			
4-0221	UNITED REFINERY CO.	PA	10/09/2003 ACT	FCC FEED HYDROTREATER HEATER	REFINERY GAS	91 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.44 LB/H	0.027 LB/MMBT	Calculated usi U heat input	ng Best available technology (BAT) review done.
							Sulfur Dioxide				- neur mpur	
-0231	UNITED REFINERY CO.	РА	10/09/2003 ACT	HYDROGEN REFORMER UNIT	REFINERY GAS	344 MMBTU/H	(SO2)	GOOD COMBUSTION PRACTICE	9.22 LB/H	0		Best available technology (BAT) review done.
							Sulfur Dioxide				Calculated usi	-
A-0231	UNITED REFINERY CO.	РА	10/09/2003 ACT	NORTH CRUDE HEATER	REFINERY GAS	147 MMBTU/H	(SO2)	USE OF DESULFURIZED REFINERY GAS	46.22 LB/H	0.3 LB/MMBT	U heat input CALCULATED	Best available technology (BAT) review done.
							Sulfur Dioxide				USING	
<-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE OF-01	ETHANE	300 MMBTU/H	(SO2) Sulfur Dioxide	NONE INDICATED	0.27 LB/H	0.001 LB/MMBT	U THROUGHPUT	T
(-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	DIESEL ENGINE, DIESELFW	DIESEL		(SO2)	NONE INDICATED	0.7 LB/H	0		
	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FLARE, FLAREX			Sulfur Dioxide (SO2)	NONE INDICATED	0.02 LB/H			

				Summary of SO ₂ Co	ntrol Determina	ation per EPA's	S RACT/BACT	/LAER Database	e for Gaseous Fuel > 100 million	BTU/hr & < 2	50 million l		
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EN LIN
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE AF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE CF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE DF-01	ETHANE	350	ММВТU/Н	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE EF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE QF-01	ETHANE	300	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.27	LB/H	0.001	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE BF-01	ETHANE	339	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	SECONDARY FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.1	LB/H	0	
								Sulfur Dioxide					
TX-0339	BAYTOWN OLEFINS PLANT	ТХ	04/05/2001 ACT	(6) FURNACES, XAF-01 THRU XFF-01	ETHANE	333	MMBTU/H	(SO2)	NONE INDICATED	1.8	LB/H	0.005	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE XGF-01	ETHANE	502	ммвти/н	Sulfur Dioxide (SO2)	NONE INDICATED	2.8	LB/H	0.006	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	EMERGENCY GENERATOR	DIESEL	156	6 H/YR	Sulfur Dioxide (SO2)	NONE INDICATED	1.2	LB/H	0	
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	(2) FURNACES, IF-01 & JF-01	ETHANE	341	MMBTU/H, MAXIMUM	Sulfur Dioxide (SO2)	NONE INDICATED	1.46	LB/H	0.004	LB/M
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	DIESEL ENGINE, DIESEL1A	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0	
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	DIESEL ENGINE, DIESEL4	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0	
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE FF-01	ETHANE	350) MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/M
T V 0000								Sulfur Dioxide				0.005	
TX-0339	BAYTOWN OLEFINS PLANT BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT 04/05/2001 ACT	FURNACE GF-01 PRIMARY FLARE	ETHANE	350	MMBTU/H	(SO2) Sulfur Dioxide (SO2)	NONE INDICATED		lb/H lb/H	0.005	LB/IVI
TX-0339	BAYTOWN OLEFINS PLANT	тх	04/05/2001 ACT	FURNACE HF-01	ETHANE	238	MMBTU/H	Sulfur Dioxide	NONE INDICATED		LB/H	0.005	LB/M
								Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0				-
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BOILER NO. 13		366 83	MMBTU/H	(SO2)	GR/ 100 DSCF. LOW S FUEL: FUEL GAS WITH H2S	9.4	LB/H	0.026	LB/M
								Sulfur Dioxide	CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0				
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BOILERS 14 AND 15	PETRO REFIN GAS	586	MMBTU/H EA	(SO2)	GR/ 100 DSCF.	15.1	LB/H	0.025	LB/M

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	CALCULATED USING	
lb/MMBTU	THROUGHPUT CALCULATED	
lb/mmbtu	USING THROUGHPUT	
lb/mmbtu	CALCULATED	
lb/mmbtu	USING THROUGHPUT	
lb/mmbtu	CALCULATED USING MAX THROUGHPUT	
lb/mmbtu	CALCULATED USING THROUGHPUT	
,		
lb/mmbtu	EACH, CALCULATED USING MAX THROUGHPUT	
lb/MMBTU	CALCULATED USING MAX THROUGHPUT	
	EACH,	
lb/mmbtu	CALCULATED USING MAX THROUGHPUT	
	CALCULATED USING	
lb/MMBTU	THROUGHPUT CALCULATED USING	
lb/MMBTU	THROUGHPUT	
	CALCULATED	
lb/mmbtu	USING MAX THROUGHPUT	
lb/mmbtu	CALCULATED	
	EACH,	
lb/mmbtu	CALCULATED	

		1	1	Summary of SO ₂ Cor	ntrol Determina	ation per EPA'	s RACT/BACT/	LAER Databas	e for Gaseous Fuel > 100 million	BTU/hr & < 2	250 million I	BTU/hr			
ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
									LOW S FUEL: FUEL GAS WITH H2S						
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
								Cultur Diavida	GR/100 DSCF AND TOTAL S CONTENT NO						
75 LYON	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU- NO 3 REACTOR FEED HEATER		58.9	5 MMBTU/H	Sulfur Dioxide (SO2)	MORE THAN 5.0 GR/ 100 DSCF.	1 '	5 LB/H	0.025	LB/MMBTU	CALCULATED	
			00/11/2002 00000000			50 5.	5	(002)	LOW S FUEL: FUEL GAS WITH H2S			0.025	20,1111210	0.12000.0.120	
									CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
									GR/100 DSCF AND TOTAL S CONTENT NO						
	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU-NO.4 REACTOR FEED HEATER			Э ММВТИ/Н	Sulfur Dioxide (SO2)	MORE THAN 5.0 GR/ 100 DSCF.	1	B LB/H	0.027	LB/MMBTU	CALCULATED	
1/5 LYON	DELL - CITGO REFINING, LP		03/14/2002 EST	BTU-NO.4 REACTOR FEED HEATER		4		(302)	LOW S FUEL: FUEL GAS WITH H2S	1.3	вцвин	0.027	LB/IVIIVIBTO	CALCULATED	
									CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
									GR/100 DSCF AND TOTAL S CONTENT NO						
				BTU-REFORMATE STABILIZER				Sulfur Dioxide	MORE THAN 5.0						
375 LYON	DELL - CITGO REFINING, LP	ТХ	03/14/2002 EST	REBOILER		54.7	7 MMBTU/H	(SO2)	GR/ 100 DSCF. LOW S FUEL: FUEL GAS WITH H2S	1.4	1 LB/H	0.026	LB/MMBTU	CALCULATED	
									CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25						
									GR/100 DSCF AND TOTAL S CONTENT NO						
				ISOM II WEST REACTOR FEED				Sulfur Dioxide	MORE THAN 5.0						
375 LYON	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		104 2	5 MMBTU/H	(SO2)	GR/ 100 DSCF.	2.7	7 LB/H	0.026	LB/MMBTU	CALCULATED	
									LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
				ISOM II COMBINATION SPLITTER				Sulfur Dioxide	MORE THAN 5.0						
375 LYON	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		77.6	2 MMBTU/H	(SO2)	GR/ 100 DSCF.	2	2 LB/H	0.026	LB/MMBTU	CALCULATED	
									LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
				ISOM II XYLENE RERUN TOWER				Sulfur Dioxide	MORE THAN 5.0						
375 LYON	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		83.	7 ММВТИ/Н	(SO2)	GR/ 100 DSCF.	2.2	2 LB/H	0.026	LB/MMBTU	CALCULATED	
									LOW S FUEL: FUEL GAS WITH H2S						
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
				ISOM II EAST REACTOR FEED				Sulfur Dioxide	GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
	DELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		-	5 ММВТИ/Н	(SO2)	GR/ 100 DSCF.	11	B/H	0.025	LB/MMBTU	CALCULATED	

				Summary of SO. Co	ntrol Determina	ation nor FDA's		/I AFR Database	e for Gaseous Fuel > 100 million	BT11/br 8. < 2	50 million B	2TU/br		
							THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION LOW SULFUR CONTENT FUEL: USE	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION
									REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100					
								Sulfur Dioxide	DSCF H2S AND NO					
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ORTHOXYLENE I HEATER		96 23	MMBTU/H		MORE THAN 5.0 GR/100 DSCF TOTAL S. LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S	2.5	LB/H	0.026	LB/MMBTU	CALCULATED
									OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO					
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	ORTHOXYLENE II HEATER		226.42	MMBTU/H	(SO2)	MORE THAN 5.0 GR/100 DSCF TOTAL S.	5.8	LB/H	0.026	lb/MMBTU	CALCULATED
									LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100					
				BACKUP AIR COMPRESSOR ENGINES	5			Sulfur Dioxide	DSCF H2S AND NO		(
TX-0375	LYONDELL - CITGO REFINING, LP	ТХ	03/14/2002 EST	(1-5)					MORE THAN 5.0 GR/100 DSCF TOTAL S. LOW S FUEL: FUEL GAS WITH H2S	4.72	LB/H	0		
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0					
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU-NO. 1 REACTOR FEED HEATER		121.74	ММВТU/Н	(SO2)	GR/ 100 DSCF.	3.1	LB/H	0.025	lb/MMBTU	CALCULATED
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU-NO.2 REACTOR FEED HEATER		69.68	ммвти/н	Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.8	LB/H	0.025	lb/mmbtu	CALCULATED
									LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0					
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BENZENE STABILIZER HEATER	PETRO REFIN GAS	38 34	MMBTU/H	(SO2)	GR/ 100 DSCF. LOW S FUEL: FUEL GAS WITH H2S	1	LB/H	0.026	LB/MMBTU	CALCULATED
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BOILER NO. 12		245	MMBTU/H	Sulfur Dioxide	CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	63	LB/H	0.026	lb/mmbtu	CALCULATED
				NO. 1 HYDROTREATER REBOILER				Sulfur Dioxide				0.020		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT		05/23/2000 ACT	HEATER	REFINERY GAS		MMBTU/H	(SO2) Sulfur Dioxide			LB/H	0		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REFORMER CHARGE HEATER NO. 1 REFORMER STABILIZER	REFINERY GAS	248	MMBTU/H	(SO2) Sulfur Dioxide		9.33	LB/H	0		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	REPOILER HEATER	REFINERY GAS	20	ММВТU/Н	(SO2) Sulfur Dioxide		0.75	LB/H	0		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO 1 INTERHEATER NO. 1 REBOILER STABILIZER	REFINERY GAS	147.2	MMBTU/H	(SO2)		5.54	LB/H	0		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	REBOILER HEATER	REFINERY GAS	45.7	MMBTU/H	Sulfur Dioxide (SO2)		1.72	LB/H	0		
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO. 1 HYDROTREATER CHARGE HEATER	REFINERY GAS	63.4	MMBTU/H	Sulfur Dioxide (SO2)		2.39	LB/H	0		

lion B	TU/hr			
ion Unit	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	0.026	lb/mmbtu	CALCULATED	
	0.026	lb/MMBTU	CALCULATED	
	0			
	0.025			
	0.025	lb/MMBTU	CALCULATED	
	0.025	lb/mmbtu	CALCULATED	
	0.026	lb/MMBTU	CALCULATED	
	0.026	lb/mmbtu	CALCULATED	
	0.020			
	0			
	0			
	0			
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RBLCID												1 '	
	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EN LIN
	SHELL OIL DEER PARK	тх	07/30/2004 ACT	SR- 3/4 INCINERATOR				Sulfur Dioxide (SO2)			PPMV	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	EAST PROPERTY FLARE				Sulfur Dioxide (SO2)			РРМ	0	ł
	SHELL OIL DEER PARK	тх	07/30/2004 ACT	COKER FLARE				Sulfur Dioxide (SO2)			PPM	0	
	SHELL OIL DEER PARK	тх	07/30/2004 ACT	TWENTY ONE FURNACES	REFINERY FUEL GAS			Sulfur Dioxide (SO2)			PPM	0	
		тх		FOURTEEN HEATERS				Sulfur Dioxide (SO2)			PPM	0	
	SHELL OIL DEER PARK		07/30/2004 ACT					Sulfur Dioxide					
	SHELL OIL DEER PARK	тх	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN CARBON			(SO2) Sulfur Dioxide			PPMV	0	
X-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	CO BOILER	MONOXIDE			(SO2) Sulfur Dioxide			PPM	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	CCU FLARE				(SO2) Sulfur Dioxide		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				(SO2) Sulfur Dioxide		300	PPM	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	WEST PROPERTY FLARE				(SO2) Sulfur Dioxide		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	THREE FLARES				(SO2) Sulfur Dioxide		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	ANALYZER				(SO2)		300	РРМ	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250) MMBtu/H	Sulfur Dioxide (SO2)		0.41	LB/H	0	<u> </u>
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250) MMBtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250) MMBtu	Sulfur Dioxide (SO2)		0.02	LB/H	0	ł
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	LB/H	0	1
	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	LB/H	0	1
	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250) mmbtu/h	Sulfur Dioxide (SO2)			LB/H		
				PYROLYSIS FURNACE (1057-1062,				Sulfur Dioxide					
	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	1091)	FUEL GAS		MMBTU/h	(SO2) Sulfur Dioxide			LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	(SO2) Sulfur Dioxide			LB/H	0	[
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1067)				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1087) DIESEL EMERGENCY GENERATOR				(SO2) Sulfur Dioxide		0.02	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	(N7900LID)	DIESEL			(SO2) Sulfur Dioxide		1.85	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REGENERATION HEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	SECOND STAGE FEED HEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (8003B)				(SO2)		0.01	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0	
	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0	ł
	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0	
	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)			LB/H	0	
	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	00	Эммвти/н	Sulfur Dioxide			LB/H	0	
	CITGO CORPUS CHRISTI REFINERY -							Sulfur Dioxide					
	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	TAIL GAS INCINERATOR MIXED DISTILLATE HYDROHEATER	REFINERY FUEL		MMBTU/H	(SO2) Sulfur Dioxide			LB/H	0	
	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	ТХ	04/20/2005 ACT	REBOILER HEATER	GAS	82	2 MMBTU/H	(SO2) Sulfur Dioxide		5.7	LB/H	0	<u> </u>

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	1	

				, 2					se for Gaseous Fuel > 100 million					
							THROUGHPU	r		EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGI TIME
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	()	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	()	
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	тх	05/05/2005 ACT	AJAX DPC-115 COMPRESSOR ENGINE	GAS	0.75	LTPD	Sulfur Dioxide (SO2)	LOWERED THROUGHPUT	0.01	LB/H	(J	
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	тх	05/05/2005 ACT	3 AJAX DPC-360LE COMPRESSOR ENGINES		0.75	LTPD	Sulfur Dioxide (SO2)	LOWER THROUGHPUT	0.01	LB/H)	
	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	тх	05/05/2005 ACT	1.8 MMBTU AMINE REBOILER	SWEET NATURAL GAS	1 9	MMBTU	Sulfur Dioxide (SO2)		0.01	LB/H		2	
17-0492	VIRTEX PETROLEUM COMPANY	1.	05/05/2005 &1105p,AC1	1.8 WIWBTO AWINE REBUILER	SWEET NATURAL	1.0		Sulfur Dioxide		0.01	цыл		·	+
X-0492	DOERING RANCH GAS PLANT	тх	05/05/2005 ACT	1.0 MMBTU DEHY REBOILER	GAS	1	MMBtu	(SO2)		0.01	LB/H	()	
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	тх	05/05/2005 ACT	FACILITY FLARE-AMINE UNIT STILL VENT	SWEET NATURAL GAS	0.75	LTPD	Sulfur Dioxide (SO2)		140.5	LB/H	()	
TX-0496	INEOS CHOCOLATE BAYOU FACILITY	тх	08/29/2006 ACT	FURNACE EMISSION CAPS				Sulfur Dioxide (SO2)		61.37	LB/H	(J	
	MCKEE REFINERY HYDROGEN		10/00/0010 0 1 007		Refinery gas (PSA			Sulfur Dioxide	Sulfur content of the fuel used in the furnace is limited to 5 grains/100dscf on					
TX-0580	PRODUCTION UNIT	тх	12/30/2010 ACT	Hydrogen Production Unit Furnace	purge gas) w/NG	355.65	MMBTU/H	(SO2) Sulfur Dioxide	an annual average basis	0		(<u>'</u>	
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	BSI Heater	Refinery Fuel Gas	50	MMBtu/hr	(SO2)	Follow Subpart Ja Fuel gas H2S limits	C		()	<u> </u>
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Emergency Air Compressor	Ultra Low Sulfur Diesel	400	hp	Sulfur Dioxide (SO2)	Ultra Low Sulfur Diesel	C		(J	
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	581 Crude Heater	Refinery Fuel Gas	233	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	O	u l	()	
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	583 Vacuum Heater	Refinery Fuel Gas	64.2	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		()	
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Naphtha Splitter Heater	Refinery Fuel Gas	46.3	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	C		(2	
	SINCLAIR REFINERY	WY	10/15/2012 ACT	Hydrocracker H5 Heater	Refinery Fuel Gas		MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	C			J	
	SINCLAIR REFINERY	WY	10/15/2012 ACT	#1 HDS Heater	Refinery Fuel Gas		MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	C		(2	1

2	50 million B	STU/hr			
	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
5	LB/H	0			
L	LB/H	0			
L	LB/H	0			
L	LB/H	0			
L	LB/H	0			
L	LB/H	0			
5	LB/H	0			
,	LB/H	0			
)		0			
)		0			
)		0			
)		0			
)		0			
)		0			
)		0			
)		0			

			Summa	rv of SO ₂ Contr	ol Determination per EPA's	RACT/BACT/L	AER Database for Natural Gas < :	100 million BTU/hr				
BLCID	FACILITY NAME FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
		PERMIT ISSUANCE DATE		PRIMART FOEL		POLLUTANT	SULFUR CONTENT OF FUEL OIL SHALL NOT		LINIT		CONDITION	POLLUTANT COMPLIANCE NOTES BACT: FUEL SULFUR CONTENT LIMITS
			MISCELLANEOUS IC ENGINES, 940			Sulfur Dioxide	EXCEED					STATE: EMISSION LIMIT 1 AND HYDROGEN SULFIDE
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	нр	DIESEL	940 HP	(SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	500 PPM	0			CONTENT RESTRICTIONS TO THE FUEL.
						Sulfur Dioxide	EXCEED					BACT-OTHER: FUEL SULFUR CONTENT LIMIT
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	CAMP GENERATOR, UNIT 6,7	DIESEL	2362 KW	(SO2)	0.15% BY WEIGHT.	500 PPM	0			18 AAC 50.055: EMISSION LIMIT 1
						Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED					
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	RIG ENGINES, UNIT 211, 212	DIESEL	1215 HP	(SO2)	0.15% BY WEIGHT.	0	0			
							USE ONLY NATURAL GAS FUEL WITH A					
							HYDROGEN					
							SULFIDE CONTENT NOT TO EXCEED 50 PPM AND USE					
							ONLY DISTILLATE FUEL OIL WITH A SULFUR	R				
038	NORTHSTAR DEVELOPMENT PROJECT	02/05/1999 ACT	BALL MILL, UNIT NO. 213		15 T/H	Sulfur Dioxide (SO2)	CONTENT NOT TO EXCEED 0.15%.	500 PPM	0			STATE STANDARD 18 AAC 50 055.
130		02/03/1999 &iibsp,Act	BALL MILL, ONIT NO. 213		15 1/11	(302)	SULFUR CONTENT OF FUEL OIL SHALL NOT		0			BACT: FUEL SULFUR CONTENT LIMIT
		02/05/4000 8	MISCELLANEOUS IC ENGINES, 4240	DIFCEI	1242112	Sulfur Dioxide	EXCEED	500,000	-			STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HP	DIESEL	4240 HP	(SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	500 PPM	0			RESTRICTION TO THE FUEL. BACT: FUEL SULFUR CONTENT LIMIT
						Sulfur Dioxide	EXCEED				CALCULATED	STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HEATERS, 35 0 MMBTU/H	DIESEL	35 MMBTU/H	(SO2)	0.15% BY WEIGHT.	500 PPM	2.71	lb/mmbtu	FROM 500 PPM	RESTRICTION TO THE FUEL.
			MISCELLANEOUS IC ENGINES, 949			Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED					BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HP	DIESEL	949 HP	(SO2)	0.15% BY WEIGHT.	500 PPM	0			RESTRICTION TO THE FUEL.
						Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED				CALCULATED	BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HEATERS, 2.0 MMBTU/H	DIESEL	2 MMBTU/H	(SO2)	0.15% BY WEIGHT.	500 PPM	2.71	lb/mmbtu		RESTRICTION TO THE FUEL.
							SULFUR CONTENT OF FUEL OIL SHALL NOT					
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 1200	DIESEL	1200 HP	Sulfur Dioxide (SO2)	EXCEED 0.15% BY WEIGHT.	500 PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
000		02/03/1999 Qilbsp,Aci		DIEJEE	1200 11	(302)	SULFUR CONTENT OF FUEL OIL SHALL NOT	50011101	0			BACT: FUEL SULFUR CONTENT LIMIT
			MISCELLANEOUS IC ENGINES, 500			Sulfur Dioxide	EXCEED					STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HP	DIESEL	500 HP	(SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	500 PPM	0			RESTRICTION TO THE FUEL. BACT: FUEL SULFUR CONTENT LIMIT
						Sulfur Dioxide	EXCEED				CALCULATED	STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HEATERS, 20 0 MMBTU/H	DIESEL	20 MMBTU/H	(SO2)	0.15% BY WEIGHT.	500 PPM	2.71	lb/MMBTU	FROM 500 PPM	RESTRICTION TO THE FUEL.
							TO ENSURE COMPLIANCE WITH THE EMISSION LIMIT,					
							THE SULFUR CONTENT OF THE FUEL OIL					
020	NORTHSTAR DEVELOPMENT PROJECT	02/05/1999 ACT				Sulfur Dioxide	SHALL NOT EXCEED 0.15% BY WEIGHT.	500 0004	2 71	lb/mmbtu	CALCULATED	
J38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 AC1	MISCELLANEOUS HEATERS	DIESEL	13 MMBTU/H	(SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT	500 PPM	2./1	LB/IVIIVIB I U	FROM 500 PPM	
						Sulfur Dioxide	EXCEED					
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	CRANE, UNIT NO. 100	DIESEL	250 HP	(SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	0	0			NO EMISSION LIMITS PROVIDED.
						Sulfur Dioxide	EXCEED					
)38	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	LIGHT PLANT, UNIT NO. 101	DIESEL	12.1 HP	(SO2)	0.15% BY WEIGHT.	0	0			NO EMISSION LIMITS PROVIDED
						Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED					
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	SNOWBLOWER, UNIT NO. 102, 103	DIESEL	15 HP	(SO2)	0.15% BY WEIGHT	0	0			NO EMISSION LIMITS PROVIDED.
							HYDROGEN SULFIDE CONTENT OF					
038	NORTHSTAR DEVELOPMENT PROJECT	02/05/1999 ACT	SPACE HEATER, WAREHOUSE, UNIT NO. 15, 16	NATURAL GAS	0.5 MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500 PPM	2 55	lb/mmbtu		BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
		, , , , , , , , , , , , , , , , , , ,	,				SULFUR CONTENT OF FUEL OIL SHALL NOT			,		BACT: FUEL SULFUR CONTENT LIMIT
020	NORTHSTAR DEVELOPMENT PROJECT	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 2195	DIESEL	2195 HP	Sulfur Dioxide (SO2)	EXCEED 0.15% BY WEIGHT.	500 PPM	~			STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
020		02/03/1339 &IIDSPACI			2132 11	(302)	SULFUR CONTENT OF FUEL OIL SHALL NOT		0		1	BACT: FUEL SULFUR CONTENT LIMIT
			MISCELLANEOUS IC ENGINES, 961.2			Sulfur Dioxide	EXCEED					STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	MMBTU/H	DIESEL	961.2 MMBTU/H	(SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	500 PPM	0			RESTRICTIONS TO THE FUEL BACT: FUEL SULFUR CONTENT LIMITS
			MISCELLANEOUS IC ENGINES, 3632			Sulfur Dioxide	EXCEED					STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
038	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	HP	DIESEL	3632 HP	(SO2)	0.15% BY WEIGHT.	500 PPM	0			RESTRICTION TO THE FUEL.
						Sulfur Dioxide	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL					COMPLY WITH THE NSPS EMISSION LIMITS BY THE
	NORTHSTAR DEVELOPMENT PROJECT AK	02/05/1999 ACT	TURBINE (GENERATOR), UNIT 3-5	NATURAL GAS	11892 KW	(SO2)	SHALL NOT EXCEED 50 PPMV	150 PPM	0			CONTROL METHOD DESCRIBED

				Summa	ry of SO ₂ Contro	ol Determination	n per EPA's R	ACT/BACT/L	AER Database for Natural Gas < :	100 million Bi	U/hr		T	T	
												STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
LCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION SULFUR CONTENT OF FUEL OIL SHALL NOT	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES BACT: FUEL SULFUR CONTENT LIMIT
		AV	02/05/4000 Bulker ACT		DIFCEI			Sulfur Dioxide	EXCEED	500	2224			CONVERTED	STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
38	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	HEATERS, 4.0 MMBTU/H	DIESEL	4 101	IMBTU/H (S	SO2)	0.15% BY WEIGHT. SULFUR CONTENT OF FUEL OIL SHALL NOT	500	PPM	2.7	1 LB/MMBTU	FROM 500 PPM	1 RESTRICTION TO THE FUEL BACT: FUEL SULFUR CONTENT LIMIT
				MISCELLANEOUS IC ENGINES, 4425			Si	Sulfur Dioxide	EXCEED						STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
38	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HP	DIESEL	4425 HF	P (S	SO2)	0.15% BY WEIGHT.	500	PPM		0		RESTRICTION TO THE FUEL
							Si	Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED						
38	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. IC ENGINES 950 HP	DIESEL	950 HF	P (S	SO2)	0.15% BY WEIGHT.	0			0		
							S	Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED						
38	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. IC ENGINES > 600 HP	DIESEL	650 HF		SO2)	0.15% BY WEIGHT.	0			D		
									HYDROGEN SULFIDE CONTENT OF						BACT: FUEL SULFUR CONTENT LIMIT
20		٨K	02/05/1999 ACT	HEATER (NATURAL CAS) UNIT 210	NATURAL GAS	4.2 M		Sulfur Dioxide	NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	DDM	25	5 LB/MMBTU	CALCULATED	STATE: EMISSION LIMIT 1 AND SULFUR CONTENT
30	NORTHSTAR DEVELOPMENT PROJECT		02/03/1339 &HUSPACT	HEATER (NATURAL GAS), UNIT 210	MATURAL GAS	4.2 11	IMBTU/H (S	SO2)	HYDROGEN SULFIDE CONTENT OF	500	PPM	25		TILOW SUU PPIN	1 RESTRICTION TO FUEL
				SPACE HEATER, WAREHOUSE, UNIT				Sulfur Dioxide	NATURAL GAS FUEL					CALCULATED	BACT: FUEL SULFUR CONTENT LIMITS
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	NO. 17	NATURAL GAS	0.63 MI	IMBTU/H (S	SO2)	SHALL NOT EXCEED 50 PPMV. HYDROGEN SULFIDE CONTENT OF	500	PPM	2 5	5 LB/MMBTU	FROM 500 PPM	1 STATE: EMISSION LIMIT NO. 1
				SPACE HEATER, WAREHOUSE, UNIT			Si	Sulfur Dioxide	NATURAL GAS SHALL					CALCULATED	BACT: FUEL SULFUR CONTENT LIMIT
038	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	NO. 18	NATURAL GAS	1 06 M	IMBTU/H (S	SO2)	NOT EXCEED 50 PPMV.	500	PPM	2 5	5 LB/MMBTU	FROM 500 PPM	1 STATE: EMISSION LIMIT 1
				RIG BOILER (NATURAL GAS), UNIT			S	Sulfur Dioxide	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL					CALCULATED	BACT: FUEL SULFUR CONTENT LIMIT
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	206, 207	NATURAL GAS	6.3 M		SO2)	SHALL NOT EXCEED 50 PPMV	500	PPM	2 5	5 LB/MMBTU		1 STATE: EMISSION LIMIT 1 PLUS FUEL RESTRICTIONS
									SULFUR CONTENT OF FUEL OIL SHALL NOT						
138	NORTHSTAR DEVELOPMENT PROJECT	ΔK	02/05/1999 ACT	RIG BOILER, DIESEL, UNIT 206, 207	DIESEL	6 3 M		Sulfur Dioxide SO2)	EXCEED 0.15% BY WEIGHT.	500	РРМ	27	1 LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT 1 STATE: EMISSION LIMIT 1 AND FUEL RESTRICTION
050		/	62/65/1555 GH550,/101		DIEGEE	0.5		302)	HYDROGEN SULFIDE CONTENT OF	500		2.7			BACT: FUEL SULFUR CONTENT LIMIT
				HEATER (NATURAL GAS), UNIT 208,				Sulfur Dioxide	NATURAL GAS FUEL					CALCULATED	STATE: EMISSION LIMIT 1 AND SULFUR RESTRICTION
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	209	NATURAL GAS	3.5 M	IMBTU/H (S	SO2)	SHALL NOT EXCEED 50 PPMV. SULFUR CONTENT OF FUEL OIL SHALL NOT	500	PPM	2 5	5 LB/MMBTU	FROM 500 PPM	1 TO THE FUEL
							Si	Sulfur Dioxide	EXCEED						
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. TURBINES, 6200 HP	DIESEL	6200 HF	P (S	SO2)	0.15% BY WEIGHT.	0			0		
							S	Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED					CALCULATED	BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT LIMIT
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATER (DIESEL), UNIT 210	DIESEL	4.2 M		SO2)	0.15% BY WEIGHT.	500	PPM	2.7	1 LB/MMBTU	FROM 500 PPM	
									SULFUR CONTENT OF FUEL OIL SHALL NOT						BACT: FUEL SULFUR CONTENT LIMIT
038	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	HEATER (DIESEL), UNIT 208, 209	DIESEL	3.5 M		Sulfur Dioxide SO2)	EXCEED 0.15% BY WEIGHT	500	PPM	2.7	1 LB/MMBTU	CALCULATED FROM 500 PPM	STATE: EMISSION LIMIT 1 AND SULFUR RESTRICTION
									USE DIESEL FUEL OIL WITH SULFUR						
									=<0.15% OR NATURAL GAS WITH HYDROGEN SULFIDE						
								Sulfur Dioxide	CONTENT						
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	INCINERATOR, UNIT 9	NATURAL GAS*	1.6 M	IMBTU/H** (S	SO2)	=<50 PPM HYDROGEN SULFIDE CONTENT OF	0			0		
							Si	Sulfur Dioxide	NATURAL GAS FUEL					CONVERTED	
038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	WASTE HEAT RECOVERY, UNIT 10	NATURAL GAS	52.8 M	IMBTU/H (S	SO2)	SHALL NOT EXCEED 50 PPMV.	500	PPM	2 5	5 LB/MMBTU	FROM 500 PPM	1
							c	Sulfur Dioxide	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL						BACT-OTHER: FUEL SULFUR CONTENT LIMITS.
038	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	HP FLARE, UNIT NO 11	PRODUCED GAS*	0 08 M		SO2)	SHALL NOT EXCEED 50 PPMV.	500	PPM		D		STATE: EMISSION LIMIT 1
						İ			HYDROGEN SULFIDE CONTENT OF						
038	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	LP FLARE (NATURAL GAS), UNIT 12	NATURAL GAS	0.02 M		Sulfur Dioxide SO2)	NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	РРМ		o		BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
23		-	. ,, <u></u> ,			0.02	, (-		HYDROGEN SULFIDE CONTENT OF	550			-	1	
									NATURAL GAS FUEL						
									SHALL NOT EXCEED 50 PPMV AND SULFUR CONTENT OF						
							S	Sulfur Dioxide	FUEL OIL SHALL NOT EXCEED 0.15% BY						BACT- FUEL SULFUR CONTENT LIMIT
)38	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	LP FLARE (PRODUCED GAS), UNIT 12	PRODUCED GAS	0.43 M	IMSCF/D (S	SO2)	WEIGHT.	500	PPM		D		
							S	Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED						ENSURE THE EMISSION LIMIT BY COMPLYING WITH THE FUEL RESTRICTION
038	NORTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	FIRE WATER PUMP, UNIT 8	DIESEL	755 HF		SO2)	0.15% BY WEIGHT	500	РРМ		0		18 AAC 50.055: EMISSION LIMIT 1
									SULFUR CONTENT OF FUEL OIL SHALL NOT						
	NORTHSTAR DEVELOPMENT PROJECT	٨ĸ	02/05/1999 ACT	MISC. IC ENGINES &It 200 HP	DIESEL	170 HF		Sulfur Dioxide SO2)	EXCEED 0.15% BY WEIGHT.	_			n		

1		1	Г	Summa	ry of SO ₂ Contr	ol Determinat	ion per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million BTU/hr	I I			1
						TURQUCURUT	THROUGHPUT	DOLLUTANT		EMISSION LIMIT	EMISSION EM	IISSION	STANDARD LIMIT AVERAGE TIME	
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION ENSURE THE EMISSION LIMIT IS MET BY	1 LIMIT 1 UNIT	LIMIT LIM	1IT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
									USING FUEL					
				PORTABLE HEATER, UNIT NO. 105-				Sulfur Dioxide	OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15% BY			c	CALCULATED	
-0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК		107	DIESEL	1	1 MMBTU/H	(SO2)	WEIGHT.	500 PPM	2.71 LB/MI		ROM 500 PPM	
								Sulfur Dioxide	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL			(CONVERTED	BACT: FUEL SULFUR CONTENT LIMIT.
0038 NOF	RTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	GLYCOL REBOILER, UNIT 13	NATURAL GAS	5	5 ММВТИ/Н	(SO2)	SHALL NOT EXCEED 50 PPMV.	500 PPM	2 55 LB/MI			STATE: EMISSION LIMIT 1
								Cultur Disuida	HYDROGEN SULFIDE CONTENT OF					
0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК		GLYCOL SKID HEATER (NATURAL GAS), UNIT NO. 14	NATURAL GAS	1 05	5 MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500 PPM	2 55 LB/MI		CALCULATED ROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
									SULFUR CONTENT OF FUEL OIL SHALL NOT					
0028 NOE	RTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	WELDER, UNIT NO. 104	DIESEL	20 -	2 HP	Sulfur Dioxide (SO2)	EXCEED 0.15% BY WEIGHT.	0	0			NO EMISSION LIMITS PROVIDED.
0030 1001			02/03/1333 &1030,ACT	WEDEN, ONIT NO. 104	DIEJEE		2 111	(302)	HYDROGEN SULFIDE CONTENT OF	0	0			
			02/05/4000 8					Sulfur Dioxide	NATURAL GAS FUEL	450,000				COMPLY WITH NSPS LIMITS LISTED AS 1 & 2 BY THE
0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	TURBINE (COMPRESSOR), UNIT 1, 2	NATURAL GAS	32715	нР	(SO2)	SHALL NOT EXCEED 50 PPMV. SULFUR CONTENT OF FUEL OIL SHALL NOT	150 PPM	0			CONTROL METHOD LISTED.
				PORTABLE HEATER (BLOWER				Sulfur Dioxide	EXCEED					BACT: FUEL SULFUR CONTENT LIMITS.
-0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	ENGINE), UNIT NO. 105-107	DIESEL	22	2 HP	(SO2)	0.15%. HYDROGEN SULFIDE CONTENT OF	500 PPM	0			STATE: EMISSION LIMIT NO. 1
				RIG ENGINES, CATERPILLAR G399,				Sulfur Dioxide	NATURAL GAS FUEL					
-0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	UNIT 200-204	NATURAL GAS	930	ОНР	(SO2)	SHALL NOT EXCEED 50 PPMV	0	0			
								Sulfur Dioxide	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED	ſ				
0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК	02/05/1999 ACT	COLD START UNIT, UNIT NO. 205	DIESEL	314	4 HP	(SO2)	0.15% BY WEIGHT.	0	0			
									SULFUR CONTENT OF FUEL OIL SHALL NOT	Г				
0038 NOF	RTHSTAR DEVELOPMENT PROJECT	АК		GLYCOL SKID HEATER (DIESEL), UNIT NO. 14	DIESEL	1 05	5 LB/MMBTU	Sulfur Dioxide (SO2)	EXCEED 0.15% BY WEIGHT.	500 PPM	2.71 LB/MI		CALCULATED ROM 500 PPM	BACT: FUEL SULFUR LIMIT STATE: EMISSION LIMIT 1
-0045 NOF	RTH COOK INLET UNIT	АК	06/06/2000 ACT	DRILLING BOILER NO. 1	NATURAL GAS	100	О НР	Sulfur Dioxide (SO2)	SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0.033 LB/MI	MBTU (CALCULATED	BASIS OF DETERMINATION- 18 AAC 50.055(C). THE HOURLY EMISSION LIMIT WAS CONVERTED INTO STANDARDIZED UNITS BY DIVIDING IT BY THE THROUGHPUT.
				CATERPILLAR D-398 ENGINES NO. 1				Sulfur Dioxide	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25%					
0045 NOF	RTH COOK INLET UNIT	AK	06/06/2000 ACT	AND 2	DIESEL	500	0 KW EACH	(SO2)	BY WEIGHT	500 PPM	0			LIMIT SET ACCORDING TO 18 AAC 50.055(C) BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE
<-0045 NOF	RTH COOK INLET UNIT	AK	06/06/2000 ACT	MANITOWOC CRANE ENGINE	DIESEL	17:	5 HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0			OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND LIMITED HOURS OF OPERATION TO 1250 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
<-0045 NOF	RTH COOK INLET UNIT	АК	06/06/2000 ACT	UNIT CRANE ENGINE	DIESEL	9(D HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT, AND LIMITED OPERATION TO 1250 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
	RTH COOK INLET UNIT			FIREWATER ENGINE NOS. 1 AND 2	DIFFE		D HP EACH	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM				BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND TO LIMIT OPERATION TO A COMBINED USE NOT TO EXCEED 300 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.

			1	Sumr	mary of SO ₂ Contr	ol Determination per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million B	ſU/hr	1	[r	
3LCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
														BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF
								USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL						GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25%
045 NOR	TH COOK INLET UNIT	АК	06/06/2000 ACT	HP FLARE PILOT	NATURAL GAS	0.13 MMBTU/H	Sulfur Dioxide (SO2)	WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			0.23% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
045 NOR		AK	06/06/2000 ACT		NATURAL GAS	0.13 MIMBTO/H	(302)		500	PPIVI	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE
														OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND
														0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF
								USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT						EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY
							Sulfur Dioxide	NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY						FLARE, AND TEMPORARY FLARE TO A COMBINED THROUGHPUT NOT TO EXCEED 252
0045 NOR	TH COOK INLET UNIT	АК	06/06/2000 ACT	HP SAFETY FLARE	NATURAL GAS	583.3 MMBTU/H	(SO2)	WEIGHT.	500	PPM	0			MMSCF/12-MO PERIOD.
														BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION
								USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL						REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY FLARE, AND
0045 NOR	TH COOK INLET UNIT	АК	06/06/2000 ACT	LP SAFETY FLARE	NATURAL GAS	53.3 MMBTU/H	Sulfur Dioxide (SO2)	WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			TEMPORARY FLARE, TO A COMBINED THROUGHPUT NOT TO EXCEED 252 MMSCF/12-MO PERIOD.
		703	00/00/2000 and 5, ref			555 (1110-10)	(302)							BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND
														0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF
								USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR						EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY FLARE, AND TEMPORARY FLARE, TO A COMBINED THROUGHPUT NOT TO
							Sulfur Dioxide	CONTENT NOT TO EXCEED 0.25% BY						EXCEED
U45 NOR	TH COOK INLET UNIT	AK	06/06/2000 ACT	TEMPORARY FLARE	NATURAL GAS	833.3 MMBTU/H	(SO2)	WEIGHT.	500	PPM	0			252 MMSCF/12-MO PERIOD. ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC
														50 055(C); 500 PPM OVER A 3 H AV. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE
														AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE- CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT
							Sulfur Dioxide	BURN GASEOUS FUEL WITH A HYDROGEN						NATURAL GAS CONSUMPTION FOR TURBINES NO. 1 AND 2 TO A COMBINED USE NOT TO EXCEED 805 MMSCF/12-MO
0045 NORT	TH COOK INLET UNIT	AK	06/06/2000 ACT	TURBINE COMPRESSOR NO. 2	NATURAL GAS	4700 HP	(SO2)	CONTENT < 200 PPM.	150	PPM	0			PERIOD.

		1		Summa	ry of SO ₂ Contr	ol Determinati	on per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million BTU/hr		[1
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	TIME	POLLUTANT COMPLIANCE NOTES
														BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE HOURLY EMISSION LIMIT WAS CONVERTED INTO STANDARDIZED UNITS BY DIVIDING IT BY THE THROUGHPUT. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	GLYCOL HEATER NOS. 1, 2, AND 3	NATURAL GAS	8 36	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0.033	lb/MMBTU	EACH, CALCULATED	OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR GLYCOL HEATERS NO. 1, 2, AND 3 TO A COMBINED USE NOT TO EXCEED 63 MMSCF/12-MO PERIOD.
														ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM AV OVER 3 H. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN
AK-0045	NORTH COOK INLET UNIT	АК	06/06/2000 ACT	TURBINE COMPRESSOR NO. 4	NATURAL GAS	6749	НР	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150 PPM	0			SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE- CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	АК	06/06/2000 ACT	ENGINE NO. 1	NATURAL GAS	500	ĸw	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0			BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
								Sulfur Dioxide	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY					BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING
K-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	ENGINE NO. 4	NATURAL GAS	500	ĸw	(SO2) Sulfur Dioxide	WEIGHT. BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE	500 PPM	0			EQUIPMENT. ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM OVER A 3 H AV. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE- CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR TURBINES NO. 1 AND 2 TO A COMBINED USE NOT TO EXCEED 805 MMSCF/12-MO
K-0045	NORTH COOK INLET UNIT	АК	06/06/2000 ACT	TURBINE COMPRESSOR NO. 1	NATURAL GAS	4700	НР	(502)	CONTENT < 200 PPM.	150 PPM	0			PERIOD. ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM AV OVER 3 H. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN
K-0045	NORTH COOK INLET UNIT	АК	06/06/2000 ACT	TURBINE COMPRESSOR NO. 3	NATURAL GAS	6749	НР	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150 PPM	n			SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE- CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
	NORTH COOK INLET UNIT	AK			DIESEL		нр	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND TO LIMIT OPERATION TO 350 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.

	-		•	Summa	ry of SO ₂ Contr	ol Determination per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million BTU/hr			•	1
						THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE
								USE NATURAL GAS WITH A HYDROGEN					OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF
								SULFIDE CONTENT					
								NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR					LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR
				GLYCOL REGENERATOR NOS. 1, 2,			Sulfur Dioxide	CONTENT NOT TO EXCEED 0.25% BY					BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW
-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	AND 3	NATURAL GAS	0 28 MMBTU/H EACH	(SO2)	WEIGHT.	500 PPM	0		CALCULATED,	OF EXISTING EQUIPMENT.
				ENGINES (2), PU-0110A AND PU-			Sulfur Dioxide	BURN FUEL OIL WITH NO GREATER THAN 0 30				ASSUMING PPM	
-0047	MILNE POINT PRODUCTION FACILIT	ГҮ АК	07/13/2001 ACT	0110B	DIESEL	187 HP	(SO2)	% SULFUR BY WEIGHT.	500 PPM	2 56	LB/MMBTU	@15% O2	
								BURN FUEL OIL WITH NO GREATER THAN 0 3% SULFUR					
								BY WEIGHT AND NATURAL GAS WITH NO					
							Sulfur Dioxide	GREATER THAN					
<-0047	MILNE POINT PRODUCTION FACILIT	ГҮ АК	07/13/2001 ACT	FLARE	NATURAL GAS	83 MMSCF/D	(SO2)	100 PPMVD H2S.	500 PPM	0	1		
								BURN NATURAL GAS WITH NO GREATER THAN 100 PPM					
								H2S. BURN FUEL OIL WITH NO GREATER					EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE
0047			07/12/2001 8	HEATERS (2), H-5701A AND H-	NATCAS		Sulfur Dioxide		E00 DDM4	2 55		CALCULATED,	ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2
-0047	MILNE POINT PRODUCTION FACILIT	IT AK	07/13/2001 ACT	5701B	NAT GAS	29 MMBTU/H EACH	(502)	% SULFUR BY WEIGHT. USE FUEL OIL WITH NO GREATER THAN	500 PPM	2 55	LB/MMBTU	SEE NOTES	AND THE FUEL IS NATURAL GAS.
								0 3% SULFUR BY					
							Culture Dia 11	WEIGHT AND NATURAL GAS WITH NO				CALC:::	EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE
K-UU7	MILNE POINT PRODUCTION FACILIT		07/13/2001 ACT	HEATERS (2), H-4510A AND H- 4510B	NAT GAS	14.4 MMBTU/H EACH	Sulfur Dioxide	GREATER THAN 100 PPMVD.	500 PPM) ==	LB/MMBTU	CALCULATED, SEE NOTES	ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2 AND THE FUEL IS NATURAL GAS.
(-0047	WIENE FOINT FRODUCTION FACILIT		07/13/2001 &IDSP,ACT	45108	NAT GAS	14.4 1010110/11 EACH	(302)	BURN NATURAL GAS WITH NO GREATER	300 FFIW	2 33		SEE NOTES	AND THE FOLL IS NATORAL GAS.
								THAN 100 PPM					
							Sulfur Dioxide	H2S. BURN FUEL OIL WITH NO GREATER	V (O) @ 15V				NSPS LIMIT IS EITHER 0.015% SO2 @ 15% O2 IN
<-0047	MILNE POINT PRODUCTION FACILIT	ГҮ АК	07/13/2001 ACT	TURBINES (2), PU-0701 AND PU- 0801	NATURAL GAS	29500 HP EACH	(SO2)	THAN 0 30 % SULFUR BY WEIGHT.	% SO2 @ 15% 0 015 O2	0			EXHAUST OR 0.8% SULFUR BY WT IN ANY FUEL. ALSO SUBJECT TO SIP LIMIT OF 500 PPM (3 HR AVER).
			. , .,,, .				()	BURN NATURAL GAS WITH NO GREATER					
								THAN 100 PPM					
				HEATERS (2), H-5302A AND H-			Sulfur Dioxide	H2S. BURN FUEL OIL WITH NO GREATER THAN 0 30				CALCULATED,	EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2
<-0047	MILNE POINT PRODUCTION FACILIT	ГҮ АК	07/13/2001 ACT		NATURAL GAS	35 MMBTU/H EA	(SO2)	% SULFUR BY WEIGHT.	500 PPM	2 55	LB/MMBTU	SEE NOTES	AND THE FUEL IS NATURAL GAS.
								BURN FUEL GAS WITH A HYDROGEN					
								SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE					BACT-PSD IS CONSIDERED COMPLIANCE WITH NSPS
								FUEL OIL WITH					BASIS OF DETERMINATION IN 40 CFR 60.333(A) AND
K 0050		AK	02/21/2000 8-1-			44402 1011	Sulfur Dioxide	A FUEL SULFUR CONTENT NOT TO EXCEED		-			(B). ADDITIONAL EMISSION LIMIT ACCORDING TO 18
K-UU53	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR TURBINE, CF-G-70002	FUEL GAS	11183 KW	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	150 PPM	0			AAC 50.055(C)- 500 PPM OVER 3 H AV.
								SULFIDE					
								CONTENT NOT TO EXCEED 200 PPM AND					
								USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT					
							Sulfur Dioxide	TO EXCEED					
(-0053	KENAI REFINERY	АК	03/21/2000 ACT	CRUDE HEATER, CF-H-31003A	FUEL GAS	65.6 MMBTU/H	(SO2)	0.15%.	0	0)	NOT AVAILABLE	18 AAC 50.055(C) LIMIT IS 500 PPM, 3 H AVER
								USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE					
								CONTENT NOT TO EXCEED 200 PPM AND					
								USE DISTILLATE					
							Sulfur Dioxide	FUEL OIL WITH A SULFUR CONTENT NOT					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, CF-H-31003B	FUEL GAS	65.6 MMBTU/H	(SO2)	TO EXCEED 0.15%.	0	0)	NOT AVAILABLE	18 AAC 50.055(C) LIMIT IS 500 PPM, 3 HR AVER
				,				USE ONLY FUEL GAS WITH A HYDROGEN			1	1	
								SULFIDE					
								CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY					
								DISTILLATE FUEL OIL WITH A SULFUR					
005-			02/24/2000 0 1				Sulfur Dioxide	CONTENT NOT TO		-			
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	HEATER, DR14		3.5 MMBTU/H	(SO2)	EXCEED 0.15% USE ONLY FUEL GAS WITH A HYDROGEN	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								SULFIDE					
								CONTENT NOT TO EXCEED 200 PPM, AND					
								USE ONLY DISTILLATE FUEL OIL WITH A SULFUR					
							Sulfur Dioxide	CONTENT NOT TO					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	MUD PLANT HEATER, DR15		4 MMBTU/H	(SO2)	EXCEED 0.15%	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)

														STANDARD	
							THROUGHPUT			EMISSION LIMI	EMISSION	STANDARD EMISSION	STANDARD EMISSION	LIMIT AVERAGE TIME	
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
									BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO						
									GREATER THAN 200 PPM OR DISTILLATE						
									FUEL OIL WITH						
								Sulfur Dioxide	A FUEL SULFUR CONTENT NOT TO EXCEED						
-0053 KENA	REFINERY	AK	03/21/2000 ACT	INJECTION TURBINE CF-C33012-TB	FUEL GAS	36700) HP	(SO2)	0.15%.	15	D PPM	0			
									BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO						
									GREATER THAN 200 PPM OR DISTILLATE						
									FUEL OIL WITH						BACT PSD IS CONSIDERED COMPLIANCE WITH NSPS
0050	DEFINERY	A.K.	02/24/2000 Babaa ACT			2500		Sulfur Dioxide	A FUEL SULFUR CONTENT NOT TO EXCEED						BASIS OF DETERMINATION IN 40 CFR 60.333 (A) AND
-0053 KENA	REFINERY	AK	03/21/2000 ACT	GENERATOR TURBINE, CF-G-70001	FUEL GAS	25800	JKW	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	15	D PPM	0			(B).
									SULFIDE						
									CONTENT NOT TO EXCEED 200 PPM, AND						
									USE ONLY						
				UTILITY HEATER MEDIUM, CF-H-				Sulfur Dioxide	DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO						BACT-PSD IS CONSIDERED COMPLIANCE WITH NSPS
-0053 KENA	REFINERY	AK	03/21/2000 ACT	-	FUEL GAS	20	ОММВТИ/Н	(SO2)	EXCEED 0.15%		D	0			STANDARD.
									USE ONLY FUEL GAS WITH A HYDROGEN	1	1			1	-
									SULFIDE						
									CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY						
									DISTILLATE FUEL OIL WITH A SULFUR						
				UTILITY HEATER MEDIUM, CF-H-				Sulfur Dioxide	CONTENT NOT TO						
-0053 KENA	REFINERY	AK	03/21/2000 ACT	64005	FUEL GAS	20	D MMBTU/H	(SO2)	EXCEED 0.15%		D	0			
									USE ONLY FUEL GAS WITH A HYDROGEN						
									SULFIDE CONTENT NOT TO EXCEED 200 PPM AND						
									USE DISTILLATE						
									FUEL OIL WITH A SULFUR CONTENT NOT						
								Sulfur Dioxide	TO EXCEED						
-0053 KENA	REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT HEATERS		1:	3 MMBTU/H	(SO2)	0.15% USE ONLY DISTILLATE FUEL OIL WITH A	50	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								Sulfur Dioxide	SULFUR						
-0053 KENA	REFINERY	AK	03/21/2000 ACT	GENERATORS, 10-23		210	хw	(SO2)	CONTENT NOT TO EXCEED 0.20%	50	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
									USE ONLY DISTILLATE FUEL OIL WITH A						
-0053 KENA	DEEINEDV	АК	03/21/2000 ACT	GENERATOR, 2		800	жw	Sulfur Dioxide (SO2)	SULFUR CONTENT NOT TO EXCEED 0.20%.	50	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
-0033 KLINA	KEIINEKI	AK	03/21/2000 &IIDSP,ACT	GENERATOR, 2		800		(302)	USE ONLY DISTILLATE FUEL OIL WITH A	30		0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								Sulfur Dioxide	SULFUR						
-0053 KENA	REFINERY	АК	03/21/2000 ACT	INCINERATOR, 3		750	D LB/H	(SO2)	CONTENT NOT TO EXCEED 0.20%	50	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								Cultur Disuida	USE ONLY DISTILLATE FUEL OIL WITH A						
-0053 KENA	REFINERY	AK	03/21/2000 ACT	GENERATOR, 4		160	жw	Sulfur Dioxide (SO2)	SULFUR CONTENT NOT TO EXCEED 0.20%.	50	D PPM	n			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
			, <u>-,, anop, an</u>			100			USE ONLY FUEL GAS WITH A HYDROGEN	50					
									SULFIDE						
									CONTENT NOT TO EXCEED 200 PPM AND						
									USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT						
								Sulfur Dioxide	TO EXCEED						
-0053 KENA	REFINERY	АК	03/21/2000 ACT	GENERATOR DR1		700	кw	(SO2)	0.15%.	50	ррм	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
									USE ONLY FUEL GAS WITH A HYDROGEN						
									SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND						
									USE ONLY						
									DISTILLATE FUEL OIL WITH A SULFUR						
								Sulfur Dioxide	CONTENT NOT TO						
0053 KENA	REFINERY	AK	03/21/2000 ACT	HP FLARE, CF-X-35002	FUEL GAS	261	1 MMSCF/D	(SO2)	EXCEED 0.15%		0	0			
									USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE						
									CONTENT NOT TO EXCEED 200 PPM, AND						
									USE ONLY						
									DISTILLATE FUEL OIL WITH A SULFUR						
0050		AK	02/21/2000 8					Sulfur Dioxide	CONTENT NOT TO			-			
-0053 KENA	KEFINEKY	AK	03/21/2000 ACT	LP FLARE, CF-X-35012	FUEL GAS	212	2 MMSCF/D	(SO2)	EXCEED 0.15% USE ONLY DISTILLATE FUEL OIL WITH A			0			
								Sulfur Dioxide	SULFUR						
	REFINERY	АК	03/21/2000 ACT	GENERATOR, D1		270	эĸw	(SO2)	CONTENT NOT TO EXCEED 0.15%	50	ррм				BASIS OF DETERMINATION IS 18 AAC 50 055(C)

				Summa	rv of SO ₂ Contr	ol Determination per FPA's	RACT/BACT/I	AER Database for Natural Gas < :	100 million BTU/hr				
				5411114		THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION USE ONLY FUEL GAS WITH A HYDROGEN	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	RIG MOVE ENGINE NO. 1		376 HP	Sulfur Dioxide (SO2)	CONTENT NOT TO EXCEED 0.15%	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
<u></u>							Sulfur Dioxide	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR4		976 KW	(SO2)		500 PPM	0			BASIS OF DETERMINATION IS 18AAC 50.055(C)
١К-0053	KENAI REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT SMALL ENGINES		170 HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
14 0050			02/21/2000 Balance ACT	EMERGENCY GENERATOR, CF-G-			Sulfur Dioxide	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	70003	FUEL OIL	2 MW	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	0	0			
							Sulfur Dioxide	SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, DR5		700 KW	(SO2)	EXCEED 0.15% USE ONLY FUEL GAS WITH A HYDROGEN	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055 (C)
ьк-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, DR6		700 KW	Sulfur Dioxide (SO2)	SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15% USE ONLY DISTILLATE FUEL OIL WITH A	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 1		930 KW	Sulfur Dioxide (SO2)	SULFUR CONTENT NOT TO EXCEED 0.20%.	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
	KENAI REFINERY	АК	03/21/2000 ACT	LISTER BOILER, DR11		100 HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500 PPM				BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	USE ONLY FUEL GAS WITH A H2S CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL		0			
K-0053	KENAI REFINERY	АК	03/21/2000 ACT	LISTER BOILER, DR12		100 HP	(SO2)	WITH A S CONTENT NOT TO EXCEED 0.15%	500 PPM	0		NOT AVAILABLE	BASIS OF DETERMINATION IS 18 AAC 50 055(C)
K-0053	KENAI REFINERY	АК	03/21/2000 ACT	WASTE INCINERATOR, CF-U- 590001B	WASTE	350 LB/H	Sulfur Dioxide (SO2)	REDUCED-SULFUR FUELS	0.42 LB/H	n			
				WELL FRACTIONATION UNIT SMALL			Sulfur Dioxide	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO					
K-0053	KENAI REFINERY	AK	03/21/2000 ACT	ENGINES		650 HP	(SO2)	EXCEED 0.15%	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
	KENAI REFINERY	AK	03/21/2000 ACT	WASTE INCINERATOR, CF-U-59001A	WASTE	350 LB/H	Sulfur Dioxide (SO2)	REDUCED-SULFUR FUEL	0.42 LB/H	~			

				Summa	ry of SO ₂ Control Determina	ition per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million B	TU/hr		1		
						THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT		POLLUTANT		1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM AND						
								USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT						
							Sulfur Dioxide	TO EXCEED						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	CEMENT PUMP, CP2	1	80 KW	(SO2)	0.15% USE ONLY FUEL GAS WITH A HYDROGEN	500) PPM	0			BASIS OF DETERMINATION: 18 AAC 50.055(C)
								SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE						
								FUEL OIL WITH A SULFUR CONTENT NOT						
							Sulfur Dioxide	TO EXCEED						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR2	9	76 KW	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	500) PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE						
								FUEL OIL WITH A SULFUR CONTENT NOT						
					_		Sulfur Dioxide	TO EXCEED						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR3	7	00 KW	(SO2)	0.15%. USE ONLY DISTILLATE FUEL OIL WITH A	500) PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	SULFUR						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 25		30 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%. USE ONLY FUEL GAS WITH A HYDROGEN	500) PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM AND						
								USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT						
							Sulfur Dioxide	TO EXCEED						
AK-0053	KENAI REFINERY	АК	03/21/2000 ACT	ELECTRIC LINE UNIT ENGINE	6	00 HP CUMULATIVE	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	500) PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM, AND						
								USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
							Sulfur Dioxide	CONTENT NOT TO						
AK-0053	KENAI REFINERY	АК	03/21/2000 ACT	SICK LINE UNIT ENGINES	9	15 HP	(SO2)	EXCEED 0.15% USE ONLY DISTILLATE FUEL OIL WITH A	500) PPM	0			BASED ON 18 AAC 50 055(C)
							Sulfur Dioxide	SULFUR						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 24		75 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%.	500) PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 5	1	60 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%.	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
AK-0053	KENAI REFINERY	АК	03/21/2000 ACT	GENERATOR, 7		25 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%.	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE						
								CONTENT NOT TO EXCEED 200 PPM, AND						
								USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
							Sulfur Dioxide	CONTENT NOT TO						
AK-0053	KENAI REFINERY	АК	03/21/2000 ACT	HEATER, DR13	4	I.2 MMBTU/H	(SO2)	EXCEED 0.15%	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 8		30 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%.	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
							Sulfur Dioxide	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR						
AK-0053	KENAI REFINERY	АК	03/21/2000 ACT	GENERATOR, 9	1	20 KW	(SO2)	CONTENT NOT TO EXCEED 0.20%.	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								USE ONLY FUEL GAS WITH A HYDROGEN						
								SULFIDE CONTENT NOT TO EXCEED 200 PPM AND						
								USE DISTILLATE						
							Sulfur Dioxide	FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED						
1	KENAI REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT LARGE ENGINES	9	50 HP	(SO2)	0.15%	500	D PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)

				6										
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	Summa PROCESS NAME	PRIMARY FUEL		THROUGHPUT	POLLUTANT	AER Database for Natural Gas < : <u> control METHOD DESCRIPTION</u> USE ONLY DISTILLATE FUEL OIL WITH A		STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
								Sulfur Dioxide	SULFUR					
(-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, N2		370	5 HP	(SO2)	CONTENT NOT TO EXCEED 0.20% USE ONLY DISTILLATE FUEL OIL WITH A	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
								Sulfur Dioxide	SULFUR					
0053	KENAI REFINERY	АК	03/21/2000 ACT	GENERATOR, D2		379	9 KW	(SO2)	CONTENT NOT TO EXCEED 0.20% USE ONLY DISTILLATE FUEL OIL WITH A	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(B)(1)
								Sulfur Dioxide	SULFUR					
053	KENAI REFINERY	АК	03/21/2000 ACT	GENERATOR, N1		376	5 HP	(SO2)	CONTENT NOT TO EXCEED 0.20% USE ONLY FUEL GAS WITH A HYDROGEN	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
									SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR					
053	KENAI REFINERY	AK	03/21/2000 ACT	HEATER, MP1		1.3	3 ММВТU/Н	Sulfur Dioxide (SO2)	CONTENT NOT TO EXCEED 0.15%	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
				EMERGENCY GENERATOR, CF-G-				Sulfur Dioxide	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED					
)053	KENAI REFINERY	АК	03/21/2000 ACT	70004	FUEL OIL	:	2 MW	(SO2)	0.15%. USE ONLY FUEL GAS WITH A HYDROGEN	0	0			
·0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, BP1		300	D KW	Sulfur Dioxide (SO2) Sulfur Dioxide	SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%. USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
0053	KENAI REFINERY	АК	03/21/2000 ACT	GENERATOR, BP2		160	хw	(SO2)	EXCEED 0.15%	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
0053	KENAI REFINERY	АК	03/21/2000 ACT	RIG MOVE ENGINE NO. 2		10	5 HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15% USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR	500 PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
0053	KENAI REFINERY	AK	03/21/2000 ACT	RIG MOVE ENGINE NO. 3		10'	БНР	Sulfur Dioxide (SO2)	CONTENT NOT TO EXCEED 0.15%	500 PPM	n			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
	KENAI REFINERY	AK	03/21/2000 ACT	CEMENT PUMP, CP1) kw	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15% USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND	500 PPM	0			BASIS OF DETERMINATION IS: 18 AAC 50.055(C)
0053	KENAI REFINERY	AK	03/21/2000 ACT	WELL FRACTIONATION UNIT LARGE		65() нр	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500 PPM	n			BASIS IS 18 AAC 50.055(C)

				Summa	ry of SO ₂ Conti	rol Determinat	tion per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million B	TU/hr				
							THROUGHPUT					STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
				WELL FRACTIONATION UNIT				Sulfur Dioxide	BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE FUEL OIL WITH A FUEL SULFUR CONTENT NOT TO EXCEED						BASIS OF DETERMINATION IS 40CFR 60.333(A) AND (B). ADDITIONAL EMISSION LIMIT BASED ON 18 AAC
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	TURBINES		620	0 НР	(SO2)	0.15%.		PPM	C)		50 055(C)- 500 PPM OVER 3 H AV.
				NATCO MISCIBLE INJECTION				Sulfur Dioxide	LIMIT SULFUR CONTENT OF FUEL						
AK-0062	BADAMI DEVELOPMENT FACILITY	АК	08/19/2005 ACT	HEATER	NATURAL GAS	14 8	7 MMBTU/H	(SO2) Sulfur Diovido		250) PPMV	0)		* LIMIT SULFUR CONTENT OF FUEL COMBUSTED
AK-0062	BADAMI DEVELOPMENT FACILITY	АК	08/19/2005 ACT	NATCO TEG REBOILER	NATURAL GAS	1 3	4 MMBTU/H	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250) PPMV	1 28	LB/MMBTU		LIMIT SULFUR CONTENT OF FUEL COMBUSTED SEE NOTES; LIMIT SULFUR CONTENT OF FUEL COMBUSTED
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	SOLAR MARS 90 TURBINE	NATURAL GAS	11 8	6 MW	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250) PPMV	c		*SEE NOTES	* S02 IS NOT REQUIRED FOR STANDARD UNITS OF PROCESS CODE 16.110
															SEE NOTES: LIMIT SULFUR CONTENT OF FUEL COMBUSTED NOTE. FOR APPENDIX E PROCESS CODE 17,110 THE FOLLOWING POLUTANTS; (SO2, PM, AND VOC) - DO NOT REQUIRE STANDARD NUMERIC LIMITS OR EMISSION UNITS.
AK-0062	BADAMI DEVELOPMENT FACILITY	АК	08/19/2005 ACT	CUMMINS IC ENGINE GENERATOR	DIESEL FUEL	185	5 HP	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	0.15	5 % BY WT	c		AVAILABLE SEE	* NOTE. FOR APPENDIX E PROCESS CODE 17,110 THE FOLLOWING POLUTANTS; (SO2, PM, AND VOC) - DO NOT REQUIRE STANDARD NUMERIC LIMITS OR EMISSION UNITS. LIMIT SULFUR CONTENT IN FUEL COMBUSTED
	BADAMI DEVELOPMENT FACILITY	АК	08/19/2005 ACT	NATCO PRODUCTION HEATER TURBINE, COMBINED CYCLE	NATURAL GAS		4 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	LIMIT SULFUR CONTENT IN FUEL COMBUSTED						* EMISSION UNITS AND NUMERIC LIMITS ARE REQUIRED FOR SO2 USING APPENDIX E. PROCESS CODE 13.110
AL-0168	GENPOWER KELLEY LLC	AL	01/12/2001 ACT	ELECTRIC GENERATING UNITS	NATURAL GAS	17	3 MW	(SO2) Sulfur Dioxide		0.002	2 LB/MMBTU		,		
AL-0168	GENPOWER KELLEY LLC	AL	01/12/2001 ACT	BOILER	NATURAL GAS	8	3 MMBTU/H	(SO2)		0 001	1 LB/MMBTU	0.001	LB/MMBTU		
AI-0169	BLOUNT MEGAWATT FACILITY	AI	02/05/2001 ACT	COMBUSTION TURBINES	NATURAL GAS	16	1 MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.006	5 LB/MMBTU	0			
		A1						Sulfur Dioxide				0.006	LB/MMBTU		
AL-0169	BLOUNT MEGAWATT FACILITY	AL	02/05/2001 ACT	AUXILIARY BOILER 2 GE 7FA GAS FIRED COMB. CYCLE	NATURAL GAS	4	0 MMBTU/H	(SO2) Sulfur Dioxide	GOOD COMBUSTION PRACTICES	0.006	5 LB/MMBTU	0.006			
AL-0180	DUKE ENERGY DALE, LLC	AL	12/11/2001 ACT	W/568 MMBTU DUCT B	NATURAL GAS	17	0 MW EACH	(SO2)	NATURAL GAS AS EXCLUSIVE FUEL.	0.0057	7 LB/MMBTU	C)		
AL-0180	DUKE ENERGY DALE, LLC	AL	12/11/2001 ACT	35 MMBTU/HR NAT. GAS FIRED AUXILIARY BOILER	NATURAL GAS	3	5 MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0057	7 LB/MMBTU	0)		
			10/00/0001.0	31.4 MMBTU/HR NATURAL GAS				Sulfur Dioxide		0.005					
AL-0181	DUKE ENERGY AUTAUGA, LLC	AL	10/23/2001 ACT	FIRED BOILER	NATURAL GAS	31.	4 MMBTU/H	(SO2) Sulfur Dioxide	NATURAL GAS IS EXCLUSIVE FUEL.	0.0057	7 LB/MMBTU				
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	FURNACE, HOT OIL, 20 MMBTU/H	NATURAL GAS	2	0 ММВТU/Н	(SO2) Sulfur Dioxide	GOOD COMBUSTION PRACTICES	0.01	1 LB/H	0.0005	LB/MMBTU		
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	FURNACE, HOT OIL, 10 MMBTU/H	NATURAL GAS	1	0 MMBTU/H	(SO2)	GOOD COMBUSTION PRACTICES	0.01	1 LB/H	0.001	LB/MMBTU		
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	PHOSGENE PRODUCTION UNIT, SCRUBBERS	NATURAL GAS	46	3 MMLB/YR	Sulfur Dioxide (SO2)	SCRUBBERS 1 & 2	1.12	2 LB/H	0)		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	Z-HIGH MILL WITH MIST ELIMINATOR (LO42) (MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	c			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	NATURAL GAS	196.	4 MMBTU/H	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	c			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBERS & amp; COMMON SCR (L072) (MULTIPLE EMISSION POINTS)	NATURAL GAS	2060	0 T/YR	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	C			THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBER & COMMON SCR (L072).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC		08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (LO52) (MULTIPLE EMISSION POINTS)		6	0 т/н	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU				THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO53).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (MULTIPLE EMISSION POINTS)		6	0 т/н	Sulfur Dioxide (SO2)		0.0006	6 LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE.

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL TH	IROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
RECED		FACILITY STATE	PERMIT ISSUANCE DATE	NATURAL GAS-FIRED BATCH		ROUGHFUT	UNIT	FOLLOTANT		1		LIIVIII		CONDITION	POLIDITANI COMPLIANCE NOTES
1 0220	THYSSENKRUPP STEEL AND STAINLESS	A1	08/17/2007 & phone ACT	ANNEALING FURNACES (LA63,		22.4	MANARTILooch	Sulfur Dioxide		0.0006	5 LB/MMBTU	0			
L-0230	USA, LLC THYSSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	LA64) NATURAL GAS-FIRED PASSIVE	NATURAL GAS	55.4	1 MMBTU each	(SO2) Sulfur Dioxide		0.0008		0			
L-0230	USA, LLC	AL	08/17/2007 ACT	ANNEALING FURNACE (LO41)	NATURAL GAS	27.2	2 ММВТU/Н	(SO2)		0.0006	5 LB/MMBTU	0			
	THYSSENKRUPP STEEL AND STAINLESS			4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION				Sulfur Dioxide							THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING
L-0230	USA, LLC	AL	08/17/2007 ACT	POINTS) 4 CONTINUOUS HOT DIP				(SO2)		0.0006	5 LB/MMBTU	0			WITH PRE & POST DRYERS.
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
1 0220	THYSSENKRUPP STEEL AND STAINLESS	A1	08/17/2007 Sehere ACT	MELTSHOP - LO (MULTIPLE		100	т/ц	Sulfur Dioxide		0.45	цр/т	_			THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO2).
L-0230	USA, LLC THYSSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	EMISSION POINTS) MELTSHOP - LO (MULTIPLE		126	5 T/H	(SO2) Sulfur Dioxide		0.15	5 LB/T	0			THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE (LO2).
L-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)		126	5 т/н	(SO2)		0.15	5 LB/T	0			VENTED TO BAGHOUSE (LO1).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & amp; ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	5 т/н	Sulfur Dioxide (SO2)		0.15	5 LB/T	о			THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BACHOUSE 3 (LA1).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	5 т/н	Sulfur Dioxide (SO2)		0.15	5 LB/T	0			THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIONS VENTED TO COMMON BAGHOUSE.
	THYSSENKRUPP STEEL AND STAINLESS			NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE
L-0230	USA, LLC	AL	08/17/2007 ACT	EMISSION POINTS)	NATURAL GAS	169	9 ММВТU/Н	(SO2)		0.0006	5 LB/MMBTU	0			(LA 21).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169) MMBTU/H	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS) BAL STEAM SWEEP WITH MIST	NATURAL GAS	169	9 MMBTU/H	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	ELIMINATOR (LA66) (MULTIPLE EMISSION POINTS)		12.6	5 Т/Н	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA70).
L-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & amp; EGR (537-539)	NATURAL GAS	64.9	MMBTU each	Sulfur Dioxide (SO2)		0.0006	5 LB/MMBTU	0			
	THYSSENKRUPP STEEL AND STAINLESS			HOT STRIP MILL (MULTIPLE				Sulfur Dioxide							THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED
L-0230	USA, LLC THYSSENKRUPP STEEL AND STAINLESS	AL	08/17/2007 ACT	EMISSION POINTS) HCL ACID REGENERATION	NATURAL GAS	690	рт/н	(SO2) Sulfur Dioxide		0.006	5 LB/MMBTU	0			WALKING BEAM REHEAT FURNACES. THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS
L-0230	USA, LLC	AL	08/17/2007 ACT	(MULTIPLE EMISSION POINTS)	NATURAL GAS	3.77	7 Т/Н	(SO2)		0.0006	5 LB/MMBTU	0			WITH CAUSTIC SCRUBBER (5-10).
1 0220	THYSSENKRUPP STEEL AND STAINLESS	A1	08/17/2007 8 share 6 CT	NATURAL GAS-FIRED BATCH	NATURAL GAS	00	ЭММВТИ/Н	Sulfur Dioxide		0.0000		0			
	USA, LLC	AL	08/17/2007 ACT	ANNEALING FURNACE (535) TWO (2) ELECTRIC ARC FURNACES AND THREE (3) LADLE METALLURGY FURNACES WITH TWO (2)				(SO2) Sulfur Dioxide				0			
L-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	MELTSHOP BAGHOUSES	ELECTRICITY	440	рт/н	(SO2) Sulfur Dioxide		0.62	2 LB/T	0			
L-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	VACUUM DEGASSER BOILER	NATURAL GAS	95	5 ММВТИ/Н	(SO2)		0.0006	5 LB/MMBTU	0			
L-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	GALVANIZING LINE FURNACE	NATURAL GAS	98.7	7 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		0.0006	5 LB/MMBTU	0			
L-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	VACUUM DEGASSER		440	т/н	(SO2)		0 005	5 LB/T	0			
R-0040	DUKE ENERGY HOT SPRINGS	AR	12/29/2000 ACT	BOILERS, AUXILIARY 2	NATURAL GAS	44.1	l MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS NATURAL GAS. FUEL SULFUR CONTENT IS		2 GR/DSCF	0.006	lb/MMBTU		
R-0040	DUKE ENERGY HOT SPRINGS	AR	12/29/2000 ACT	TURBINE, DUCT BURNER, (4), GE 7FA CT/HRSG	NATURAL GAS	580) ММВТU/Н	Sulfur Dioxide (SO2)	0 05% BY WEIGHT	0 006	5 LB/MMBTU	0.006	lb/mmbtu		
				TURBINES, COMBINED CYCLE,				Sulfur Dioxide							
		AR	04/01/2002 ACT	NATURAL GAS, (2)	NATURAL GAS			(SO2) Sulfur Dioxide)	0			fuel limit: < 2 gr S/100 dscf
K-UU51	DUKE ENERGY-JACKSON FACILITY	АК	04/01/2002 ACT	BOILER, AUXILIARY	NATURAL GAS	33	3 MMBTU/H	(SO2) Sulfur Dioxide	FUELS LIMIT: < 2 GR/100 DSCF			0			no emission rate limit, fuels limit.
R-0051	DUKE ENERGY-JACKSON FACILITY	AR	04/01/2002 ACT	GENERATOR, DIESEL-FIRED	DIESEL FUEL	671	LHP	(SO2)	FUELS LIMIT: 0 05% S BY WT	(0	0			no emission rate limit, limit is fuels limit.

		-	1	Summa	ry of SU ₂ Contro	Di Determinati	on per EPA's	KACI/BACT/L	AER Database for Natural Gas < :	100 million B	iU/nr	Γ	1
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND EMISS LIMIT (
				BRINE REDUCTION AREA SN-PBCDF-				Sulfur Dioxide					
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	07 BOILER, HOT WATER, (2) SN-PBCDF-	NATURAL GAS	0 01	MMDSCF/H	(SO2) Sulfur Dioxide	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.008	LB/MMB
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	05, -06	NATURAL GAS	0 01	MMDSCF/H	(SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0085	LB/MMB
				INCINERATOR COMMON STACK SN-				Sulfur Dioxide	QUENCH TOWER WITH CAUSTIC SCRUBBING LIQUID FOLLOWED BY VENTURI SCRUBBER (COMBINED EFFICIENCY 50%), FOLLOWED BY A PACKED-BED SCRUBBER (95% EFFICIENCY). OVERALL SYSTEM IS EXPECTED TO				
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	PBCDF-01 BOILER, PROCESS STEAM, (2) SN-	AGENT	40	ROCKETS/H	(SO2) Sulfur Dioxide	REMOVE 97.5% OF SO2.	17.2	LB/H	C	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	PBCDF-03, -04	NATURAL GAS	0 03	MMDSCF/H	(SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0035	LB/MMB
								Sulfur Dioxide					
	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16			mmbtu/h	(SO2) Sulfur Dioxide	LOW-SULFUR NATURAL GAS ONLY. LOW SULFUR DIESEL: LESS THAN OR EQUAL TO 0.05 WT % S. ALSO: LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN- PBCDF-10 AND LESS THAN 500 HOURS/YR		LB/H	0.071	LB/MMB
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	GENERATOR (2) IC ENGINE, EMERGENCY	DIESEL FUEL	2500	кW	(SO2) Sulfur Dioxide	FOR SN-PBCDF-12. LOW SULFUR DIESEL; <= 0.05 WT % S.	0.6	i lb/H	C	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	GENERATOR SN-PBCDF-12	DIESEL FUEL	250	кw	(SO2)	ALSO OPERATING LIMIT: < 500 H/YR.	0.4	LB/H	C	
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	GALVANIZING LINE	NATURAL GAS	9	ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	C)
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	BOILERS	NATURAL GAS	22	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMB
/			077227200 Failespirior	SOLELING				Sulfur Dioxide	NATURAL GAS COMBUSTION ONLY IN	0.0000	20,1111010	0.0000	20,1110
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	DEGASSER HOTWELL FLARE	NATURAL GAS			(SO2)	FLARE	0.09	LB/H	C)
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	TUNNEL FURNACE	NATURAL GAS	160	ММВТИ/Н	Sulfur Dioxide (SO2) Sulfur Dioxide	NATURAL GAS COMBUSTION ONLY LOW SULFUR COKE AND SCRAP	0.0006	LB/MMBTU	0.0006	LB/MMB
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	ELECTRIC ARC FURNACE (EAF)	NATURAL GAS	350	t/h	(SO2) Sulfur Dioxide	MANAGEMENT	0.2	LB/T	C	
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	LADLE METALLURGY FURNACE		350	т/н	(SO2)		0.08	LB/T	C	
AB 0077		AD	07/22/2004 & phone ACT	FURNACES, HEATERS, & amp;	NATURAL GAS	11		Sulfur Dioxide		0.0006		0.0006	
AR-0077	BLUEWATER PROJECT NUCOR-YAMATO STEEL COMPANY,	AR	07/22/2004 ACT	DRYERS	NATURAL GAS	11	MMBTU/H	(SO2) Sulfur Dioxide	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMB
AR-0086	BLYTHEVILLE MILL	AR	06/11/2004 ACT	EAF #1 BAGHOUSE, SN-01	NATURAL GAS	450	T/H STEEL	(SO2)	LOW SULFUR COKE USAGE	90	LB/H	0.2	LB/T STEE
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	AR	06/11/2004 ACT	LMF #1 BAGHOUSE, SN-35		250	T/YR STEEL	Sulfur Dioxide (SO2)	LOW SULFUR COKE USAGE	90	LB/H	0 36	LB/T STEE
	NUCOR-YAMATO STEEL COMPANY,							Sulfur Dioxide	GOOD COMBUSTION PRACTICE, NATURAL		4.		
AR-0086	BLYTHEVILLE MILL	AR	06/11/2004 ACT	VTD BOILER	NATURAL GAS	50	MMBTU/H	(SO2) Sulfur Dioxide	GAS COMBUSTION	0.1	LB/H	0.0006	LB/MMB
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	LADLE DRYER	NATURAL GAS			(SO2)		0.0006	LB/MMBTU	C)
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	EAF'S LMF'S	NATURAL GAS	585	TONS STEEL	Sulfur Dioxide (SO2)		176.8	LB/H	0.2	LB/T STEE
	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	NATURAL GAS		MMBTU EACH	Sulfur Dioxide			LB/H		
								Sulfur Dioxide					
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	ANNEALING FURNACES SN-61	NATURAL GAS	4.8	lb/MMBTU	(SO2) Sulfur Dioxide		0.1	LB/H	0.0006	LB/MMB
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	GALVANIZING LINE, SN-54	NATURAL GAS			(SO2)		0.1	LB/H	0.0006	LB/MMB
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	MISCELLANEOUS NATURAL GAS FIRED BURNERS AND DRYERS				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	C	
	WELLTON MOHAWK GENERATING			COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F				Sulfur Dioxide					
AZ-0047	STATION WELLTON MOHAWK GENERATING	AZ	12/01/2004 ACT	TURBINES OPTION	NATURAL GAS	180	MW	(SO2) Sulfur Dioxide		0.0023	LB/MMBTU	C	
AZ-0047	STATION	AZ	12/01/2004 ACT	AUXILIARY BOILER COMBUSTION TURBINE	NATURAL GAS	38	ММВТИ/Н	(SO2)		0.0023	LB/MMBTU	0.0023	LB/MMB
	WELLTON MOHAWK GENERATING STATION	AZ	12/01/2004 ACT	GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	NATURAL GAS		MW	Sulfur Dioxide (SO2)			LB/MMBTU		

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
.B/MMBTU	CALCULATED	
.B/MMBTU	CALCULATED	
		THE MOST STRINGENT CONTROL WAS SELECTED: A PACKED BED SCRUBBER, IN CONJUNCTION WITH A QUENCH TOWER AND VENTURI SCRUBBER.
.B/MMBTU	CALCULATED	
.B/MMBTU	CALCULATED	
.B/MMBTU		
.B/MMBTU		ADDITIONAL LIMIT: .1 LB/H
.B/MMBTU		
.B/T STEEL		
.B/T STEEL		
.B/MMBTU		
.B/T STEEL		
.B/MMBTU		
.B/MMBTU		
.B/MMBTU		
.B/MMBTU		

												STANDARD	STANDARD	STANDARD LIMIT AVERAGE	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	EMISSION LIMIT	EMISSION LIMIT UNIT	TIME CONDITION	
				SIEMENS WESTINGHOUSE											
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS GE COMBUSTION TURBINES AND	NATURAL GAS	1080	MW	Sulfur Dioxide (SO2)		0.0021	lb/MMBTU	0			
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1040	MW	Sulfur Dioxide (SO2)		0.0021	lb/mmbtu	0			
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	NATURAL GAS	41	MMBTU/H	Sulfur Dioxide (SO2)		0.0025	LB/MMBTU	0.0025	lb/mmbtu		
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	AUXILIARY BOILER FOR SIEMENS TURBINES	NATURAL GAS	55 34	MMBTU/H	Sulfur Dioxide (SO2)		0.0025	LB/MMBTU	0.0025	lb/mmbtu		
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2	GS/100 SCF GAS	0			SULFUR FL COMBUST REPRESEN
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	NATURAL GAS	99.8	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS	FUEL OIL			Sulfur Dioxide (SO2)		0.0015	% S FUEL OIL	0			
															Basis for si ?FM? mea
FL-0335	SUWANNEE MILL	FL	09/05/2012 ACT	Four(4) Natural Gas Boilers - 46 MMBtu/hour	Natural Gas	46	MMBTU/H	Sulfur Dioxide (SO2)	Good Combustion Practice		GR OF S/100 SCF	0			of the nati scf) or less
				Two(2) Biomass-Fuel Boilers - 120				Sulfur Dioxide	Sulfur dioxide (SO2) will be minimized by						The SO2 lin boilers me NSPS Subp with Rule Less than 2
FL-0335	SUWANNEE MILL	FL	09/05/2012 ACT	MMBtu/hr each	wood products	120	MMBTU/H	(SO2) Sulfur Dioxide	the use of low sulfur fuels.	0.0336	LB/MMBTU	0			only low s
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	IC ENGINE, EMERGENCY FIRE PUMP	#2 FUEL OIL	2 59	MMBTU/H	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	0.51	LB/MMBTU	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	GENERATOR (6)	#2 FUEL OIL	25	MMBTU/H	(SO2)	LOW SULFUR FUEL. LOW SULFUR NG. < 0.8 GR/100 SCF OR <	0.51	lb/mmbtu	0			
IA-0062	EMERY GENERATING STATION	١۵	12/20/2002 ACT	TURBINE, SIMPLE CYCLE, (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	0 05% S BY WT FUEL OIL.	0.0022	lb/MMBTU	0			
17 0002			12/20/2002 (1105);/(01			170		Sulfur Dioxide	LOW SULFUR FUEL, NG. NATURAL GAS <	0.0022	EDJIMINETO				
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	TURBINE, COMBINED CYCLE (2)	NATURAL GAS	170	MW	(SO2) Sulfur Dioxide	GR/100SCF; FUEL OIL < 0.05% S BY WT	0.0022	lb/mmbtu	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	GAS HEATER, (2)	NATURAL GAS	16.4	MMBTU/H	(SO2)	LOW SULFUR FUEL, NG	0.0006	lb/MMBTU	0.0006	lb/mmbtu		
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	AUXILIARY BOILER	NATURAL GAS	68	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NG	0.0006	LB/MMBTU	0.0006	lb/MMBTU		
IA-0068	EMERY GENERATING STATION	IA	06/26/2003 ACT	GAS HEATER	NATURAL GAS	9	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NATURAL GAS	0.0006	lb/mmbtu	0.0006	lb/MMBTU		
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	DDGS COOLER		140	T/H OF DRY FEED			10	PPMVD	0			SO2 OCCU LADEN WI
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	INDIRECT-FIRED DDGS DRYER	NATURAL GAS	93.7	MMBTU/H	Sulfur Dioxide (SO2)		6	PPMVD	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	GERM DRYERS AND COOLERS		15	т/н	Sulfur Dioxide (SO2)	WET SCRUBBER	10	PPMVD	0			SO2 OCCU LADEN WI
	ADM CORN PROCESSING - CEDAR							Sulfur Dioxide	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE						
IA-0088	RAPIDS	IA	06/29/2007 ACT	FIRE PUMP	DIESEL #2	540	HP	(SO2)	NSPS REQUIREMENT. LIMITED THE HYDROGEN SULFIDE CONCENTRATION OF THE BOIGAS	0.17	G/B-HP-H	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	WASTEWATER TREATMENT PLANT (WWTP) ANAEROBIC DIGESTER		1500	SCFM OF BIOGAS	Sulfur Dioxide (SO2)	PRODUCED TO 200 PPMV (24-HOUR ROLLING AVERAGE).	0 023	LB/MMBTU	0			
															SO2 OCCU LADEN WI FERMENT/ NCG SCRU DISTILLATI ACROSS B(CONCENTI
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	١۵	06/29/2007 ACT	FERMENTATION, DISTILLATION AND DEHYDRATION		840000	CAL/11	Sulfur Dioxide (SO2)	CO2 SCRUBBER AND DISTILLATION NCG SCRUBBER		% REDUCTION				IS AFTER T

ſU/hr				
EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LB/MMBTU	0			
lb/MMBTU	0			
lb/MMBTU	0.0025	lb/MMBTU		
LB/MMBTU	0.0025	lb/MMBTU		SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT
GS/100 SCF GAS	0			COMBUSTION DESIGN AND OPERATION OF EACH GAS TURBINE REPRESENTS (BACT) FOR PM/PM10 EMISSIONS.
GS/100 SCF GAS	0			
GS/100 SCF GAS	0			
% S FUEL OIL	0			
GR OF S/100 SCF	0			Basis for standard is Reasonable Assurance. ?FM? means fuel monitoring to demonstrate that the sulfur content of the natural gas is 2 grains per hundred standard cubic foot (gr/100 scf) or less. Vendor certification can be used in lieu of FM
lb/MMBTU	0			The SO2 limit in terms of ?lb/MMBtu? will ensure that the biomass boilers meet the SO2 emission limit exemption in §60.42b(k)(2) of NSPS Subpart Db. A ?state? BACT is required for SO2 in accordance with Rule 62-296.406(3), F A.C for Fossil Fuel Steam Generators with Less than 250 MMBtu/hr Heat Input. This requirement is met by firing only low sulfur biomass fuels in the boilers.
LB/MMBTU	0			
lb/mmbtu	0.0006	lb/mmbtu		
lb/MMBTU	0.0006	lb/mmbtu		
lb/MMBTU	0.0006	lb/MMBTU		
PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
PPMVD	0			
PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
G/B-HP-H	0			
LB/MMBTU	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2. THE CO2 SCRUBBER CONTROLS THE FERMENTATION TANKS, YEAST PROPAGATORS AND BEERWELLS. THE NCG SCRUBBER CONTROLS THE NITROGEN STRIPPER AND DISTILLATION COLUMN. THE PERCENT REDUCTION LIMIT APPLIES ACROSS BOTH OF THE SCRUBBER INDIVIDUALLY. THE CONCENTRATION LIMIT APPLIES TO THE OUTLET OF THE RTO, WHICH IS AFTER THE SCRUBBERS. THE LIMITS ARE WRITTEN AS 90 % REDUCTION OR 10 PPMV.

									AER Database for Natural Gas <				
RBLCID		FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EM LIM
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	NATURAL GAS BOILER (292.5 MMBTU/H)	NATURAL GAS	292.5	5 ММВТU/Н	Sulfur Dioxide (SO2)	NATURAL GAS FUEL ONLY	0.0006	LB/MMBTU	0	
	ADM CORN PROCESSING - CEDAR							Sulfur Dioxide	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE				
IA-0088	RAPIDS	IA	06/29/2007 ACT	EMERGENCY GENERATOR	DIESEL	1500) KW	(SO2)	NSPS REQUIREMENT.	0.17	G/B-HP-H	0	
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	ALCOHOL RAIL LOADOUT		12000) GAL/MIN	Sulfur Dioxide (SO2)	FUEL FIRED IN THE FLARE IS LIMITED TO NATURAL GAS AND BIOGAS LOW SULFUR NATURAL GAS ONLY (LESS	0.0025	lb/mmbtu	0	
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	AUXILARY BOILER, NATURAL GAS (2)	NATURAL GAS	35	5 MMBTU/H	Sulfur Dioxide (SO2)	THAN 0 8% BY WEIGHT). LB/H LIMIT IS FOR EACH BOILER.	0.0006	lb/MMBTU	0.0006	LB/M
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	TURBINE, NATURAL GAS, SIMPLE CYCLE, FOUR	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION. LOW SULFUR NATURAL GAS (LESS THAN 0.8% BY WEIGHT). LB/H LIMIT IS FOR EACH CT.	0.0028	LB/MMBTU	0	
			05/05/2001 & 1059,AC1	TURBINE, NATURAL GAS,		170		Sulfur Dioxide	LOW SULFUR NATURAL GAS ONLY (LESS THAN 0 8% BY WEIGHT). EMISSION LIMIT IS	0.0020			
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	COMBINED CYCLE	NATURAL GAS	170	MW	(SO2)	FOR EACH CT. GOOD COMBUSTION. NATURAL GAS	4.2	LB/H	0	
IN-0087	DUKE ENERGY, VIGO LLC	IN	06/06/2001 ACT	TURBINE, NATURAL GAS, COMBINED CYCLE (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	ONLY. UNFIRED EMISSIONS = 11.35 LB/H. LB/H LIMIT IS FOR EACH CT.	0.0057	lb/mmbtu	0	
IN-0087	DUKE ENERGY, VIGO LLC	IN	06/06/2001 ACT	AUXILARY BOILER, NATURAL GAS (2)	NATURAL GAS	46	5 ММВТU/Н	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL. LIMIT IS FOR EACH BOILER.	0.0006	LB/MMBTU	0.0006	LB/M
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	BATCH ANNEALING FURNACE, 18	NATURAL GAS		3 MMBTU/H EACH	Sulfur Dioxide	PERMIT LIMITATION IS USAGE OF NATURAL GAS OR PROPANE ONLY	0		0	
					NATORAL GAS				PERMIT LIMITATION IS USE OF NATURAL			0	
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	TUNDISH PREHEATERS (2)		6	5 MMBTU/H	Sulfur Oxides (SOx) Sulfur Dioxide	GAS.	0		0	
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	STRIP CASTER LINE		135	5 T/H	(SO2)		0.185	LB/T	0	
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	LADLE PREHEATERS	NATURAL GAS	15	MMBTU/HR 5 EACH	Sulfur Dioxide (SO2)	PERMIT LIMITATION IS NATURAL GAS OR PROPANE USAGE	0		0	
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	AUXILLIARY BOILER	NATURAL GAS	21	l MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT NATURAL GAS	0.0006	lb/mmbtu	0.0006	LB/MI
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	TWO SIMPLE CYCLE COMBUSTION TURBINES GELM6000 2 CMBND CYCLE COMBUST.	NATURAL GAS	469	9 ММВТU/Н	Sulfur Dioxide (SO2) Sulfur Dioxide	USE OF LOW SULFUR NATURAL GAS USE OF LOW SULFUR NATURAL GAS AS	0.0035	lb/MMBTU	0.7	PPM@ (EST.) PPM (
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	TURBINE WESTINGHOUSE 501F	NATURAL GAS	2071	L MMBTU/H (HHV)		SOLE FUEL	0.0034	LB/MMBTU		(EST.)
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	EAF, AOD VESSELS, DESULFURIZATION, & OTHER PROCESS	NATURAL GAS	502	2 Т/Н	Sulfur Dioxide (SO2)	SCRAP MANAGEMENT PLAN. COMPLIANCE METHOD: SO2 CEM.	0.25	LB/T	0	
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	LADLE METALLURGY FURNACES (2)		502	2 Т/Н	Sulfur Dioxide (SO2)		0.185	LB/T	0	
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	NATURAL GAS	34	1 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	COMPLIANCE BY USING NATURAL GAS	0.0006	lb/mmbtu	0.0006	LB/MI
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	TURBINES, COMBINED CYCLE, (3)	NATURAL GAS	1944.1	L ММВТU/Н	(SO2)	GOOD COMBUSTION PRACTICE	0 006	LB/MMBTU	0	
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	TURBINES, COMBINED CYCLE, & DUCT BURNERS, (3)	NATURAL GAS	1944.1	L ММВТU/Н		GOOD COMBUSTION PRACTICE	0 006	LB/MMBTU	0	
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	BOILER, AUXILIARY, NATURAL GAS	NATURAL GAS	35	5 ММВТИ/Н	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0 006	lb/mmbtu	0.006	LB/MI
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES TWO (2) NATURAL GAS AUXILIARY	NATURAL GAS	2300	ММВТИ/Н	Sulfur Dioxide (SO2) Sulfur Dioxide	FUEL SPECIFICATION	0.75	GR S/100 SCF FUEL	0	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	BOILERS	NATURAL GAS	80) MMBTU/H	(SO2)	FUEL SPECIFICATIONS	0.0022	LB/MMBTU	0	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) FIREWATER PUMP DIESEL ENGINES	DIESEL	371	L BHP, EACH	Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0.0015	% SUFLUR DIESEL FUEL	0	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	5 HP EACH	Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0 012	LB/H	0	
		1	,,					Sulfur Dioxide	ULTRA LOW SULFUR DISTILLATE AND				

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
		TON PER YEAR LIMIT IS THE SUM OF EMISSIONS FROM BOTH ALCOHOL LOADOUT FLARES AND CORRESPONDS TO A PLANTWIDE LOADOUT LIMIT OF 752,325,000 GALLONS OF ETHANOL PER 12- MONTH ROLLING PERIOD.
lb/mmbtu		
lb/MMBTU		
lb/mmbtu		
PPM@ 15% O2 (EST.)		
PPM @15% O2 (EST.)		
		These SO2 limits cover emissions from the EAFs, AOD, desulfurization and continuous casters in the meltshop area. The limits supersede limits in PSD permit 107-5236, issued 11/30/93 and PSD permit 107-5235, issued on 6/30/96 Compliance testing. Sulfur content of the charge
		compliance testing. Sufficient of the charge carbon and injection carbon added to the LMFs is monitored.
lb/mmbtu		
lb/mmbtu		
		LIMIT ONE AND TWO ARE FOR EACH BOILER
		LIMIT ONE AND TWO ARE FOR EACH FIREWATER PUMP ENGINE. LIMIT THREE: EACH FIRE PUMP SHALL NOT EXCEED 500 HOURS OF OPERATION PER YEAR.
		LIMIT ONE AND TWO ARE FOR EACH GENERATOR
		LIMIT ONE AND TWO ARE FOR EACH GENERATOR

				Summa	rv of SO ₂ Contr	ol Determinat	ion per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million BTU/hr				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1 LIMIT 1 UNIT	EMISSION EMI	NDARD LIN	TANDARD MIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
KY-0087	QUEBECOR WORLD FRANKLIN	ĸy	07/12/2002 ACT	BOILER, NATURAL GAS, #4	NATURAL GAS	33 1	5 ММВТU/Н	Sulfur Dioxide (SO2)	CLEAN FUEL: FUEL OIL LIMITED TO < 0.5% S BY WT	1 057 LB/MMBTU	1.057 LB/MN	ABTU		
				BLEACH PLANT NO. 2				Sulfur, Total						
LA-0174	PORT HUDSON OPERATIONS		01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD			3 T/D	Reduced (TRS) Sulfur Dioxide		0.12 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	EXHAUST 2 TOWEL MACHINE NO. 6 YANKEE	NATURAL GAS	300	5 T/D	(SO2) Sulfur Dioxide	NATURAL GAS AS FUEL	0.04 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	AIRCAP EXHAUST		30	5 T/D	(SO2)	NATURAL GAS AS FUEL	0.02 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 8:	l MM lb/d	Sulfur Dioxide (SO2)		105.91 LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV @ 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 8:	L MM LB/D	Sulfur, Total Reduced (TRS)	UPGRADE BLOX SYSTEM	4.53 LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
۱۵-0174	PORT HUDSON OPERATIONS		01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 1	NATURAL GAS	300	5 T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.07 LB/H	0			
								Sulfur Dioxide			-			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 90	5 MM LB/D	(SO2) Sulfur, Total		143.23 LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV AT 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 90	5 MM LB/D	Reduced (TRS) Sulfur, Total	UPGRADE BLOX SYSTEM	6.13 LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 1		1024	ŧ т/D	Reduced (TRS)		0.19 LB/H	0			
								Sulfur, Total						ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	2 MM LB BLS/D	Reduced (TRS) Sulfur Dioxide		0.84 LB/H	0.032 LB/T BI	LS CAL	LCULATED	FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	2 MM LB BLS/D	(SO2)	WET SCRUBBER	9.22 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 2	5 MM LB BLS/D	Sulfur Dioxide (SO2)	WET SCRUBBERS	6.24 LB/H	0			
10.0174	PORT HUDSON OPERATIONS		01/25/2002 ACT	SMELT TANK NO. 2		2.21	5 MM LB BLS/D	Sulfur, Total Reduced (TRS)	WET SCRUBBER	0.63 LB/H	0.032 LB/T BI		LCULATED	ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
								Sulfur Dioxide	WET SCRUBBERS AND OPTIMAL MUD		0.032 LB/ 1 BI		LCOLATED	STANDARDIZED ENIISSIONS. 0.010 G/KG BLSTIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340) T/D	(SO2) Sulfur, Total	WASHING	3.26 LB/H	0 PPMV	@ 10%		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340	DT/D	Reduced (TRS) Sulfur Dioxide	WET SCRUBBERS AND OPTIMAL MUD	3.5 LB/H	8 O2			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270	DT/D	(SO2)	WASHING	2.59 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		27(DT/D	Sulfur, Total Reduced (TRS)		2.81 LB/H	8 O2	@ 10%		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	98	7 ММВТИ/Н	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS	5126 LB/H	5.19 LB/MN	/IBTU		
10-0174	PORT HUDSON OPERATIONS		01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	08.	7 ММВТИ/Н	Sulfur, Total Reduced (TRS)		0.48 LB/H	0			
								Sulfur, Total						
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 3		623	3 T/D	Reduced (TRS) Sulfur Dioxide		0.11 LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 2	NAT GAS	65.5	5 MMBTU/H	(SO2)	FIRING NATURAL GAS ADD-ON: WET SCRUBBER.	0.26 LB/H	0.004 LB/MN	/IBTU		
14 0174			01/25/2002 8 about 6CT	COMPINIATION POLICE NO. 1	WOOD WASTE /	450		Sulfur Dioxide	P2: FUEL CAN BE EITHER WOOD WASTE OR NATURAL	, , , , , , , , , , , , , , , , , , ,	0.73 LB/MM			
	PORT HUDSON OPERATIONS		01/25/2002 ACT	COMBINATION BOILER NO. 1	NAT GAS WOOD WASTE /		5 MMBTU/H	(SO2) Sulfur, Total	GAS.	37.37 LB/H	U.73 LB/IVIV			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	NAT GAS	459.5	5 MMBTU/H	Reduced (TRS) Sulfur Dioxide	USE OF LOW SULFUR NATURAL GAS, 1.8	0.46 LB/H	0			
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	GAS TURBINES - 187 MW (2)		2000	5 ММВТИ/Н	(SO2)	GRAINS PER 100 SCF	10.1 LB/H	0			
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	FUEL GAS HEATERS (3)		19) MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR PIPELINE NATURAL GAS AND GOOD COMBUSTION PRACTICES	5 0 008 LB/H	0.0004 LB/MIV	ADTU AVE	NUAL ERAGE	*TPY LIMIT FOR ALL 3 HEATERS. AGGREGATE HEAT INPUT IS LIMITED TO 14,250 MM BTU/YR. ONLY 2 OF THE 3 HEATERS ARE ALLOWED TO OPERATE AT ANY GIVEN TIME.
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DIESEL FIRED WATER PUMP				Sulfur Dioxide (SO2)	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.61 LB/H	0.65 G/B-HF		NUAL ERAGE	OPERATING TIME = 52 HR/YR
							1	Sulfur Dioxide	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS				NUAL	
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DUCT BURNERS (2)		759	9 MMBTU/H	(SO2)	PER 100 SCF	3.8 LB/H	0.005 LB/MN		ERAGE	
LA-0203	OAKDALE OSB PLANT	LA	06/13/2005 ACT	ROTARY DRYER NOS. 1-3	WOOD	30000	MSF/YR 3/8 inch basi	Sulfur Dioxide (SO2)		4.18 LB/H	0			
	OAKDALE OSB PLANT		06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	NATURAL GAS		5 MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES		0.001 LB/MN		LCULATED BY	
								Sulfur Dioxide	FUELED BY NATURAL GAS OR SUBSTITUTE		0.001 LB/ WIW			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	(LA	06/22/2009 ACT	SHIFT REACTOR STARTUP HEATER GASIFIER STARTUP PREHEATER	NATURAL GAS	34.2	2 MMBTU/H	(SO2) Sulfur Dioxide	NATURAL GAS (SNG) FUELED BY NATURAL GAS OR SUBSTITUTE	0.02 LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	/ LA	06/22/2009 ACT	BURNERS (5)	NATURAL GAS	3!	5 ММВТU/Н	(SO2)	NATURAL GAS (SNG)	0.02 LB/H	0			

				Summa	$ry \text{ of } SO_2 \text{ Contr}$	of Determinati	ion per EPA s	RACI/BACI/L	AER Database for Natural Gas < :				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND. EMISS
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	ACID GAS FLARE	NATURAL GAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	0.01	LB/H	C)
LA-0231	LAKE CHARLES GASIFICATION FACILITY		06/22/2009 ACT	FIRE WATER DIESEL PUMPS (3)	DIESEL		HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII		LB/H	C)
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	HYDROCARBON/GASIFIERS STARTUP FLARE	NATURAL GAS	487 55	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	1303.99	LB/H	C)
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	METHANATION STARTUP HEATERS	NATURAL GAS	56.9	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.03	LB/H	C	D
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	AUXILIARY BOILER	NATURAL GAS	938.3	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.28	LB/H	C)
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	THERMAL OXIDIZERS (2)	NATURAL GAS	40.9	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	22.92	LB/H	C	þ
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	DIESEL	1341	HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	C)
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	WET SULFURIC ACID PLANTS (2)		2000	T/D	Sulfur Dioxide (SO2)	HYDROGEN PEROXIDE SCRUBBERS	13.8	LB/H	C	D
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010 ACT	EQT0323 - Boiler 401F	refinery fuel	99	MMBTU/H	Sulfur Dioxide (SO2)	Natural gas or Refinery Fuel Gas with H2S <=100 ppv (annual average)	2.54	LB/H	C	þ
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010 ACT	MVR Thermal Oxidizers (EQT0350 and EQT0351)		240	MMBTU/H	Sulfur Dioxide (SO2)	Natural gas, Refinery Fuel Gas, or process fuel gas with H2S <=100 ppv (annual average)	15.1	LB/H	C)
	CABOT POWER CORPORATION	МА	05/07/2000 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS		MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL - NATURAL GAS WITH 8 GRAINS SULFUR PER 100 SCF.		LB/H	C)
MA-0027	CABOT POWER CORPORATION	MA	05/07/2000 ACT	AUXILIARY BOILER	NATURAL GAS	26.6	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL OF < .8 GRAINS PER 100 SCF.	0.06	LB/H	0.0022	LB/MMB
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	ма	09/29/1999 EST	IC ENGINE, EMERGENCY DIESEL GENERATOR	DIESEL	1500	ĸw	Sulfur Dioxide (SO2)	SULFUR CONTENT THAT DOES NOT EXCEED .05% BY WEIGHT, LIMITED TO CONSUMPTION OF 8 250 GALLONS BASED ON 75 HOURS OF OPERATION PER 12 MONTH ROLLING PERIOD.		LB/H	0.17	7 G/ВНР-Н
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	ма	09/29/1999 EST	BOILER, AUXILIARY	NATURAL GAS	96	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL WITH NO MORE THAN .8 GRAINS OF SULFUR PER 100 CU FT.		LB/H		B LB/MMB
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	MA	09/29/1999 EST	TURBINE, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	2699	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT IN FUEL - NO MORE THAN 8 GRAINS PER 100 CU FT.		LB/H) PPM @ 1
MD-0040	CPV ST CHARLES	MD	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	DIESEL	300	НР	Sulfur Dioxide (SO2)		o		c)
MD-0040	CPV ST CHARLES	MD	11/12/2008 ACT	HEATER	NATURAL GAS	1.7	ИМВТИ/Н	Sulfur Dioxide (SO2)		0		C	D
								Sulfur Dioxide	SIDE WELL EMISSIONS PASS THROUGH LIME-INJECTED				
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	SIDE-WELLS	NATURAL GAS	42000	LB/H	(SO2) Sulfur Dioxide	BAGHOUSES. NO CONTROL CLAIMED, %.	0.52	LB/H	C	LB/MMB
MI-0301	ALCHEM ALUMINUM	мі	05/02/2000 ACT	CRUSHER	NA	20000	LB/H	(SO2) Sulfur Dioxide	N/A	1.47	LB/H	c	LB/MMB
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	CRUCIBLE HEATERS/STATIONS	NATURAL GAS	2	MMBTU/H EACH		N/A COMBUSTION FLUES ARE WITHOUT ADD-	0.01	lb/H	C)
MI-0301	ALCHEM ALUMINUM	мі	05/02/2000 ACT	FLUES	NATURAL GAS	42000	LB/H	Sulfur Dioxide (SO2)	ON CONTROLS. ONLY PIPELINE QUALITY NATURAL GAS FOR FUEL.	0.12	LB/H	C) LB/MMB
	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	IC ENGINE, SMALL, FUEL OIL (1)	DIESEL	250		Sulfur Dioxide (SO2)	LOW SULFUR FUEL.		lb/mmbtu		
	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	NATURAL GAS		MMBTU/H	Sulfur Dioxide	LOW SULFUR FUEL.		GR/SCF))
	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	#2 DISTILLATE OIL		MMBTU/H	Sulfur Dioxide	LOW SULFUR FUEL.		lb/mmbtu	C)
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	BOILER, NATURAL GAS (1)	NATURAL GAS		MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL 0.8 GR/SCF, CALENDAR YEAR AVERAGE			C	þ
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	BOILER, DISTILLATE OIL (1)	#2 FUEL OIL	40	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	lb/mmbtu	0.051	
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT		DIESEL	670	НР	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	lb/MMBTU	C)
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, LARGE	DIESEL FUEL	1850	НР	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.59	G/B-HP-H	c	
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, SMALL	DIESEL FUEL	290	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.14	G/B-HP-H	c	þ

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
.B/MMBTU		
G/BHP-H		
.B/MMBTU		
PPM @ 15% O2		listed standardized limit is nsps limit.
<u> </u>		EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL WITH A SULFUR
		CONTENT NOT TO EXCEED 15 PARTS PER MILLION BY WEIGHT EXCLUSIVE USE OF NATURAL GAS WITH SULFUR CONTENT NOT TO
		EXCLUSIVE USE OF NATURAL GAS WITH SULFUR CONTENT NOT TO EXCEED 2.0 GR/100 SCF
.B/MMBTU		
.B/MMBTU		
	NOT AVAILABLE	
.B/MMBTU		
		EMISSION LIMIT 1 IS EQUAL TO 0 05% S BY WEIGHT.
		BACT is fuel sulfur limit.
.B/MMBTU		EMISSION LIMIT 1 EQUALS TO 0 05% S BY WEIGHT.
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									AER Database for Natural Gas <				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND EMISS LIMIT
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE 2 EACH	NATURAL GAS	1827	ИМВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFLUR FUEL	0.05 %	S BY WT		2
MN-0054		MN	12/04/2003 ACT	DUCT BURNER, 2 EACH	NATURAL GAS		ммвти/н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL		R/100SCF	(5
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE, 2 EACH	NATURAL GAS	1916	ммвти/н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8 G	R/100SCF	0	D
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	BOILER, COMMERCIAL	NATURAL GAS	70	ММВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 001 LI	B/MMBTU	0.001	1 LB/MME
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	LADLE PREHEATER	NATURAL GAS	48	ММВТИ/Н	Sulfur Dioxide (SO2)		346.59 LI	B/T		0
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNI REHEAT FURNACE	NATURAL GAS	133	MMBTU/H	Sulfur Dioxide (SO2)		0.0006 LI	B/MMBTU	(D
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII REHEAT FURNACE	NATURAL GAS	143	ММВТИ/Н	Sulfur Dioxide (SO2) Sulfur Dioxide		0.0006 LI	B/MMBTU		D
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII BILET POST-HEATER	NATURAL GAS	6.8	ММВТИ/Н	(SO2) Sulfur Dioxide		0.0006 LI	B/MMBTU	0	0
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	CUT-OFF TORCHES	NATURAL GAS			(SO2)		2.25 LI	B/T	(D
NJ-0036	AES RED OAK LLC	IJ	10/24/2001 ACT	AUXILIARY BOILER- DISTILLATE OIL	DISTILLATE FUEL OIL	99	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR OIL (NO PERCENTAGES GIVEN)	5 021 LI	в/н	0.0507	7 LB/MMB
NJ-0036	AES RED OAK LLC	ци	10/24/2001 ACT	FUEL GAS HEATER	NATURAL GAS	16	ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 069 LI	в/н	0.0043	3 LB/MMB
NJ-0036	AES RED OAK LLC	L	10/24/2001 ACT	AUXILIARY BOILER	NATURAL GAS	120	ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 514 LI	B/H	0.0043	3 LB/MME
NJ-0036	AES RED OAK LLC	L	10/24/2001 ACT	EMERGENCY GENERATOR	DIESEL FUEL	49	ММВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.45 LI	в/н	C	0
NJ-0042	ROCHE VITAMINS	LN	02/05/1999 ACT	BOILER 4 (NAT GAS)	NATURAL GAS	118	ММВТИ/Н	Sulfur Dioxide (SO2)	NONE LISTED	0.1 LI	в/н	0.0008	8 LB/MMB
NJ-0042	ROCHE VITAMINS	ы	02/05/1999 ACT	BOILER 1 (NO. 2 OIL)	NATURAL GAS	84.4	ММВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL- 0.05% BY WEIGHT	4.3 LI	в/н	0.051	1 LB/MME
NJ-0042	ROCHE VITAMINS	ы	02/05/1999 ACT	BOILER 2 (NAT GAS)	NATURAL GAS	134	ММВТИ/Н	Sulfur Dioxide (SO2)	NONE LISTED	0.1 LI	B/H	0.0007	7 LB/MMB
NJ-0042	ROCHE VITAMINS	IJ	02/05/1999 ACT	BOILER 3 (NAT GAS)	NATURAL GAS	152	ММВТИ/Н	Sulfur Dioxide (SO2)	NONE LISTED LIMITED OPERATING HOURS FOR NO. 2	0.1 LI	B/H	0.0007	7 LB/MME
NJ-0042	ROCHE VITAMINS	LΝ	02/05/1999 ACT	BOILER 3 (NO. 2 OIL)	NAT GAS	241 6	ммвти/н	Sulfur Dioxide (SO2)	OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	12.4 LI	в/н	0.0513	3 LB/MME
	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NO. 2 OIL)	NAT GAS		MMBTU/H	Sulfur Dioxide	LIMITED OPERATING HOURS FOR NO. 2 OIL, FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	11.9 Li			5 LB/MME
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NO. 2 OIL)	NAT GAS	204.2	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	10.5 LI	B/H	0.0514	4 LB/MME
NJ-0042	ROCHE VITAMINS	ци	02/05/1999 ACT	BOILER 1 (NATURAL GAS)	NATURAL GAS	84.4	ММВТИ/Н	Sulfur Dioxide (SO2)	NONE LISTED	0.1 LI	в/н	0.001	1 LB/MME
				BOILER 1 (LASALOCID OIL & amp;				Sulfur Dioxide	LIMITED OPERATING HOURS FOR NO. 2 OIL; NO. 2 OIL LIMITED TO 0.05% SULFUR BY				
NJ-0042	ROCHE VITAMINS CONSOLIDATE EDISON DEVELOPMENT	NJ	02/05/1999 ACT	NO. 2 OIL COMBINED)	NATURAL GAS	35.5	MMBTU/H	(SO2) Sulfur Dioxide	WEIGHT.	2.8 LI	B/H	0.079	9 lb/mmb
NJ-0062	(CED)	IJ	10/22/2002 ACT	FUEL GAS HEATERS (3 UNITS) Commercial/Institutional size	NATURAL GAS	4.62	ММВТU/Н	(SO2) Sulfur Dioxide	LOW SULFUR FUEL.	0 014 LI	В/Н	(0
NJ-0079	WOODBRIDGE ENERGY CENTER	ци	07/25/2012 ACT	boilers less than 100 MMBtu/hr Combined Cycle Combustion	natural gas	2000	hours/year	(SO2) Sulfur Dioxide	Use of natural gas Good Combustion Practices and use of	0.162 LI	в/н	(0
NJ-0079	WOODBRIDGE ENERGY CENTER	LN	07/25/2012 ACT	Turbine with Duct Burner Combined Cycle Combustion	Natural gas	40297.6	mmcubic ft/year	(SO2) Sulfur Dioxide	Natural gas,a clean burning fuel. Use of only natural gas a clean burning	4.9 LI	В/Н	(D
NJ-0079	WOODBRIDGE ENERGY CENTER	IJ	07/25/2012 ACT	Turbine w/o duct burner Combined cylce turbine with duct	natural gas	40297.6	mmcubic ft/year mmcubic	(SO2) Sulfur Dioxide	fuel	4.1 LI	В/Н	(0
NJ-0080	HESS NEWARK ENERGY CENTER	LN	11/01/2012 ACT	burner	natural gas	39463	ft/year*	(SO2) Sulfur Dioxide	Use of natural gas, a clean low sulfur fuel use of natural gas a clean fuel and a low	2.5 LI	в/н	(D
NJ-0080	HESS NEWARK ENERGY CENTER	LΝ	11/01/2012 ACT	Boiler less than 100 MMBtu/hr Combined Cycle Combustion	Natural Gas	51.9	mmcubic ft/year	(SO2) Sulfur Dioxide	sulfur fuel	0.08 LI	в/н	(D
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/01/2012 ACT	Turbine AUXILIARY BOILERS (AUX-1 AND	natural gas	39463	MMCubic ft/yr	(SO2) Sulfur Dioxide	Use of natural gas a clean low sulfur fuel NATURAL GAS, GOOD COMBUSTION	2.8 LI	B/H	(0
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	AUXILIARY BOILERS (AUX-1 AND AUX-2)	NATURAL GAS	33	ММВТИ/Н	(SO2)	PRACTICE PIPELINE QUALITY NATURAL GAS, GOOD	0.1 LI	в/н	0.003	3 LB/MMB
				TURBINES, COMBINED CYCLE,				Sulfur Dioxide	ENGINEERING				

STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME CONDITION	
LIMIT UNIT		
		LIMIT IS FOR SULFUR CONENT OF NG
lb/MMBTU		
LB/MMBTU		
LB/MMBTU		
LB/MMBTU		
lb/MMBTU		
lb/mmbtu		
		Stack testing for SO2 not required due to extremely low emissions
		· · · · · · · · · · · · · · · · · · ·
lb/mmbtu	calculated	

					1				AER Database for Natural Gas < :					
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STAND EMISS LIM	SION EMISSION	STANDARD LIMIT AVERAGE TIME CONDITION	E POLLUTANT COMPLIANCE NOTES
NDECID		TACLETT STATE	TERMIT ISSUARCE DATE	TROCESS NAME	TRIMART FOLL	interest of		TOLLOTAN	PIPELINE QUALITY NATURAL GAS, GOOD				contribution	
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT		NATURAL GAS	643	3 ММВТИ/Н	Sulfur Dioxide (SO2)	COMBUSTION PRACTICE.	1.5 LB/H		0.002 LB/MMBTU	calculated	
				LARGE COMBUSTION TURBINES, COMBINED CYCLE & amp;				Sulfur Dioxide	USE OF CLEAN-BURNING, LOW-SULFUR,					
NV-0037	COPPER MOUNTAIN POWER	NV	05/14/2004 ACT		NATURAL GAS	600	мw	(SO2)	PIPELINE-QUALITY NATURAL GAS	5.1 LB/H		0		EMISSION LIMIT 1 IS FOR EACH TURBINE/DUCT BURNER PAIR.
NV-0037	COPPER MOUNTAIN POWER	NV	05/14/2004 ACT	AUXILIARY BOILER	NATURAL GAS	60	О ММВТИ/Н	Sulfur Dioxide (SO2)	USE OF LOW-SULFUR NATURAL GAS	0.04 LB/H		0		
NV-0039	CHUCK LENZIE GENERATING STATION	NV	06/01/2001 ACT	LARGE COMBUSTION TURBINE - COMBINED CYCLE	NATURAL GAS	1170	лw	Sulfur Dioxide (SO2)	USE OF PIPE-LINE QUALITY NATURAL GAS	4.78 LB/H		0		EMISSION LIMIT 1 APPLIES TO EACH COMBUSTION TURBINE GENERATOR WITH DUCT-FIRING.
11/-0030	CHUCK LENZIE GENERATING STATION	NIV	06/01/2001 ACT	AUXILIARY BOILERS	NATURAL GAS	14	1 MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE-QUALITY NATURAL GAS	0.4 LB/H		0.009 LB/MMBTU		EMISSION LIMIT 1 APPLIES TO EACH AUXILIARY BOILER.
10-0035	GOODSPRINGS COMPRESSOR		00/01/2001 &105p,AC1	LARGE COMBUSTION TURBINE -	NATORAL GAS	44		Sulfur Dioxide	LOW-SULFUR NATURAL GAS IS THE ONLY	0.4 LB/11		0.009 28/10101810		EMISSION EINIT I AFFEIES TO EACH ADVIEIANT BOILEN.
VV-0046		NV	05/16/2006 ACT		NATURAL GAS	97 8:	1 MMBTU/H	(SO2)	FUEL FOR THE PROCESS.	0.0034 LB/MMBTU	(0.0034 LB/MMBTU	15% OXYGEN	THE EMISSION LIMITS APPLY TO EACH OF THE THREE TURBINES.
VV-0046	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	NATURAL GAS	3 8	5 ММВТИ/Н	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0026 LB/MMBTU		0.0026 LB/MMBTU		
				BOILERS/HEATERS - NATURAL GAS-				Sulfur Dioxide						
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	FIRED BOILERS/HEATERS - DIESEL OIL-	NATURAL GAS			(SO2) Sulfur Dioxide	USE OF PIPELINE-QUALITY NATURAL GAS LIMITING SULFUR CONTENT IN THE DIESEL	0.0015 LB/MMBTU	(0.0015 LB/MMBTU		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	FIRED	DIESEL OIL			(SO2)	OIL TO 0.05% BY WEIGHT	0.0094 LB/MMBTU		0.0094 LB/MMBTU		
					12.0			Sulfur Dioxide	SULFUR CONTENT IN THE LIQUID FUEL (JP-	LB/1000 LB				
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	AIRCRAFT ENGINE TESTING LARGE INTERNAL COMBUSTION	JP-8	11490) LB/H	(SO2) Sulfur Dioxide	8) IS LIMITED TO 0.05%. LIMITING SULFUR CONTENT IN THE DIESEL	0.5 FUEL		0		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	ENGINES (>500 HP)	DIESEL OIL			(SO2)	OIL TO 0.05%	0.02 G/B-HP-H		0		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	SMALL INTERNAL COMBUSTION ENGINES (<= 500 HP)	DIESEL OIL			Sulfur Dioxide (SO2)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%	0.99 G/B-НР-Н		0 99 G/B-HP-H		
		ND (02/26/2000 8 share ACT					Sulfur Dioxide				0.00 0 /0 1/0 1/		
	NELLIS AIR FORCE BASE NELLIS AIR FORCE BASE	NV NV	02/26/2008 ACT 02/26/2008 ACT	AIRCRAFT ARRESTORS MEDICAL WASTE INCINERATOR	GASOLINE NATURAL GAS			(SO2) Sulfur Oxides (SOx)	USE OF LOW-SULFUR GASOLINE USE OF NATURAL GAS AS THE FUEL	0.28 G/B-HP-H 0.05 LB/H		0 28 G/B-HP-H 0		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	ASPHALT CONCRETE MANUFACTURING	N/A			Sulfur Dioxide (SO2)	GOOD OPERATING PRACTICE	1.38 LB/H		0		
10-0047			02/20/2000 &103p,AC1		11/1			(502)		1.50 [[6]11		0		
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.	5 MW	Sulfur Dioxide (SO2)	USING LOW-SULFUR NATURAL GAS ONLY	0.0034 LB/MMBTU	(0.0034 LB/MMBTU		THE EMISSION LIMITS APPLY TO EACH TURBINE.
	GOODSPRINGS COMPRESSOR	ND /		COMMERCIAL/INSTITUTIONAL-SIZE		2.01		Sulfur Dioxide	LOW-SULFUR NATURAL GAS IS THE ONLY					THE EMISSION LIMITS ARE BASED ON THE EMISSION FACTOR LISTED
10-0048	STATION GOODSPRINGS COMPRESSOR	NV	05/16/2006 ACT	BOILER (&It100 MMBTU/H) LARGE INTERNAL COMBUSTION	NATURAL GAS	3 8	5 MMBTU/H	(SO2) Sulfur Dioxide	FUEL USED BY THE UNIT. LOW-SULFUR NATURAL GAS IS THE ONLY	0.0015 LB/MMBTU		0.0015 LB/MMBTU		IN AP-42. THE EMISSION LIMITS ARE BASED ON THE EMISSION FACTOR LISTED
VV-0048	STATION	NV	05/16/2006 ACT	ENGINE (>500 HP)	NATURAL GAS	5 9:	1 MMBTU/H	(SO2)	FUEL USED BY THE UNIT.	0.0052 G/B-HP-H	(0.0052 G/B-HP-H		IN AP-42.
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	AUXILIARY BOILER	DISTILLATE OIL	28	в ммвти/н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%).	0 041 LB/MMBTU		0		
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	COMBUSTION TURBINE	NATURAL GAS	2222	1 MMBUT/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0011 LB/MMBTU		0		
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	COMBUSTION TURBINE	#2 DISTILLATE OIL	212	5 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 042 LB/MMBTU		0		
	CAITHNES BELLPORT ENERGY CENTER		05/10/2006 ACT	AUXILIARY BOILER	NATURAL GAS		4 MMBTU/H	Sulfur Dioxide	LOW SULFUR FUEL	0.0005 LB/MMBTU		0		
				TURBINES (3), COMBINED CYCLE,								0		
DH-0248	LAWRENCE ENERGY	ОН	09/24/2002 ACT	DUCT BURNERS OFF TURBINES (3), COMBINED CYCLE,	NATURAL GAS	180	MW	Sulfur Oxides (SOx)	BURNING NATURAL GAS	11.9 LB/H		0		Limits for each turbine. Limits are for one turbine. Additional limit:
OH-0248	LAWRENCE ENERGY	он	09/24/2002 ACT	DUCT BURNERS ON	NATURAL GAS	180	мw		BURNING NATURAL GAS	16.1 LB/H		0		11 9 lbs/hr without duct burner
OH-0248	LAWRENCE ENERGY	он	09/24/2002 ACT	BOILER	NATURAL GAS	99	Э ММВТИ/Н	Sulfur Dioxide (SO2)		0.56 LB/H	(0.0057 LB/MMBTU		Limits are for each boiler.
OH-0251	CENTRAL SOYA COMPANY INC.	ОН	11/29/2001 ACT	DRYER, SOY PROTEIN CONCENTRATE - COMBUSTION	NATURAL GAS	3	7 ММВТИ/Н	Sulfur Dioxide (SO2)		0 021 LB/H	(0.0006 LB/MMBTU		Emissions from natural gas combustion, using 0.0006 lb SO2/mmBtu
511 0251														Using AP-42 emission factor of 0.6 lb/million cubic feet and manufacturer's data 0.21 lb SO2/mmBtu on #2 fuel oil or may opt for burning oil with no greater than 0.5 weight % sulfur. For each shipment of oil, the supplier shall provide the sulfur content and heat content from analytical results from testing. Additional
OH-0251	CENTRAL SOYA COMPANY INC.	ОН	11/29/2001 ACT	BOILER, NO 2 FUEL OIL	NO 2 FUEL OIL	91 :	2 MMBTU/H	Sulfur Dioxide (SO2)		18.2 LB/H		0 21 LB/MMBTU	calculated	limit: 26.2 tons/rolling 12 months when using No 2 fuel oil.
	CENTRAL SOYA COMPANY INC.	ОН	11/29/2001 ACT		NATURAL GAS		2 MMBTU/H	Sulfur Dioxide (SO2)		0 055 LB/H		0.0006 LB/MMBTU		Using AP-42 emission factor of 0.6 lb/million cubic feet
211-0201			11/23/2001 απυςρ;ΑC1		INAT UNAL GAS	91.			LOW SULFUR FUEL: MAXIMUM S					LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 52 82 TONS OF SO2/ROLLING 12-
	DUKE ENERGY HANGING ROCK ENERGY FACILITY	он	12/28/2004 ACT	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON	NATURAL GAS	17	2 MW	Sulfur Dioxide (SO2)	CONTENT OF NATURAL GAS SHALL NOT EXCEED 2 GRAINS/100 SCF	14.4 LB/H		0		MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.

							THROUGHPUT			EMISSION LIMIT		STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES LIMIT IS FOR EACH TURBINE.
	JKE ENERGY HANGING ROCK NERGY FACILITY	он	12/28/2004 ACT	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF	NATURAL GAS	172	2 MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: MAXIMUM S CONTENT OF NATURAL GAS SHALL NOT EXCEED 2 GRAINS/100 SCF	11	1 LB/H	(D		EACH TURBINE HAS A LIMIT OF 52 82 TONS OF SO2/ROLLING 12- MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
	JKE ENERGY HANGING ROCK NERGY FACILITY	он	12/28/2004 ACT	BACKUP GENERATORS (2)	DIESEL	500	жw	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.27	7 LB/H	0.18	3 G/B-НР-Н		
	JKE ENERGY HANGING ROCK							Sulfur Dioxide							
	JERGY FACILITY	ОН	12/28/2004 ACT	FIRE WATER PUMP (1)	DIESEL	26	5 HP	(SO2)	LOW SULFUR FUEL THE MAXIMUM S CONTENT OF THE NATURAL GAS SHALL	0.1	1 LB/H	0.16	5 G/B-HP-H		
	JKE ENERGY HANGING ROCK IERGY FACILITY	ОН	12/28/2004 ACT	BOILERS (2)	NATURAL GAS	30.0	5 MMBTU/H	Sulfur Dioxide (SO2)	NOT EXCEED 2 GRAINS PER 100 CUBIC FEET.	0 031	1 LB/H	0.001	L LB/MMBTU		LIMITS ARE FOR EACH BOILER.
DU DH-0254 LL	JKE ENERGY WASHINGTON COUNTY C	он	08/14/2003 ACT	BOILER	NATURAL GAS	30.0	5 MMBTU/H	Sulfur Dioxide (SO2)		0 031	1 LB/H	0.001	L LB/MMBTU		
	JKE ENERGY WASHINGTON COUNTY	ОН	08/14/2003 ACT	EMERGENCY DIESEL-FIRED GENERATOR	DIESEL		ркw	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, COMBUSTION CONTROL		1 LB/H		3 G/B-HP-H		
	C JKE ENERGY WASHINGTON COUNTY		00/14/2003 and 50/. (c)	EMERGENCY DIESEL FIRE PUMP	DILGEE			Sulfur Dioxide	LOW SULFUR FUEL, COMBUSTION	0		025			
OH-0254 LL	с	он	08/14/2003 ACT	ENGINE	DIESEL	400	Р	(SO2)	CONTROL	0.84	4 LB/H	0 95	5 G/B-HP-H		LIMIT IS FOR EACH TURBINE.
DI OH-0254 LL	JKE ENERGY WASHINGTON COUNTY C	он	08/14/2003 ACT	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS ON	NATURAL GAS	170) MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - LOW S NATURAL GAS 2 GR/100 SCF		5 LB/H	()		EACH TURBINE HAS A LIMIT OF 56 5 TONS OF SO2/ROLLING 12- MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
DL OH-0254 LL	JKE ENERGY WASHINGTON COUNTY	OH I	08/14/2003 ACT	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS OFF	NATURAL GAS	17(Sulfur Dioxide (SO2)	LOW S NATURAL GAS 2 GR/100 SCF	11 -	2 LB/H				LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 56 5 TONS OF SO2/ROLLING 12- MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
511-0234 LL		011	08/14/2003 &105p,AC1	TURBINES (3), COMBINED CYCLE,	NATORAL GAS	170	0 MW	Sulfur Dioxide		11.2					BORNERS AND STARTOFS.
DH-0255 AE	EP WATERFORD ENERGY LLC	ОН	03/29/2001 ACT	W/ DUCT FIRING COMBUSTION TURBINES (3),	NATURAL GAS	170	0 MW	(SO2) Sulfur Dioxide		14	4 LB/H	(0		LIMITS FOR EACH TURBINE.
OH-0255 AE	EP WATERFORD ENERGY LLC	он	03/29/2001 ACT	SIMPLE CYCLE	NATURAL GAS	170	лw	(SO2)		12	2 LB/H	(D		Limits are for each turbine.
DH-0255 AE	EP WATERFORD ENERGY LLC	он	03/29/2001 ACT	EMERGENCY GENERATOR	DIESEL	1000	ркw	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.01	1 T/YR		D		Unit limited to 500 hours per 12 month period.
OH-0255 AE	EP WATERFORD ENERGY LLC	ОН	03/29/2001 ACT	FIRE WATER PUMP	DIESEL	290	окw	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 003	3 T/YR	(D		Unit limited to 500 hours per 12 month period.
OH-0255 AE	EP WATERFORD ENERGY LLC	ОН	03/29/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	85.2	2 MMBTU/H	Sulfur Dioxide (SO2)	LOW S NATURAL GAS, 2 GR/100 SCF	0.05	5 LB/H	0.0006	5 LB/MMBTU		
			10/07/0001 0 1 107	COMBUSTION TURBINES,				Sulfur Dioxide							
JH-U257 JA	CKSON COUNTY POWER, LLC	ОН	12/27/2001 ACT	COMBINED CYCLE, (4)	NATURAL GAS	30:	5 MW	(SO2)	LOW SULFUR FUEL - 2 GR/100 SCF LOW SULFUR FUEL, NATURAL GAS SULFU LIMIT - 2 CR/400		3 LB/H				Limits are for each turbine.
OH-0257 JA	CKSON COUNTY POWER, LLC	ОН	12/27/2001 ACT	AUXILIARY BOILER	NATURAL GAS	7(5 MMBTU/H	Sulfur Dioxide (SO2)	GR/100 SCF	0.5	5 LB/H	0.006	5 LB/MMBTU		Additional limit: 2 grains/100 scf natural gas
OH-0263 FR	REMONT ENERGY CENTER, LLC	ОН	08/09/2001 ACT	COMBUSTION TURBINES(2), COMB CYCLE W/O DUCT BURNER	NATURAL GAS	180	лww	Sulfur Dioxide (SO2)		11.9	9 LB/H	()		Limit is for each turbine. Additional limits: 65 8 T/YR
				COMBUSTION TURBINES (2), COMB				Sulfur Dioxide							Limit is for each turbine. Additional limit:
JH-0263 FR	EMONT ENERGY CENTER, LLC	ОН	08/09/2001 ACT	CYCLE W DUCT BURNER	NATURAL GAS	180	0 MW	(SO2) Sulfur Dioxide		16.1	1 LB/H	(65 8 T/YR
OH-0263 FR	EMONT ENERGY CENTER, LLC	ОН	08/09/2001 ACT	AUXILIARY BOILER COMBUSTION TURBINE (9), COMB	NATURAL GAS	80) MMBTU/H	(SO2) Sulfur Dioxide		0.48	3 LB/H	0.006	5 LB/MMBTU		Limits are for each turbine. Limited to 4,160
DH-0264 NG	ORTON ENERGY STORAGE, LLC	он	05/23/2002 ACT	CYCLE W/O DUCT BURNER	NATURAL GAS	300	мw	(SO2)		1.98	B LB/H	C	D		hours per year.
OH-0264 NG	ORTON ENERGY STORAGE, LLC	ОН	05/23/2002 ACT	COMBUSTION TURBINES (9), COMB CYCLE W DUCT BURNER	NATURAL GAS	300	лw	Sulfur Dioxide (SO2)		2.55	5 LB/H	(D		Limits are for each turbine. Limited to 4,160 hours per year.
			05/22/2022 0 - k A - T			42.0		Sulfur Dioxide	THE MAXIMUM SULFUR CONTENT OF TH NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD		1.5 (1)	0.000			Limits are for each boiler. Each boiler is
л-0264 N(DRTON ENERGY STORAGE, LLC	ОН	05/23/2002 ACT	RECUPERATOR PRE-HEATERS (9)	NATURAL GAS	12 84	4 MMBTU/H	(SO2) Sulfur Dioxide	CUBIC FEET. THE MAXIMUM SULFUR CONTENT OF TH NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD	E	3 LB/H	0.002	2 LB/MMBTU		retricted to 100 hours of operation.
DH-0264 NG	ORTON ENERGY STORAGE, LLC	он	05/23/2002 ACT	FUEL SUPPLY HEATERS (9)	NATURAL GAS	11.4	5 ММВТИ/Н	(SO2)	CUBIC FEET.	0 021	1 LB/H	0.002	2 LB/MMBTU		Limits are for each heater.
0H-0265 DF	RESDEN ENERGY LLC	он	10/16/2001 ACT	COMBUSTION TURBINE (2), COMB. CYCLE W/O DUCT BURN	#2 DIS. FUEL OIL	171.	7 MW	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.05% SULFUR BY WEIGHT.		1 LB/H	(0		Limits are for each turbine. Additional limit: Turbines are restricted to 500 hrs/yr on fuel oil.
				COMBUSTION TURBINE (2), COMB.				Sulfur Dioxide	THE MAXIMUM SULFUR CONTENT OF NG SHALL NOT						Limits are for each turbine. Additional limit: Turbines are limited to 2000 hrs/yr w/ duct
H-0265 DF	RESDEN ENERGY LLC	ОН	10/16/2001 ACT	CYCLE W DUCT BURN	NATURAL GAS	171.	7 MW	(SO2)	EXCEED 3 GRAINS/100SCF	1.8	B LB/H	(D		burners.

RBLCID						al Datasmination nes CDA!a	DACT /DACT /	AED Detekses for Natural Cos d	100 million DTU/hr				
	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	POLLUTANT	LAER Database for Natural Gas <	EMISSION LIMIT 1 LIMIT 1 UNIT	EMISSION	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
								THE MAXIMUM SULFUR CONTENT OF NG					Limits are for each turbine. Additional limit:
OH-0265 [DRESDEN ENERGY LLC	он	10/16/2001 ACT	COMBUSTION TURBINE (2), COMB. CYCLE W/O DUCT BURN	NATURAL GAS	171.7 MW	Sulfur Dioxide (SO2)	SHALL NOT EXCEED 0 3 GRAINS/100 SCF.	1.6 LB/H	0			Turbines are limited to 6260 hrs/yr w/o duct burners on NG.
							Sulfur Dioxide	THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.3 GRAINS PER 100 STANDARD					Boiler is restricted to 800 hours or operation
он-0265 с	DRESDEN ENERGY LLC	ОН	10/16/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	49 MMBTU/H	(SO2)	CUBIC FEET.	0.05 LB/H	0.001 LE	B/MMBTU		per a rolling 12 months.
OH-0276 (CHARTER STEEL	он	06/10/2004 ACT	ELECTRIC ARC FURNACE	ELECTRIC	110 T/H MELT	Sulfur Dioxide (SO2)	PRODUCTION LIMITS. SEE NOTE	22 LB/H	0.2 LE	B/T		CUYAHOGA COUNTY WAS NON-ATTAINMENT FOR SO2 AT THE TIN THE PERMIT WAS ISSUED; THIS PERMIT WAS A SYNTHETIC MINOR FOR SO2 AT 99 53 TONS; WITH RESTRICTIONS ON PRODUCTION: 710,600 TONS OF STEEL AND 28,000 TONS OF RESULFURIZATION GRADE STEEL. ADDITIONAL LIMITS: FROM ELECTRIC ARC FURNACI AND LADLE METALLURGY FURNACE TOGETHER: 71.06 T/ROLLING 1 MO FROM ALL GRADES OF STEEL EXCEPT RESULFURIZED GRADES. 0 2 LB SO2 EMISSION FACTOR PER TON OF STEEL
							Sulfur Dioxide						CUYAHOGA COUNTY WAS NON-ATTAINMENT FOR SO2 AT THE TIN THE PERMIT WAS ISSUED; THIS PERMIT WAS A SYNTHETIC MINOR FOR SO2 AT 99 53 TONS; WITH RESTRICTIONS ON PRODUCTION: 710,600 TONS OF STEEL AND 28,000 TONS OF RESULFURIZATION GRADE STEEL. ADDITIONAL LIMITS: 28.0 T/ROLLING 12-MO FROM RESULFURIZED GRADE STEEL; AND FROM ELECTRIC ARC FURNACE AND LADLE METALLURGY FURNACE TOGETHER: 71.06 T/ROLLING 1
DH-0276 C	CHARTER STEEL	ОН	06/10/2004 ACT	LADLE METALLURGY FURNACE	ELECTRIC	110 T/H	(SO2) Sulfur Dioxide		220 LB/H	0			MO FROM ALL GRADES OF STEEL EXCEPT RESULFURIZED GRADES. LIMIT IS FOR EACH UNIT; LIMIT TIMES 3 EQUALS TOTAL EMISSIONS
он-0276 с	CHARTER STEEL	он	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	NATURAL GAS	12 MMBTU/H	(SO2)		0 007 LB/H	0			FROM ALL TUNDISH PREHEATERS
он-0276 (CHARTER STEEL	он	06/10/2004 ACT	VACUUM OXYGEN DEGASSER VESSEL W/ FLARE BOILER FOR VACUUM OXYGEN	STEAM	150 T/H STEEL	Sulfur Dioxide (SO2) Sulfur Dioxide		0 009 LB/H	0			EMISSIONS FROM NATURAL GAS COMBUSTION FROM FLARE; ONLY DURING OXYGEN LANCING DEGASSING PROCESS FOR LOW CARBON AND STAINLESS STEEL PRODUCTION.
ЭН-0276 С	CHARTER STEEL	ОН	06/10/2004 ACT		NATURAL GAS	28.6 MMBTU/H	(SO2)		0.02 LB/H	0		NOT AVAILABLE	
он-0276 с	CHARTER STEEL	ОН	06/10/2004 ACT	LADLE PREHEATER AND DRYER, 4 UNITS	NATURAL GAS	10 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		0 006 LB/H	0			LIMITS ARE FOR EACH PREHEATER; LIMIT TIMES 4 EQUALS TOTAL EMISSIONS FROM ALL PREHEATERS
ОН-0309 Т	TOLEDO SUPPLIER PARK- PAINT SHOP	он	05/03/2007 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	20.4 MMBTU/H	(SO2)		0.01 LB/H	0.0006 LE	B/MMBTU		LIMITS ARE FOR EACH BOILER.
ОН-0309 Т	TOLEDO SUPPLIER PARK- PAINT SHOP	ОН	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	FUEL OIL #2	20.4 MMBTU/H	Sulfur Dioxide (SO2)		10.4 LB/H	0 51 LE	B/MMBTU		LIMITS ARE FOR EACH BOILER.
ОН-0309 Т	TOLEDO SUPPLIER PARK- PAINT SHOP	ОН	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (24)	NATURAL GAS	20 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H	0.0006 LE	B/MMBTU		LIMITS ARE FOR EACH UNIT. 24 AIR SUPPLY MAKE UP UNITS.
он-0309 т	TOLEDO SUPPLIER PARK- PAINT SHOP	он	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	28 95 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H	0.0006 LE	B/MMBTU		
04 0200	TOLEDO SUPPLIER PARK- PAINT SHOP		05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (6)	NATURAL GAS	14 MMBTU/H	Sulfur Dioxide (SO2)		0.01 LB/H	0.000611	B/MMBTU		LIMITS ARE FOR EACH UNIT. 6 AIR SUPPLY UNITS.
G	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	он	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	JET FUEL	0	Sulfur Dioxide		0.11 LB/MMBTU	0	BJWWBTC		T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	он	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	JET FUEL	0	Sulfur Dioxide (SO2)		0.11 LB/MMBTU	0			T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	он	05/07/2013 ACT	4 Indirect-Fired Air Preheaters	Natural gas	0	Sulfur Dioxide (SO2)		0 001 LB/MMBTU	0			T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
OK-0043 \	WEBERS FALLS ENERGY FACILITY	ок	10/22/2001 ACT	AUXILIARY BOILER	NATURAL GAS	30 MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS	150 PPM	0		NOT AVAILABLE	
OK-0043 /	WEBERS FALLS ENERGY FACILITY	ОК	10/22/2001 ACT	COMBUSTION TURBINES	NATURAL GAS		Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0 006 LB/MMBTU	0			
							Sulfur Dioxide	USE OF PIPELINE NATURAL GAS W/SULFUR CONTENT 2	2				
JK-UU44 S	SMITH POCOLA ENERGY PROJECT	ОК	08/16/2001 ACT	AUXILIARY BOILERS, (2) TURBINES, COMBINED CYCLE,	NATURAL GAS	48 MMBTU/H	(SO2) Sulfur Dioxide	GRAINS SULFUR/100 SCF USE OF PIPELINE NATURAL GAS, SULFUR CONTENT LESS	0.57 LB/H	0.2 LE	B/MMBTU		

							THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STA EM
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION USE OF PIPELINE NATURAL GAS, SULFUR	1	LIMIT 1 UNIT	LIMIT	LIM
ОК-0044	SMITH POCOLA ENERGY PROJECT	ОК	08/16/2001 ACT	TURBINES, NATURAL GAS, (4)	NATURAL GAS	171.5	5 MW	Sulfur Dioxide (SO2)	CONTENT LESS THAN 2 GR/100SCF OR 65 PPMW	10.59	LB/H	0	
		_						Sulfur Dioxide					
OK-0050	ONETA GENERATING STA	ОК	01/21/2000 ACT	DUCT BURNERS (4) COMBUSTION TURBINES,	NATURAL GAS	328	3 MMBTU/H	(SO2)	LOW SULFUR FUEL - NATURAL GAS	0.0013	lb/MMBTU	0.0013	LB/M
OK-0050	ONETA GENERATING STA	ОК	01/21/2000 ACT	COMBINED CYCLE (4)	NATURAL GAS	170	мw		USE OF LOW SULFUR NATURAL GAS	2.5	LB/H	0	
OK-0051	GREEN COUNTRY ENERGY PROJECT	ок	10/01/1999 ACT	TURBINES WITH DUCT BURNERS, COMBINED CYCLE, (3)	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0.006	lb/mmbtu	0	
011 0031			10/01/1999 ((1999), (01					Sulfur Dioxide		0.000	LUJININDIO		
OK-0051	GREEN COUNTRY ENERGY PROJECT	ОК	10/01/1999 ACT	AUXILIARY BOILER	NATURAL GAS			(SO2) Sulfur Dioxide	USE OF NATURAL GAS	0 006	LB/MMBTU	0.006	LB/M
OK-0071	MCCLAIN ENERGY FACILITY	ок	10/25/2001 ACT	AUXILIARY BOILER	NATURAL GAS	22	2 ММВТU/Н	(SO2)	USE OF PIPELINE QUALITY NATURAL GAS	0 001	LB/MMBTU	0.001	LB/M
	DUKE ENERGY STEPHENS, LLC							Sulfur Dioxide	USE OF PIPELINE-QUALITY NATURAL GAS (VERY LOW				
OK-0090	STEPHENS ENERGY	ОК	03/21/2003 ACT	TURBINES, COMBINED CYCLE (2)	NATURAL GAS	1701	L MMBTU/H	(SO2)	SULFUR FUEL) MAXIMUM 0.8 % S BY WT.	0 006	lb/mmbtu	0	
	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	ок	03/21/2003 ACT	BOILER, AUXILIARY	NATURAL GAS	33	в ммвти/н	Sulfur Dioxide (SO2)	BACT IS USE OF PIPE-LINE QUALITY NATURAL GAS	0.2	LB/H	0.006	IR/M
<u>en cosc</u>	DUKE ENERGY STEPHENS, LLC		03/21/2003 ansp)/ 101	IC ENGINE, BACKUP GENERATOR,				Sulfur Dioxide	USE OF LOW SULFUR DIESEL FUEL (< 0 05%			0.000	20,111
OK-0090	STEPHENS ENERGY	ОК	03/21/2003 ACT	DIESEL	DIESEL	749	Э ВНР	(SO2)	S BY WT) USE OF VERY LOW SULFUR DIESEL FUEL	0.3	LB/H	0	
	DUKE ENERGY STEPHENS, LLC							Sulfur Dioxide	(<0.05% S BY				
OK-0090	STEPHENS ENERGY	ОК	03/21/2003 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	265	БНР	(SO2)	WT)	0.5	LB/H	0	
OK-0128	MID AMERICAN STEEL ROLLING MILL	ок	09/08/2008 ACT	Continuous Caster	natural gas	()	Sulfur Dioxide (SO2)	natural gas fuel	0.01	LB/H	0	
								Sulfur Dioxide	500 hours per year, 0.05% sulfur diesel		/··	-	
OK-0128	MID AMERICAN STEEL ROLLING MILL	ОК	09/08/2008 ACT	Emergency Generator Ladle pre-heater and refractory	No. 2 diesel	1200) HP	(SO2) Sulfur Dioxide	fuel	0.49	LB/H	0	
OK-0128	MID AMERICAN STEEL ROLLING MILL	ок	09/08/2008 ACT	drying	natural gas	c.	D	(SO2)	natural gas fuel	0.0006	LB/MMBTU	0	
014 04 20		01	00/00/2000 8 show ACT	Electric Ann Engeneration	a la atuña			Sulfur Dioxide	dame damen				
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Electric Arc Furnaces	electric	50) tons per furnace	(SU2) Sulfur Dioxide	cleaned scrap	0.3	LB/T SCRAP	0	
OK-0128	MID AMERICAN STEEL ROLLING MILL	ОК	09/08/2008 ACT	Ladle Metallurgy Furnace		C	0	(SO2)		0.05	LB/T	0	
OK-0129	CHOUTEAU POWER PLANT	ок	01/23/2009 ACT	COMBINED CYCLE COGENERATION >25MW	NATURAL GAS	1882	2 ММВТU/Н	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	1.06	LB/H	0	
								Sulfur Dioxide					
OK-0129	CHOUTEAU POWER PLANT	ОК	01/23/2009 ACT	AUXILIARY BOILER	NATURAL GAS	33.5	5 MMBTU/H	(SO2) Sulfur Dioxide	LOW SULFUR FUEL	0.03	lb/H	0	
OK-0129	CHOUTEAU POWER PLANT	ОК	01/23/2009 ACT	FUEL GAS HEATER (H2O BATH)		18.8	В ММВТИ/Н	(SO2)	LOW SULFUR FUEL	0.01	LB/H	0	
OK-0129	CHOUTEAU POWER PLANT	ОК	01/23/2009 ACT	EMERGENCY DIESEL GENERATOR (2200 HP)	LOW SULFUR DIESEL	2200		Sulfur Dioxide (SO2)	LOW SULFUR DIESEL 0.05%S	0.80	LB/H	0	
0123	CHOUTEAU FOWER FEANT	OK	01/23/2009 &hbsp,Act	EMERGENCY FIRE PUMP (267-HP	LOW SULFUR	2200		Sulfur Dioxide		0.85	60/11	0	
OK-0129	CHOUTEAU POWER PLANT	ОК	01/23/2009 ACT	DIESEL)	DIESEL	267	7 HP	(SO2) Sulfur Dioxide	LOW SULFUR DIESEL	0.11	LB/H	0	
OK-0134	PRYOR PLANT CHEMICAL	ок	02/23/2009 ACT	Primary Reformer (EUID #101, EUG#1-NH3 Plant #4)	Natural Gas	700	T/D Ammonia Production	(SO2)	Natural Gas	0.2	lb/mmbtu	0	
				Nitric Acid Preheaters No. 1 (EU				Sulfur Dioxide				_	
OK-0134	PRYOR PLANT CHEMICAL	ОК	02/23/2009 ACT	401, EUG 4)	Natural Gas	20) MMBTUH	(SO2) Sulfur Dioxide	natural gas combustion	0.03	lb/H	0	
OK-0135	PRYOR PLANT CHEMICAL	ОК	02/23/2009 ACT	PRIMARY REFORMER	NATURAL GAS	700) Tons per Day	(SO2)		1.35	LB/H	0	
OK-0135	PRYOR PLANT CHEMICAL	ОК	02/23/2009 ACT	NITRIC ACID PREHEATERS #1, #3, AND #4	NATURAL GAS	20) ММВТU/Н	Sulfur Dioxide (SO2)		0.03	LB/H	0	
01-0135			02/23/2005 & B39,ACT			20		Sulfur Dioxide		0.05	20/11	0	
OK-0135	PRYOR PLANT CHEMICAL	ОК	02/23/2009 ACT	BOILERS #1 AND #2	NATURAL GAS	80) ММВТU/Н	(SO2)		0.2	LB/H	0	
								Sulfur Dioxide	USING PROPANE AND LOW SULFUR DISTILLATE OIL AND				
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	LIMESTONE DRYER	PROPANE	13	3 ММВТU/Н	(SO2)	DIRECT CONTACT WITH LIMESTONE	0.26	LB/H	0 02	LB/M
									LOW-SULFUR COAL (MAX 1% S) AND DISTILLATE OIL				
									(MAX 0.05% S)AND A LIMESTONE				
DB 0007		DD	10/20/2001 & share ACT	2 COAL-FIRED CIRCULATING				Sulfur Dioxide	INJECTION SYSTEM		PPMVD @ 7%	0.022	10/14
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	FLUIDIZED BED BOILERS	BITUMINOUS COAL	454	1 MW (NET)	(SO2) Sulfur Dioxide	AND CIRCULATING DRY SCRUBBER	9	02	0.022	LB/IVI
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	FIRE PUMP- DIESEL	DISTILLATE OIL			(SO2)	LIMITED OPERATION- LIMITED S IN FUEL	0.13	LB/H	0	
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	DIESEL GENERATOR, EMERGENCY EQUIPMENT	DISTILLATE OIL*			Sulfur Dioxide (SO2)	LIMITED OPERATION- LIMITED S IN FUEL	0.29	LB/H	0	
			.,,,,	EMERGENCY BOILER FEED PUMP-			1	Sulfur Dioxide	LIMITED OPERATION AND LIMITED FUEL	0.25			
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	DIESEL ENGINE	DISTILLATE OIL*			(SO2)	SULFUR CONTENT	0.82	LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
lb/mmbtu		
lb/mmbtu		
lb/MMBTU		
lb/mmbtu	calculated	
lb/MMBTU		
lb/MMBTU		

								AER Database for Natural Gas < :				I	
						THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
SC-0061	COLUMBIA ENERGY LLC	<u>در</u>	04/09/2001 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	170 MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	4.9 LB/H	(
30-0001		30	04/09/2001 &1103p,AC1	NATONAL GAS (2)	NATONALGAS	MMBTU/H	Sulfur Dioxide		4.5 10/11				
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	BOILERS, NATURAL GAS (2)	NATURAL GAS	350 (EACH)	(SO2) Sulfur Dioxide	LOW SULFUR FUELS	0.63 LB/H	0.0018	B LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	sc	04/09/2001 ACT	BOILERS, FUEL OIL (2)	NO. 2 FUEL OIL	350 MMBTU/H	(SO2)	COMBUSTION OF LOW SULFUR FUELS	21 LB/H	0.06	5 LB/MMBTU		
50 0001			04/00/2001 8 short ACT				Sulfur Dioxide			2.0			
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	HOT WATER HEATERS (2) TURBINES, COMBINED CYCLE,	NATURAL GAS DISTILLATE FUEL	11 MMBTU/H	(SO2) Sulfur Dioxide	CLEAN FUEL	3.5 LB/MMBTU	3.5	5 LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	DISTILLATE FUEL OIL (2)	OIL	170 MW (EACH)	(SO2)	LOW SULFUR FUEL	99 LB/H	(D		
				COMBUSTION TURBINES, NATURAL			Sulfur Dioxide						SO2 IS NOT SIGNIFICANT UNDER PSD-BACT, BUT A STATE BACT ANALYSIS WAS PERFORMED (SC DHEC 61-
SC-0065	BROAD RIVER INVESTORS - GAFFN	EY SC	12/21/2000 ACT	GAS (2)	NATURAL GAS	193 MW (EACH)	(SO2)	LOW SULFUR FUELS	1.1 LB/H	(D		62 5, STANDARD 7)
SC-0065	BROAD RIVER INVESTORS - GAFFN	FY SC	12/21/2000 ACT	HOT WATER HEATERS, NAT. GAS (2)	NATURAL GAS	MMBTU/H 11 (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0065 LB/H	(0		STATE BACT PERFORMED
							Sulfur Dioxide	SCRAP MANAGEMENT PROGRAM, GOOD			-		
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	MELT SHOP		4380000 T/YR	(SO2)	OPERATING PRACTICES USE OF NATURAL GAS COMBUSTION WITH	0.2 LB/T	(
							Sulfur Dioxide	GOOD COMBUSTION PRACTICES PER					
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	VACUUM TANK DEGASSER		0	(SO2)	MANUFACTURER'S GUIDANCE NATURAL GAS COMBUSTION WITH GOOD	6.6 T/YR	(0		
							Sulfur Dioxide	COMBUSTION PRACTICES PER					
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	VACUUM DEGASSER BOILER	NATURAL GAS	50 21 MMBTU/H	(SO2)	MANUFACTURER'S GUIDANCE	0.0006 LB/MMBTU	0.0006	5 LB/MMBTU		
							Sulfur Dioxide	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER					
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	TUNNEL FURNACE BURNERS	NATURAL GAS	58 MMBTU/H	(SO2)	MANUFACTURER'S GUIDANCE	0.0006 LB/MMBTU	0.0006	6 LB/MMBTU		
							Sulfur Dioxide	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER					
SC-0112	NUCOR STEEL - BERKELEY	sc	05/05/2008 ACT	COIL CUTTING		0	(SO2)	MANUFACTURER'S GUIDANCE	0.0006 LB/MMBTU	(D		
SC-0113	PYRAMAX CERAMICS, LLC	sc	02/08/2012 ACT	PELLETIZER	NATURAL GAS	75 MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS/PROPANE TO MINIMIZE COMBUSTION RELATED SO2.	0	(0		MONITOR AND RECORD THE AMOUNT AND TYPE OF FUEL USED.
	, -										-		
							Sulfur Dioxide	CATALYTIC BAGHOUSE. FUEL RESTRICTED					MONITOR TYPE AND AMOUNT OF FUEL USAGE. CONTINUOUSLY MONITOR SORBENT INJECTION RATE. SAMPLE AND RECORD SULFUR
SC-0113	PYRAMAX CERAMICS, LLC	sc	02/08/2012 ACT	CALCINING/SINTERING KILN	NATURAL GAS	56.8 MMBTU/H	(SO2)	TO NATURAL GAS AND PROPANE.	11.64 LB/H	(D		CONTENT OF CLAY WEEKLY. SOURCE TESTING EVERY TWO YEARS.
SC-0113	PYRAMAX CERAMICS, LLC	sc	02/08/2012 ACT	BOILERS	NATURAL GAS	5 MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND PROPANE.	0	ſ	0		MONITOR AND RECORD TYPE AND QUANTITY OF FUEL USED.
000110			02,00,2012 (1000),101				(002)	LOW SULFUR DIESEL. MAXIMUM OF 100					
SC-0113	PYRAMAX CERAMICS, LLC	sc	02/08/2012 ACT	EMERGENCY ENGINE 1 THRU 8	DIESEL	29 HP	Sulfur Dioxide (SO2)	HOURS PER YEAR RUNNING TIME FOR MAINTENANCE AND TESTING.	0	ſ			DIESEL FUEL SULFUR CONTENT SHALL BE < 0.0015 PERCENT. REPORTS OF FUEL SULFUR CONTENT SHALL BE MAINTAINED.
50-0115		50			DIEJEE	25111	(502)	USE OF LOW SULFUR FUEL DIESEL, SULFUR	1				
								CONTENT LESS THAN 0 0015 PERCENT. OPERATING HOURS LESS THAN 100					SULFUR CONTENT OF DIESEL FUEL TO BE LESS THAT 0.0015 PERCENT.
							Sulfur Dioxide	HOURS PER YEAR FOR MAINTENACE AND					SUPPLIER CERTIFICATION OF FUEL SULFUR CONTENT SHALL BE
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	FIRE PUMP	DIESEL	500 HP	(SO2)	TESTING. USE OF LOW SULFUR FUEL DIESEL, SULFUR	0	(0		MAINTAINED.
								CONTENT LESS THAN 0 0015 PERCENT.	`				
							Culfur Disuida	OPERATING HOURS LESS THAN 100					SULFUR CONTENT OF DIESEL FUEL TO BE LESS THAT 0.0015 PERCENT.
SC-0113	PYRAMAX CERAMICS, LLC	sc	02/08/2012 ACT	EMERGENCY GENERATORS 1 THRU 8	DIESEL	757 HP	Sulfur Dioxide (SO2)	HOURS PER YEAR FOR MAINTENACE AND TESTING.	0	C	D		SUPPLIER CERTIFICATION OF FUEL SULFUR CONTENT SHALL BE MAINTAINED.
							Culture Direct 1	TUNE-UPS AND INSPECTIONS WILL BE					
SC-0114	GP ALLENDALE LP	sc	11/25/2008 ACT	PROPANE VAPORIZERS (ID15)	PROPANE	5 MMBTU/H	Sulfur Dioxide (SO2)	PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.15 LB/H	(D		
								TUNE-UPS AND INSPECTIONS WILL BE			1		
SC-0114	GP ALLENDALE LP	sc	11/25/2008 ACT	FIRE WATER DIESEL PUMP	DIESEL	525 HP	Sulfur Dioxide (SO2)	PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39 LB/H	(b		ANNUAL EMISSIONS FROM THE DIESEL FIRE PUMP ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
							Sulfur Dioxide						
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	DIESEL EMERGENCY GENERATOR NATURAL GAS SPACE HEATERS - 14	DIESEL	1400 HP	(SO2) Sulfur Dioxide		5.4 LB/H	(י ו		
SC-0114	GP ALLENDALE LP	sc	11/25/2008 ACT	UNITS (ID 18)	NATURAL GAS	20 89 MMBTU/H	(SO2)		0.01 LB/H	(D		
													THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT
													TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM
													MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A
				334 MILLION BTU/HR WOOD FIRED			Sulfur Dioxide	SO2 EMISSIONS CONTROLLED THROUGH					LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	FURNACE #1	WOOD	334 MMBTU/H	(SO2)	GOOD OPERATING PRACTICES.	28.14 LB/H		0		3/8'' BASIS/YR.

				J				AER Database for Natural Gas <		0/11		1		
						THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT		1	LIMIT 1 UNIT	LIMIT		CONDITION	POLLUTANT COMPLIANCE NOTES THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A
C-0114 GP ALLEN	IDALE LP	sc	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	WOOD	334 MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHOR
C-0114 GP ALLEN	IDALE LP	sc	11/25/2008 ACT	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197 MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH	28.14	LB/H	0			TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8&isquo & lsquo; BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8&isquo & lsquo; BASIS/YR.
SC-0114 GP ALLEN	IDALE LP	sc	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	NATURAL GAS	75 MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR SO2 EMISSIONS.	0.04	LB/H	0			
5C-0114 GP ALLEN	IDALE LP	sc	11/25/2008 ACT	ROTARY FLAKE DRYER #1		95000 LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR.
							Sulfur Dioxide	SO2 EMISSIONS CONTROLLED THROUGH			-			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF
5C-0114 GP ALLEN		SC SC	11/25/2008 ACT	ROTARY FLAKE DRYER #2		95000 LB/H OVEN DRY	Sulfur Dioxide	GOOD OPERATING PRACTICES SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14		0			3/8'' BASIS/YR. THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHOR TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR.
						MSF/YR	SO2 EMISSIONS CONTROLLED THROUGH GOOD						APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF J/8&Isquo&Isq uo; BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF	

			Summa	ry of SO ₂ Contr	ol Determination per EPA's	RACT/BACT/L	AER Database for Natural Gas <	100 million B	U/hr	[Т	1
RBLCID FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
			334 MILLION BTU/HR WOOD FIRED			Sulfur Dioxide	SO2 EMISSIONS CONTROLLED THROUGH						THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8&Isquo&Isquo BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF
SC-0115 GP CLARENDON LP	SC	02/10/2009 ACT	FURNACE #2	WOOD	334 MMBTU/H	(SO2)	GOOD OPERATING PRACTICES.	28.14	LB/H	0			3/8'' BASIS/YR. THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS
SC-0115 GP CLARENDON LP	sc	02/10/2009 ACT	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197 MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD COMBUSTION PRACTICES.	28.14	<u>LB/H</u>	0			BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR.
			75 MILLION BTU/HR BACKUP			Sulfur Dioxide	GOOD COMBUSTION PRACTICES WILL BE						
CC-0115 GP CLARENDON LP	SC SC	02/10/2009 ACT	THERMAL OIL HEATER	NATURAL GAS	75 MMBTU/H	(SO2) Sulfur Dioxide	USED AS CONTROL FOR SO2 EMISSIONS.	0.04	<u>LB/H</u>	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF
SC-0115 GP CLARENDON LP	SC	02/10/2009 ACT	ROTARY FLAKE DRYER #1		95000 OVEN DRY/H	(SO2)	USED AS CONTROL FOR SO2 EMISSIONS.	28.14	LB/H	0			3/8'' BASIS/YR. THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS
SC-0115 GP CLARENDON LP	sc	02/10/2009 ACT	ROTARY FLAKE DRYER #2		95000 LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR. THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS
SC-0115 GP CLARENDON LP	sc	02/10/2009 ACT	ROTARY FINES DRYER		75000 LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR. THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A
C-0115 GP CLARENDON LP	sc	02/10/2009 ACT	MULTI-OPENING PRESS		1200000 MSF 3/8/YR"	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	IB/H	0			LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8'' BASIS/YR.
5C-0115 GP CLARENDON LP	sc	02/10/2009 ACT	PROPANE VAPORIZERS (ID 14)	PROPANE	5 MMBTU/H	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.		LB/H	0			THE TWO VAPORIZERS ARE LIMITED TO 16,000 MM BTU/YR, COMBINED.
GP CLARENDON LP	sc	02/10/2009 ACT	FIRE WATER DIESEL PUMP	DIESEL	525 HP	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39	LB/H	0			ANNUAL EMISSIONS FROM THE DIESEL FIRE PUMP ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
C-0115 GP CLARENDON LP	sc	02/10/2009 ACT		DIESEL	1400 HP	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.4	LB/H	0			ANNUAL EMISSIONS FROM THE DIESEL EMERGENCY GENERATOR ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
SC-0115 GP CLARENDON LP	sc	02/10/2009 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 17)	NATURAL GAS	20 89 MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
			334 MILLION BTU/HR WOOD FIRED			Sulfur Dioxide	SO2 EMISSIONS CONTROLLED THROUGH						THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8'' BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF

<u> </u>				Summa	ry of SO ₂ Conti	ol Determinat	ion per EPA's	RACT/BACT/L/	AER Database for Natural Gas < 1	100 million B	U/hr				
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	FACILITINAME		PERMIT ISSUARCE DATE			Theodarot	UNIT	Sulfur Dioxide	FUEL SPECIFICATIONS OF NO MORE THAN 2 5 GRAINS TOTAL SULFUR PER 100 DRY STANDARD CUBIC FEET ON A SHORT-TERM BASIS AND 0 5 GRAIN TOTAL SULFUR			LIVIT		CONDITION	FOLLOTANT COMPLIANCE NOTES
74 S	SOLAR GAS TURBINE COGEN.	тх	04/03/2000 ACT	COGENERATION TURBINE WITH DUCT BURNER	NATURAL GAS	4.4	5 MW (CTG)	(SO2)	PER 100 DSCF ON A ROLLING 12-MONTH AVERAGE BASIS.	1.87	LB/H	0			
274 3	JOLAN GAS TONDINE COOLN.		04/03/2000 kilosp,rk1					Sulfur Dioxide	FUEL SPECIFICATIONS OF NO MORE THAN 2 5 GRAINS TOTAL SULFUR PER 100 DRY STANDARD CUBIC FEET ON A SHORT-TERM BASIS AND 0 5 GRAIN TOTAL SULFUR PER 100 DSCF ON A ROLLING 12-MONTH	1.07				CONVERTED USING	
j274 S	SOLAR GAS TURBINE COGEN.	тх	04/03/2000 ACT	AUXILIARY BOILER	NATURAL GAS	54 0	1 MMBTU/H	(SO2)	AVERAGE BASIS.	0.77	LB/H	0.014	lb/mmbtu	THROUGHPUT	
0309 F	ORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	(2) STARTUP HEATERS, 70H101- 1&-2		7	5 MMBTU/H, EA	Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0.0005	lb/mmbtu	CALCULATED FROM HOURLY E.L. AND THRUPUT	
								Sulfur Dioxide							FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE
0309 F	FORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	PROCESS FUGITIVES, 70ANFUG				(SO2)	NONE INDICATED	0.46	lb/H	0			EMISSION RATE.
309 F	ORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	WASTE HEAT BOILER, 70Z401	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
)309 F	ORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	PROCESS FLARE, 70Z522				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
0354 A	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
				TRAIN 1 - MESH PRODUCTION				Sulfur, Total	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION,						
)354 A	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FUGITIVES				Reduced (TRS)	AND REPAIR. FOLLOW PROCEDURES OF LEAK	0.02	LB/H	0			
)354 A	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
0354 A	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			
															ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL
				TANK TRUCK LOADING/UNLOADING	i			Sulfur, Total	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK						BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL

		1		Summa	ary of SO ₂ Contr	ol Determination per EPA's	RACT/BACT/I	LAER Database for Natural Gas <	100 million B	ſU/hr	1	1	1	l
						THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	
														TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN
														FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE
														FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS
														AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL
														EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS
														TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED
														SO2 IMPACTS IN THE VICINITY OF THE CAMS54
														MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE
														AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2
														CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF
														IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED
														SO2 IMPACTS FROM THE FLARE AT THE CAMS54
														MONITOR, AND THAT THE IMPACTS AT THE CAMS54
														MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS
								FOLLOW THE REQUIREMENTS OF 40 CFR						APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE
4 ATO	FINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, SSM			Sulfur Dioxide (SO2)	60.18. SEE THE POLLUTANT NOTES.	2541.37	LB/H	(0		FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
			· · ·				Sulfur, Total	FOLLOW THE REQUIREMENTS OF 40 CFR						
ATO	FINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, SSM			Reduced (TRS)	60.18	24.27	lb/H	(TAC CHAPTER 112 REQUIREMENT: WHEN THE
														DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN
														FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE
														TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS
														AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL
														EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS
														FROM THE FLARE WOULD LIKELY RESULT IN INCREASED
														SO2 IMPACTS IN THE VICINITY OF THE CAMS54
														MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54
														MONITOR TO DETERMINE IF CURRENT SO2
														CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS
														FROM THE FLARE WOULD LIKELY RESULT IN INCREASED
														SO2 IMPACTS FROM THE FLARE AT THE CAMS54
														MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL
														SHALL CURTAIL PERMITTED ACTIVITIES, AS
				FLARE, TOTAL HOURLY AND			Sulfur Dioxide	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE						APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
54 ATO	FINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	ANNUAL			(SO2)	POLLUTANT NOTES.	6207.34	LB/H	(D		AT LEAST AT OR BELOW 5193 LB/H.
	FINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL			Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	10/4				
			12/15/2002 @1030,ACT				heddeed (113)	FUEL GAS SHALL BE SWEET NATURAL GAS		20/11			CALCULATED,	
	FINA CHEMICALS INCORPORATED	TV	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31 MMBTU/H	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.03	LB/H	0.0006	5 LB/MMBTU	USING THROUGHPUT	
			12/13/2002 andsp;ACI	11202	INAT UNAL GAS		(302)	FUEL GAS SHALL BE SWEET NATURAL GAS		-0/11	0.0006		TINUUGHPUT	
			42/40/2002 0	(2) (1) (1) (2) (2) (2) (2) (2) (2) (2) (2) (2) (2			Sulfur Dioxide			1.5.(1)			NOT	
4 ATO	FINA CHEMICALS INCORPORATED	IX	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS			(SO2)	NO MORE THAN 5 GR S/100 DSCF. FUEL GAS SHALL BE SWEET NATURAL GAS		LB/H		י 	NOT AVAILABLE CALCULATED	
				HEAT TRANSFER FLUID HEATER,			Sulfur Dioxide	CONTAINING		4.			USING	
4 ATO	FINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	H2202	NATURAL GAS	31 MMBTU/H	(SO2) Sulfur Dioxide	NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	5 LB/MMBTU	THROUGHPUT	
4 ATO	FINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	INCINERATOR			(SO2)	NONE INDICATED	139	LB/H		0		
1 ATO	FINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR STORAGE TANK, S-1			Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0	D		
			· · ·				Sulfur Dioxide			,				
+ A10	FINA CHEMICALS INCORPORATED	17	12/19/2002 ACT	SULFUR PIT, S-2	1		(SO2)	NONE INDICATED FOLLOW PRACTICES OF LEAK DETECTION,		LB/H	(
							Sulfur, Total	ISOLATION,						
ATO	FINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES			Reduced (TRS)	AND REPAIR.	0.01	LB/H	0)		

			Summa	ry of SO ₂ Conti	rol Determination per EPA's	RACT/BACT/I	.AER Database for Natural Gas <	100 million BTU/hr				
BLCID	FACILITY NAME FACILITY ST	ATE PERMIT ISSUANCE DAT		PRIMARY FUEL	тнгоиднрит	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
BLCID				FRIMARTFOLL			FUEL GAS SHALL BE SWEET NATURAL GAS		LINIT		CONDITION	FOLLOTANT COMPLIANCE NOTES
0354	ATOFINA CHEMICALS INCORPORATED	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5 MMBTU/H	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1156.47 LB/H	C			
						Sulfur, Total	· · · · · · · · · · · · · · · · · · ·					
0354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5 MMBTU/H	Reduced (TRS)	NONE INDICATED THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100	0.89 LB/H	C			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET
-0354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	AND ANNUAL THERMAL OXIDIZER, TOTAL HOURLY	r	134.5 MMBTU/H	(SO2) Sulfur, Total	DSCF.	1157.44 LB/H	C			CONCENTRATION OF 10 PPMV.
0354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	AND ANNUAL		134.5 MMBTU/H	Reduced (TRS)	NONE INDICATED	0.89 LB/H	C)		
						Sulfur Dioxide	FOLLOW SPECIFICATIONS OF 40 CFR 60.18 SEE					TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR TO DETERMINE OF THE CARS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTALL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION			(SO2) Sulfur, Total	POLLUTANT NOTES.	3665.97 LB/H	C			AT LEAST AT OR BELOW 5193 LB/H.
354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION			Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18 FOLLOW PRACTICES OF LEAK DETECTION,	41.35 LB/H	C			
			PRODUCT RECOVERY TOWER			Sulfur, Total	ISOLATION,					
	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES			Reduced (TRS) Sulfur, Total Reduced (TRS)	AND REPAIR. SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION,	0.01 LB/H	C			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
-0354	ATOFINA CHEMICALS INCORPORATED TX	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES			Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.06 LB/H	C		FACI	
	ATOFINA CHEMICALS INCORPORATED	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X- 426B	NATURAL GAS	15.8 MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01 LB/H		lb/mmbtu	EACH, CALCULATED USING THROUGHPUT	

				<u>Cumma</u>	w. of SO. Contr	ol Dotorminati				100 million P	FU / h.,			
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	AER Database for Natural Gas <			STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION
RECED		TACIENT STATE			TRIMARTICE		U.I.I.	TOLLOTAN	MMP DAY STORAGE TANKS WILL VENT TO	1		Enviri		CONDITION
									THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO.					
								Sulfur, Total	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION,					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Reduced (TRS)	AND REPAIR.		LB/H	0		
									MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO.					
									FOLLOW PRACTICES OF LEAK DETECTION,					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.15	LB/H	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED		12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.		LB/H	0		
									FOLLOW PRACTICES OF LEAK DETECTION,					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.01	LB/H	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0		
									FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS					
				THERMAL OXIDIZER, STEADY STATE				Sulfur Dioxide	CONTAINING NO MORE THAN 5 GR S/100					
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	SERVICE FOREHEARTH MONITOR, FURNACE		134.5	MMBTU/H	(SO2) Sulfur Dioxide	DSCF.	4.21	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	NO 5				(SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	CURING OVEN NO 1 & amp; 2 FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(5) HOT AIR DRYERS, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 6, FURNACE 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363		тх	11/13/2000 ACT	(6) HOT AIR DRYER NO 31, 32, 33, 34, 35, 36				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0		
TX-0363		тх	11/13/2000 ACT	RTP DRYER NO 15				Sulfur Dioxide	NONE INDICATED		LB/H	0		
				MAT LINE (DRYERS & amp;				Sulfur Dioxide						
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	ТХ	11/13/2000 ACT	CLEANER)				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 45				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	BOILER NO. 2	NAT GAS			(SO2)	NONE INDICATED	0.04	LB/H	0		NOT AVAILABLE
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) EMERGENCY GENERATORS NO. 1 & amp; 2	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	5.51	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	PROPANE FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.49	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	PROPANE EVAPORATOR NO. 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363		тх	11/13/2000 ACT	(3) PROPANE EVAPORATORS NO 2, 3, 4				Sulfur Dioxide	NONE INDICATED		LB/H			
				(2) FURNACE FOREHEARTHS NO 1				Sulfur Dioxide				0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	ТХ	11/13/2000 ACT	& 2				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) RTP DRYERS NO 12 & amp; 13				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(3) RTP DRYERS NO 16, 17, 18				(SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	BOILER NO 3	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.03	LB/H	0		NOT AVAILABLE
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	DIESEL GENERATOR	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.93	LB/H	0		
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 5	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	11.4	LB/H	0		
		тх		FURNACE FOREHEARTH NO 3				Sulfur Dioxide				0		1
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	1.4	11/13/2000 ACT	FURNACE FUREHEARTH NU 3	ļ	ļ	L	(SO2)	NONE INDICATED	0.01	LB/H	0	l	1

31	U/hr				
т	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
.1	LB/H	0			
5	LB/H	0			
)2	LB/H	0			
	LB/H	0			
39	LB/H	0			
1	10/4	~			
	LB/H LB/H	0			
	LB/H	0			
	LB/H	0			
	LB/H	0			
	LB/H	0			
	LB/H	0			
	LB/H	0			
)1	LB/H	0			
)4	LB/H	0		NOT AVAILABLE	
51	LB/H	0			
19	LB/H	0			
)1	LB/H	0			
)1	LB/H	0			
)1	LB/H	0			
)1	lb/H	0			
)1	LB/H	0			
	LB/H	0		NOT AVAILABLE	
93	LB/H	0			
	lB/H	0			
)1	LB/H	0			

							THROUGHPUT		AER Database for Natural Gas <		EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME FURNACE NO 4 FOREHEARTH	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	& RTP CHOPPER				(SO2)	NONE INDICATED	0.01	l lb/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 98				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) RTP DRYERS 10 & amp; 11				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	POST CURING OVEN NO 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
				(2) POST CURING OVENS NO 2				Sulfur Dioxide				0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	& 3				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	l lb/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 3	NAT GAS			(SO2)	ESP & SCRUBBER	6.66	5 LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO. 1	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	L LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 2	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	L LB/H	0			
		T)/	44/42/2000 Binking ACT					Sulfur Dioxide							
1X-0363	SAINT-GOBAIN VETROTEX AMERICA	IA	11/13/2000 ACT	FURNACE NO 4 (2) INGERSOLL-RAND ENGINES, #IR-	NAT GAS			(SO2) Sulfur Dioxide	ESP & SCRUBBER	9.03	3 LB/H	0			
TX-0364	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	SVG-8, EPN4&5	NAT GAS	44() HP	(SO2) Sulfur Dioxide	NONE INDICATED	0.7	7 LB/H	0			STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT
TX-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER, EPN6	NAT GAS	12	2 MMBTU/H	(SO2)	NONE INDICATED	0.01	L LB/H	0.0008	lb/mmbtu		RATING AND HOURLY EMISSION LIMIT CACCOLATED TROM THAT
TX-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR- SVG-8, EPN10A&B	NAT GAS	1330	НР	Sulfur Dioxide (SO2)	NONE INDICATED	0.33	B LB/H	0			
		T V						Sulfur Dioxide				0.000			STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT
1X-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	GLYCOL REBOILER, EPN11 (3) COOPER-BESSEMER ENGINES,	NAT GAS	2.:	5 MMBTU/H	(SO2) Sulfur Dioxide	NONE INDICATED	0.02	2 LB/H	0.008	lb/MMBTU	SEE NOTE	RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	#GMVH-12C2, EPN21-23	NAT GAS	3105	5 HP	(SO2) Sulfur Dioxide	NONE INDICATED	0.26	5 LB/H	0	-		STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT
TX-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER, EPN26	NAT GAS	32.5	5 MMBTU/H	(SO2)	NONE INDICATED	0.02	2 LB/H	0.0006	lb/mmbtu		RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	(2) FLARES, EPN 9 & amp; 29				Sulfur Dioxide (SO2)	NONE INDICATED	50.48	B LB/H	0			
TX-0364	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HP TEG FIREBOX, EPN30	NAT GAS	3	3 ММВТИ/Н	Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0.003	LB/MMBTU		STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	COOPER-BESSEMER ENGINE,	NAT GAS	2400		Sulfur Dioxide (SO2)	USE PIPELINE QUALITY SWEET NATURAL GAS			0			
17-0304	SALI CILLI GAS FLANT		01/31/2003 &103p,AC1	#GMVH-12, EPN1 (2) CLARK ENGINE, #TLAB-6,	INAT GAS	2400		Sulfur Dioxide	UA3	0.50	5 LB/H	0			
TX-0364	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	EPN2&3	NAT GAS	2000) HP EACH	(SO2) Sulfur Dioxide	NONE INDICATED	0.31	L LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			(SO2)	NONE INDICATED	0.01	L LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
								Sulfur Dioxide						CALCULATED USING	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60) ММВТU/Н	(SO2)	NONE INDICATED	0.95	5 LB/H	0 02	lb/mmbtu	THROUGHPUT	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS		1	Sulfur Dioxide (SO2)	NONE INDICATED		L LB/H	0		NOT AVAILABLE	
								Sulfur Dioxide				0		AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	X	11/05/2001 ACT	TRAIN NO. 8 FLARE				(SO2) Sulfur Dioxide	NONE INDICATED		L LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	ALKYL FLARE				(SO2)	NONE INDICATED LOW SULFUR (0.23 GRAINS S/100	0.01	L LB/H	0			
TV 0200		TV	02/12/2002 8-6-					Sulfur Dioxide	DSCF)PIPELINE			-			
	SAND HILL ENERGY CENTER	ТХ	02/12/2002 ACT	, , , , , , , , , , , , , , , , , , , ,	NATURAL GAS		3 MW (EACH)	(SO2) Sulfur Dioxide	QUALITY NATURAL GAS.		3 LB/H	0			
TX-0388	SAND HILL ENERGY CENTER	тх	02/12/2002 ACT	COMBINED CYCLE GAS TURBINE	NATURAL GAS	164	1 MW	(SO2) Sulfur Dioxide	LOW SULFUR FUEL (0.23 GR/DSCF)	1.6	5 LB/H	0			
TX-0388	SAND HILL ENERGY CENTER	тх	02/12/2002 ACT	INLET AIR HEATERS (3)				(SO2)	FUEL RESTRICTED TO 0.23 GR S/100 DSCI	F. 0 003	B LB/H	0			
TX-0389	BAYTOWN CARBON BLACK PLANT	тх	12/31/2002 ACT	CARBON BLACK PROCESS CAPS	NATURAL GAS			Sulfur Dioxide (SO2)	SCRUBBER, LOW SULFUR (<2.5%)FEEDSTOCK OIL	859.3	B LB/H	0			
TX-0389	BAYTOWN CARBON BLACK PLANT	тх	12/31/2002 ACT	BACK-UP BOILER	NATURAL GAS	13.4	1 MMBUT/H	Sulfur Dioxide (SO2)		0.01	L LB/H	0			
		тх						Sulfur Dioxide							
18-0392	LUCITE BEAUMONT	1A	12/09/2002 ACT	SULFURIC ACID PLANT		I	1	(SO2)		130) LB/H	4	LB/T H2SO4		

				Summa	ry of SO ₂ Conti	roi Determinat	on per EPA s	RACI/BACI/L	AER Database for Natural Gas < 1		U/nr		1	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION
TX-0392	LUCITE BEAUMONT	тх	12/09/2002 ACT	NO.1 PRE-HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.1	LB/H	0		
TX-0392	LUCITE BEAUMONT	тх	12/09/2002 ACT	NO. 2 PRE-HEATER	NATURAL GAS			Sulfur Dioxide (SO2)			LB/H	0		
TX-0408	INDIAN ROCK GATHERING COMPANY	тх	11/22/2002 ACT	AUXILIARY BOILER, (2)	NATURAL GAS	6	ММВТИ/Н	Sulfur Dioxide (SO2)		0.01	LB/H	0.0017	lb/MMBTU	
TX-0408	INDIAN ROCK GATHERING COMPANY	тх	11/22/2002 ACT	SULFUR RECOVERY UNIT		20	LT/D	Sulfur Dioxide (SO2)	THERMAL OXIDIZER	61.86	LB/H	0		
TX-0408	INDIAN ROCK GATHERING COMPANY	тх	11/22/2002 ACT	IC ENGINE COMPRESSOR, (5)	NATURAL GAS	800	НР	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0.01	LB/H	0		
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	COMBUSTION TURBINE WITH 550 MMBTU/HR DUCT BURNER	NATURAL GAS			Sulfur Dioxide (SO2)	BURN LOW SULFUR NATURAL GAS	14.5	LB/H	0		
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	AUXILIARY BOILER	NATURAL GAS	36	mmbtu/h	Sulfur Dioxide (SO2) Sulfur Dioxide		0.3	LB/H	0		
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	FIRE WATER PUMP ENGINE				(SO2) Sulfur Dioxide		0.5	LB/H	0		
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	EMERGENCY GENERATOR (6) TURBINE EXHAUST DUCT BURNER				(SO2) Sulfur Dioxide		1.4	LB/H	0		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	(3)	NATURAL GAS			(SO2) Sulfur Dioxide		0.02	LB/H	0		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	93	ММВТU/Н	(SO2)		0.05	LB/H	0		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	TREATED GAS COMPRESSOR ENGINE STACK WITH CATALYTIC CONVERTER WAUKESHA L-7042GSI		875	НР	Sulfur Dioxide (SO2)		0.46	LB/H	0		
						073		Sulfur Dioxide			LB/H	0		
TX-0501 TX-0501	TEXSTAR GAS PROCESS FACILITY	тх тх	07/11/2006 ACT 07/11/2006 ACT	TAIL GAS INCINERATOR STACK BOTTOM HEATERS (2)		15	MMBTU/H	(SO2) Sulfur Dioxide (SO2)		0.01	-	0		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	ALLISON 501KB GAS TURBINE GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)		0.67		0		
VA-0243	STANLEY FURNITURE	VA	12/01/2002 EST	BOILER, NAT GAS & OIL	NATURAL GAS	26.5	MMBTU/H	Sulfur Dioxide (SO2)	EMISSION LIMITS IN T/YR ONLY		T/YR	0		NOT AVAILABLE
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, DUCT BURNER	NATURAL GAS		ММВТU/Н	Sulfur Dioxide (SO2)		2.08	LB/H	0		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE , FUEL OIL	DISTILLATE FUEL OIL	2080	ММВТU/Н	Sulfur Dioxide (SO2)		98.9	LB/H	0		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT	NATURAL GAS	2350	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS AND GOOD COMBUSTION PRACTICES.	14	T/YR	0.0014	lb/MMBTU	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, AUXILIARY	NATURAL GAS	99	ММВТИ/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.	0.1	LB/H	0.001	lb/mmbtu	EACH UNIT
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, NATURAL GAS, NO DUCT BURNER FIRING	NATURAL GAS	1937	ММВТU/Н	Sulfur Dioxide (SO2)		1.74	LB/H	0		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	DUCT BURNERS	NATURAL GAS	385	ммвти/н	Sulfur Dioxide (SO2)		0.2	lb/mmbtu	0.2	lb/mmbtu	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT	NATURAL GAS	1150	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	14	T/YR	0.0028	lb/MMBTU	
									DRY FLUE GAS SCRUBBING SYSTEM USING A HYDRATED LIME SORBENT OR OTHER DEQ APPROVED SUITABLE					
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	MUNICIPAL WASTE COMBUSTION	SOLID WASTE	36500	T/YR	Sulfur Dioxide (SO2)	SORBENT. A CONTINUOUS EMISSION MONITORING SYSTEM CONTINUOUS EMISSION MONITORING	5.5	LB/H	0		NOT AVAILABLE
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO. 1	NATURAL GAS	43.2	MMBTU/H	Sulfur Dioxide (SO2)	SYSTEM AND GOOD COMBUSTION PRACTICES.	2.19	LB/H	0 05	lb/MMBTU	
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO.2	DISTILLATE FUEL OIL	43.2	MMBTU	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	2.19	LB/H	0		NOT AVAILABLE
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO. 3	NAT GAS OR DIS OIL	43.2	MMBTU	Sulfur Dioxide (SO2)	CONTINUOUS EMISSION MONITORING SYSTEM AND GOOD COMBUSTION PRACTICES.	4.76	T/YR	0		NOT AVAILABLE
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	TURBINE SHREDDER	DISTILLATE OIL	1 08	ммвти/н	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFER FUEL.	0.32		0		
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	200	ĸw	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT: < 0.05% S BY WT	0		0		

	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
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,	lb/mmbtu		UNCONTROLLED BECAUSE BOILER IS LESS THAN 40 MMBTU/H.
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L	lb/mmbtu	EACH UNIT	
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2	lb/MMBTU		
3	lb/mmbtu		
)		NOT AVAILABLE	1 of 2 units
	lb/mmbtu		One of two units.
,			
)		NOT AVAILABLE	One of two units
,			Combined units on either fuel trans
,		NOT AVAILABLE	Combined units on either fuel type
,			limit is fuel sulfur limit. No emission rate
)			limit.

				Summa	ry of SQ. Contr	ol Dotorminat	ion nor EDA's		AEB Database for Natural Cas	100 million PTU/hr			
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1 LIMIT 1 UNIT	EMISSION EMIS	STANDARD DARD LIMIT AVERAG SION TIME TUNIT CONDITION	E POLLUTANT COMPLIANCE NOTES
									FUEL SULFUR LIMIT: 0 8 GR/100 DSCF,				
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	NATURAL GAS	8	2 MW	Sulfur Dioxide (SO2)	ANNUAL AVG, AND 1.5 GR/100 DSCF ON HOURLY BASIS.	4 LB/H	0		
				HEATER, PIPELINE WATER BATH,				Sulfur Dioxide	FUEL SULFUR LIMIT: 0 8 GR/100 DSCF ANNUAL AVG.,				limit is fuel sulfur limit, no emission rate
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	NATURAL GAS	NATURAL GAS		5 MMBTU/H	(SO2)	1 5 GR/100 DSCF ON AN HOURLY BASIS	0	0		limit.
													NATURAL GAS SULFUR IS HIGHER THAN NATIONAL AV. IF PLANT IS UNABLE TO COMPLY WITH LIMIT IT MAY HAVE TO INSTALL A NATURAL GAS OR FLUE GAS SULFUR REMOVAL PROCESS TO PROTEC VISIBILITY AND DEPOSITION AT OLYMPIC NATIONAL PARK.
	SATSOP COMBUSTION TURBINE			(2) NAT GAS COMBINED CYCLE				Sulfur Dioxide					THE ORIGINAL PERMIT LIMITED SO2 EMISSIONS TO 0.11 PPM AND 1.
WA-0292	PROJECT SATSOP COMBUSTION TURBINE	WA	10/23/2001 ACT	COMBUSTION TURBINES	NATURAL GAS	32	5 MW	(SO2) Sulfur Dioxide		3.3 LB/H	0		LB/HR. THE ORIGINAL PERMIT LIMITED SO2 EMISSIONS TO 0.03 LB/HR AND
WA-0292	PROJECT	WA	10/23/2001 ACT	AUXILIARY BOILER	NAT GAS	29.	3 ММВТU/Н	(SO2)		0.07 LB/H	0		0.001 LB/MMBTU.
				PROCESS HEATER, PAPER MACHINE				Sulfur Dioxide					No emission rate limits, BACT is pollution
WI-0195	SENA NIAGARA MILL	WI	10/18/2002 ACT	P51	NATURAL GAS	34.	4 MMBTU/H	(SO2)	BACT IS USE OF NATURAL GAS	0	0		prevention
WI-0226	WPS - WESTON PLANT	wi	08/27/2004 ACT	NATURAL GAS FIRED BOILER	NATURAL GAS	46.	2 ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS FUEL ONLY	0.05 LB/H	0		
WI-0227	PORT WASHINGTON GENERATING STATION	wi	10/13/2004 ACT	COMBINED CYCLE COMBUSTION TURBINES (4 W/ DUCT BURNER, HRSG)	NATURAL GAS	209	6 MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	1.48 LB/H	0		FOUR (4) COMBINED CYCLE COMBUSTION TURBINES (2096 MMBTU/HR EACH.)
WI-0227	PORT WASHINGTON GENERATING		10/12/2004 8 phone A CT	DIESEL ENGINE GENERATOR (P05 /		7		Sulfur Dioxide	LOW SULFUR DIESEL FUEL OIL (0 05 WT%	0.281.0/11			
VVI-0227	PORT WASHINGTON GENERATING	VVI	10/13/2004 ACT	S05) NATURAL GAS FIRED AUXILLIARY	DIESEL FUEL OIL	7.	6 MMBTU/H	(SO2) Sulfur Dioxide	5)	0.38 LB/H	0		
WI-0227		wi	10/13/2004 ACT	BOILER	NATURAL GAS	97.	1 MMBTU/H	(SO2)	NATURAL GAS FUEL	0.06 LB/H	0.006 LB/MM	BTU CALCULATED	
	PORT WASHINGTON GENERATING							Sulfur Dioxide					
WI-0227	STATION	WI	10/13/2004 ACT	GAS HEATER (P06, S06)	NATURAL GAS	1	0 MMBTU/H	(SO2)	NATURAL GAS FUEL	0.02 LB/H	0.002 LB/MM	BTU CALCULATED	
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	NATURAL GAS	229.	8 ММВТU/Н	Sulfur Dioxide (SO2)	NATURAL GAS	0.0006 LB/MMBTU	0		
								Sulfur Dioxide	FUEL SULFUR CONTENT LIMIT (0 003 WT. % S)				
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	DIESEL BOOSTER PUMP (B27, S27)	DIESEL FUEL OIL	26	5 HP	(SO2)	GOOD COMBUSTION PRACTICES	0.54 LB/H	0		'ULTRA LOW SULFUR DIESEL FUEL'
								Sulfur Disside	GOOD COMBUSTION PRACTICES, ULTRA				
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	MAIN FIRE PUMP (DIESEL ENGINE)	DIESEL FUEL OIL	46	ОНР	Sulfur Dioxide (SO2)	LOW SULFUR (0.003 WT. % S) DIESEL FUEL OIL	0.94 LB/H	0		
		1		B63, S63; B64, S64 - NATURAL GAS		40		Sulfur Dioxide		0.04 ED/11			
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	STATION HEATER 1 AND 2	NATURAL GAS	0.7	5 MMBTU/H	(SO2)	NATURAL GAS	0.0004 LB/H	0	NOT AVAILABL	E (LIMIT IS FOR EACH UNIT)
WI-0228	WPS - WESTON PLANT	wi	10/19/2004 ACT	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173 0	7 MMBTU/H	Sulfur Dioxide (SO2)	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.	0.1 LB/MMBTU	0		POLLUTANT LIMITS INCLUDE STARTUP / SHUTDOWN AND ATOMIZEF CHANGEOUT. PERMITTEE MAY ONLY USE ACTUAL HOURS OF OPERATION WHEN DETERMINING TIME AVERAGED EMISSIONS. WHEN CONDUCTING MAINTENANCE ON CONTROL SYSTEM (ROUTIN ATOMIZER CHANGEOUT): 3491 8 POUNDS PER HOUR ON A 3-HOUR AVERAGE AND 1508.9 POUNDS PER HOUR ON A 24-HOUR AVERAGE. CONTROLLED EMISSIONS: SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 621 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 3-HOUR PERIOD AND SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 589 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 24-HOUR PERIOD

								AER Database for Gaseous Fuel <						
BLCID		FACULTY STATE		DEOCTOS NAME	PRIMARY FUEL	THROUGHPUT THROUGHPUT UNIT	DOLULTANT		EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME CONDITION	
	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION FUEL SULFUR CONTENT LIMITS AS	1		LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
				DUCT BURNER FOR STEAM			Sulfur Dioxide	FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY					ASSUMED @	ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO
0037 KENAI R	EFINERY	AK	03/21/2000 ACT	GENERATION, E-1410	NATURAL GAS*	36.5 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	0		500	PPM @ 15% O2	15% 02	NSPS FOR SO2.
							Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.						EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S TOGETHER. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. LIMITS ARE PROVIDED BASED ON FUEL CONTENT (SEE POLLUTION PREVENTION DESCRIPTION). ESTIMATED EMISSIONS ARE 21.7 T/YR, BUT THIS IS NOT A LIMIT. ADDITIONAL LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF FOR EQUIPMENT FIRED ON REFINERY GAS, AND 500 PPM
0037 KENAI R	FINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101B	NATURAL GAS*	165 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	0		0			SO2 FOR EQUIPMENT NOT FIRED ON REFINERY GAS.
-0037 KENAI R	EFINERY	АК	03/21/2000 ACT	POWERFORMER PREHEATER, H201	NATURAL GAS*	31.8 MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 SO IT IS NOT SUBJECT TO BACT-PSD.	0		0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
							Sulfur Dioxide	SOURCE IS NOT SUBJECT TO FUEL LIMITATIONS UNDER BACT-PSD BECAUSE IT WAS INSTALLED	-					ESTIMATED EMISSIONS ARE 6.7 T/YR, BUT THIS IS
K-0037 KENAI R	FINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H202	NATURAL GAS*	51 MMBTU/H	(SO2)	PRIOR TO 1975.	0		0			NOT AN EMISSION LIMIT.
-0037 KENAI R		АК	03/21/2000 ACT	POWERFORMER PREHEATER, H203		27.9 MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 AND IS THEREFORE NOT SUBJECT TO PSD.	0		0			ESTIMATED EMISSIONS ARE 3.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
K-0037 KENAI R	FINERY	АК	03/21/2000 ACT	POWERFORMER REHEATER, H204	NATURAL GAS*	53.8 MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT FUEL LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR, NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. ESTIMATED SO2 EMISSIONS ARE 7.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
				HYDROCRACKER RECYCLE GAS			Sulfur Dioxide	FUEL SULFUR LIMITS AS FOLLOWS IS CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS,						EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 5.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO
K-0037 KENAI R	FINERY	AK	03/21/2000 ACT	HEATER, H401	NATURAL GAS*	38.9 MMBTU/H	(SO2)	168 PPMV H2S.	0		0			NSPS FOR SO2. EMISSIONS INFORMATION IS COMBINED FOR SO2 AND
				HYDROCRACKER RECYCLE GAS			Sulfur Dioxide	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR;	6					H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. ESTIMATED EMISSIONS OF SO2 ARE 5 0 T/YR, BUT
K-0037 KENAI R	-FINERY	AK	03/21/2000 ACT	HEATER, H402	NATURAL GAS*	38 MMBTU/H	(SO2)	REFINERY GAS, 168 PPMV H2S. THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01%			0			THIS IS NOT AN EMISSION LIMIT.
-0037 KENAI R	FINERY	АК	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1410	NATURAL GAS*	50.9 MMBTU/H	Sulfur Oxides (SOx	SULFUR; SULFUR; REFINERY GAS, 168 PPMV H2S. THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE	0		0			NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
			03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1400		50.9 MMBTU/H		CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR;) REFINERY GAS, 168 PPMV H2S.	6					ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.

				Summar	y of SO ₂ Contro	ol Determination per EPA's I	RACT/BACT/LA	AER Database for Gaseous Fuel <	< 100 million BTU/hr			1	
						THROUGHPUT			EMISSION LIMIT EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
LCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION FUEL SULFUR CONTENT LIMITS AS	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					ESTIMATED EMISSIONS WHEN BURNING LPG, NG, OR
037	KENAI REFINERY	АК	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1400	NATURAL GAS*	36.5 MMBTU/H	Sulfur Dioxide (SO2)	LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0	500) PPM @ 15% O2	ASSUMED 15%	DIESEL, ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
							Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MB H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION
037	KENAI REFINERY	АК	03/21/2000 ACT	REFINERY FLARE, J 801	NATURAL GAS*	1 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	0	0)		LIMIT. THIS SOURCE IS SUBJECT TO NSPS FOR SO2.
				ELECTRIC GENERATOR CAT 3412,			Sulfur Disuida	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					
0037	KENAI REFINERY	АК	03/21/2000 ACT		DIESEL	4.8 MMBTU/H	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0	þ		ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
0027	KENAI REFINERY	АК	03/21/2000 ACT	STEWART-STEVENSON GENERATOR, E6801	DIESEL	6.1 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
037	KENALKETINEKT	AN	03/21/2000 &1155P,AC1	10001	DILGLE	0.1 101010/11	(302)	FUEL SULFUR CONTENT LIMITS AS	500 FFIM	0			
1037	KENAI REFINERY	АК	03/21/2000 ACT	NORTH CATERPILLAR, P605A	NATURAL GAS	5.6 MMBTU/H	Sulfur Dioxide (SO2)	FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR SO2, BUT THIS IS NOT AN EMISSION LIMIT.
037	KENALKETINEKT		03/21/2000 &1105p,AC1	NORTH CATERFILLAR, FOOSA	NATORAL GAS	3.0 101010711	(302)	FUEL SULFUR CONTENT LIMITS AS	500 FFINI				
037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CATERPILLAR, P605B	NATURAL GAS	830 HP	Sulfur Dioxide (SO2)	FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
727	KENAI REFINERY	АК	03/21/2000 ACT	NORTH CUMMINS, P708A	DIESEL	290 HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
			03/21/2000 @n059,AC1			250 11	Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV		0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS
037	KENAI REFINERY	АК	03/21/2000 ACT	SOUTH CUMMINS, P708B	DIESEL	290 HP	(SO2)	H2S.	500 PPM	0)		NOT AN EMISSION LIMIT.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG,					
0037	KENAI REFINERY	AK	03/21/2000 ACT	UPPER TANK FARM CAT 3412DT, P708C	DIESEL	660 HP	Sulfur Dioxide (SO2)	0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500 PPM	n)		ESTIMATED EMISSIONS ARE 0 5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
			,				Sulfur Dioxide	NONE INDICATED. SOURCE IS NOT SUBJECT TO BACT- PSD BECAUSE IT WAS INSTALLED PRIOR TO					ESTIMATED EMISSIONS ARE 7.4 T/YR, BUT THIS IS
037	KENAI REFINERY	AK	03/21/2000 ACT	HOT OIL HEATER, H609	NATURAL GAS*	56 MMBTU/H	(SO2)	1975.	0	0)		NOT AN EMISSION LIMIT.
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;					EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE
)37	KENAI REFINERY	АК	03/21/2000 ACT	HYDROGEN REFORMER FURNACE, H1001	NATURAL GAS*	152.3 MMBTU/H	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0	0			20 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.

										00 million B					
							THROUGHPUT		EF		EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
CID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
				REACTION FURNACE BURNER,				Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS 168						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS
37	KENAI REFINERY	AK	03/21/2000 ACT	H1101	NATURAL GAS*	5.2	2 MMBTU/H	(SO2)	PPMV H2S.	0		0			ALSO SUBJECT TO NSPS FOR SO2.
								Sulfur Dioxide	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV						ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS
037	KENAI REFINERY	АК	03/21/2000 ACT	COOLING TOWER CAT, P719C	NATURAL GAS	1.:	1 MMBTU/H	(SO2) Sulfur Dioxide	H2S.	500	PPM	0			NOT AN EMISSION LIMIT. ESTIMATED EMISSIONS ARE 14.4 T/YR, BUT THIS IS
037	KENAI REFINERY	АК	03/21/2000 ACT	SULFUR RECOVERY UNIT		19.3	3 LTPD	(SO2)	NONE INDICATED	0		0			NOT AN EMISSION LIMIT.
0007	KENAI REFINERY	АК	03/21/2000 :ACT	TAIL GAS BURNER, H1105	NATURAL GAS*		2 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 3 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO
037		AN			NATURALGAS				FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01%	0		0			SUBJECT TO NSPS FOR SO2. EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0 2 T/YR, BUT
037	KENAI REFINERY	AK	03/21/2000 ACT	#4 REHEATER STARTUP BURNER, H1106	NATURAL GAS*	1.9	9 ММВТИ/Н	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
0037	KENAI REFINERY	АК	03/21/2000 ACT	PRIP ABSORBER FEED FURNACE, H1201/1203	NATURAL GAS*	10,4	4 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			FOR SO2 AND H2S. EMISSION LIMIT IS A PROVATED IN COMBINATION FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
						-			NONE INDICATED AS SOURCE WAS	-					SOURCE IS NOT SUBJECT TO PSD REQUIREMENTS BECAUSE IT WAS INSTALLED PRIOR TO 1975.
037	KENAI REFINERY	АК	03/21/2000 ACT	CRUDE HEATER, H101A	NATURAL GAS*	140	0 ММВТU/Н	Sulfur Dioxide (SO2)	INSTALLED PRIOR TO 1975 AND IS NOT SUBJECT TO BACT-PSD.	0		0			ESTIMATED EMISSIONS ARE 18.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
								Sulfur Dioxide	A PRORATED CONCENTRATION OF THE FOLLOWING FUEL LIMITS IS CONSIDERED BACT: DIESEL FUEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01%						COMBINED EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S. ESTIMATED EMISSIONS OF SO2 ARE 6.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ADDITIONAL EMISSION LIMITS ARE: A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. THIS SOURCE IS ALSO SUBJECT TO
037	KENAI REFINERY	АК	03/21/2000 ACT	POWERFORMER REHEATER, H205	NATURAL GAS*	48.8	8 MMBTU/H	(SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S. FUEL SULFUR CONTENT LIMITS AS	0		0			NSPS FOR SO2. EMISSIONS INFORMATION IS COMBINED FOR SO2 AND
0037	KENAI REFINERY	АК	03/21/2000 ACT	HYDROCRACKER FRACTIONATER REBOILER, H403	NATURAL GAS*	50	0 MMBTU/H	Sulfur Dioxide (SO2)	FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S. FUEL SULFUR CONTENT IS LIMITED AS	0		0			H2S. ESTIMATED SO2 EMISSIONS ARE 6.6 T/YR. SOURCE IS ALSO SUBJECT TO NSPS. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. EMISSIONS INFORMATION FOR SO2 AND H2S IS
037	KENAI REFINERY	АК	03/21/2000 ACT	RESIDUAL OIL HEATER, H612	NATURAL GAS*	22.:	2 ММВТU/Н	Sulfur Dioxide (SO2)	FOLLOWS: FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			COMBINED. ESTIMATED SO2 EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSP5 FOR SO2. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								Sulfur Dioxide	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO	-					CONTROLS NOT INDICATED. ESTIMATED EMISSIONS ARE
1037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H701	NATURAL GAS*	36 5	5 ММВТU/Н	(SO2)	1975. NONE INDICATED. THIS SOURCE IS NOT	0		0			4.8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
									SUBJECT TO						ESTIMATED EMISSIONS ARE 4 8 T/YR, BUT THIS IS

			Summar	y of SO ₂ Contro	l Determinati	on per EPA's l	RACT/BACT/LA	ER Database for Gaseous Fuel	< 100 million l	BTU/hr			1	
						THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
CID FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								FUEL SULFUR EONTENT LIMITS AS FOLLOWS: DIESEL						
								FUEL, 0.35% SULFUR; NATURAL GAS,						
								0 01% SULFUR;						
			NATURAL GAS SUPPLY HEATER,				Sulfur Dioxide	LIQUIFED PETROLEUM GAS, 0.01% SULFUR; REFINERY						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. ESTIMATED EMISSIONS OF SO2 ARE 0.1
037 KENAI REFINERY	АК	03/21/2000 ACT	H704	NATURAL GAS*	:	2 MMBTU/H	(SO2)	GAS, 168 PPMV H2S.	500	PPM	0			T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
								FUEL SULFUR CONTENT LIMITS AS						
								FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS,						
								0 01% SULFUR;						
							Sulfur Dioxide	LIQUIFIED PETROLEUM GAS, 0.01%						
037 KENAI REFINERY	АК	03/21/2000 ACT	FIRED STEAM GENERATOR, H801	NATURAL GAS*	3:	2 MMBTU/H	(SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.	500) PPM	0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
			,					FUEL SULFUR CONTENT LIMITS AS						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL FUEL. 0.35% SULFUR: NATURAL GAS.						WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3
								0 01% SULFUR;						HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								LIQUIFIED PETROLEUM GAS, 0.01%						ESTIMATED SO2 EMISSIONS ARE 1 5 T/YR, BUT THIS
037 KENAI REFINERY	АК	03/21/2000 ACT	PRIP RECYCLER H2 FURNACE, H1202		11	2 MMBTU/H	Sulfur Dioxide (SO2)	SULFUR; REFINERY GAS, 168 PPMV H2S.			0			IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	AK	03/21/2000 &110sp,AC1	FRIF RECTCEER TIZ FORNACE, THIZOZ	NATORAL GAS	11.		(302)	FUEL SULFUR CONTENT LIMITS AS			0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL						WITH H2S. EMISSION LIMIT IS A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;						CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								LIQUIFIED PETROLEUM GAS, 0.01%						ESTIMATED EMISSIONS OF SO2 ARE 12.0 T/YR, BUT
							Sulfur Dioxide	SULFUR; REFINERY						THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO
037 KENAI REFINERY	АК	03/21/2000 ACT	VACUUM TOWER HEATER, H1701	NATURAL GAS*	9:	1 MMBTU/H	(SO2)	GAS, 168 PPMV H2S. FUEL SULFUR CONTENT LIMITS AS	()	0			SUBJECT TO NSPS FOR SO2. EMISSIONS INFORMATION IS COMBINED FOR SO2 AND
								FOLLOWS: DIESEL						H2S. EMISSION LIMITS ARE A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS,						CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER
								0 01% SULFUR; LIQUIFED PETROLEUM GAS, 0.01%						THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4
							Sulfur Dioxide	SULFUR; REFINERY						T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE
037 KENAI REFINERY	AK	03/21/2000 ACT	HOT GLYCOL HEATER, H802	NATURAL GAS*	10.3	в ммвти/н	(SO2)	GAS, 168 PPMV H2S.	()	0			IS ALSO SUBJECT TO NSPS FOR SO2.
								FUEL SULFUR CONTENT LIMITS AS						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE
								FOLLOWS: DIESEL						8.5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
								FUEL, 0.35% SULFUR; NATURAL GAS,						SOURCE IS ALSO SUBJECT TO NSPS. EMISSION LIMITS
			HYDROCRACKER STABILIZER				Sulfur Dioxide	0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168						ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2
037 KENAI REFINERY	AK	03/21/2000 ACT		NATURAL GAS*	64.4	4 MMBTU/H	(SO2)	PPMV H2S.	(D	0			AVERAGED OVER 3 HOURS.
								FUEL SULFUR CONTENT IS LIMITED						EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								ACCORDING TO THE FOLLOWING: DIESEL FUEL, 0.35% SULFU	R:					FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER
								NATURAL	.,					THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE
							Cultur Disuida	GAS, 0.01% H2S; LPG, 0.01% SULFUR; REFINERY						HOURS. ESTIMATED SO2 EMISSIONS ARE 0.2 T/YR,
37 KENAI REFINERY	АК		#1 REHEATER STARTUP BURNER, H1102	NATURAL GAS*	1.6	5 MMBTU/H	Sulfur Dioxide (SO2)	GAS, 168 PPMV H2S.	()	0			BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
										1				EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL						FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3
								FUEL, 0.35% SULFUR; NATURAL GAS,						HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
								0 01% SULFUR;						ESTIMATED SO2 EMISSIONS ARE 0 2 T/YR, BUT THIS
037 KENAI REFINERY	АК	03/21/2000 ACT	#2 REHEATER STARTUP BURNER, H1103	NATURAL GAS*	1 1	5 ММВТИ/Н	Sulfur Dioxide (SO2)	LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.			0			IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
	/ WX				1.1.		(332)	FUEL SULFUR CONTENT LIMITS AS	`	1	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION
								FOLLOWS: DIESEL						WITH H2S. EMISSION LIMIT IS A PRORATED
								FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR;						CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED
								LIQUIFIED PETROLEUM GAS, 0.01%						OVER 3 HOUR. ESTIMATED EMISSIONS OF SO2 ARE 0.1
		00 /04 /0000 0 · · · · · ·	#3 REHEATER STARTUP BURNER,		_		Sulfur Dioxide	SULFUR; REFINERY						T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS
037 KENAI REFINERY	AK	03/21/2000 ACT	H1104	NATURAL GAS*	1 0	5 MMBTU/H	(SO2)	GAS, 168 PPMV H2S. LIMIT FUEL SULFUR CONTENT TO: 200	(ر ا	0			SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
								PPM FUEL GAS						
ALPINE DEVELOPMENT PROJECT,		00/01/1005 0					Sulfur Dioxide	H2S, OR FUEL OIL SULFUR CONTENT 0.15		PPM @ 15%				DUEL FUEL FIRED TURBINE. OIL-FIRED OPERATIONS
056 CENTRAL PROCESSING FAC ALPINE DEVELOPMENT PROJECT,	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 11 2 MW	FUEL GAS	11.	2 MW	(SO2) Sulfur Dioxide	BY WEIGHT	150	02 PPM @ 15%	150	PPM @ 15% O2		LIMITED TO 500 HRS ANNUALLY
D56 CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 36,700 HP	FUEL GAS	27.	1 MW	(SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150) 02	150	PPM @ 15% O2		

				Summar	v of SO. Control Dotorminati	on nor EDA's I		ER Database for Gaseous Fuel <	100 million B	TU/br				
						THROUGHPUT				EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME ALPINE DEVELOPMENT PROJECT,	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT PPM @ 15%	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
	CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 25 8 MW	FUEL GAS 25800	o кw	(SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150		0			
	ALPINE DEVELOPMENT PROJECT,			HEATER, CRUDE PRODUCTION, 65.6			Sulfur Dioxide							
	CENTRAL PROCESSING FAC ALPINE DEVELOPMENT PROJECT,	AK	02/01/1999 ACT	MMBTU/H HEATER, CRUDE PRODUCTION, 65.6	FUEL GAS 65.6	6 MMBTU/H	(SO2) Sulfur Dioxide	FUEL GAS H2S NOT TO EXCEED 200 PPMV	0		0			Fuel limit no emission rate limit.
	CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	MMBTU/H	FUEL GAS 65.0	6 ММВТН/Н	(SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV.	0		0			fuel sulfur limit no emission rate limit
	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	HEATER, UHM, 20 MMBTU/H	FUEL GAS 20	0 MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING USING LIQUID FUEL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0.5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limit. No emission rate limit
	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, HMU, 20 MMBTU/H	FUEL GAS 20	0 MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING ON FUEL OIL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0 5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limits. No emission rate limits
	ALPINE DEVELOPMENT PROJECT,						Sulfur Dioxide	FUEL OIL SULFUR CONTENT NOT TO EXCEED 0.15%						
	CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	IC ENGINES, 2 MW	FUEL OIL	2 MW	(SO2)	SULFUR BY WEIGHT	0		0			SULFUR LIMIT ON FUEL
					REFINERY FUEL									
17.0046			04/44/2005 0 share ACT	DISTILLATE HYDROTREATER	GAS OR NATURAL		Sulfur Dioxide		25	555.41/				THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CHARGE HEATER	GAS 2: REFINERY FUEL	5 MMBTU/H	(SO2)	S LIMITED TO 35 PPM.	35	PPMV	0			CONCENTRATION OF THE REFINERY FUEL GAS.
				DISTILLATE HYDROTREATER	GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPLITTER REBOILER		7 MMBTU/H	(SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
							Cultur Disvide							
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TANK FARM THERMAL OXIDIZER	GAS AND GASES FROM TANKS		Sulfur Dioxide (SO2)		35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
/12 00 10			0 I/ 1 I/ 2005 all 55p), let		NATURAL GAS OR		(002)							
				WASTEWATER TREATMENT PLANT	REFINERY FUEL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	THERMAL OXIDIZER	GAS		(SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	PPMV	0			CONCENTRATION OF THE REFINERY FUEL GAS.
47-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFER PIT NOS. 1 AND 2			Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR PITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33 5	lb/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY
A2-0040		~ <u>~</u>	04/14/2005 &103p,AC1	SOLIENTI NOS. I AND Z	REFINERY FUEL		(302)			20/11	0		NOTAVALABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET
				CATALYTIC REFORMING UNIT	GAS AND NATURAL		Sulfur Dioxide							CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CHARGE HEATER		2 MMBTU/H	(SO2)	SULFUR LIMITED TO 35 PPM IN FUEL.	35	PPMV	0		NOT AVAILABLE	UNIT.
				TRUCK AND RAIL CAR LOADING	REFINERY FUEL GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTATION
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	RACK THERMAL OXIDIZERS		3 MMBTU/H	(SO2)		35	PPMV	0			OF THE REFINERY FUEL GAS.
T					REFINERY FUEL		Culture Discutzto							THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 :ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 1	GAS AND NATURAL GAS 192	2 MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	25	PPMV	n		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT	REFINERY FUEL GAS OR NATURAL	9 MMBTU/H	Sulfur Dioxide	S LIMITED TO 35 PPM.		PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
, 12-0040		/ 16	0-7, 1-7, 2003 GHD3P,ACT		REFINERY FUEL		(302)		55		. 0		AVAILABLE	CONCENTRATION OF THE REFINERT FOLLOAD.
				CATALYTIC REFORMING UNIT	GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DEBUTANIZER REBOILER		2 MMBTU/H	(SO2)	S LIMIT OF 35 PPM.	35	PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
				BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR	REFINERY FUEL GAS OR NATURAL		Sulfur Dioxide							THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CHARGE HEATER		1 MMBTU/H	(SO2)	35 PPM SULFUR LIMIT ON FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
				BUTANE CONVERSION UNIT	REFINERY FULE									
A7 004C		47	04/14/2005 Sabar ACT	DEHYDROGENATION REACTOR	GAS OR NATURAL GAS 328		Sulfur Dioxide	SULFUR LIMIT OF 35 PPM IN FUEL BURNED.			_			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	INTERHEATER	GAS 328 REFINERY FUEL	8 MMBTU/H	(SO2) Sulfur Dioxide		35	PPMV	0		NUT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS. THIS LIMIT IS FOR SULFUR, AS H2S, AND IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	VACUUM CRUDE CHARGE HEATER		1 ММВТU/Н	(SO2)		35	PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
				HYDROCRACKER UNIT CHARGE	REFINERY FUEL		Sulfur Dioxide							THIS LIMIT FOR SULFUR, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HEATER HYDROCRACKER UNIT MAIN	GAS OR NG 70 REFINERY FUEL	D MMBTU/H	(SO2) Sulfur Dioxide	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
		1	1	INTURUERAL KERTINIT MAIN	INFEINERY FUEL								1	THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET

				Summa	wof SO Contro	N Determination per EDA's		AER Database for Gaseous Fuel <	< 100 million BTU/br				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL		POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
				NAPHTHA HYDROTREATER CHARGE	REFINERY FUEL		Sulfur Dioxide						THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HEATER	GAS OR NG REFINERY FUEL	21.4 MMBTU/H	(SO2)	S LIMITED TO 35 PPM	35 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
				BUTANE CONVERSION UNIT	GAS AND NATURAL		Sulfur Dioxide	SULFUR LIMITED TO 35 PPM IN FUEL					THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	ISOSTRIPPER REBOILER	GAS NATURAL GAS OR	222 MMBTU/H	(SO2)	BURNED.	35 PPMV	0			CONCENTRATION OF THE REFINERY FUEL GAS. THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLE
				ATMOSPHERIC CRUDE CHARGE	REFINERY FUEL		Sulfur Dioxide						CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HEATER	GAS REFINERY FUEL	346 MMBTU/H	(SO2)	35 PPM SULFUR LIMIT IN FUEL.	35 PPMV	0		NOT AVAILABLE	UNIT.
					GAS OR NATURAL		Sulfur Dioxide						THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROGEN REFORMER HEATER	GAS REFINERY FUEL	1435 MMBTU/H	(SO2)	S LIMITED TO 35 PPM	35 PPMV	0		NOT AVAILABLE	CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPRAY DRYER HEATER	GAS OR NATURAL GAS	44 MMBTU/H	Sulfur Dioxide (SO2)		35 PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY UNITS 1 AND 2			Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR RECOVERY UNITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2. ALL GASES DISCHARGED FROM THE TAIL GAS TREATMENT UNIT MUST BE ROUTED	33.5 LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
47.0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TAIL GAS TREATMENT UNIT			Sulfur Dioxide (SO2)	TO THE SULFUR RECOVERY PLANT THERMAL OXIDIZER	33.5 LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY
				SULFUR RECOVERY PLANT	REFINERY FUEL GAS OR NATURAL		Sulfur Dioxide			0			THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	THERMAL OXIDIZER	GAS REFINERY FUEL	100 MMBTU/H	(SO2)		33.5 LB/H	0		NOT AVAILABLE	PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY PLANT THERMAL OXIDIZER	GAS OR NATURAL GAS	100 MMBTU/H	Sulfur, Total Reduced (TRS)		0 089 LB/H	0		NOT AVAILABLE	
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DELAYED COKING UNIT CHARGE HEATER NOS. 1 AND 2	REFINERY FUEL GAS OR NATURAL GAS	99.5 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide	FUEL LIMITED TO 35 PPM S. SULFUR RECOVERY SYSTEM, LOW SULFUR	35 PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
CO-0046	EXCEL CORPORATION - FT. MORGAN	со	04/27/2000 ACT	WASTE WATER TREATMENT PLANT		54 MMGAL/MO	(SO2)	CONTENT WATER.	98 % REDUCTION	0			
CO-0046	EXCEL CORPORATION - FT. MORGAN	со	04/27/2000 ACT	FLARE (B-9)	BIOGAS	67.5 MMBTU/H	Sulfur Dioxide (SO2)	ALL LIMITS ARE ON A FACILITY WIDE BASIS, NO OTHER INFORMATION IS AVAILABLE.	98 % REDUCTION	0			
CO-0046	EXCEL CORPORATION - FT. MORGAN	со	04/27/2000 ACT	STEAM BOILER (B-1)	NATURAL GAS / BIOGAS	20.9 MMBTU/H	Sulfur Dioxide (SO2)	SULFUR RECOVERY SYSTEM. ALL LIMITS ARE ON A FACILITY WIDE BASIS, NO OTHER INFORMATION AVAILABLE. SULFUR RECOVERY SYSTEM. ALL LIMITS	98 % REDUCTION	0			
					NATURAL		Sulfur Dioxide	ON A FACILITY WIDE BASIS, NO OTHER					
CU-0046	EXCEL CORPORATION - FT. MORGAN		04/27/2000 ACT	STEAM BOILER 2 (B-3)	GAS/BIOGAS	25.1 MMBTU/H	(SO2)	INFORMATION IS AVAILABLE.	98 % REDUCTION	U			The fire pump engine is an Emergency Stationary Compression
EL 0340	HIGHLANDS ETHANOL FACILITY		12/10/2009 EST		ULSD fuel oil		Sulfur Dioxide (SO2)	Ultra low sulfur fuel oil (ULSFO)	0.0015 % S				Ignition Internal Combustion Engine (Stationary ICE) and shall compl with applicable provisions of 40 CFR 60, Subpart IIII.
<u>1 E-0318</u>		11	12/10/2003 &IIID20:E21	Emergency Fired Pump			Sulfur Dioxide		0.0013	0			with applicable provisions of 40 CFR 60, Subpart IIII. Use of low sulfur fossil fuels such as ULSD FO, natural gas or propane in the backup boiler insures that uncontrolled SO2 emissions are less than 0.32 lb SO2/mmBtu. Therefore, no specific limit from 40 CFR 60
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Backup 198 mmBtu/hr boiler 198 mmBtu/hr Biomass Fueled	Natural gas	0	(SO2) Sulfur Dioxide	Limestone injection in the DED bailors to	0.0056 LB/MMBTU	0			NSPS Subpart Db applies to the backup boiler.
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Boiler	Stillage & biomass	198 MMBTU	(SO2)	Limestone injection in the BFB boilers to control SO2 and HCI	0.06 LB/MMBTU	0			A These emergency generators are Stationary Compression Ignition
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Emergency Generators	NAT & REFINERY	0 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		0.0015 % S	0			Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification.
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	CRUDE HEATER (2)	GAS	281.1 (EACH)	(SO2)	LOW SULFUR FUEL	11.25 LB/H	0.0044 L	.B/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON CHARGE HEATER	NAT & REFINERY GAS	69.4 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.78 LB/H	0.041	.B/MMBTU	CALCULATED	
				LGO HYDROCARBON STRIPPER			Sulfur Dioxide						
	LOUISIANA REFINING DIVISION		10/21/1999 ACT 10/21/1999 ACT	REBOILER DEASPHALTING HEATER	NAT & REFINERY GAS	62.1 MMBTU/H	(SO2) Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2.49 LB/H 8.85 LB/H		.B/MMBTU .B/MMBTU	CALCULATED	
3143				MARINE LOADING VAPOR			Sulfur Dioxide		0.03 20/11	0.04 L	,	5.2000.120	
A-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	COMBUSTOR		50000 BBL	(SO2)	NONE INDICATED	0.13 LB/H	0			

				-									
				Summar	y of SO ₂ Contro	ol Determinati	THROUGHPUT	RACT/BACT/LA	ER Database for Gaseous Fuel <	100 million BTU/hr	STANDARD STANDARD EMISSION EMISSION	STANDARD LIMIT AVERAGE TIME	E
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT LIMIT UNIT		POLLUTANT COMPLIANCE NOTES
140	LOUISIANA REFINING DIVISION		10/21/1999 ACT	HGO HYDROCARBON CHARGE HEATER		08	8 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	3.95 LB/H	0 04 LB/MMBTU	CALCULATED	
0149		LA	10/21/1999 & hbsp,Act	ILATEN	NAT & REFINERY	56.		Sulfur Dioxide		5.55 EB/11	0.04 EB/101010	CALCOLATED	
0149	LOUISIANA REFINING DIVISION	LA		BOILER NO. 1	GAS	35	0 MMBTU/H	(SO2)	USE OF LOW SULFUR FUEL	11.21 LB/H	0.032 LB/MMBTU		
0140				HF ALKYLATION MAIN FRACTIONATOR REBOILER	NAT & REFINERY GAS	269	6 MMBTU/H	Sulfur Dioxide (SO2)					
0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HGO HYDROCARBON STRIPPER	GAS NAT & REFINERY	208.	6 IVIIVIBTO/H	(SU2) Sulfur Dioxide	LOW SULFUR FUELS	10.75 LB/H	0 04 LB/MMBTU	CALCULATED	
-0149	LOUISIANA REFINING DIVISION	LA		REBOILER	GAS	7	8 MMBTU/H	(SO2)	LOW SULFUR FUEL	3.13 LB/H	0 04 LB/MMBTU	CALCULATED	
-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNIT #3				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA) AND THERMAL OXIDIZER	56.86 LB/H	PPMV @ 0% 60 EXCESS AIR	EMISSION CAP, SEE NOTES	SULFUR RECOVERY UNIT EMISSIONS FROM THERMAL OXIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A CAP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 T/YR (60 PPMV)
				SULFUR RECOVERY UNITS NO. 1				Sulfur Dioxide	AMINE BASED SCRUBBER (CLAUS/MDEA)AND THERMAL		PPMV @ 0%	EMISSION CAP,	
149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	AND NO. 2				(SO2) Sulfur Dioxido	OXIDIZER.	56.86 LB/H	60 EXCESS AIR	SEE NOTES	T/YR (60 PPMV)
)149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	COKER HEATER		241.	1 MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	9.64 LB/H	0 04 LB/MMBTU	1	
-							-,	Sulfur Dioxide			,	1	THERE IS AN EMISSION CAP FOR MAXIMUM SO2
0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR PLANT NO. 3 FUGITIVES		-		(SO2) Sulfur Diovido		0.07 LB/H	0		EMISSIONS
0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	FCC REGENERATOR		11	0 TO 130 MBBL/D	Sulfur Dioxide (SO2)	BELCO WET GAS SCRUBBER	450 LB/H	0	NOT AVAILABLE	
	ORION REFINING CORP (NOW				REFINERY FUEL		, ,	Sulfur Dioxide					
	VALERO)	LA		HEATER F-72-703	GAS	52	8 MMBTU/H	(SO2)	LOW SULFUR REFINERY FUEL GAS	14.2 LB/H	0.027 LB/MMBTU		
	ORION REFINING CORP (NOW VALERO)	LA		MARINE TANK VESSEL LOADING OPERATIONS				Sulfur Dioxide (SO2)	NONE INDICATED	3.3 LB/H	0		
	ORION REFINING CORP (NOW		,,					Sulfur Dioxide					
	VALERO)	LA	01/10/2002 ACT	HEATER H-15-01A		4	6 MMBTU/H	(SO2)	COMBUSTION OF LOW SULFUR FUEL	1.2 LB/H	0.0261 LB/MMBTU		
	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	HEATER H-15-01B		4	6 MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	1.2 LB/H	0.0261 LB/MMBTU		
	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	SULFUR RECOVERY UNITS 1 AND 2				Sulfur Dioxide (SO2)	EFFICIENCY OF SULFUR RECOVERY PROCESS TOGETHER WITH OXIDATION OF RESIDUAL SULFUR COMPOUNDS LIMITS SO2 EMISSIONS TO 250 PPM EFFICIENCY OF SULFUR RECOVERY PROCESS TOGETHER	103 LB/H	250 PPMV	@ 0% EXCESS AIR	
	ORION REFINING CORP (NOW		o. (Sulfur Dioxide	WITH OXIDATION OF RESIDUAL SULFUR COMPOUNDS	515/0		@ 0% EXCESS	
	VALERO) ORION REFINING CORP (NOW	LA	01/10/2002 ACT	SULFUR RECOVERY UNIT NO. 3				(SO2) Sulfur Dioxide	LIMITS SO2 EMISSIONS TO 250 PPM	5 LB/H	250 PPMV	AIR	
0166	VALERO)	LA	01/10/2002 ACT	FLARE NO.1 (EMISSION PT. 15-77)		60.	7 ММВТИ/Н	(SO2)		133 LB/H	0		
	ORION REFINING CORP (NOW VALERO)		01/10/2002 8 share 4 CT			CO		Sulfur Dioxide		12210/11		1	
-0100	VALENUJ		01/10/2002 ACT	FLARE NO. 2 (EMISSION PT. 12-81)		60.	7 MMBTU/H	(SO2)	FIXED ROOF STORAGE TANK AND	133 LB/H	U		
	ORION REFINING CORP (NOW							Sulfur Dioxide	SUBMERGED FILL				
0166	VALERO)	LA	01/10/2002 ACT	SPENT SULFURIC ACID STORAGE				(SO2)	LOADING FIXED ROOF STORAGE TANK AND	1.1 LB/H	0		
	ORION REFINING CORP (NOW							Sulfur Dioxide	SUBMERGED FILL			1	
-0166	VALERO)	LA	01/10/2002 ACT	SPENT SULFURIC LOADING				(SO2)	LOADING	1.1 LB/H	0		
				PIPESTILL, COKER, HYDROCRACKING, & LIGHT				Sulfur Dioxide	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160			1	
-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	ENDS FURNACES				(SO2)	PPMV (0.01 GR/DSCF)	0 034 LB/MMBTU	0.034 LB/MMBTU	1	
								Ì	LIMIT CONCENTRATION OF H2S IN FUEL				
-0206	BATON ROUGE REFINERY	IA		PIPESTILL, COKER, CAT COMPLEX, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034 LB/MMBTU	0.034 LB/MMBTU		
5200			52, 10, 2004 GIDSP,ACI	Comp, LIGHT LINDS FORMACLS			+	(302)	LIMIT CONCENTRATION OF H2S IN FUEL		0.004 20/101010	1	1
0206	BATON ROUGE REFINERY	LA		REFORMING, HYDROFINING, & HEAVY CAT FURNACES				Sulfur Dioxide (SO2)	GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034 LB/MMBTU	0.034 LB/MMBTU		
-0206	BATON ROUGE REFINERY	LA		FEED PREPARATION FURNACES F-30 & F-31		35	2 MMBTU/H	Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778 LB/MMBTU	0.1778 LB/MMBTU		
-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	CRU REGENERATOR VENT		32	9 UNITS/YR	Sulfur Dioxide (SO2)	GOOD ENGINEERING DESIGN AND PROPER OPERATION	0.88 LB/H	0		
0206	BATON ROUGE REFINERY			POWERFORMING & amp; LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778 LB/MMBTU	0.1778 LB/MMBTU		

			Γ	Julina					ER Database for Gaseous Fuel <					1	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING 2 & amp; EAST LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 1778	LB/MMBTU	0 1778	lb/mmbtu		
				NAPHTHA HYDROTREATER REACTOR CHARGE HEATER (5-08), KHT REACTOR CHARGE HEATER (9- 08), & HCU TRAIN 1&2 REACTOR CHARGE HEATERS (11-08				Sulfur Dioxide				0.1770			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	& 12-08) NAPHTHA HYDROTREATER STRIPPER REBOILER HEATER (6-08) & KHT STRIPPER REBOILER	GAS REFINERY FUEL			(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HEATER (10-08)	GAS REFINERY FUEL			(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	BOILER NO. 1 (16-08)	GAS	525.	ИМВТИ/Н	(SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	SRU THERMAL OXIDIZER NOS. 1 & 2 (18-08 & 19-08)	NATURAL GAS	63.	/ MM BTU/H EA.	Sulfur Dioxide (SO2)	SEE NOTES	93.41	PPMVD	0			OXYGEN AUTOMA DEGASSII SULFUR F THE SRU STORAGE THERMAI
				EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 &				Sulfur Dioxide							
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	22-08) A & B CRUDE HEATERS (1-08	DIESEL			(SO2)		0.02	MAX LB/H	0			USE OF D
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	& 2-08) & COKER CHARGE HEATER (15-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN REFORMER FURNACE FLUE GAS VENT (48-08)	PURGE GAS	1412.5	ммвти/н	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL GAS	25	PPMV AS H2S	0			
				PLATFORMER HEATER CELLS NO. 1- 3 (7A-08, 7B-08, & amp; 7C-08) & amp; HCU FRACTIONATOR	REFINERY FUEL			Sulfur Dioxide							
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HEATER (13-08) A & B VACUUM TOWER	GAS REFINERY FUEL			(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HEATERS (3-08 & amp; 4-08)	GAS	155.2	MMBTU/H EA.	(SO2) Sulfur Dioxide	USE OF LOW SULFUR REFINERY FUEL GAS VENTURI WET GAS SCRUBBER W/	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	FCCU REGENERATOR VENT (86-74) MARINE VAPOR COMBUSTOR (55-				(SO2)	ADDITION OF CAUSTIC SOLUTION	25	PPMV@0%02	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	08) & MARINE LOADING VAPOR COMBUSTOR (107-90)		5000) BBL/H EA.	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18.	0		o			NO EMISS
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	REFINERY FUEL GAS	9.6	MM BTU/H	Sulfur Dioxide (SO2)		0.2	MAX LB/H	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN PLANT FLARE (52-08)	H2 PLANT FEED GAS	2472	ммвти/н	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18	0.01	MAX LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	STARTUPS/SHUTDOWNS - SRU				Sulfur Dioxide (SO2)	FOLLOW WRITTEN SOP, MINIMIZE DURATION AND FREQUENCY, PROPERLY DOCUMENT ALL SU/SD	0		0			NO EMISS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (94-43 & amp; 94-45)	REFINERY FUEL GAS	354	MMBTU/H EA	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	9.43	LB/H	0			
				FLARE 1-5 (15-77, 12-81, 2004-5A,				Sulfur Dioxide	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE) AS FUELS AT FLARE						
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	2004-5B & amp; 2005-38) SRU THERMAL OXIDIZERS (99-3, 99-				(SO2) Sulfur Dioxide	TIP. CONTROL DEVICE - COMPLY WITH 40 CFR	0)	0			NO EMISS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	4, 2005-39, 2007-4)		50) ММВТИ/Н	(SO2)	60 SUBPART J	250	PPMVD	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FCCU REGENERATOR (16-77)				Sulfur Oxides (SOx)	USE OF PIPELINE QUALITY NATURAL GAS	176.12	LB/H	50	PPMV	7 DAY ROLLING AVERAGE	
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	MVR THERMAL OXIDIZER NO. 1 (94- 8)		240	MMBTU/H	Sulfur Dioxide (SO2)	OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	3.3	LB/H	o			
	ST. CHARLES REFINERY	LA	11/17/2009 ACT	ARU FLARE (2008-36)	PROCESS FUEL GAS			Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAL AVERAGE)	0		n			NO EMISS

/				
U/hr				
EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
.B/MMBTU	0.1778	lb/mmbtu		
-,				
	0			
PPMV AS H2S	0			
	0			
PPMV AS H2S	0			
PMV	0			
PPMVD	0			OXYGEN ENRICHMENT AND SULFUR SHEDDING PROCEDURES WITH AUTOMATED CONTROLS WITHIN THE SRU; EXCESS SRU CAPACITY; DEGASSING THE LIQUID SULFUR PRODUCT UPSTREAM OF THE SULFUR PIT TO <= 15 PPMV H2S; RECYCLING SULFUR PIT VENTS TO THE SRU INLET; PROPER OPERATING PRACTICES FOR SOUR WATER STORAGE; OVERALL SULFUR CONVERSION EFFICIENCY OF 99.9%; THERMAL OXIDIZER CONVERSION EFFICIENCY OF 99.5%
MAX LB/H	0			USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS.
PMV	0			
PMV AS H2S	0			
PPMV AS H2S	0			
PPMV	0			
PMV@0%02	0			
	0			NO EMISSION LIMITS AVAILABLE
MAX LB/H	0			
MAX LB/H	0			
	0			NO EMISSION LIMITS AVAILABLE
.в/н	0			
	0			NO EMISSION LIMITS AVAILABLE
PPMVD	0		7 DAY ROLLING	
.B/H	50	PPMV	AVERAGE	
D./11	_			
.B/H	0			
	0			NO EMISSION LIMITS AVAILABLE

		r		Summa	ary of SO ₂ Contro	ol Determinati	on per EPA's	RACT/BACT/LA	AER Database for Gaseous Fuel <	100 million B	BTU/hr				
						TURQUCURUT	THROUGHPUT					STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION USE OF PIPELINE QUALITY NATURAL GAS	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
									OR REFINERY FUEL GASES WITH AN H2S						
					REFINERY FUEL			Sulfur Dioxide	CONCENTRATION LESS THAN 100 PPMV						
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS/REBOILERS	GAS			(SO2)	(ANNUAL AVERAGE). USE OF PIPELINE QUALITY NATURAL GAS	0	1	0			NO EMISSION LIMITS
									OR PROCESS FUEL GASES WITH AN H2S						
								Sulfur Dioxide	CONCENTRATION LESS THAN 10 PPMV						
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (2008-1 - 2008-9)	PROCESS FUEL GAS			(SO2)	(ANNUAL AVERAGE).	0)	0			NO EMISSION LIMITS
									USE OF PIPELINE QUALITY NATURAL GAS						
				MVR THERMAL OXIDIZER NO. 2	REFINERY FUEL			Sulfur Dioxide	OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV						
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	(2008-38)	GAS	200	ммвти/н	(SO2)	(ANNUAL AVERAGE).	0.45	LB/H	0			
									USE OF PIPELINE QUALITY NATURAL GAS						
									OR REFINERY FUEL GASES WITH AN H2S						
4 0212			11/17/2000 8 shan ACT		REFINERY FUEL			Sulfur Dioxide	CONCENTRATION LESS THAN 100 PPMV			0			
. A- UZ13	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (94-21 & amp; 94-29)	GAS		-	(SO2)	(ANNUAL AVERAGE). USE OF PIPELINE QUALITY NATURAL GAS	0		0		+	NO EMISSION LIMITS AVAILABLE
									OR REFINERY FUEL GASES WITH AN H2S						
				CPF HEATER H-39-03 & amp; H-39-	REFINERY FUEL			Sulfur Dioxide	CONCENTRATION LESS THAN 100 PPMV						
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	02 (94-28 & 94-30)	GAS			(SO2)	(ANNUAL AVERAGE).	0	1	0			NO EMISSION LIMITS
									FUELED BY NATURAL GAS AND/OR REFINERY FUEL GAS WITH H2S <= 100						
									PPMV (ANNUAL AVERAGE) OR PROCESS						
				BOILERS (2008-10, 2008-11, 2008-	REFINERY FUEL			Sulfur Dioxide	FUEL GAS WITH H2S <= 10 PPMV (ANNUAL	-					
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	40)	GAS	715	5 MMBTU/H EA	(SO2)	AVERAGE)	0	ı	0			NO EMISSION LIMITS AVAILABLE
									FUELED BY NATURAL GAS OR REFINERY						
4 0212			11/17/2000 8 shan ACT		REFINERY FUEL	70) MMBTU/H EA	Sulfur Dioxide	FUEL GAS WITH H2S <= 100 PPMV			0			
A-0215	ST. CHARLES REFINERY	LA	11/17/2009 ACT	DHT HEATERS (4-81, 5-81)	GAS	Λ		(SO2)	(ANNUAL AVERAGE) FUELED BY NATURAL GAS OR REFINERY			0			NO EMISSION LIMITS AVAILABLE
					REFINERY FUEL			Sulfur Dioxide	FUEL GAS WITH H2S <= 100 PPMV						
A-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATER F-72-703 (7-81)	GAS	633	в ммвти/н	(SO2)	(ANNUAL AVERAGE)	0)	0			NO EMISSION LIMITS AVAILABLE
									FUELED BY NATURAL GAS AND PROCESS						
A_0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	THERMAL OXIDIZERS (2008-32, 2008-33, 2008-34)	PROCESS FUEL GAS	10	MMBTU/H EA	Sulfur Dioxide (SO2)	FUEL GAS WITH H2S <=10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
A-0215			11/17/2005 @1050,ACT	2008-33, 2008-34	TROCESSTOLEGAS	1.		(502)			, 	0			
	LAKE CHARLES COMPLEX - CAT GAS							Sulfur Dioxide	LOW SULFUR CONCENTRATION IN THE						ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4
A-0234	HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-102 FURNACE B-102	FUEL GAS	62.8	B MMBTU/H	(SO2)	FUEL GAS	5.08	LB/H	0			PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
.A-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-201 FURNACE B-201	FUEL GAS	56.5) MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	5.08	с ГВ/Н	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
															ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION
															OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR
A-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-202 FURNACE B-202	FUEL GAS	56.9	ммвти/н	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	5.08	LB/H	0			CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
	LAKE CHARLES COMPLEX - CAT GAS							Sulfur Dioxide	LOW SULFUR CONCENTRATION IN THE						ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4
	HYDRO LAKE CHARLES COMPLEX - CAT GAS HYDRO		01/26/2009 ACT 01/26/2009 ACT	3(XXXIV)7-103 REBOILER B-103	FUEL GAS		MMBTU/H	(SO2) Sulfur Dioxide (SO2)	FUEL GAS		LB/H	0			PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS. ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.

				Summar	y of SO ₂ Contro	ol Determination per EPA's	RACT/BACT/LA	AER Database for Gaseous Fuel <	100 million B	TU/hr				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
														ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION
	LAKE CHARLES COMPLEX - CAT GAS		oo /oo /ooo oo laasa				Sulfur Dioxide	USE LOW SULFUR CONCENTRATION FUEL						OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4
LA-0234	HYDRO I	LA	01/26/2009 ACT	3(XXXIV)7-101 FURNACE B-101	FUEL GAS	62.8 MMBTU/H MMBTU/H	(SO2) Sulfur Dioxide	GAS.	5.08	LB/H	0			PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
NJ-0053	MCUA	NJ	03/09/1999 ACT	DUCT FIRED HRSG	LANDFILL GAS	31 NOMINAL *	(SO2) Sulfur Dioxide	NONE	1.73	LB/H	0 04	LB/MMBTU		
NJ-0053	MCUA	NJ	03/09/1999 ACT	TURBINE WITH HRSG	LANDFILL GAS	74 MMBTU/H	(SO2)	NONE	4.71	LB/H	0			
NJ-0053	MCUA	NJ	03/09/1999 ACT	OPEN FLARE	LANDFILL GAS	90 MMBTU/H*	Sulfur Dioxide (SO2)	NONE	3.6	LB/H	0			ADDITIONAL EMISSION LIMIT: 0.04 LB/MMBTU
						MMBTU/H	Sulfur Dioxide							
NJ-0053	MCUA	NJ	03/09/1999 ACT	LANDFILL GAS TURBINE	LANDFILL GAS	65 (NOMINAL)*	(SO2)	NONE THE USE OF LOW SULFUR CONTENT IN FUEL : 0 055 % SULFUR IN FUEL BY WEIGHT FOR THE MIXTURE OF NATURAL		LB/H	0			
NJ-0061	MERCK-RAHWAY PLANT	NJ	09/18/2003 ACT	BOILERS (2) - NATURAL GAS CO- FIRED WITH WASTE SOLVENT	FIRED WITH WASTE SOLVENT	99.5 MMBTU/H	Sulfur Dioxide (SO2)	GAS AND WASTE SOLVENT IS CONSIDERED BACT FOR SO2.		LB/H	0			
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	DELAYED COKER UNIT, HEATER	REFINERY GAS	116 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.71	LB/H	0.023	lb/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	FCC FEED HYDROTREATER HEATER	REFINERY GAS	91 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2 44	LB/H	0.027	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
							Sulfur Dioxide			-	0.027	LD/ WIND TO	neurmput	
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	HYDROGEN REFORMER UNIT	REFINERY GAS	344 MMBTU/H	(SO2)	GOOD COMBUSTION PRACTICE	9.22	LB/H	0			Best available technology (BAT) review done.
							Sulfur Dioxide		16.00				Calculated using	
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	NORTH CRUDE HEATER	REFINERY GAS	147 MMBTU/H	(SO2) Sulfur Dioxide	USE OF DESULFURIZED REFINERY GAS	46.22	LB/H	0.3	LB/MMBTU	heat input	Best available technology (BAT) review done.
TX-0322	WEST PLANT	ТХ	10/15/1999 ACT	COKER HEATER, 521-H1		291 MMBTU/H	(SO2)	NONE INDICATED	9.19	lb/H	0.032	LB/MMBTU		INCLUDES 3.86 LB/H OF SO2 FROM BURNING MEROX
TX-0322	CITGO CORPUS CHRISTI REFINERY- WEST PLANT	тх	10/15/1999 ACT	MIXED DIST HYDROTREATER CHARGE HEATER, 527-H1		62 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	5.82	LB/H	0.094	lb/mmbtu	CALCULATED FROM HEAT INPUT	UNIT VENT GAS. MEROX VENT GAS CONTAINS 0 0056 MOL S/MOL VENT GAS.
			-, -,							,		, -	CALCULATD	
TX-0322		тх	10/15/1999 ACT	MIXED DIST HYDROTREATER REBOILER HEATER, 527-H2		82 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	2.6	LB/H	0.032	lb/MMBTU	FROM HEAT INPUT	
TX-0322	CITGO CORPUS CHRISTI REFINERY- WEST PLANT	тх	10/15/1999 ACT	FLARE - COKE DRUM BLOWDOWN, 573-ME1			Sulfur Dioxide (SO2)	NONE INDICATED	528	LB/H	0			
TX-0322	CITGO CORPUS CHRISTI REFINERY- WEST PLANT	тх	10/15/1999 ACT	TAIL GAS INCINERATOR, 554-ME5		9 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	12.52	IB/H	0			
17 0522			10/13/1333 (1030), (01						12.52	20/11			CALCULATED	
TX-0322	CITGO CORPUS CHRISTI REFINERY- WEST PLANT	тх	10/15/1999 ACT	NO. 3 BOILER, 561-B3		99 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	3.13	LB/H	0.032	LB/MMBTU	FROM HEAT	
TV 0240						20 5 14140711/11	Sulfur Dioxide	NONE INDICATED	1.45	1.5/11	0.020			STANDARD EMISSION LIMITS CALCULATED FROM HOURLY
	DIAMOND SHAMROCK MCKEE PLANT		10/19/2001 ACT	SPLITTER REBOILER HEATER, H-66 NO. 3 REFORMER CHARGE HEATERS		38.5 MMBTU/H	(SO2) Sulfur Dioxide			LB/H		lb/MMBTU	CALCULATED	LIMITS AND PROCESS RATING. STANDARD EMISSION LIMITS CALCULATED FROM HOURLY
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	ТХ	10/19/2001 ACT	H-67A, H-67B, H-67C NO. 3 REFORMER STABILIZER	FUEL GAS	160.4 MMBTU/H	(SO2) Sulfur Dioxide	NONE INDICATED	6.07	LB/H	0.038	lb/MMBTU	CALCULATED	LIMITS AND PROCESS RATING. STANDARD EMISSION LIMITS CALCULATED FROM HOURLY
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	ТХ	10/19/2001 ACT	REBOILER HEATER, H-68	FUEL GAS	13.5 MMBTU/H	(SO2)	NONE INDICATED	0.51	LB/H	0.038	lb/mmbtu	CALCULATED	LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	тх	10/19/2001 ACT	NO. 3 SRU HEAT TRANSFER HEATER, H-69	FUEL GAS	10.8 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.41	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	тх	10/19/2001 ACT	NO. 4 HYDROTREATER CHARGE HEATER, H-64	FUEL GAS	30.1 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.14	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED BY DIVIDING THE HOURLY EMISSION LIMIT BY THE THROUGHPUT.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	ту	10/19/2001 ACT	NO. 4 HYDROTREATER STRIPPER REBOILER HEATER, H-65	FUEL GAS	37 MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1 /	LB/H	0.020	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
				NO. 3 SRU TAIL GAS INCINERATOR,	I ULL URJ	37 IVIIVID10/П	Sulfur Dioxide				0.038		CALCULATED	
<u>TX-0348</u>	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	V-27			(SO2)	NONE INDICATED LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0	22.27	LB/H	0			
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BOILER NO. 13		366 83 MMBTU/H	(SO2)	GR/ 100 DSCF.	9.4	LB/H	0.026	LB/MMBTU	CALCULATED	

				Summar	y of SO ₂ Contro	DI Determination per EPA's	RACT/BACT/L	AER Database for Gaseous Fuel <	EMISSION LIMIT	TU/hr	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL		POLLUTANT	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT		LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
								LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25						
								GR/100 DSCF AND TOTAL S CONTENT NO						
TV 0275		T) (02/44/2002 0 show ECT				Sulfur Dioxide	MORE THAN 5.0	45.4	1.5./11	0.025		EACH,	
TX-0375	LYONDELL - CITGO REFINING, LP	ТХ	03/14/2002 EST	BOILERS 14 AND 15	PETRO REFIN GAS	586 MMBTU/H EA	(SO2)	GR/ 100 DSCF. LOW S FUEL: FUEL GAS WITH H2S	15.1	LB/H	0.025	lb/MMBTU	CALCULATED	
							C. K Dinith	CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU- NO 3 REACTOR FEED HEATER		58 95 MMBTU/H	Sulfur Dioxide (SO2)	MORE THAN 5.0 GR/ 100 DSCF.	15	lb/H	0.025	LB/MMBTU	CALCULATED	
17-0373			105/14/2002 @http:///			38 33 (MWB10/11		LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO			0.023			
TV 0275	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU-NO.4 REACTOR FEED HEATER		49 MMBTU/H	Sulfur Dioxide (SO2)	MORE THAN 5.0 GR/ 100 DSCF.	1.2	lb/H	0.027	LB/MMBTU	CALCULATED	
				BTU-REFORMATE STABILIZER			Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	REBOILER		54.77 MMBTU/H	(SO2)	GR/ 100 DSCF.	1.4	LB/H	0.026	LB/MMBTU	CALCULATED	
				ISOM II WEST REACTOR FEED			Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		104 25 MMBTU/H	(SO2)	GR/ 100 DSCF.	2.7	LB/H	0.026	lb/mmbtu	CALCULATED	
				ISOM II COMBINATION SPLITTER			Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		77.62 MMBTU/H	(SO2)	GR/ 100 DSCF.	2	LB/H	0.026	lb/mmbtu	CALCULATED	
				ISOM II XYLENE RERUN TOWER			Sulfur Dioxide	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
TX-0375	LYONDELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		83.7 MMBTU/H	(SO2)	GR/ 100 DSCF.	2.2	LB/H	0.026	lb/mmbtu	CALCULATED	

			1	Summar	y of SO ₂ Contro	ol Determinati	on per EPA's	RACT/BACT/LA	ER Database for Gaseous Fuel <	< 100 million I	BTU/hr	T	1		
							THROUGHPUT					STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
CID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION LOW S FUEL: FUEL GAS WITH H2S	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
				ISOM II EAST REACTOR FEED				Sulfur Dioxide	MORE THAN 5.0						
0375 LYON	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	HEATER		75	5 MMBTU/H	(SO2)	GR/ 100 DSCF. LOW SULFUR CONTENT FUEL: USE	1.9	9 LB/H	0.025	lb/MMBTU	CALCULATED	
									REFINERY FUEL GAS						
									WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL						
									GAS WITH NO MORE THAN 0 25 GR/100						
		TV	02/14/2002 & phoneEST			06.27		Sulfur Dioxide	DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	2.0	5 LB/H	0.026	LB/MMBTU	CALCULATED	
	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	ORTHOXYLENE I HEATER		96 2:	8 MMBTU/H	(SO2)	LOW SULFUR CONTENT FUEL: USE	2.5		0.026		CALCULATED	
									REFINERY FUEL GAS						
									WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL						
									GAS WITH NO MORE THAN 0 25 GR/100						
0375	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	ORTHOXYLENE II HEATER		226 A	MMBTU/H	Sulfur Dioxide (SO2)	DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	E 0	8 LB/H	0.026	LB/MMBTU	CALCULATED	
			55, 17, 2002 (1103µ,131			220.42		(502)	LOW SULFUR CONTENT FUEL: USE	5.0		0.020	-0,101010		
									REFINERY FUEL GAS						
									WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL						
									GAS WITH NO MORE THAN 0 25 GR/100						
0375 1 YON	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BACKUP AIR COMPRESSOR ENGINES (1-5)				Sulfur Dioxide (SO2)	DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	4 72	2 LB/H	0			
			03/14/2002 and 50/201	(1.5)				(302)	LOW S FUEL: FUEL GAS WITH H2S	4.72	2 20/11				
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
								Sulfur Dioxide	MORE THAN 5.0						
0375 LYON	IDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO. 1 REACTOR FEED HEATER		121.74	MMBTU/H	(SO2)	GR/ 100 DSCF. LOW S FUEL: FUEL GAS WITH H2S	3.1	1 LB/H	0.025	lb/MMBTU	CALCULATED	
									CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
								Sulfur Dioxide	GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0						
0375 LYON	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BTU-NO.2 REACTOR FEED HEATER		69.68	В ММВТИ/Н	(SO2)	GR/ 100 DSCF.	1.8	8 LB/H	0.025	LB/MMBTU	CALCULATED	
									LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE						
									THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25						
								o 10	GR/100 DSCF AND TOTAL S CONTENT NO						
0375 LYON	IDELL - CITGO REFINING, LP	тх	03/14/2002 EST	BENZENE STABILIZER HEATER	PETRO REFIN GAS	38 34	MMBTU/H	Sulfur Dioxide (SO2)	MORE THAN 5.0 GR/ 100 DSCF.	1	1 LB/H	0.026	LB/MMBTU	CALCULATED	
			,,						LOW S FUEL: FUEL GAS WITH H2S		-,	0.020	.,		
									CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING						
									BASIS, OR						
									NATURAL GAS WITH H2S CONTENT NO						
									MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO						
								Sulfur Dioxide	MORE THAN 5.0						
-0375 LYON	IDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILER NO. 12 NO. 1 HYDROTREATER REBOILER		245	5 MMBTU/H	(SO2) Sulfur Dioxide	GR/ 100 DSCF.	6.3	3 LB/H	0.026	LB/MMBTU	CALCULATED	
-0395 DIAN	IOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT		REFINERY GAS	32.7	ИМВТИ/Н	(SO2)		1.23	3 LB/H	0			

									ER Database for Gaseous Fuel <				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EN LIN
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO. 1 REFORMER CHARGE HEATER	REFINERY GAS	248	3 ММВТU/Н	Sulfur Dioxide (SO2)		9.33	LB/H	0	1
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO. 1 REFORMER STABILIZER REPOILER HEATER	REFINERY GAS) MMBTU/H	Sulfur Dioxide (SO2)			LB/H	0	
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO 1 INTERHEATER	REFINERY GAS	147.2	2 MMBTU/H	Sulfur Dioxide (SO2)		5.54	LB/H	0	
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	NO. 1 REBOILER STABILIZER REBOILER HEATER NO. 1 HYDROTREATER CHARGE	REFINERY GAS	45.7	7 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		1.72	LB/H	0	
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	тх	05/23/2000 ACT	HEATER	REFINERY GAS	63.4	1 ММВТU/Н	(SO2)		2.39	LB/H	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	SR- 3/4 INCINERATOR				Sulfur Dioxide (SO2) Sulfur Dioxide		300	PPMV	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	EAST PROPERTY FLARE				(SO2) Sulfur Dioxide		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	COKER FLARE	REFINERY FUEL			(SO2) Sulfur Dioxide		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	TWENTY ONE FURNACES	GAS			(SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	FOURTEEN HEATERS				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN			Sulfur Dioxide (SO2)		300	ΡΡΜν	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	CO BOILER	CARBON MONOXIDE			Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	CCU FLARE				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	WEST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	THREE FLARES				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	ANALYZER				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	44-H-1 DIESEL HDS HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT THE CONENT OF H2S IN FUEL GAS	0.8	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	44-H-2 DIESEL HDS HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LOWER THE CONTENT OF H2S IN FUEL GAS	0.6	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	7-H-2 DELAYED COKER CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	3.2	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	8-H-3 #4 VACUUM CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.6	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	8-H-4 #4 CRUDE CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	4	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	8-H-5 #4 VACUUM CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT HS2 CONTENT IN FUEL GAS	0.6	LB/H	0	1
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	8-H-6 #4 CRUDE CHARGE HEATER				Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	5.4	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	H-TK-47,48,54,70,83	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.1	LB/H	0	L
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	EP-B-1 & EP-B-2 COMPLEX 8 #1&2	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN THE FUEL GAS	4	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	B-4, B-5 COMPLEX 6 WEST & amp; EAST BOILER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	4.1	LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	EP-B-5 COMPLEX 8 BOILER #5	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS		LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	12-H-1 FCCU RAW OIL CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS		LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	17-H-1 ALKY. ISO. STRIPPER REBOILER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS		LB/H	0	
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	27-H-1 KTX. CLAR TWR. CHARGE HEATER	FUEL GAS			Sulfur Dioxide	LIMIT H2S IN FUEL GAS		LB/H	0	
	VALERO CORPUS CHRISTI REFINERY							Sulfur Dioxide				0	
TX-0443	EAST PLANT	ТХ	01/01/2005 ACT	27-H-2 TETRAMER SPL. REB. HTR.	FUEL GAS			(SO2)	LIMIT H2S IN FUEL GAS	0.2	lb/H	0	
	VALERO CORPUS CHRISTI REFINERY EAST PLANT	тх	01/01/2005 ACT	37-H-1 KERO. HDS CHARGE HEATER, 38-H-2KEROSENE HDS HEATER, 39- H-1 #4 HC CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS		lb/H		1

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES

							THROUGHPUT			EMISSION LIMIT	EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	E
RBLCID	FACILITY NAME VALERO CORPUS CHRISTI REFINERY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	-
X-0443	EAST PLANT	тх	01/01/2005 ACT	37-H-2 KERO HDS FRAC REBOILER	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.3	LB/H	0			
	VALERO CORPUS CHRISTI REFINERY			38-H-1 KEROSENE HDS CHARGE				Sulfur Dioxide			,			<u> </u>	
X-0443	EAST PLANT	тх	01/01/2005 ACT	HEATER	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0			
	VALERO CORPUS CHRISTI REFINERY							Sulfur Dioxide							
X-0443	EAST PLANT	тх	01/01/2005 ACT	39-H-2 #4 HC STRIPPER REBOILER				(SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0		L	
	VALERO CORPUS CHRISTI REFINERY							Sulfur Dioxide							
X-0443	EAST PLANT	тх	01/01/2005 ACT	39-Н-7	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	1.4	lb/H	0		<u> </u>	
V 0442	VALERO CORPUS CHRISTI REFINERY	TY	01/01/2005 8 aboat ACT					Sulfur Dioxide		11	1.0/11	0			
TX-0443	EAST PLANT VALERO CORPUS CHRISTI REFINERY	тх	01/01/2005 ACT	Q3-H-4A/B Q3-H-3 #2 REFORMER HDS	FUEL GAS			(SO2) Sulfur Dioxide	LIMIT H2S CONTENT IN FUEL GAS	1.1	lb/H	0			+
X-0443	EAST PLANT	тх	01/01/2005 ACT	CHARGER AND STRIPPER	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.9	LB/H	0			
7 0445	VALERO CORPUS CHRISTI REFINERY		01/01/2003 anosp,//er		1022 0/10			Sulfur Dioxide		0.5	20/11	0		<u> </u>	+
X-0443	EAST PLANT	тх	01/01/2005 ACT	Q10-H-1 SMR HEATER	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	7.2	LB/H	0			
	VALERO CORPUS CHRISTI REFINERY							Sulfur Dioxide							1
X-0443	EAST PLANT	тх	01/01/2005 ACT	Q11-H-301 HCU RX CHARGE	FUEL GAS			(SO2)		1.5	LB/H	0			
				Q3-H-3 FRACTIONATOR AND Q11-H	-										
	VALERO CORPUS CHRISTI REFINERY			3001,3002 HCU DEBUT. REB. AND				Sulfur Dioxide							
TX-0443	EAST PLANT	ТХ	01/01/2005 ACT	FRACT. REB.	FUEL GAS			(SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0			
TX-0472	FLINT HILLS RESOURCES CORPUS CHRISTI WEST PLANT	тх	01/24/2005 ACT	New Boilers, Flint Hills West Refinery	Natural Gas and refinery fuel gas	(0	Sulfur Dioxide (SO2)		100	% COMB CONV TO SO2	0			SO2 emission content in the SO2. The sho rolling avera content is 81
		14.07	40/45/2042 Bulker ACT	DCI II	Defining Fielder	-		Sulfur Dioxide	Falley, Subsert to Fuel and USC limits			0			
WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	BSI Heater	Refinery Fuel Gas Ultra Low Sulfur	50) MMBtu/hr	(SO2) Sulfur Dioxide	Follow Subpart Ja Fuel gas H2S limits	0		0			
WY-0071	SINCLAIR REFINERY	wy	10/15/2012 ACT	Emergency Air Compressor	Diesel	400	hp	(SO2)	Ultra Low Sulfur Diesel	0		0			
			10/13/2012 (1103);//01	Emergency via compressor	Diesei	+00	np	Sulfur Dioxide				0			
WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	581 Crude Heater	Refinery Fuel Gas	233	8 MMBtu/hr	(SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
					,			Sulfur Dioxide							-
WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	583 Vacuum Heater	Refinery Fuel Gas	64.2	2 MMBtu/hr	(SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
								Sulfur Dioxide							
'WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Naphtha Splitter Heater	Refinery Fuel Gas	46.3	8 MMBtu/hr	(SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0		<u> </u>	
								Sulfur Dioxide							
WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Hydrocracker H5 Heater	Refinery Fuel Gas	44.9	9 MMBtu/hr	(SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0		 	<u> </u>
	SINCLAIR REFINERY	WY	10/15/2012 ACT	#1 HDS Heater	Refinery Fuel Gas		1 MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits						1

3	TU/hr				
	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
3	LB/H	0			
7	LB/H	0			
7	LB/H	0			
1	LB/H	0			
1	LB/H	0			
9	LB/H	0			
2	LB/H	0			
5	LB/H	0			
	LB/H % COMB CONV TO SO2	0			SO2 emissions are estimated using the maximum and average H2S content in the fuel gas and assuming 100% combustion conversion to SO2. The short-term maximum H2S content is 162 ppmv on a 3-hour rolling average in accordance with NSPS Subpart J. The average H2S content is 81 ppmv on a 365-day rolling average.
)		0			
5		0			
)		0			
)		0			
)		0			
)		0			
)		0			

	1	1	1	Su	ummary of SO ₂	Control Determination per	EPA's RACT/B	ACT/LAER Database for Chemica	al Plant Flares	г	T	r	1	I.
						THROUGHPUT				EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME HOMELAND ENERGY SOLUTIONS, LLC,	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME EMERGENCY DIESEL FIRE WATER	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
A-0089	PN 06-672	IA	08/08/2007 ACT	PUMP S110 (07-A-982P)		300 BHP	(SO2)	NONE	0 203	G/KW-H	0			BACT EQUIVALENT TO 0.203 G/KWH
A-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	THERMAL OXIDIZER FOR HRSG FROM DRYERS AND GASIFICATION - TWO SYSTEMS, S10 AND S11 (07-A- 955P AND 07-A-956P)	SYNGAS	250 MMBTU/H	Sulfur Dioxide (SO2)	H2S REMOVAL SYSTEM AFTER THE GASIFICATION PROCESS AND PRIOR TO THE USE IN THE DRYERS OR THERMAL OXIDIZERS	0 034	LB/MMBTU	0.2	lb/MMBTU	30-DAY	FOR THE SYN-GAS MADE FROM COAL, THE SO2 IS LIMITED TO 0.01- LB / MM BTU AND THE SO2 FROM THE PROCESS IS LIMITED TO 0.02 LB / MM BTU EACH BASED ON 250 MM BTU / HR HEAT INPUT.
	HOMELAND ENERGY SOLUTIONS, LLC,			BIOMETHANATOR FLARE, EP11 (07-	METHANE / SYNGAS /		Sulfur Dioxide							
A-0089	PN 06-672	IA	08/08/2007 ACT	A-957P)	NATURAL GAS	6.4 MM BTU / H	(SO2)		0.0007	LB/MMBTU	0			
A-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	PRODUCT LOADOUT FOR TRUCKS AND RAIL CARS, EP22 AND F50 (07- A-965P) STARTUP AND SHUTDOWN FLARES		1500 GAL/MIN	Sulfur Dioxide (SO2)	FLARE	0.0006	LB/MM BTU	0			
A-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	١۵	08/08/2007 ACT	1, 2, AND 3, EP33A, EP33B, AND EP33C (07-A-967P, 07-A-968P, AND 07-A-969P)	NATURAL GAS OR SYNGAS	25 MMBTU	Sulfur Dioxide (SO2)	FLARE	0 395	LB/MM BTU	0			
			55, 50, 2007 & 103p,ACT			25 19191010	Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK OIL IS	0.393	LO, MINI DI U				
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 FILTER FUGITIVES	FEEDSTOCK OIL		(SO2)	LIMITED TO 4%	C	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 DRYER FUGITIVES	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 PROCESS FUGITIVES	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (LIMITS BEFORE UNIT 5)	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	4.6	LB/H	0			EMISSION LIMITS BEFORE INSTALLATION OF UNIT 5
A-0163	CABOT CORPORATION- VILLE PLATTE	IΔ	11/04/1999 ACT	UNIT 3 PROCESS FILTER (AFTER UNIT 5 IS INSTALLED)	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%		LB/H	0			EMISSION LIMITS AFTER INSTALLATION OF UNIT 5
				UNIT 3 PELLET DRYER PURGE GAS			Sulfur Dioxide							
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	FILTER	FEEDSTOCK OIL		(SO2)	BAG FILTER LIMITATION OF SULFUR CONTENT IN	9.4	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNITS 1&2 FLARE	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	FEEDSTOCK OIL TO 4%	2555.8	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 FLARE	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL LIMITED TO 4%.	2295.1	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR FUGITIVES	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	C	LB/H	0			
A-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR WARM UP VENT	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	0.01	LB/H	0			
				ACRYLIC ACID INCINERATOR (POINT			Sulfur Dioxide	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO						COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM
X-0277	BASF CORPORATION	тх	12/12/2001 ACT	NO. IN-701)	NATURAL GAS		(SO2)	MORE THAN 20 GR/100 DSCF OF SULFER. NATURAL GAS AS SUPPLEMENTAL FUEL	20	LB/H	0			OPERATING SCHEDULE OF 8,760 H/YR.
Y-0277	BASF CORPORATION	тх	12/12/2001 ACT	INCINERATOR (POINT NO. IN-5500)			Sulfur Ovides (SO)	CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO () MORE THAN 20 GR/100 DSCF SULFER.		LB/H				COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760 H/YR.
							Sanar Oxides (50)		00.17					COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. EMISSION RATES ARE
		T V	12/12/2021 8	CONTINUOUS FLARE (POINT NO. 4-2			Sulfur Dioxide			1.5.41	-			BASED ON A MAXIMUM OPERATING SCHEDULE OF 8760
		TX	12/12/2001 ACT	4) (2) STARTUP HEATERS, 70H101-	NATURAL GAS		(SO2) Sulfur Dioxide			LB/H	0		CALCULATED FROM HOURLY E.L. AND	H/YR.
	FORMOSA PLASTICS TEXAS	тх тх	02/10/2000 ACT 02/10/2000 ACT	1&-2 PROCESS FUGITIVES, 70ANFUG		75 MMBTU/H, EA	(SO2) Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0.0005	LB/MMBTU		FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
		тх	02/10/2000 ACT		NAT GAS		Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	n			
		тх	02/10/2000 ACT	PROCESS FLARE, 70Z522			Sulfur Dioxide			LB/H				

						THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION
(-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	FIREWATER PUMP, 81			Sulfur Dioxide (SO2)	NONE INDICATED	0.26 LB/H	0		
-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	SOLAR TURBINE & amp; DUCT BURNER, 70	NATURAL GAS		Sulfur Dioxide (SO2)	NONE INDICATED	0.28 LB/H	0		
-0555			12/05/2000 &IIDSP,ACT	CONTINUOUS CATALYST	INATORAL GAS		(302) Sulfur Dioxide	NONE INDICATED	0.20 LD/H	0		
(-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	REGENERATOR, 71			(SO2)	CAUSTIC SCRUBBER	0.12 LB/H	0		
							Sulfur Dioxide					
-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS		(SO2)	FIRING NAT GAS FIRING NAT GAS WITH S CONCENTRATION	0.38 LB/H	0		NOT AVAILABLE
				3 DIP TURBINES & amp; 3 DUCT			Sulfur Dioxide	OF NO MORE				
-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	BURNERS, 74	NAT GAS		(SO2)	THAN 15 PPMW.	0.46 LB/H	0		
							Sulfur Dioxide					
-0333	MONT BELVIEU COMPLEX	ТХ	12/05/2000 ACT	FLARE, 76			(SO2)	NONE INDICATED	0.01 LB/H	0		
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1			Sulfur Dioxide (SO2)	NONE INDICATED	0.08 LB/H	0		NOT AVAILABLE
			10/10/2001 0				(002)			Ű		
				(2) HYDROTREATER REGENERATOR			Sulfur Dioxide					
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	STACKS,DD-606&DDD-606			(SO2)	NONE INDICATED	45.8 LB/H	0		
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101			Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0		
0347			10/10/2001 01050,/101				Sulfur Dioxide		0.01 20/11	0		
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101			(SO2)	NONE INDICATED	0.01 LB/H	0		
							Sulfur Dioxide					
0347	CHOCOLATE BAYOU PLANT	ТХ	10/16/2001 ACT	REGENERATION FURNACE, DB-201			(SO2) Sulfur Dioxide	NONE INDICATED	0.52 LB/H	0		NOT AVAILABLE
0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DB-601			(SO2)	NONE INDICATED	0.07 LB/H	0		NOT AVAILABLE
				,			Sulfur Dioxide					
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DDB-201			(SO2)	NONE INDICATED	0.5 LB/H	0		NOT AVAILABLE
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DDB-601			Sulfur Dioxide (SO2)	NONE INDICATED	0.07 LB/H	0		NOT AVAILABLE
0347			10/10/2001 @1030,AC1	REGENERATION TEATER, DDD-001			(502)		0.07 20/11	0		ADDIT
				FURNACE EMISSION CAPS FOR 30			Sulfur Dioxide					53.66
-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	EMISSION POINTS			(SO2)	NONE INDICATED	48 LB/H	0		61 37 I
								FUEL SULFUR CONTENT LIMIT: THE NATURAL GAS				
								STREAM				
								SHALL CONTAIN LESS THAN 5 GR TOTAL				
							Sulfur Dioxide	SULFUR/100				
(-0353	NAFTA REGION OLEFINS COMPLEX	ТХ	09/05/2001 ACT	BOILER, BLR	NAT GAS		(SO2)	DSCF.	3.25 LB/H	0		NOT AVAILABLE
(-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE		Sulfur Dioxide (SO2)	NONE INDICATED	14.13 LB/H	0		
			03/03/2001 0				Sulfur Dioxide		1 115 20,11	Ű		
-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS		(SO2)	NONE INDICATED	0.01 LB/H	0		
								FOLLOW PROCEDURES OF LEAK				
-0354	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES			Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.01 LB/H	0		
5554					<u> </u>			FOLLOW PROCEDURES FOR LEAK	0.01 LD/11	0		
				TRAIN 1 - MESH PRODUCTION			Sulfur, Total	DETECTION, ISOLATION,				
-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES			Reduced (TRS)	AND REPAIR.	0.02 LB/H	0		
				TRAIN 2- MESH PRODUCTION			Sulfur, Total	FOLLOW PROCEDURES OF LEAK				
-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES			Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.02 LB/H	0		
			,,		1	1	Sulfur Dioxide			Ű		1 1
-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR TRUCK, S-3			(SO2)	NONE INDICATED	0.07 LB/H	0		

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г	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
6	LB/H	0			
8	LB/H	0			
	LB/H	0			
	LB/H	0		NOT AVAILABLE	
0	20/11	0			
6	LB/H	0			
1	LB/H	0			
8	LB/H	0		NOT AVAILABLE	
8	LB/H	0			
1	LB/H	0			
1	LB/H	0			
2	LB/H	0		NOT AVAILABLE	
7	LB/H	0		NOT AVAILABLE	
5	LB/H	0		NOT AVAILABLE	
	LB/H	0		NOT AVAILABLE	
					ADDITIONAL CAPS: 53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06,
8	LB/H	0			61 37 LB/H, 13.44 T/YR AFTER 6/30/06
5	LB/H	0		NOT AVAILABLE	
3	LB/H	0			
	LB/H	0			
	,				
1	LB/H	0			
2	LB/H	0			
2	LB/H	0			
7	LB/H	0			

				Su	mmary of SO ₂	Control Deter	mination per	EPA's RACT/B	ACT/LAER Database for Chemica	al Plant Flares				
					<u>_</u>		THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	:
CID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	
									SEE POLLUTANT NOTES. FOLLOW					ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE
				TANK TRUCK LOADING/UNLOADING				Sulfur, Total	PRACTICES OF LEAK					WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL
354 ATOFINA C	HEMICALS INCORPORATED	TX	12/19/2002 ACT	FUGITIVES				Reduced (TRS) Sulfur, Total	DETECTION, ISOLATION, AND REPAIR. FOLLOW THE REQUIREMENTS OF 40 CFR	0.03 LB/H	0			VENT TO THE SULFOX-TO.
354 ATOFINA C	HEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, SSM				Reduced (TRS)	60.18	24.27 LB/H	0			
									FOLLOW THE REQUIREMENTS OF 40 CFR					TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE
								Sulfur Dioxide	60.18. SEE		-			FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
354 ATOFINA C	HEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				(SO2) Sulfur Total	THE POLLUTANT NOTES.	2541.37 LB/H	0			AT LEAST AT OR BELOW 5193 LB/H.
	HEMICALS INCORPORATED	ту	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62 LB/H				

				Su	Immary of SO ₂	Control Deter	mination per	EPA's RACT/B	ACT/LAER Database for Chemica	l Plant Flares			1
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD STANDAI EMISSION EMISSIO LIMIT LIMIT UN	N TIME	POLLUTANT COMPLIANCE NOTES
													TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF
				FLARE, TOTAL HOURLY AND				Sulfur Dioxide	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE				SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
354 ATOFINA C	CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	ANNUAL				(SO2)	POLLUTANT NOTES.	6207.34 LB/H	0	0.1.0111.1750	AT LEAST AT OR BELOW 5193 LB/H.
0354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02 LB/H	0.0006 LB/MMBTU	CALCULATED, USING I THROUGHPUT	
0354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01 LB/H	0		
0354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02 LB/H	0.0006 LB/MMBTU	CALCULATED USING THROUGHPUT	
J354 ATOFINA C	CHEMICALS INCORPORATED		12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139 LB/H	0		
)354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86 LB/H	0		
354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED FOLLOW PRACTICES OF LEAK DETECTION,	0.17 LB/H	0		
354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.01 LB/H	0		
354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	ММВТИ/Н	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89 LB/H	0		
								Sulfur Dioxide	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING				
	CHEMICALS INCORPORATED		12/19/2002 ACT	THERMAL OXIDIZER, SSM THERMAL OXIDIZER, TOTAL HOURLY			MMBTU/H	(SO2) Sulfur, Total	NO MORE THAN 5 GR S/100 DSCF.	1156.47 LB/H	0		
354 ATOFINA C	CHEMICALS INCORPORATED	TX	12/19/2002 ACT	AND ANNUAL	<u> </u>	134.5	MMBTU/H	Reduced (TRS) Sulfur Dioxide	NONE INDICATED THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100		0		WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET
354 ATOFINA C	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	AND ANNUAL		134.5	MMBTU/H	(SO2)	DSCF.	1157.44 LB/H	0		CONCENTRATION OF 10 PPMV.
	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35 LB/H	0		

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No. 100 No. 100 <t< th=""><th></th><th></th><th>LIMIT AVERAGE TIME CONDITION</th><th>MISSION</th><th>IISSION</th><th>EM</th><th></th><th>EMISSION LIMIT 1</th><th>CONTROL METHOD DESCRIPTION</th><th>POLLUTANT</th><th></th><th>THROUGHPUT</th><th>PRIMARY FUEL</th><th>PROCESS NAME</th><th>PERMIT ISSUANCE DATE</th><th>FACILITY STATE</th><th>FACILITY NAME</th></t<>			LIMIT AVERAGE TIME CONDITION	MISSION	IISSION	EM		EMISSION LIMIT 1	CONTROL METHOD DESCRIPTION	POLLUTANT		THROUGHPUT	PRIMARY FUEL	PROCESS NAME	PERMIT ISSUANCE DATE	FACILITY STATE	FACILITY NAME
A APPEND County Montperson See APPEND County Montperson See APPEND County Montperson See APPEND County Montperson See APPEND APPE	QUIREMENT: WHEN THE ROL SYSTEM ENUNCIATES THAT EPN IS EXCEED 5193 LB/H, THE RES SHALL BE TAKEN AS APPROPRIATE EXTENT PRACTICABLE SO2 IMPACTS UITOR: 1) PLANT PERSONNEL SHALL ANT METEORLOGICAL CONDITIONS THER ADDITIONAL SO2 EMISSIONS JULD LIKELY RESULT IN INCREASED VICINITY OF THE CAMS54 PERSONNEL SHALL EVALUATE IY DATA PROVIDED BY THE CAMS54 MINE IF CURRENT SO2 RE GREATER THAN 160 PPB; 3) IF HAT ADDITIONAL SO2 EMISSIONS JULD LIKELY RESULT IN INCREASED THE FLARE AT THE CAMS54 IT HE IMPACTS AT THE CAMS54 IT HE IMPACTS AT THE CAMS54 E 160 PPB, PLANT PERSONNEL IITTED ACTIVITIES, AS DUCE SO2 EMISSIONS FROM THE	DISTRIBUTIVE C FLARE SO2 EMI FOLLOWING M TO CONTROL TO AT THE CAMS54 EVALUATE ALL I TO DETERMINE FROM THE FLAI SO2 IMPACTS II MONITOR; 2) P AMBIENT AIR C MONITOR TO D CONCENTRATIC IT IS DETERMIN FROM THE FLAI SO2 IMPACTS F MONITOR, ANE MONITOR ARE SHALL CURTAIL APPROPRIATE,							DLLOW SPECIFICATIONS OF 40 CFR 60.18.								
A define chance is incorrong that is a defined chance is incorrong that is a defined chance is incorrong that is incorrect that is incorrong that is incorrect th	/UM EXTENT PRACTICABLE, BUT TO DW 5193 LB/H.				0		LB/H	3665.97	DLLUTANT NOTES.					FLARE, STEADY STATE OPERATION	12/19/2002 ACT	тх	ATOFINA CHEMICALS INCORPORATED
154 TOTING CHEMICALS INCORPORATED TA 12/19/2012 delaptor MILCAN LADDIG/UNLOD/ONE (1) STAME OLIFICATION (1)					0		LB/H	0.01	OLATION,						12/19/2002 ACT	тх	ATOFINA CHEMICALS INCORPORATED
N354 ATOFINA CHEMICALS INCORPORATED TX 12/19/2002 & hbsp;ACT DIMETYL DISULFIDE AREA PROCESS FUGITIVES C Sulfar, Total Reduced (TRS) SolATION, Reduced (TRS) OLO< LB/H OL LB/H OL LB/H C LB/H	ITES BEFORE THE START OF ANY IS. DAMAGED HOSES SHALL BE IED BEFORE ANY LOADING ENCE. UPON COMPLETION OF LOADIN ADING LINES (EXCEPT FOR MMP) ITH INERT GAS TO THE FLARE CTIONS BETWEEN THE LOADING RACK S ARE BROKEN. MMP RAILCAR LOSED LOOP VAPOR BALANCE D TO THE MMP STORAGE TANK OR TH OMPLETION OF MMP LOADING ADING LINE WILL BE PURGED INTO MMP STORAGE TANK. WHEN ILCAR FROM THE LOADING LINE, AN IVALENT WASH WILL BE DONE DADING. THE WASH MATERIAL WILL D MANAGED IN THE ON-SITE M. THE WASH MATERIAL TANK WILL	FOR POSSIBLE L LOADING OPER REPAIRED OR R OPERATIONS C OPERATIONS C OPERATIONS C SHALL BE PURG BEFORE ANY CC AND LOADED V LOADING WILL SYSTEMS CONN SULFOX-TO. UF OPERATIONS TI THE RAILCAR O UNHOOKING TI ACETIC ACID OI AFTER EACH M BE NEUTRALIZE WASTEWATER S			0		LB/H	0.03						-	12/19/2002 ACT	тх	ATOFINA CHEMICALS INCORPORATED
154 ATOFINA CHEMICALS INCORPORATED TX 12/19/2002 ACT (2) STEAM BOILERS, X-426A AND X- 426B NATURAL GAS 15.8 MMBTU/H Sulfur Dioxide (SO2) CONTAINING NO MORE THAN 5 GR 5/100 DSCF. 0.01 LB/H 0.0006 LB/MMBTU THROUGHPUT 154 ATOFINA CHEMICALS INCORPORATED TX 12/19/2002 ACT 426B NATURAL GAS 15.8 MMBTU/H Sulfur Dioxide (SO2) NO MORE THAN 5 GR 5/100 DSCF. 0.01 LB/H 0.0006 LB/MMBTU THROUGHPUT 154 ATOFINA CHEMICALS INCORPORATED TX 12/19/2002 ACT RUNDOWN TANK FUGITIVES Image: Control of the second control of the seco					0		ів/н	0.06	OLATION,						12/19/2002 -ACT	тх	ATOFINA CHEMICALS INCORPORATED
MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULFOX-TO. FOLLOW PRACTICES OF LEAK DETECTION, Sulfur, Total ISOLATION, Reduced (TRS) AND REPAIR. 0.11 LB/H 0			CALCULATED USING						JEL GAS SHALL BE SWEET NATURAL GAS	Sulfur Dioxide							
			THROUGHPUT	ММВТU	0.0006 LB/		LB/H	0.01	MP DAY STORAGE TANKS WILL VENT TO HE MMP BULK ORAGE TANK WHICH WILL VENT TO JLF0X-TO. DLLOW PRACTICES OF LEAK DETECTION,		3 MMBTU/H	15.	NATURAL GAS	4268	12/19/2002 ACT	тх	ATOFINA CHEMICALS INCORPORATED
THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, Sulfur, Total ISOLATION,					0		LB/H	0.11	MP DAY STORAGE TANKS WILL VENT TO HE MMP BULK ORAGE TANK WHICH WILL VENT TO JLF0X-TO. DLLOW PRACTICES OF LEAK DETECTION,					RUNDOWN TANK FUGITIVES	12/19/2002 ACT	TX	ATOFINA CHEMICALS INCORPORATED

L	1		1	Su	ummary of SO ₂	Control Deter	mination per	EPA's RACT/E	BACT/LAER Database for Chemica	I Plant Flares		1		1	Τ
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
									FOLLOW PROCEDURES OF LEAK						T
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.02	2 LB/H	0			
									FOLLOW PRACTICES OF LEAK DETECTION,						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.01	L LB/H	0			
				THERMAL OXIDIZER, STEADY STATE				Sulfur, Total							
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SERVICE		134.5	MMBTU/H	Reduced (TRS)	NONE INDICATED FUEL GAS COMBUSTED IN EACH	0.89) LB/H	0			┢
									COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS						
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	L LB/H	0			
					NATCAS			Sulfur Dioxide							
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			(SO2) Sulfur Dioxide	NONE INDICATED	0.01	L LB/H	0		NOT AVAILABLE	+
TX-0378	LA PORTE POLYPROPYLENE PLANT	ТХ	11/05/2001 ACT	STANDBY INCINERATOR				(SO2)	NONE INDICATED	0.01	l lb/H	0		CALCULATED	╞
								Sulfur Dioxide						USING	
TX-0378	LA PORTE POLYPROPYLENE PLANT	ТХ	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	(SO2) Sulfur Dioxide	NONE INDICATED	0.95	5 LB/H	0 02	LB/MMBTU	THROUGHPUT	+
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			(SO2)	NONE INDICATED	0.01	L LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
-								Sulfur Dioxide						_	T
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			(SO2) Sulfur Dioxide	NONE INDICATED	0.01	l lb/H	0		NOT AVAILABLE	┢
TX-0378	LA PORTE POLYPROPYLENE PLANT	ТХ	11/05/2001 ACT	TRAIN NO. 8 FLARE				(SO2)	NONE INDICATED	0.01	L LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0			
TX-0380	SYNTHESIS GAS UNIT	тх	06/01/2001 ACT	(2) AIR PREHEATERS 1106 & amp; 1206, F1106SGU & amp;F1206SGU				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	L LB/H	0		NOT AVAILABLE	
17-0580				1200,11100500 @amp,11200500				Sulfur Dioxide				0			+
TX-0380	SYNTHESIS GAS UNIT	ТХ	06/01/2001 ACT	FLARE, FS28 HEATER, STARTUP, MALEIC	SYNGAS			(SO2) Sulfur Dioxide	NONE INDICATED PIPELINE QUALITY NATURAL GAS < 2.0 GR	3337.57	7 LB/H	0			┢
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	ANHYDRIDE REACTOR	NATURAL GAS	160.7	mmbtu/h	(SO2)	S PER 1000 DSCF	0.64	1 LB/H	0.004	lb/mmbtu	CALCULATED	
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			Sulfur Dioxide (SO2)		0.05	5 LB/H	0			
TX-0422		ТХ	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS				Sulfur Oxides (SO	x)		5 LB/H	0		SEE NOTE	ST.
				FLARE BEFOER THE RECYCLE COMPRESSOR PROJECTS IS				Sulfur Dioxide	MEETS HEATING VALUES AND VELOCITY						
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	COMPLETE				(SO2)	REQ. AND BTU ANALYZERS	1.38	B LB/H	0			
				FLARE AFTER THE RECYCLE COMPRESSOR PROJECTS IS				Sulfur Dioxide	MEETS HEATING VALUES AND VELOCITY						
TX-0449	UCC SEADRIFT OPERATIONS	ТХ	04/03/2004 ACT	COMPLETE FLARE NATURAL GAS COMBUSTION				(SO2)	REQ. AND BTU ANALYZERS MEETS HEATING VALUES AND VELOCITY	1.38	3 LB/H	0			_
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	(6)	NATURAL GAS			Sulfur Dioxide (SO2)	REQ. AND BTU ANALYZERS	0.5	5 LB/H	0			
				STARTUP, SHUTDOWN,											
				MAINTENANCE BEFORE THE				Sulfur Dioxide							
TX-0449	UCC SEADRIFT OPERATIONS	ТХ	04/03/2004 ACT	RECYCLE PROJECT IS COMPLETE (5)				(SO2)	GOOD PRACTICES	1.38	3 LB/H	0			╞
				STARTUP, SHUTDOWN,											
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	MAINTENANCE AFTER THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	BLB/H	0			
	CONTINENTAL CARBON SUNRAY							Sulfur Dioxide							
TX-0464	PLANT CONTINENTAL CARBON SUNRAY	TX	03/18/2005 ACT	PILOT PLANT FLARE				(SO2) Sulfur Dioxide		435.27	7 LB/H	0			┢
TX-0464	PLANT	тх	03/18/2005 ACT	PROCESS BAG FILTER				(SO2)		0.15	5 LB/H	0			
	CONTINENTAL CARBON SUNRAY				NATURAL GAS, FUEL OIL, OR FLUE			Sulfur Dioxide							
TX-0464	PLANT	ТХ	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	GAS	0.9	ММВТU/Н	(SO2) Sulfur Dioxide		0 001	L LB/H	0			\vdash
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	ТΧ	03/18/2005 ACT	OXYGEN PRE HEATER	NATURAL GAS			(SO2)		0.01	L LB/H	0			
TX-0465	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	COOPER-BESSEMER ENGINE 3105 HP		3105	НР	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.24	5 LB/H				
17-0403		17	01/31/2003 @HDSP,ACT			5105	1.11-	(SU2) Sulfur Dioxide		0.26		0		1	┢
TX-0465	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	HOT OIL HEATER		32.5	MMBTU/H	(SO2)		0.02	2 LB/H	0			

NC TINIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	0			
	0			
	0			
	0		NOT AVAILABLE	
		lb/MMBTU	CALCULATED USING THROUGHPUT	
	0		NOT AVAILABLE	
	0			
	0		NOT AVAILABLE	
	0			
	0			
	0		NOT AVAILABLE	
	0			
	0.004	lb/MMBTU	CALCULATED	
	0		SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.
	0			
	0			
	0			
	0			
	0			
	0			
	0			
	0			
	0			
	0			
	0			
	0			

	1	1	1	Si	ummary of SO ₂	Control Deterr	mination per	EPA's RACT/B	ACT/LAER Database for Chemica	al Plant Flares	1	1	1
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANI EMIS LIMIT
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	FLARES (2)				Sulfur Dioxide (SO2)		50.48		0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HP TEG FIREBOX				Sulfur Dioxide (SO2)			LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400	НР	Sulfur Dioxide (SO2)	LEAN COMBUSTION		LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	CLARK ENGINE (2)		2000		Sulfur Dioxide (SO2)	LEAN COMBUSTION		LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440		Sulfur Dioxide	LEAN COMBUSTION		LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER			MMBTU/H	Sulfur Dioxide (SO2)			LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330	НР	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	GLYCOL REBOILER		2.5	MMBUT/H	Sulfur Dioxide (SO2)		0.02	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0	
TX-0481	AIR PRODUCTS BAYTOWN I I	тх	11/02/2004 ACT	BOILER STACK	NATURAL GAS			Sulfur Dioxide (SO2)		24.2	LB/H	0	
TX-0481	AIR PRODUCTS BAYTOWN I I	тх	11/02/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2) Sulfur Dioxide		4.8	LB/H	0	
TX-0481		тх	11/02/2004 ACT	FLARE (NORMAL OPERATION)	NATURAL GAS			(SO2)		0.04	LB/H	0	
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2) Sulfur Dioxide		0.03	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	ТХ	03/24/2005 ACT	N5/6 FLARE N-3 BACKUP INSTRUMENT AIR				(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	COMPRESSOR				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N7/8 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N-3,4 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ENTERPRISE MONT BELVIEU	тх	03/24/2005 ACT	N-5/6 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0514	COMPLEX AIR PRODUCTS HYDROGEN, STEAM,	тх	01/24/2006 ACT	FLARE-NORMAL OPERATION				(SO2) Sulfur Dioxide		1.1	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	FLARE PILOTS ONLY				(SO2) Sulfur Dioxide		0 002	LB/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	FLARE-MSS				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	(SO2) Sulfur Dioxide		0.92	LB/H	0	
TX-0526	AND ELECTRICITY PRODUCTION	тх	08/18/2006 EST	REFORMER FURNACE STACK	STEAM	1373	MMBTU/H	(SO2)		7.3	LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES

			Τ	Т	Summary of	SO ₂ Control Determination	n per EPA's RA	CT/BACT/LAER Database for Oth	ner Flares	1	1	1	1	
						THROUGHPUT			EMISSION LIMIT		STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME HOMELAND ENERGY SOLUTIONS, LLC,	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME EMERGENCY DIESEL FIRE WATER	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
A-0089	PN 06-672	IA	08/08/2007 ACT	PUMP S110 (07-A-982P)		300 BHP	(SO2)	NONE	0 203	G/KW-H	0			BACT EQUIVALENT TO 0.203 G/KWH
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	а	08/08/2007 ACT	THERMAL OXIDIZER FOR HRSG FROM DRYERS AND GASIFICATION - TWO SYSTEMS, S10 AND S11 (07-A- 955P AND 07-A-956P)	SYNGAS METHANE /	250 MMBTU/H	Sulfur Dioxide (SO2)	H2S REMOVAL SYSTEM AFTER THE GASIFICATION PROCESS AND PRIOR TO THE USE IN THE DRYERS OR THERMAL OXIDIZERS	0 034	LB/MMBTU	0.2	LB/MMBTU	30-DAY ROLLING, NSPS	FOR THE SYN-GAS MADE FROM COAL, THE SO2 IS LIMITED TO 0.014 LB / MM BTU AND THE SO2 FROM THE PROCESS IS LIMITED TO 0.02 LB / MM BTU EACH BASED ON 250 MM BTU / HR HEAT INPUT.
	HOMELAND ENERGY SOLUTIONS, LLC,			BIOMETHANATOR FLARE, EP11 (07-	SYNGAS /		Sulfur Dioxide							
A-0089	PN 06-672	IA	08/08/2007 ACT	A-957P)	NATURAL GAS	6.4 MM BTU / H	(SO2)		0.0007	LB/MMBTU	0			
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	PRODUCT LOADOUT FOR TRUCKS AND RAIL CARS, EP22 AND F50 (07- A-965P) STARTUP AND SHUTDOWN FLARES		1500 GAL/MIN	Sulfur Dioxide (SO2)	FLARE	0.0006	EB/MM BTU	0			
A-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	1, 2, AND 3, EP33A, EP33B, AND EP33C (07-A-967P, 07-A-968P, AND 07-A-969P)	NATURAL GAS OR SYNGAS	25 MMBTU	Sulfur Dioxide (SO2)	FLARE	0 395	LB/MM BTU	o			
							Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK OIL IS						
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 FILTER FUGITIVES	FEEDSTOCK OIL		(SO2) Sulfur Dioxide	LIMITED TO 4% SULFUR CONTENT OF FEEDSTOCK OIL IS	0) LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 DRYER FUGITIVES	FEEDSTOCK OIL		(SO2)	LIMITED TO 4%	C	LB/H	0			
							Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK OIL IS						
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 PROCESS FUGITIVES	FEEDSTOCK OIL		(SO2)	LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (LIMITS BEFORE UNIT 5)	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	4.6	5 LB/H	0			EMISSION LIMITS BEFORE INSTALLATION OF UNIT 5
A 0462			14/04/4000 Bulkers ACT	UNIT 3 PROCESS FILTER (AFTER			Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK OIL IS						
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 5 IS INSTALLED) UNIT 3 PELLET DRYER PURGE GAS	FEEDSTOCK OIL		(SO2) Sulfur Dioxide	LIMITED TO 4%	4.6	5 LB/H	0			EMISSION LIMITS AFTER INSTALLATION OF UNIT 5
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	FILTER	FEEDSTOCK OIL		(SO2)	BAG FILTER	9.4	LB/H	0			
							Sulfur Dioxide	LIMITATION OF SULFUR CONTENT IN FEEDSTOCK OIL TO						
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNITS 1&2 FLARE	FEEDSTOCK OIL		(SO2)	4%	2555.8	B LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	ΙΔ	11/04/1999 ACT	UNIT 3 FLARE	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL LIMITED TO 4%.	2295.1	IB/H	0			
2110100			11/01/1000 ((1000))/101				Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK OIL IS	225513					
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR FUGITIVES	FEEDSTOCK OIL		(SO2)			LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR WARM UP VENT	FEEDSTOCK OIL		Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	0.01	LB/H	0			
				ACRYLIC ACID INCINERATOR (POINT			Sulfur Dioxide	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO						COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM
TX-0277	BASF CORPORATION	ТХ	12/12/2001 ACT	NO. IN-701)	NATURAL GAS		(SO2)	MORE THAN 20 GR/100 DSCF OF SULFER. NATURAL GAS AS SUPPLEMENTAL FUEL	20) LB/H	0			OPERATING SCHEDULE OF 8,760 H/YR.
77 0277		TV	12/12/2001 & phone ACT				Sulfur Ovidos (SO	CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO		110/11				COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760
1 A-UZ / /	BASF CORPORATION	ТХ	12/12/2001 ACT	INCINERATOR (POINT NO. IN-5500)	INAL GAS		Saliar Oxides (SO)	MORE THAN 20 GR/100 DSCF SULFER.	0.17	'LB/H				H/YR. COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. EMISSION RATES ARF
				CONTINUOUS FLARE (POINT NO. 4-2			Sulfur Dioxide							ARE BASED ON A MAXIMUM OPERATING SCHEDULE OF 8760
TX-0277	BASF CORPORATION	тх	12/12/2001 ACT	4)	NATURAL GAS		(SO2)		0.01	LB/H	0			H/YR.
TX-0309	FORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	(2) STARTUP HEATERS, 70H101- 1&-2		75 MMBTU/H, EA	Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0.0005	lb/mmbtu	CALCULATED FROM HOURLY E.L. AND THRUPUT	
TX-0309	FORMOSA PLASTICS TEXAS	ТХ	02/10/2000 ACT	PROCESS FUGITIVES, 70ANFUG			Sulfur Dioxide (SO2)	NONE INDICATED	0.46	5 LB/H	0			FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0309	FORMOSA PLASTICS TEXAS	тх	02/10/2000 ACT	WASTE HEAT BOILER, 70Z401	NAT GAS		Sulfur Dioxide (SO2)	NONE INDICATED	0.26	5 LB/H	0			
		-	. ,,,, , , , , , , , , , , , ,				Sulfur Dioxide		0.20		ľ		1	

							THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION
X-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	FIREWATER PUMP, 81				Sulfur Dioxide (SO2)	NONE INDICATED	0.26 LB/H	0		
X-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	SOLAR TURBINE & amp; DUCT BURNER, 70	NATURAL GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.28 LB/H	0		
X-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	CONTINUOUS CATALYST REGENERATOR, 71				Sulfur Dioxide	CAUSTIC SCRUBBER	0.12 LB/H	0		
			12/03/2000 ((1050)/101					Sulfur Dioxide		0112 20,11	0		
X-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS			(SO2)	FIRING NAT GAS FIRING NAT GAS WITH S CONCENTRATION	0.38 LB/H	0		NOT AVAILABLE
X-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	3 DIP TURBINES & amp; 3 DUCT BURNERS, 74	NAT GAS			Sulfur Dioxide (SO2)	OF NO MORE THAN 15 PPMW.	0.46 LB/H	0		
								Sulfur Dioxide					
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	FLARE, 76				(SO2)	NONE INDICATED	0.01 LB/H	0		
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.08 LB/H	0		NOT AVAILABLE
				(2) HYDROTREATER REGENERATOR				Sulfur Dioxide					
X-0347	CHOCOLATE BAYOU PLANT	ТХ	10/16/2001 ACT	STACKS,DD-606&DDD-606				(SO2) Sulfur Dioxide	NONE INDICATED	45.8 LB/H	0		
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101				(SO2)	NONE INDICATED	0.01 LB/H	0		
X-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0		
X-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION FURNACE, DB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.52 LB/H	0		NOT AVAILABLE
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07 LB/H	0		NOT AVAILABLE
X-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DDB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.5 LB/H	0		NOT AVAILABLE
								Sulfur Dioxide					
X-0347	CHOCOLATE BAYOU PLANT	ТХ	10/16/2001 ACT	REGENERATION HEATER, DDB-601				(SO2)	NONE INDICATED	0.07 LB/H	0		NOT AVAILABLE ADDIT
FX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	FURNACE EMISSION CAPS FOR 30 EMISSION POINTS				Sulfur Dioxide (SO2)	NONE INDICATED	48 LB/H	0		53.66 61 37
									FUEL SULFUR CONTENT LIMIT: THE				
									NATURAL GAS STREAM				
								Sulfur Dioxide	SHALL CONTAIN LESS THAN 5 GR TOTAL SULFUR/100				
FX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	BOILER, BLR	NAT GAS			(SO2)	DSCF.	3.25 LB/H	0		NOT AVAILABLE
TX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE			Sulfur Dioxide (SO2)	NONE INDICATED	14.13 LB/H	0		
								Sulfur Dioxide					
TX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS			(SO2)	NONE INDICATED FOLLOW PROCEDURES OF LEAK	0.01 LB/H	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.01 LB/H	0		
				TRAIN 1 - MESH PRODUCTION			1	Sulfur, Total	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION,				
X-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES				Reduced (TRS)	AND REPAIR.	0.02 LB/H	0		
				TRAIN 2- MESH PRODUCTION				Sulfur, Total	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION,				
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	FUGITIVES			<u> </u>	Reduced (TRS) Sulfur Dioxide	AND REPAIR.	0.02 LB/H	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR TRUCK, S-3				(SO2)	NONE INDICATED	0.07 LB/H	0		

г	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
6	LB/H	0			
8	LB/H	0			
	LB/H	0			
8	LB/H	0		NOT AVAILABLE	
6	LB/H	0			
1	LB/H	0			
	LB/H	0		NOT AVAILABLE	
8	LB/H	0			
1	LB/H	0			
1	LB/H	0			
2	LB/H	0		NOT AVAILABLE	
7	LB/H	0		NOT AVAILABLE	
	LB/H	0		NOT AVAILABLE	
	LB/H	0		NOT AVAILABLE	
/	LB/II	0			ADDITIONAL CAPS:
8	LB/H	0			53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06, 61 37 LB/H, 13.44 T/YR AFTER 6/30/06
5	LB/H	0		NOT AVAILABLE	
	LB/H	0			
T	LB/H	0			
1	LB/H	0			
2	LB/H	0			
2	lb/H	0			
1	LB/H	0		1	

					Summary of	SO ₂ Control D	etermination	per EPA's RAC	T/BACT/LAER Database for Oth	er Flares				
							THROUGHPUT				STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
D	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
									SEE POLLUTANT NOTES. FOLLOW					ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADIN OPERATIONS COMMENCE. UPON COMPLETION OF LOADIN OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACK: AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THI SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE
				TANK TRUCK LOADING/UNLOADING				Sulfur, Total	PRACTICES OF LEAK					WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL
4	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES				Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.03 LB/H	0			VENT TO THE SULFOX-TO.
4	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27 LB/H	0			
									FOLLOW THE REQUIREMENTS OF 40 CFR					TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE
								Sulfur Dioxide	60.18. SEE					FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
1	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	FLARE, SSM				(SO2)	THE POLLUTANT NOTES.	2541.37 LB/H	0			AT LEAST AT OR BELOW 5193 LB/H.
	ATOFINA CHEMICALS INCORPORATED		12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL			1	Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62 LB/H				

					Summary of	SO ₂ Control D	etermination	per EPA's RAG	CT/BACT/LAER Database for Oth	er Flares			
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD STANDAR EMISSION EMISSION LIMIT LIMIT UNI	Ι ΤΙΜΕ	POLLUTANT COMPLIANCE NOTES
													TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54
				FLARE, TOTAL HOURLY AND				Sulfur Dioxide	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE				SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
354 ATOFINA	CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	ANNUAL				(SO2)	POLLUTANT NOTES.	6207.34 LB/H	0		AT LEAST AT OR BELOW 5193 LB/H.
0354 ATOFINA	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	ММВТU/Н	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02 LB/H	0.0006 LB/MMBTU	CALCULATED, USING THROUGHPUT	
0354 ATOFINA	CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01 LB/H	0		
)354 ATOFINA	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02 LB/H	0.0006 LB/MMBTU	CALCULATED USING THROUGHPUT	
J354 ATOFINA	CHEMICALS INCORPORATED		12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139 LB/H	0		
)354 ATOFINA	CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86 LB/H	0		
)354 ATOFINA	CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED FOLLOW PRACTICES OF LEAK DETECTION,	0.17 LB/H	0		
354 ATOFINA	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.01 LB/H	0		
354 ATOFINA	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	ММВТU/Н	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89 LB/H	0		
								Sulfur Dioxide	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING				
	CHEMICALS INCORPORATED		12/19/2002 ACT	THERMAL OXIDIZER, SSM THERMAL OXIDIZER, TOTAL HOURLY			MMBTU/H	(SO2) Sulfur, Total	NO MORE THAN 5 GR S/100 DSCF.	1156.47 LB/H	0		
354 ATOFINA	CHEMICALS INCORPORATED	TX	12/19/2002 ACT	AND ANNUAL THERMAL OXIDIZER, TOTAL HOURLY		134.5	MMBTU/H	Reduced (TRS) Sulfur Dioxide	NONE INDICATED THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100	0.89 LB/H	0		WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET
354 ATOFINA	CHEMICALS INCORPORATED	тх	12/19/2002 ACT	AND ANNUAL		134.5	MMBTU/H	(SO2)	DSCF.	1157.44 LB/H	0		CONCENTRATION OF 10 PPMV.
	CHEMICALS INCORPORATED	TV	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35 LB/H			

					Summary of	SO ₂ Control De	termination	per EPA's RA	CT/BACT/LAER Database for Oth	er Flares					
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL		THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
															TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED
								Sulfur Dioxide	FOLLOW SPECIFICATIONS OF 40 CFR 60.18 SEE						SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO
0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				(SO2) Sulfur, Total	POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION,	3665.97	lb/H	0			AT LEAST AT OR BELOW 5193 LB/H.
0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES				Reduced (TRS)	AND REPAIR.	0.01	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY
0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION,	0.03	LB/H	0			FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
)354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.06	LB/H	0		FACIL	
1354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X- 426B	NATURAL GAS	15.8 M	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF. MMP DAY STORAGE TANKS WILL VENT TO	0.01	LB/H	0.0006	LB/MMBTU	EACH, CALCULATED USING THROUGHPUT	
354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Sulfur, Total Reduced (TRS)	THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.		LB/H	0			
									MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULFOX-TO. FOLLOW PRACTICES OF LEAK DETECTION,						
25/	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.15	LB/H	0			

						f SO ₂ Control D								
	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE		PRIMART FUEL	THROUGHPUT	UNIT		FOLLOW PROCEDURES OF LEAK					CONDITION
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR. FOLLOW PRACTICES OF LEAK DETECTION,	0.02	LB/H	0		
TV 0254		T)/	42/40/2002 Bakes ACT					Sulfur, Total	ISOLATION,	0.01	1.5/11			
TX-0354	ATOFINA CHEMICALS INCORPORATED		12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES THERMAL OXIDIZER, STEADY STATE				Reduced (TRS) Sulfur, Total	AND REPAIR.	0.01	LB/H	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SERVICE		134.5	ММВТИ/Н	Reduced (TRS)		0.89	LB/H	0		
									FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	ММВТИ/Н	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	LB/H	0		
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
17-0370			11/03/2001 @1030,AC1							0.01				CALCULATED
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/MMBTU	USING THROUGHPUT
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0		NOT AVAILABLE
								Sulfur Dioxide						
TX-0378	LA PORTE POLYPROPYLENE PLANT	ТХ	11/05/2001 ACT	MONUMENT NO. 2 FLARE				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0		
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			(SO2)	NONE INDICATED	0.01	LB/H	0)	NOT AVAILABLE
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	TRAIN NO. 8 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0)	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		
TX-0380	SYNTHESIS GAS UNIT	тх	06/01/2001 ACT	(2) AIR PREHEATERS 1106 & amp; 1206, F1106SGU & amp;F1206SGU				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	,	NOT AVAILABLE
								Sulfur Dioxide						
TX-0380	SYNTHESIS GAS UNIT	ТХ	06/01/2001 ACT	FLARE, FS28 HEATER, STARTUP, MALEIC	SYNGAS			(SO2) Sulfur Dioxide	NONE INDICATED PIPELINE QUALITY NATURAL GAS < 2.0 GR	3337.57	LB/H	0		
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	ANHYDRIDE REACTOR	NATURAL GAS	160.7	/ mmbtu/h	(SO2) Sulfur Dioxide	S PER 1000 DSCF	0.64	LB/H	0.004	LB/MMBTU	CALCULATED
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			(SO2)			LB/H	0		
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	ТХ	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS FLARE BEFOER THE RECYCLE				Sulfur Oxides (SOx	:)	7.75	LB/H	0		SEE NOTE STAN
				COMPRESSOR PROJECTS IS				Sulfur Dioxide	MEETS HEATING VALUES AND VELOCITY					
TX-0449	UCC SEADRIFT OPERATIONS	ТХ	04/03/2004 ACT	COMPLETE FLARE AFTER THE RECYCLE				(SO2)	REQ. AND BTU ANALYZERS	1.38	LB/H	0		
TY 0440		TV	04/02/2004 8 phone 4 CT	COMPRESSOR PROJECTS IS				Sulfur Dioxide	MEETS HEATING VALUES AND VELOCITY	1.20				
TX-0449	UCC SEADRIFT OPERATIONS	ТХ	04/03/2004 ACT	COMPLETE FLARE NATURAL GAS COMBUSTION				(SO2) Sulfur Dioxide	REQ. AND BTU ANALYZERS MEETS HEATING VALUES AND VELOCITY	1.38	LB/H	U		
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	(6)	NATURAL GAS			(SO2)	REQ. AND BTU ANALYZERS	0.5	LB/H	0		
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	STARTUP, SHUTDOWN, MAINTENANCE BEFORE THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.20	LB/H			
1X-0449		1X	04/03/2004 AC1	STARTUP, SHUTDOWN,					GOOD PRACTICES	1.38	БСВ/П	0		
TX-0449	UCC SEADRIFT OPERATIONS	тх	04/03/2004 ACT	MAINTENANCE AFTER THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	LB/H	0		
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	тх	03/18/2005 ACT	PILOT PLANT FLARE				Sulfur Dioxide (SO2)		435.27	ив/н	0		
	CONTINENTAL CARBON SUNRAY							Sulfur Dioxide				0		
TX-0464	PLANT	ТХ	03/18/2005 ACT	PROCESS BAG FILTER	NATURAL GAS,			(SO2)		0.15	LB/H	0		+
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	тх	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	FUEL OIL, OR FLUE GAS		ммвти/н	Sulfur Dioxide (SO2)		0 001	IB/H			
	CONTINENTAL CARBON SUNRAY					0.9	viivio I U/ fl	Sulfur Dioxide						+ +
TX-0464	PLANT	тх	03/18/2005 ACT	OXYGEN PRE HEATER COOPER-BESSEMER ENGINE 3105	NATURAL GAS			(SO2) Sulfur Dioxide		0.01	LB/H	0		<u> </u>
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HP		3105	i HP	(SO2)	LEAN COMBUSTION	0.26	LB/H	0)	<u> </u>
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER	1	27 5	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H			

EMISSION IMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
3/Н	0			
,				
3/Н	0			
3/Н	0			
3/H	0			
3/H	0		NOT AVAILABLE	
3/Н	0			
3/H	0 02	lb/MMBTU	CALCULATED USING THROUGHPUT	
3/Н	0		NOT AVAILABLE	
3/Н	0			
3/Н	0		NOT AVAILABLE	
3/Н	0			
3/Н	0			
3/Н	0		NOT AVAILABLE	
3/Н	0			
3/H	0.004	lb/mmbtu	CALCULATED	
3/H	0			
3/H	0		SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.
3/H	0			
3/н	0			
3/Н	0			
5,				
3/Н	0			
,	-			
3/Н	0			
3/Н	0			
3/Н	0			
3/H	0			
3/H	0			
3/H	0			
3/Н	0			

				1	Summary of	SO ₂ Control D	etermination	per EPA's RAC	CT/BACT/LAER Database for Oth	er Flares			
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EN LIN
					PRIMART FUEL	THROUGHPUT	UNIT	Sulfur Dioxide				LINIT	LIIV
TX-0465 TX-0465	SALT CREEK GAS PLANT SALT CREEK GAS PLANT	тх	01/31/2003 ACT 01/31/2003 ACT	FLARES (2) HP TEG FIREBOX				(SO2) Sulfur Dioxide (SO2)		0.01	lb/H LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION		LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	CLARK ENGINE (2)		2000) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.31	LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION		LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER		12	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	GLYCOL REBOILER		2.5	MMBUT/H	Sulfur Dioxide (SO2)		0.02	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	ММВТИ/Н	Sulfur Dioxide (SO2)		1.4	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99) ММВТU/Н	Sulfur Dioxide (SO2)		2.2	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	TAIL GAS INCINERATOR		100) MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	2 ММВТU/Н	Sulfur Dioxide (SO2)		5.7	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0	
TX-0481	AIR PRODUCTS BAYTOWN I I	тх	11/02/2004 ACT	BOILER STACK	NATURAL GAS			Sulfur Dioxide (SO2)		24.2	LB/H	0	
TX-0481	AIR PRODUCTS BAYTOWN I I	тх	11/02/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		4.8	LB/H	0	
TX-0481		тх	11/02/2004 ACT	FLARE (NORMAL OPERATION)	NATURAL GAS			Sulfur Dioxide (SO2)		0.04	LB/H	0	
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2) Sulfur Dioxide		0.03	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N5/6 FLARE N-3 BACKUP INSTRUMENT AIR				(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	COMPRESSOR				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N7/8 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N-3,4 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ENTERPRISE MONT BELVIEU	тх	03/24/2005 ACT	N-5/6 PREHEATER				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0514	COMPLEX AIR PRODUCTS HYDROGEN, STEAM,	тх	01/24/2006 ACT	FLARE-NORMAL OPERATION				(SO2) Sulfur Dioxide		1.1	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	FLARE PILOTS ONLY				(SO2) Sulfur Dioxide		0 002	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	FLARE-MSS				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION AIR PRODUCTS HYDROGEN, STEAM,	тх	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	(SO2) Sulfur Dioxide		0.92	lb/H	0	
TX-0526	AND ELECTRICITY PRODUCTION	тх	08/18/2006 EST	REFORMER FURNACE STACK	STEAM	1373	ммвти/н	(SO2)		7.3	LB/H	0	

DN NIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
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		1		Summary of SO ₂	2 Control Determi	nation per l	EPA'S RACI/B	ACI/LAER Data	abase for Combustion of Misc. B	Sollers, Furnad	es, & Heate	ers		-	
			PERMIT ISSUANCE DATE		PRIMARY FUEL 1		THROUGHPUT				EMISSION	STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME		THROUGHPUT	UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION LIMIT FUEL SULFUR CONTENT TO: 200	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 11 2 MW	FUEL GAS	11.2	2 MW	Sulfur Dioxide (SO2)	PPM FUEL GAS H2S, OR FUEL OIL SULFUR CONTENT 0.15% BY WEIGHT		PPM @ 15% O2	150	PPM @ 15% O2		DUEL FUEL FIRED TURBINE. OIL-FIRED OPERATIONS LIMITED TO 500 HRS ANNUALLY
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 36,700 HP	FUEL GAS	27.4	1 MW	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	PPM @ 15% O2	150	PPM @ 15% O2		
	ALPINE DEVELOPMENT PROJECT,	AK	02/01/1000 8 phone 4 CT			25800	KINI (Sulfur Dioxide		150	PPM @ 15%				
4K-0050	CENTRAL PROCESSING FAC ALPINE DEVELOPMENT PROJECT,	АК	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 25 8 MW HEATER, CRUDE PRODUCTION, 65.6	FUELGAS			(SO2) Sulfur Dioxide	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	02	0			
AK-0056	CENTRAL PROCESSING FAC ALPINE DEVELOPMENT PROJECT,	AK	02/01/1999 ACT	MMBTU/H HEATER, CRUDE PRODUCTION, 65.6	FUEL GAS	65.6	5 MMBTU/H	(SO2) Sulfur Dioxide	FUEL GAS H2S NOT TO EXCEED 200 PPMV	C		0)		Fuel limit no emission rate limit.
AK-0056	CENTRAL PROCESSING FAC	АК	02/01/1999 ACT		FUEL GAS	65.6	5 ММВТН/Н	(SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV.	. 0		0)		fuel sulfur limit no emission rate limit
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	HEATER, UHM, 20 MMBTU/H	FUEL GAS	20) MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING USING LIQUID FUEL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0.5 WEIGHT PERCENT SULFUR.	с		0			limit is fuel sulfur limit. No emission rate limit
	ALPINE DEVELOPMENT PROJECT,							Sulfur Dioxide	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING ON FUEL OIL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0 5 WEIGHT PERCENT						limit is fuel sulfur limits. No emission rate
AK-0056	CENTRAL PROCESSING FAC	АК	02/01/1999 ACT	HEATER, HMU, 20 MMBTU/H	FUEL GAS	20) MMBTU/H	(SO2)	SULFUR. FUEL OIL SULFUR CONTENT NOT TO	C		0)		limits
	ALPINE DEVELOPMENT PROJECT,							Sulfur Dioxide	EXCEED 0.15%						
AK-0056	CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	IC ENGINES, 2 MW	FUEL OIL	2	2 MW	(SO2)	SULFUR BY WEIGHT	C		0)		SULFUR LIMIT ON FUEL POLLUTANT INFORMATION CONT.:
								Sulfur Dioxide							OPACITY EMISSION LIMIT: 10%, 93% OVERALL EFFICIENCY
AL-0221	LOUISIANA PACIFIC CORPORATION	AL	06/14/2006 ACT		BARK	85000) lb/h	(SO2)		4.7	LB/H	0)		ODT: OVEN DRIED TON
AL-0221	LOUISIANA PACIFIC CORPORATION	AL	06/14/2006 ACT	BURNER, START UP/SHUT DOWN, NG	NATURAL GAS	30) MMBtu/h	Sulfur Dioxide (SO2)	GOOD DESIGN/OPERATION	0.02	LB/H	0.0006	LB/MMBTU		
	THOMAS B. FITZHUGH GENERATING			TURBINE, COMBINED CYCLE,				Sulfur Dioxide			PPM @ 15%				
AR-0052	STATION THOMAS B. FITZHUGH GENERATING	AR	02/15/2002 ACT	NATURAL GAS HEAT RECOVERY STEAM	NATURAL GAS	170.6	5 MW	(SO2) Sulfur Dioxide	GOOD COMBUSTION. GOOD COMBUSTION PRACTICES AND	1	02 PPM @ 15%	0)		
AR-0052	STATION	AR	02/15/2002 ACT		NATURAL GAS	220) ММВТU/Н	(SO2)	DESIGN.	1	02	0)	NOT AVAILABLE	Standardized units not available.
AR-0052	THOMAS B. FITZHUGH GENERATING STATION	AR	02/15/2002 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	NO. 2 FUEL OIL	170.6	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, FUEL S LIMIT: < 0.33% S BY WT	85	PPM@ 15% O2	0			
								Sulfur Dioxide							
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, LADLE METALLURGY		225	5 Т/Н	(SO2) Sulfur Dioxide	LOW SULFUR COKE USE.	0 076	LB/T	0)		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	PROCESS HEATERS	NATURAL GAS			(SO2) Sulfur Dioxide	GOOD COMBUSTION PRACTICE	0.0006	lb/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, ELECTRIC ARC		225	5 т/н	(SO2)	MANAGEMENT.	1.5	LB/T	0)		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT		NATURAL GAS	225	5 ММВТИ/Н	Sulfur Dioxide (SO2)	CLEAN FUELS	0.0006	lb/mmbtu	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	LADLE PREHEAT & amp; DRYOUT STATIONS	NATURAL GAS	225	5 Т/Н	Sulfur Dioxide (SO2)	CLEAN FUEL	0.0006	lb/mmbtu	0.0006	LB/MMBTU		
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BRINE REDUCTION AREA SN-PBCDF- 07	NATURAL GAS		L MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0 በቦጳ	LB/MMBTU	CALCULATED	
	,			BOILER, HOT WATER, (2) SN-PBCDF-				Sulfur Dioxide							
4K-UU/b	U.S. ARMY, PINE BLUFF ARSENAL	AK	02/17/2004 ACT	05, -06	NATURAL GAS	0 03	L MMDSCF/H	(SO2) Sulfur Dioxide	LOW-SULFUR NATURAL GAS ONLY. QUENCH TOWER WITH CAUSTIC SCRUBBING LIQUID FOLLOWED BY VENTURI SCRUBBER (COMBINED EFFICIENCY 50%), FOLLOWED BY A PACKED-BED SCRUBBER (95% EFFICIENCY) OVERALL SYSTEM IS EXPECTED TO		LB/H	0.0085	LB/MMBTU	CALCULATED	THE MOST STRINGENT CONTROL WAS SELECTED: A PACKED BED SCRUBBER, IN CONJUNCTION WITH A QUENCH TOWER AND VENTUR
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	PBCDF-01	AGENT	40	ROCKETS/H	(SO2)	REMOVE 97.5% OF SO2.	17.2	LB/H	0)		SCRUBBER.
	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, PROCESS STEAM, (2) SN- PBCDF-03, -04	NATURAL GAS	0.07	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.		LB/H	0.0025	LB/MMBTU	CALCULATED	

				Summary of SU	2 Control Detei	rmination per i	EPA S RACI/B	ACT/LAER Data	abase for Combustion of Misc. B	ollers, Furnaces, & Heater	ſS			[
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	NATURAL GAS	1.	1 mmbtu/h	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1 LB/H	0.071	lb/mmbtu	CALCULATED	
41-0070	U.S. ANWIT, FINE BEOTT ANDENAL		02/17/2004 @HDSD,AC1	IC ENGINE, EMERGENCY	INTURAL URS			Sulfur Dioxide	LOW SULF ON NATIONAL OSCIONAL LOW SULFUR DIESEL: LESS THAN OR EQUAL TO 0.05 WT % S. ALSO: LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN- PBCDF-10 AND LESS THAN 500 HOURS/YR		0.071			
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	GENERATOR (2) IC ENGINE, EMERGENCY	DIESEL FUEL	2500	кw	(SO2) Sulfur Dioxide	FOR SN-PBCDF-12. LOW SULFUR DIESEL; <= 0.05 WT % S.	0.6 LB/H	0			
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	GENERATOR SN-PBCDF-12	DIESEL FUEL	250	кw	(SO2) Sulfur Dioxide	ALSO OPERATING LIMIT: < 500 H/YR.	0.4 LB/H	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	GALVANIZING LINE	NATURAL GAS	9	9 ММВТИ/Н	(SO2)	NATURAL GAS COMBUSTION ONLY	0.0006 LB/MMBTU	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	BOILERS	NATURAL GAS	22	2 ММВТИ/Н	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006 LB/MMBTU	0.0006	lb/MMBTU		
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	DEGASSER HOTWELL FLARE	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY IN FLARE	0.09 LB/H	0			<u> </u>
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	TUNNEL FURNACE	NATURAL GAS	160) MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006 LB/MMBTU	0.0006	lb/mmbtu		ADDITION
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	ELECTRIC ARC FURNACE (EAF)	NATURAL GAS	350) t/h	Sulfur Dioxide (SO2)	LOW SULFUR COKE AND SCRAP MANAGEMENT	0.2 LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	LADLE METALLURGY FURNACE		350) т/н	Sulfur Dioxide (SO2)		0.08 LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	FURNACES, HEATERS, & amp; DRYERS	NATURAL GAS	11	L MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006 LB/MMBTU	0.0006	lb/mmbtu		
	FPL WEST COUNTY ENERGY CENTER			THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-										FUEL SPECI STANDARE COMPLIAN DEMONST CONTENT. SHALL BE E
FL-0303	UNIT 3 FPL WEST COUNTY ENERGY CENTER	FL	07/30/2008 ACT	FIRED HRSG TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS	NATURAL GAS	2333		Sulfur Oxides (SOx) Sulfur Dioxide		2 GR S/100SCF	0			WITH EPA VOC, SO2,
FL-0303	UNIT 3	FL	07/30/2008 ACT	HEATERS TWO NOMINAL 2,250 KW (~ 21	NATURAL GAS	10	ММВТU/Н	(SO2)		2 GS/100 SCF	0			2 GR S/100
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	07/30/2008 ACT	MMBTU/H) EMERGENCY GENERATORS	ULTRA LOW SULFUR OIL	21	L MMBTU/H	Sulfur Dioxide (SO2)	ULTRA LOW FUEL OIL	0.0015 %	0			
				(2) GAS TURBINES ANNUAL					THE DISTILLATE FUEL OIL BURNED IN ANY TURBINE SHALL NOT CONTAIN SULFUR IN EXCESS OF 0.05% BY WEIGHT. THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT EXCEED 1					
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	EMISSION LIMITS, BOTH FUEL	NATURAL GAS			Sulfur Oxides (SOx)		36.4 T/YR	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITHOUT DUCT BURNERS, DIST	DISTILLATE FUEL	1699) MMBTU/H	Sulfur Oxides (SOx)	TURBINE SHALL NOT CONTAIN SULFUR IN EXCESS OF 0 05% BY WEIGHT.	92.9 LB/H	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) DUCT BURNERS	NATURAL GAS	390) MMBTU/H	Sulfur Dioxide (SO2)	THE NATURAL GAS BURNED IN ANY DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	0.2 LB/MMBTU	0.2	LB/MMBTU		THE PERM COMBUST CONTAIN S COMBUST THAN 0.20
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITH DUCT BURNERS, NAT GAS	NATURAL GAS			Sulfur Oxides (SOx)	THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	6.6 LB/H	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITHOUT DUCT BURNERS, NAT GAS	NATURAL GAS			Sulfur Oxides (SOx)	THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	5.4 LB/H	0			

Heate	rs		<u> </u>	[
ISSION T 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	0.071	lb/mmbtu	CALCULATED	
	0			
	0			
MBTU	0			
мвти	0.0006	lb/mmbtu		
	0			
MBTU	0.0006	lb/mmbtu		ADDITIONAL LIMIT: .1 LB/H
	0			
	0			
мвти	0.0006	lb/mmbtu		
100SCF	0			THE SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT COMBUSTION DESIGN AND OPERATION OF EACH CTG REPRESENTS (BACT) FOR PM/PM10/PM2.5 EMISSIONS. COMPLIANCE WITH THE FUEL SPECIFICATIONS, CO STANDARDS, AND VISIBLE EMISSIONS STANDARDS SHALL SERVE AS INDICATORS OF GOOD COMBUSTION. COMPLIANCE WITH THE FUEL SPECIFICATIONS SHALL BE DEMONSTRATED BY KEEPING RECORDS OF THE FUEL SULFUR CONTENT. COMPLIANCE WITH THE VISIBLE EMISSIONS STANDARD SHALL BE DEMONSTRATED BY CONDUCTING TESTS IN ACCORDANCE WITH EPA METHOD 9.
00 SCF	0			VOC, SO2, PM/PM10 2 GR S/100SCF NATURAL GAS SPEC AND 10% OPACITY
	0			
	0			
	0			
MBTU	0.3	lb/MMBTU		THE PERMITTEE SHALL NOT DISCHARGE ANY GASES FROM COMBUSTION OF LIQUID OR GASEOUS FUELS WHICH CONTAIN SO2 IN EXCESS OF 100% OF THE POTENTIAL COMBUSTION CONCENTRATION WHEN EMISSIONS ARE LESS THAN 0.20 LB/MMBTU HEAT INPUT.
MDIU	0.2			
	0			

											.				
			[Summary of SO	Control Deter	mination per E	PA'S RACT/B	ACT/LAER Data	base for Combustion of Misc. I	Boilers, Furnac	es, & Heate	ers			
												STANDARD	STANDARD	STANDARD LIMIT AVERAGE	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	EMISSION LIMIT	EMISSION LIMIT UNIT	TIME CONDITION	POLLUTANT COMPLIANCE NOTES
															IDENTIFIED AS (EU-001) SHALL BE
															LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE SO2 EMISSIONS DURING STARTUPS, SHUTDOWNS, AND OTHER FLARING EVENTS. THE PERMITTEE WILL USE METHANOL, RATHER THAN COAL OR PET COKE, AS THE FEEDSTOCK IN EACH GASIFIER DURING STARTUP CONDITIONS REQUIRING SYNGAS FLARING, THEREBY REDUCING EMISSIONS OF SULFUR DIOXIDE AT THE SYNGAS HYDROCARBON FLARE. DURING A PLANNED SHUTDOWN OF A GASIFIER, THE PERMITTEE SHALL ROUTE THE CONTENTS OF EACH GASIFIER UNIT (GASIFIER VESSEL, QUENCH CHAMBER, SCRUBBER VESSEL) DURING INITIAL DEPRESSURIZATION TO ONE OF THE WET SULFURIC ACID (WSA) PLANTS. THE PERMITTEE SHALL REDUCE GASIFIER FEED RATES SUCH THAT ALL SYNGAS CAN BE PROCESSED THROUGH ONE GAS TREATMENT TRAIN PRIOR TO A SCHEDULED GAS TREATMENT TRAIN OUTAGE. THIS LIMITS THE AMOUNT OF SYNGAS THAT WILL HAVE TO BE SENT TO THE SYNCAS HYDROCARDON FLAGE
															SYNGAS HYDROCARBON FLARE. THE PERMITTEE SHALL HAVE WRITTEN PROCEDURES FOR THE ABOVE
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	SYNGAS HYDROCARBON FLARE	SYNGAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	A FLARE MINIMIZATION PLAN	0		o			OPERATIONS AND THE PERMITTEE SHALL TRAIN THE OPERATORS ON THESE PROCEDURES. EMISSION LIMITS: NONE
								Sulfur Dioxide							(3) THE SO2 EMISSIONS FROM THE ACID GAS FLARE, IDENTIFIED AS (EU-002) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE EMISSIONS DURING FLARING EVENTS. THE PERMITTEE SHALL INVESTIGATE THE ?ROOT CAUSE? OF MALFUNCTION EVENTS THAT CAUSE GASES TO BE SENT TO A FLARE AND DETERMINE WHETHER THERE ARE ADDITIONAL PREVENTATIVE MEASURES THAT CAN BE IMPLEMENTED TO MINIMIZE RE-OCCURRENCE OF THESE EVENTS. SUCH IDENTIFIED MEASURES SHALL BE
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ACID GAS FLARE	ACID GAS	0 27	MMBTU	(SO2)	FLARE MINIMIZATION PLAN	0		0			IMPLEMENTED AND DOCUMENTED.
*IN-0166	INDIANA GASIFICATION, LLC	IN		TWO (2) AUXILIARY BOILERS REGENERATIVE THERMAL OXIDIZER	NATURAL GAS	408	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS OR SNG	0.0006	ммвти/н	o			
*IN-0166	INDIANA GASIFICATION, LLC	IN		(RTO) ON THE ACID GAS REMOVAL	NATURAL GAS	38.8	MMBTU/H, EACH	Sulfur Dioxide (SO2)	RECTISOL ACID GAS REMOVAL SYSTEM	3.17	LB/H	0			EMISSION LIMIT 1 IS FOR EACH RTO.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FIVE (5) GASIFIER PREHEAT BURNERS	NATURAL GAS AND SNG		MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF CLEAN BURNING GASEOUS FUEL	0 0006	lb/mmbtu				EMISSION LIMIT IS FOR EACH BURNER.
	INDIANA GASIFICATION, LLC			TWO (2) EMERGENCY GENERATORS			HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION		PPM SULFUR	0			EMISSION LIMIT: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	N 15	PPM SULFUR	0			EMISSION LIMITS: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN		TWO (2) WET SULFURIC ACID PLANTS	STPD	800	STPD	Sulfur Dioxide (SO2)	PEROXIDE SCRUBBER	0.25	LB/T ACID PRODUCED	C			EMISSION LIMIT IS FOR EACH UNIT.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ZLD SPRAY DRYER		5.6	ММВТИ/Н	Sulfur Dioxide (SO2)	USE OF A CLEAN BURNING GASEOUS FUE	L O		0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FUGITIVE LEAKS FROM PIPING		c		Sulfur Dioxide (SO2)	LEAK DETECTION AND REPAIR (LDAR) PROGRAM	0		0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	SPACE HEATERS	NATURAL GAS	1	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	lb/mmbtu	0			LIMIT IS FOR EACH HEATER
	MAGNETATION LLC			COKE BREEZE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS		MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES		LB/MMBTU	0			
	MAGNETATION LLC			EMERGENCY GENERATOR	NATURAL GAS) HP	Sulfur Dioxide (SO2)	USE OF NATRUAL GAS AND GOOD COMBUSTION PRACTICES		G/KW-H	0			

				Summary of SO	2 Control Determination per	LFA S RACI/D				es, & neate	.15			
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
*111 04 67		1.51	04/46/2012 Bullion ACT				Sulfur Dioxide	USE OF NATUAL GAS AND GOOD	0.0045	C MAN LL				
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FIRE WATER PUMP	NATURAL GAS 30	00 HP	(SO2) Sulfur Dioxide	COMBUSTION PRACTICES	0.0015	G/KW-H	U			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM	16	.5 T/H	(SO2)		0.0005	lb/mmbtu	C			
*101 01 07			04/16/2012 8 share ACT	GROUND LIMESTONE/DOLOMITE			Sulfur Dioxide	USE OF NATURAL GAS AND GOOD	0.0005	lb/mmbtu				
· IIN-0167	MAGNETATION LLC		04/16/2013 ACT	ADDITIVE SYSTEM AIR HEATER	NATURAL GAS 1	19 MMBTU/H	(SO2)	COMBUSTION PRACTICES	0.0005	LB/IVIIVIB I U	L. L			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE HOOD EXHAUST	NATURAL GAS 43	36 MMBTU/H	Sulfur Dioxide (SO2)		21.68	LB/H	C			LIMIT ONE: 7.1 PPMV WET AT 20% O2 NOTE: 0.089 LB SO2/TON PELLETS * 450 TONS/HR = 40.1 LB/HR SO2
				FURNACE WINDBOX EXHAUST			Sulfur Dioxide	GSA DRY SCRUBBER AND BAGHOUSE						LIMIT ONE: 5.0 PPMV WET AT 15% O2
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT		NATURAL 43	86 MMBTU/H	(SO2)	CE016	19.61	LB/H	C			NOTE: 0.048 LB SO2/TON PELLETS * 450 TONS/HR = 21.6 LB/HR SO2
	SULFURIC ACID REGENERATION			SULFURIC ACID PLANT STACK (1-76,			Sulfur Dioxide	DOUBLE CONTACT DOUBLE ABSORPTION		/				
LA-0262	PLANT SULFURIC ACID REGENERATION	LA	05/03/2012 ACT	EQT 0051) ACID REGENERATION UNIT	24(00 T/D	(SO2) Sulfur Dioxide	TECHNOLOGY	434	lb/H	Ŭ			
LA-0262	PLANT	LA	05/03/2012 ACT	FUGITIVES (10-92, FUG 0003)		0	(SO2)		6.66	LB/H	C			
	SULFURIC ACID REGENERATION			START-UP HEATER STACK (37-88,			Sulfur Dioxide							
LA-0262	PLANT SULFURIC ACID REGENERATION	LA	05/03/2012 ACT	EQT 0053) ACID PLANT AIR PREHEATER (1-95,	NATURAL GAS 6	51 MMBTU/H	(SO2) Sulfur Dioxide	USE OF NATURAL GAS AS FUEL USE OF NATURAL GAS AND/OR LANDFILL		LB/H	C			OPERATION LIMITED TO 340 HR/YR.
LA-0262	PLANT	LA	05/03/2012 ACT	EQT 0074)	NATURAL GAS 8	36 ММВТИ/Н	(SO2)	GAS AS FUEL		LB/H	C			
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	SIDE-WELLS	NATURAL GAS 4200	00 LB/H	Sulfur Dioxide (SO2)	SIDE WELL EMISSIONS PASS THROUGH LIME-INJECTED BAGHOUSES. NO CONTROL CLAIMED, %.	0.52	LB/H	ſ	LB/MMBTU		
111 0501			03/02/2000 01030,/101				Sulfur Dioxide		0.52	20/11		LB/INIVIDIO		
MI-0301	ALCHEM ALUMINUM	МІ	05/02/2000 ACT	CRUSHER	NA 2000	00 LB/H	(SO2)	N/A	1.47	LB/H	C	lb/MMBTU		
MI 0201	ALCHEM ALUMINUM	5.41	05/02/2000 ACT	CRUCIBLE HEATERS/STATIONS	NATURAL GAS	2 MMBTU/H EACH	Sulfur Dioxide	NI / A	0.01	LB/H			NOT AVAILABLE	
1011-0301			05/02/2000 ,Act		NATURAL GAS			N/A COMBUSTION FLUES ARE WITHOUT ADD- ON CONTROLS.		цруп			NOT AVAILABLE	
MI-0301	ALCHEM ALUMINUM	NAL	05/02/2000 ACT	FLUES	NATURAL GAS 4200	00 LB/H	Sulfur Dioxide (SO2)	ONLY PIPELINE QUALITY NATURAL GAS FOR FUEL.	0.12	LB/H	0	LB/MMBTU		
1011-0301	GEORGIA PACIFIC CORPORATION,		03/02/2000 ,Act		NATONAL 0A3 4200		Sulfur, Total	WET (VENTURI) SCRUBBER WITH	0.12	PPMV @ 10%		PPMV @ 10%		LIMIT IS PPM EXPRESSED AS H2S ON A DRY GAS BASIS, CORRECTED
MS-0077	MONTICELLO MILL	MS	03/04/2005 ACT	LIME KILN	NATURAL GAS 145	.9 MMBTU/H	Reduced (TRS)	OPTIONAL MUD WASHING		02	20	02		TO 10% O2 (12-HOUR BASIS)
MS-0077	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	03/04/2005 ACT	LIME KILN	NATURAL GAS 145	.9 MMBTU/H	Sulfur Dioxide (SO2)	WET (VENTURI) SCRUBBER WITH OPTIMA MUD WASHING		LB/H				ADDITIONAL LIMIT: 50 PPMV ON DRY GAS BASIS CORRECTED TO 10%
1013-0077	GEORGIA PACIFIC CORPORATION,	1015	05/04/2005 &IIDSP,ACT		NATURAL GAS 145	.9 IVIIVIBTO/H	Sulfur Dioxide		23.4	цол				02.
MS-0077		MS	03/04/2005 ACT	AIR HEATER, PETROLEUM COKE	NATURAL GAS	5 MMBTU/H	(SO2)	GOOD COMBUSTION PRACTICES	0		C)		NO EMISSION LIMITS
			06 /27 /2002 Bulker ACT	AUXILIARY BOILERS (AUX-1 AND			Sulfur Dioxide	NATURAL GAS, GOOD COMBUSTION		10/11	0.000		and a stand	
	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	AUX-2) TURBINES, COMBINED CYCLE,		33 MMBTU/H	(SO2) Sulfur Dioxide	PRACTICE PIPELINE QUALITY NATURAL GAS, GOOD ENGINEERING		LB/H	0.003	lb/MMBTU	calculated	
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	NATURAL GAS (4)	NATURAL GAS 151	15 MMBTU/H	(SO2)	PRACTICE PIPELINE QUALITY NATURAL GAS, GOOD	4.3	lb/H	C			
							Sulfur Dioxide	COMBUSTION						
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	DUCT BURNERS (DB-1 AND DB-2)	NATURAL GAS 64	13 MMBTU/H	(SO2)	PRACTICE.	1.5	LB/H	0.002	LB/MMBTU	calculated	
0H-0370	GRAFTECH INTERNATIONAL HOLDINGS, INC.	он	04/27/2011 ACT	Graphite Furnaces (12)		0	Sulfur Dioxide (SO2)		12 0	LB/H				
2 0345	GRAFTECH INTERNATIONAL		, =., =021 anosp,net			-	Sulfur Dioxide	1	12.5					
OH-0349	HOLDINGS, INC.	ОН	04/27/2011 ACT	Graphite Rolling Lines (4)	natural gas	0	(SO2)	Scrubber	15.6	lb/H	C)		If required Method 6
OH-0349	GRAFTECH INTERNATIONAL HOLDINGS, INC.	он	04/27/2011 ACT	West Treatment System PAPER MACHINE COMBUSTION #11-		0	Sulfur Dioxide (SO2) Sulfur Dioxide		0.24	LB/H	C			If required Method 6
OK-0112	MUSKOGEE MILL	ОК	03/27/2006 ACT	14			(SO2)	EXISTING CONTROL - CLEAN FUEL	0.2	T/YR	C			
SC-0060	RAINEY GENERATING STATION	sc	04/03/2000 ACT	TURBINES, SIMPLE CYCLE, DISTILLATE FUEL OIL (2) TURBINES, COMBINED CYCLE,	DISTILLATE FUEL OIL 17	70 MW (EACH)	Sulfur Dioxide (SO2) Sulfur Dioxide	LOW SULFUR FUEL, MAXIMUM SULFUR CONTENT OF 0.05%	105.6	LB/H	C			ADDITIONAL EMISSION LIMIT: 0.4 GR/100 SCF, EACH
SC-0060	RAINEY GENERATING STATION	sc	04/03/2000 ACT		NATURAL GAS 17	0 MW (EACH)	(SO2)	LOW SULFUR FUEL	2.1	LB/H	C)		TURBINE
	RAINEY GENERATING STATION	SC	04/03/2000 ACT	TURBINES, SIMPLE CYCLE, NATURAL GAS (2)	NATURAL GAS 17	70 MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS		LB/H	C			ADDITIONAL EMISSION LIMIT: 0.4 GR/100 SCF, EACH TURBINE
SC-0060	RAINEY GENERATING STATION	sc	04/03/2000 ACT		DISTILLATE FUEL OIL 17	70 MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	105.6	LB/H	n			
			,,			MMBTU/H	Sulfur Dioxide		100.0	.,				
SC-0060	RAINEY GENERATING STATION	sc	04/03/2000 ACT	HEATERS, PROCESS (2)		.9 (EACH)	(SO2)	LOW SULFUR FUEL	3.5	lb/MMBTU	3.5	lb/mmbtu	EACH	
TN-0078	WAUPACA FOUNDRY, INC.	TN	04/28/2000 ACT	SPACE HEATERS - MAKE-UP AIR	NATURAL GAS, PROPANE 0	.1 MMCF/H	Sulfur Dioxide (SO2)		0.06	LB/H	c.			
			,	MAJOR PANEL TOPCOAT		- ,	Sulfur Dioxide	NATURAL GAS, GOOD COMBUSTION					1	
TNI 0000	SATURN - SPRING HILL	TN	06/06/2000 ACT	OPERATIONS	NATURAL GAS		(SO2)	CONTROL	0		C)		EMISSIONS ARE REFLECTED IN PAL

		Г		Summary of SO	2 Control Deter	mination per l	PA'S RACI/BA	ACT/LAER Data	abase for Combustion of Misc. I	Boilers, Furnac	es, & Heate	rs	1		
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
BLCID		FACILITY STATE	PERMIT ISSUANCE DATE	SPACE FRAME AND SHEET METAL E-	PRIMART FOLL	THROUGHPUT	UNIT	Sulfur Dioxide	NATURAL GAS, GOOD COMBUSTION			LIIVIII		CONDITION	POLLOTANT COMPLIANCE NOTES
-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	COAT SYSTEM				(SO2) Sulfur Dioxido	CONTROL NATURAL GAS, GOOD COMBUSTION	0		0			EMISSIONS ARE REFLECTED IN PAL
-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	MAJOR PANEL PRIME SYSTEM	NATURAL GAS			Sulfur Dioxide (SO2)	CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
0000		TN	05 /05 /2000 8 share A CT	FASCIA/REPROCESS TOPCOAT (BASE AND CLEARCOAT)				Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL			0			
-0088	SATURN - SPRING HILL		06/06/2000 ACT	SPACE FRAME UNDERBODY				Sulfur Dioxide	NATURAL GAS, GOOD COMBUSTION	0		0			EMISSIONS ARE REFLECTED IN PAL
-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	PVC/SEAM SEAL APPLICATION SITE-WIDE PRODUCTS OF				(SO2) Sulfur Dioxide		0		0			EMISSIONS REFLECTED IN PAL
-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT		NATURAL GAS			(SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
0153	WILLIAMS REFINING & MARKETING,	TN	04/02/2002 8 share 4 CT					Sulfur Dioxide		150	DDM	75	PPMV @ 0%		
0153	L.L.C.		04/03/2002 ACT	SULFUR RECOVERY UNIT				(SO2)		150	PPM	/5	EXCESS AIR	annual avg.	no emission rate limits. Natural gas: 50 ppm H2S
0450	WILLIAMS REFINING & MARKETING,	-	04/02/2002 8 share A CT			-		Sulfur Dioxide							in fuel - annual; fuel gas: 100 ppm H2S in fuel -
0153	L.L.U.	IN	04/03/2002 ACT	HEATERS, (5) TURBINE, COMBINED CYCLE, DUCT	NATURAL GAS	50) MMBTU/H	(SO2) Sulfur Dioxide	FUEL SULFUR LIMITS	0	PPM @ 15%	0			24 h avg.
0156	MEMPHIS GENERATION, LLC	TN	04/09/2001 ACT		NATURAL GAS	14583	3 MMSCF/YR	(SO2)		150	02	0			
0156	MEMPHIS GENERATION, LLC	TN	04/09/2001 ACT	BOILER, AUXILIARY, NATURAL GAS	NATURAL GAS	180	MMSCF	Sulfur Dioxide (SO2)	CLEAN FUEL	0.01	LB/H	0.0005	lb/mmbtu	calculated	permit limit is in lb/h.
								Sulfur Dioxide							
0156	MEMPHIS GENERATION, LLC DONAHUE INDUSTRIES, INC. PAPER	TN	04/09/2001 ACT	DUCT BURNER	NATURAL GAS	300) MMBTU/H	(SO2) Sulfur, Total		0.2	lb/MMBTU	0.2	lb/MMBTU		
0263	MILL	тх	10/17/2000 ACT	SOAP RECOVERY AND STORAGE				Reduced (TRS)	NONE INDICATED	0.05	LB/H	0			
0263	DONAHUE INDUSTRIES, INC. PAPER MILL	тх	10/17/2000 ACT	WEAK BLACK LIQUOR STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.06	LB/H	0			
	DONAHUE INDUSTRIES, INC. PAPER							Sulfur, Total							
263	MILL DONAHUE INDUSTRIES, INC. PAPER	ТХ	10/17/2000 ACT	HEAVY BLACK LIQUOR STORAGE				Reduced (TRS) Sulfur, Total	NONE INDICATED	0.18	lb/H	0			
263	MILL	тх	10/17/2000 ACT	BROWN KRAFT PULP STORAGE				Reduced (TRS)	NONE INDICATED	0.18	LB/H	0			
263	DONAHUE INDUSTRIES, INC. PAPER MILL	тх	10/17/2000 ACT	BLEACHED KRAFT PULP STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.18	LB/H	0			
200	DONAHUE INDUSTRIES, INC. PAPER		10/17/2000 000500					Sulfur, Total		0.10	20,11				
0263	MILL DONAHUE INDUSTRIES, INC. PAPER	ТХ	10/17/2000 ACT	MISC. STORAGE				Reduced (TRS) Sulfur, Total	NONE INDICATED	0.04	LB/H	0			
263	MILL	тх	10/17/2000 ACT	LIME KILN	NAT GAS, NO.2 OIL			Reduced (TRS)	SCRUBBER	0.9	LB/H	0			
	DONAHUE INDUSTRIES, INC. PAPER							Sulfur Dioxide	SCRUBBER AND SWEET NAT GAS WITH A SULFUR CONTENT						
263	MILL	тх	10/17/2000 ACT	LIME KILN	NAT GAS, NO.2 OIL			(SO2)	LIMIT OF 0.3%	5.4	LB/H	0			
263	DONAHUE INDUSTRIES, INC. PAPER MILL	ту	10/17/2000 ACT	SLAKER				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.1	LB/H	0			
203	DONAHUE INDUSTRIES, INC. PAPER		10/17/2000 & mbsp,Act	SLAKEN				Sulfur Dioxide		0.1	10/11	0			ADDITIONAL LIMIT: SO2 FROM REC BOILER NOT TO
263		тх	10/17/2000 ACT	RECOVERY BOILER				(SO2) Sulfur Total	NONE INDICATED	206	lb/H	0			EXCEED 250 PPM DRY BASIS, BASED ON A 12-HR AVER.
263	DONAHUE INDUSTRIES, INC. PAPER MILL	тх	10/17/2000 ACT	RECOVERY BOILER				Sulfur, Total Reduced (TRS)	NONE INDICATED	2.7	LB/H	0			
262	DONAHUE INDUSTRIES, INC. PAPER	ту	10/17/2000 8 share ACT					Sulfur, Total			10/4				
203	MILL DONAHUE INDUSTRIES, INC. PAPER		10/17/2000 ACT	SMELT TANK				Reduced (TRS) Sulfur Dioxide	NONE INDICATED	1.4	LB/H	0			
263		ТХ	10/17/2000 ACT	SMELT TANK				(SO2) Sulfur Total	NONE INDICATED	2.5	LB/H	0			
263	DONAHUE INDUSTRIES, INC. PAPER MILL	тх	10/17/2000 ACT	BLOW HEAT SYSTEM				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.23	LB/H	0			
262	DONAHUE INDUSTRIES, INC. PAPER	TV	10/17/2000 8 char ACT					Sulfur, Total		0.00	10/11	-			
0263	MILL DONAHUE INDUSTRIES, INC. PAPER	1X	10/17/2000 ACT	BROWN STOCK WASHERS				Reduced (TRS) Sulfur Dioxide	NONE INDICATED	9.82	LB/H	0		NOT AVAILABLE	
263	MILL	тх	10/17/2000 ACT	POWER BOILER NOS. 4, 5, 8, AND 9				(SO2)	NONE INDICATED	1.4	T/YR	0		NOT AVAILABLE	NEED EMISSION LIMIT IN STANDARD UNITS
263	DONAHUE INDUSTRIES, INC. PAPER MILL	тх	10/17/2000 ACT	TURBINE				Sulfur Dioxide (SO2)	NONE INDICATED	0.14	LB/H	0			
	DONAHUE INDUSTRIES, INC. PAPER			LIME MUD CLARIFICATION AND			1	Sulfur, Total							
0263	MILL DONAHUE INDUSTRIES, INC. PAPER	IX	10/17/2000 ACT	STORAGE				Reduced (TRS) Sulfur Dioxide	NONE INDICATED	0.02	LB/H	0			
0263	MILL	тх	10/17/2000 ACT	POWER BOILER 11				(SO2)	NONE INDICATED	5.4	LB/H	0		NOT AVAILABLE	
	TEMPLE INLAND PINELAND			(2) KILN, DRYING, STUDMILLS				Sulfur Dioxide							FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE
)292	MANUFACTURING COMPLEX	тх	08/06/2000 EST	1&2, EPN91&92		3 25	5 т/н	(SO2)	NONE INDICATED	0.07	LB/H	0			EMISSION RATE.
0292	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	тх	08/06/2000 EST	BOILER, WOOD-FIRED, EPN22	WOOD	20.1	5 т/н	Sulfur Dioxide (SO2)	NONE INDICATED	0.16	LB/H			NOT AVAILABLE	
5252			00,00,2000 anbsp,131			20.3		(302)	LIMITED TO PIPELINE QUALITY NAT GAS	0.10	- 5/11	0		AVAILABLE	
	1	1	1	(2) GAS TURBINES, HRSG-1 & amp; -				Sulfur Dioxide	CONTAINING						

		1	1	Summary of SO2	Control Deter	mination per	EPA's RACT/B	ACT/LAER Dat	abase for Combustion of Misc. I	Boilers, Furnaces, & Heate	ers	1	· · · · ·	
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
0299	KAUFMAN COGEN LP	тх	01/31/2000 ACT	FIREWATER PUMP ENGINE, FWP-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.8 LB/H	0			
								Sulfur Dioxide						
0299	KAUFMAN COGEN LP GLOBAL OCTANES DEER PARK	ТХ	01/31/2000 ACT	AUX. BOILER, B-1 CHARGE HEATER, H-101 AND	NAT GAS			(SO2) Sulfur Dioxide	NONE INDICATED NAT GAS OR NAT GAS/PLANT GAS	0.02 LB/H	0		NOT AVAILABLE	
0314	FACILITY	тх	06/15/1999 ACT	STEAM BOILER, U-5001	NAT GAS	18	0 ММВТИ/Н	(SO2)	MIXTURE	25 T/YR	0		NOT AVAILABLE	
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	(2) VACUUM PIPE STILL 8 FURNACES, VPS 8, F-803&4	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	60.9 LB/H	0			
				(2) SULFUR CONVERSION UNIT				Sulfur Dioxide						ASSUMED NSPS SUBPART J APPLIED. EMISSIONS DURING HOT STANDBY ONLY. INCINERATORS ARE FOR UPSET AND
)315	EXXON MOBIL BAYTOWN REFINERY	ТХ	07/12/1999 ACT	(SCU) 2, INCINERATOR FLEXICOKING (FXK), F-301 & amp;				(SO2) Sulfur Dioxide	NONE INDICATED	0.73 LB/H	0		NOT AVAILABLE	MAINTENANCE PROCEDURES ONLY.
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HC SKIMMER DRUM	LBG	11	0 ММВТU/Н	(SO2)	NONE INDICATED	49.8 LB/H	0			
								Sulfur Dioxide						THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND
J315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 3, F-1	LBG			(SO2)	NONE INDICATED	108.1 LB/H	0		NOT AVAILABLE	PS8F804) ARE NOT FIRING: 130 5 LB/H, 554 T/YR
								Sulfur Dioxide						THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 3, F-2	LBG			(SO2)	NONE INDICATED	119.5 LB/H	0			PS8F804) ARE NOT FIRING: 144 3 LB/H, 614 T/YR
								Sulfur Dioxide						THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 3, F-3	LBG			(SO2)	NONE INDICATED	83.6 LB/H	0			PS8F804) ARE NOT FIRING: 101 0 LB/H, 429 T/YR
								Sulfur Dioxide						THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 3, F-4	LBG			(SO2)	NONE INDICATED	58.1 LB/H	0			PS8F804) ARE NOT FIRING: 70.2 LB/H, 298 T/YR
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	(2) PIPE STILL 8, FURNACES, PS 8, F- 801& F-802 HYDROFORMER 4 FURNACE, HF 4, F-	LBG			Sulfur Dioxide (SO2) Sulfur Dioxide	NONE INDICATED	190.2 LB/H	0		NOT AVAILABLE	
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	401	LBG			(SO2)	NONE INDICATED	243.4 LB/H	0			
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HYDROFORMER 4 FURNACE, HF 4, F- 402	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	232.9 LB/H	0		NOT AVAILABLE	
)315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 4, F-403	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	131.2 LB/H	0		NOT AVAILABLE	
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	HF 4, F-404	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	124.6 LB/H	0		NOT AVAILABLE	
0315	EXXON MOBIL BAYTOWN REFINERY	тх	07/12/1999 ACT	(4) BH 7, WHB-71 THRU -74	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	65.1 LB/H	0		NOT AVAILABLE	
				FLEXICOKING GAS TURBINE/WASTE				Sulfur Dioxide						
	EXXON MOBIL BAYTOWN REFINERY ANHEUSER-BUSH HOUSTON	тх	07/12/1999 ACT	HEAT BOILER				(SO2) Sulfur Dioxide	NONE INDICATED	100.1 LB/H	0			
	BREWERY	тх	07/13/1999 ACT		NAT GAS			(SO2)	NONE INDICATED	24.3 LB/H	0		NOT AVAILABLE	
	ANHEUSER-BUSH HOUSTON BREWERY	тх	07/13/1999 ACT	(2) BOILERS NO 4 & amp; 5, PWR-4 & amp; -5	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	49.1 LB/H	0		NOT AVAILABLE	
	ANHEUSER-BUSH HOUSTON BREWERY	тх	07/13/1999 ACT		NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	30.3 LB/H	0		NOT AVAILABLE	
0316	ANHEUSER-BUSH HOUSTON BREWERY	тх	07/13/1999 ACT	FLARE, BERS-1				Sulfur Dioxide (SO2)	NONE INDICATED	60.6 LB/H				
	ANHEUSER-BUSH HOUSTON		07/13/1339 απυςβ;ACT					(SO2) Sulfur Dioxide			0			
0316	BREWERY	тх	07/13/1999 ACT	FIRE WATER PUMP ENGINE, FIRE-01	DIESEL			(SO2)	NONE INDICATED	0.64 LB/H	0			THIS ENTRY LISTED ONLY THE TOTAL ANNUAL LIMITS
	ANHEUSER-BUSH HOUSTON BREWERY	тх	07/13/1999 ACT		NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	77 T/YR	0			FOR ALL THREE BOILERS COMBINED. EMISSION RATES WHEN BURNING FULL CAPACITY OF BIO-GAS. WHEN BIO- GAS FUELS THE BOILERS, THERE ARE NO EMISSIONS FROM THE FLARE AND WHEN BIOFUELS THE FLARE, BOILER EMISSIONS ARE 136.60 TPY NOX.
0240		TY	00/10/1000 0	SCU 2 HOT OIL RECYCLE FURNACE,				Sulfur Dioxide		4 33 15 11	-		NOT AVAILABLE	
0319	EXXON MOBIL BAYTOWN REFINERY	ТХ	09/10/1999 ACT	SCU2F703 FLUID CATALYTIC CRACKING UNIT 2,				(SO2) Sulfur Dioxide	NONE INDICATED	1.22 LB/H	0		NOT AVAILABLE	
0319	EXXON MOBIL BAYTOWN REFINERY	тх	09/10/1999 ACT	FCCU2				(SO2)	SCRUBBER	423 LB/H	0		NOT AVAILABLE	
0319	EXXON MOBIL BAYTOWN REFINERY	тх	09/10/1999 ACT	FLUID CATALYTIC CRACKING UNIT 3, FCCU3				Sulfur Dioxide (SO2)	SCRUBBER	240 LB/H	0		NOT AVAILABLE	
		тх	09/10/1999 ACT	BOILER HOUSE 6, BOILER 64, BH6B64				Sulfur Dioxide (SO2)	NONE INDICATED	12.76 LB/H	0		NOT AVAILABLE	
	EXXON MOBIL BAYTOWN REFINERY	тх	09/10/1999 ACT	(2) DELAYED COKER FURNACE DCUF601, DCU F602				Sulfur Dioxide (SO2)	MINIMIZE THE H2S IN THE FUEL	7.89 LB/H			NOT AVAILABLE	

					Ī				abase for Combustion of Misc. B				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANE EMISS LIMIT
TX-0319	EXXON MOBIL BAYTOWN REFINERY	тх	09/10/1999 ACT	SCU 2 INCINERATOR F702, SCU2F702				Sulfur Dioxide (SO2)	NONE INDICATED	0.52	LB/H	0	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	тх	09/10/1999 ACT	FLEXSORB ADSORBER VENT SCU2T601				Sulfur, Total Reduced (TRS)			LB/H	0	
					NAT GAS			Sulfur Dioxide				0	
TX-0320	ALON USA BIG SPRING REFINERY	TX	09/02/1999 ACT	(11) HEATERS	NATGAS			(SO2) Sulfur Dioxide		10.71		0	
TX-0327	FORMOSA PLASTICS TEXAS	ТХ	02/10/2000 ACT	WASTE HEAT BOILER, EP910 (2) GE-7241FA TURBINES, HRSG-				(SO2) Sulfur Dioxide	NONE INDICATED	0.03	lb/H	0	
TX-0330	JACK COUNTY POWER PLANT	тх	03/14/2000 ACT	1&-2	NAT GAS	520	MW	(SO2)	FIRING PIPELINE NAT GAS	10	LB/H	0	
TX-0330	JACK COUNTY POWER PLANT	тх	03/14/2000 ACT	AUXILIARY BOILER, B-1	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0	
TX-0330	JACK COUNTY POWER PLANT	тх	03/14/2000 ACT	FIREWATER PUMP ENGINE, FWP-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0	
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	FIREWATER PUMP, 81				Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0	
TV 0222	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	SOLAR TURBINE & amp; DUCT BURNER, 70	NATURAL GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.28	LB/H	0	
TX-0333	NONT BELVIED CONPLEX	1.	12/03/2000 &110sp,AC1	CONTINUOUS CATALYST	NATORAL GAS			Sulfur Dioxide		0.28	цол	0	
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	REGENERATOR, 71				(SO2)	CAUSTIC SCRUBBER	0.12	LB/H	0	
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS	0.38	LB/H	0	
				3 DIP TURBINES & amp; 3 DUCT				Sulfur Dioxide	FIRING NAT GAS WITH S CONCENTRATION OF NO MORE				
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	BURNERS, 74	NAT GAS			(SO2)	THAN 15 PPMW.	0.46	LB/H	0	
TX-0333	MONT BELVIEU COMPLEX	тх	12/05/2000 ACT	FLARE, 76				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	SPRAY DRYER, FCC-21				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	CALCINER, FCC-5A		37	ммвти/н	Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	SCR UNIT, FCC-75				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	FINAL PRODUCT CALCINER, FCC-74	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	STEAM BOILER, FCC-27	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.1	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	DIESEL ENGINE, FCC-67	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
	AKZO NOBEL POLYMER CHEMICALS				010000			Sulfur Dioxide		0111			
TX-0334	TRIGONOX 201 AKZO NOBEL POLYMER CHEMICALS	тх	06/20/2000 ACT	FLASH DRYER, FCC-8				(SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0334	TRIGONOX 201	тх	06/20/2000 ACT	MOLSIEVE CALCINER, FCC-9				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	тх	06/20/2000 ACT	FLASH DRYER, FCC-10				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
	AKZO NOBEL POLYMER CHEMICALS							Sulfur Dioxide					
TX-0334	TRIGONOX 201	ТХ	06/20/2000 ACT	MOLSIEVE CALCINER, FCC-12				(SO2)	NONE INDICATED PIPELINE QUALITY, SWEET NAT GAS	0.01	lB/H	0	
								Sulfur Dioxide	CONTAINING NO MORE THAN 0.25 GR H2S AND 5 GR S/100				
TX-0335	TRIGEANT CORPUS CHRISTI	тх	08/07/2000 ACT	PROCESS HEATER, STACK 3	NAT GAS			(SO2)	DSCF.		LB/H	0	
									PIPELINE QUALITY, SWEET NAT GAS CONTAINING NO				
TY 0225		TV	09/07/2000 8 share ACT		NATCAS			Sulfur Dioxide	MORE THAN 0.25 GR H2S AND 5 GR S/100		1.0./11	0	
TX-0335	TRIGEANT CORPUS CHRISTI	ТХ	08/07/2000 ACT	BOILER B, STACK 1B	NAT GAS			(SO2)	DSCF. CONT. IGNITION WITH TWO PILOTS, AN	0.03	LB/H	0	
									ULTRA- VIOLET FIRE-EYE FLAME MONITOR, KNOCK	< c			
								Sulfur Dioxide	OUT POT,		4.		
TX-0335	TRIGEANT CORPUS CHRISTI	ТХ	08/07/2000 ACT	FLARE, FLARE	NAT GAS			(SO2)	AND SEAL DRUM. PIPELINE QUALITY, SWEET NAT GAS	71.48	LB/H	0	
									CONTAINING NO				
TX-0335	TRIGEANT CORPUS CHRISTI	тх	08/07/2000 ACT	BOILER A, STACK 1A	NAT GAS			Sulfur Dioxide (SO2)	MORE THAN 0.25 GR H2S AND 5 GR S/100 DSCF.		LB/H	0	
		ту	05/22/2001 Paber ACT					Sulfur Dioxide		0.50	10/4	_	
TX-0338	CHAMBERS PLANT	ТХ	05/23/2001 ACT	BOILER 3, 8736 (3) HEU PROCESS HEATERS, 8707-				(SO2) Sulfur Dioxide	NONE INDICATED	0.58	LB/H	0	
TX-0338	CHAMBERS PLANT	тх	05/23/2001 ACT	8709				(SO2)	NONE INDICATED	0.19	LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	NOT AVAILABLE	CAP FOR COMBINATION OF THE 11 HEATERS
	NOT AVAILABLE	
	NOT AVAILABLE	
	NOT AVAILABLE	
	NOT AVAILABLE	
	NOTAVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
	NOT AVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
	NOT AVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
	NOT AVAILABLE	
	NOT AVAILABLE	
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		1		Summary of SO	2 Control Deter	mination per E	PA's RACT/B	ACT/LAER Dat	abase for Combustion of Misc. E	Sollers, Furnac	es, & Heate	ers	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANI EMIS LIMIT
TX-0338	CHAMBERS PLANT	тх	05/23/2001 ACT	NS PROCESS HEATER, 8705				Sulfur Dioxide (SO2)	NONE INDICATED	0.47	LB/H	0	
TX-0338	CHAMBERS PLANT	тх	05/23/2001 ACT	(2) BOILERS 1 & amp; 2, 8729 & amp; 8730				Sulfur Dioxide			LB/H	0	,
TX-0338	CHAMBERS PLANT	тх	05/23/2001 ACT	WATER STRIPPER HEATER, 8731				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H		
				C/CF PROCESS HEATER, 8733				Sulfur Dioxide				0	,
TX-0338		TX	05/23/2001 ACT	(3) LEF PROCESS HEATERS, 8701-				(SO2) Sulfur Dioxide			LB/H	0	,
TX-0338	CHAMBERS PLANT	ТХ	05/23/2001 ACT	8703				(SO2) Sulfur Dioxide	NONE INDICATED		LB/H	0)
TX-0338	CHAMBERS PLANT	тх	05/23/2001 ACT	HF PROCESS HEATER, 8706 PROCESS HEATER, LSM HEATER F-				(SO2) Sulfur Dioxide	NONE INDICATED	0.31	LB/H	0	0
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	101 DEPENTANIZER PROCESS HEATER, LSM HEATER F-				(SO2) Sulfur Dioxide	FUEL SCRUBBING SYSTEM	7.01	LB/H	0)
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	361 TREAT GAS HEATER PROCESS LSM HEATER F-371				(SO2) Sulfur Dioxide	FUEL SCRUBBING SYSTEM	10.58	LB/H	0)
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	STABILIZER REBOILER PROCESS HEATER, LSM F-381 HOT				(SO2) Sulfur Dioxide	FUEL SCRUBBING SYSTEM	4.07	LB/H	0)
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	OIL HEATER PROCESS HEATER, HF-4 HEATER F-				(SO2)	FUEL SCRUBBING SYSTEM	6.34	LB/H	0)
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	401, HF4F401				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	12.21	LB/H	0)
TX-0340	EXXON MOBIL BAYTOWN REFINERY	тх	04/13/2001 ACT	PROCESS HEATER, HF-4 HEATER F- 403, HF4F403				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	6.11	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0)
				(2) HYDROTREATER REGENERATOR				Sulfur Dioxide					
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	STACKS, DD-606& amp; DDD-606				(SO2) Sulfur Dioxide	NONE INDICATED	45.8	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION FURNACE, DB-201				(SO2)	NONE INDICATED	0.52	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DDB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.5	LB/H	0)
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	REGENERATION HEATER, DDB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0)
				FURNACE EMISSION CAPS FOR 30				Sulfur Dioxide					
TX-0347	CHOCOLATE BAYOU PLANT	тх	10/16/2001 ACT	EMISSION POINTS				(SO2)	NONE INDICATED FUEL SULFUR CONTENT LIMIT: THE	48	LB/H	0)
									NATURAL GAS STREAM SHALL CONTAIN LESS THAN 5 GR TOTAL				
TX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	BOILER, BLR	NAT GAS			Sulfur Dioxide (SO2)	SULFUR/100 DSCF.	3.25	LB/H	0)
TX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE			Sulfur Dioxide (SO2)	NONE INDICATED	14.13	LB/H	0)
TX-0353	NAFTA REGION OLEFINS COMPLEX	тх	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0)
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0)
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	TRAIN 1 - MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0)
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0)
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0)

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	NOT AVAILABLE	
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
		NSPS SUBPART J ALSO BASIS OF DETERMINATION
	NOT AVAILABLE	
	NOT AVAILABLE	
		ADDITIONAL CAPS: 53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06, 61 37 LB/H, 13.44 T/YR AFTER 6/30/06
	NOT AVAILABLE	

				Summary of SO ₂	Control Deter	mination per I	EPA's RACT/B	ACT/LAER Data	base for Combustion of Misc. B	Boilers, Furnaces, & Heate	rs STANDARD	STANDARD	STANDARD LIMIT AVERAG	
					PRIMARY FUEL	THROUGHPUT	THROUGHPUT	DOLUTANT		EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	EMISSION	EMISSION	TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL		UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION		LIMIT		CONDITION	POLLUTANT COMPLIANCE NOTES ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN
				TANK TRUCK LOADING/UNLOADING				Sulfur, Total	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK					ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL
	ATOFINA CHEMICALS INCORPORATED		12/19/2002 ACT	FLARE, SSM				Reduced (TRS) Sulfur Dioxide (SO2)	DETECTION, ISOLATION, AND REPAIR.	0.03 LB/H				VENT TO THE SULFOX-TO. TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR AND THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW S193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27 LB/H	C			
								Eulfue Disci de	FOLLOW THE REQUIREMENTS OF 40 CFR					TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE ILADE TO DETERMINE DRACTICABLE BUT TO
	ATOFINA CHEMICALS INCORPORATED			FLARE, TOTAL HOURLY AND ANNUAL				Sulfur Dioxide (SO2)	60.18. SEE POLLUTANT NOTES.	6207.34 LB/H				FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDA LIMIT AVE TIME CONDITI
TX-0354	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	1 D /LI	0		
17-0354	ATOTINA CHEMICALS INCORPORATED	17	12/13/2002 &1103p,AC1	ANNOAL				Reduced (TRS)	FUEL GAS SHALL BE SWEET NATURAL GAS		солт	0		CALCULATE
				HEAT TRANSFER FLUID HEATER,				Sulfur Dioxide	CONTAINING					USING
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	H202	NATURAL GAS	31	L MMBTU/H	(SO2)	NO MORE THAN 5 GR S/100 DSCF.		lb/H	0.0006	lb/mmbtu	THROUGHP
								Sulfur Dioxide	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				(SO2)	NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0		NOT AVAIL
								Culfur Disuida	FUEL GAS SHALL BE SWEET NATURAL GAS					CALCULATE
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	L MMBTU/H	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	USING THROUGHP
			, , , , , , , , , , , , , , , , ,					Sulfur Dioxide			,			
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	INCINERATOR				(SO2)	NONE INDICATED	139	LB/H	0		-
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0		
			12/13/2002 ((1000))/(01					Sulfur Dioxide		0.00	20/11			
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SULFUR PIT, S-2				(SO2)	NONE INDICATED	0.17	LB/H	0		
								Sulfur, Total	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION,					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Reduced (TRS)	AND REPAIR.	0.01	LB/H	0		
									FUEL GAS SHALL BE SWEET NATURAL GAS					
TV 0254		T Y	42/40/2002 0 share ACT			424		Sulfur Dioxide		4456 47	1.5.41	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	IX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	5 MMBTU/H	(SO2) Sulfur, Total	NO MORE THAN 5 GR S/100 DSCF.	1156.47	цв/п	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	5 ММВТИ/Н	Reduced (TRS)	NONE INDICATED	0.89	LB/H	0		
									THE FUEL GAS SHALL BE SWEET NATURAL GAS					
				THERMAL OXIDIZER, TOTAL HOURLY				Sulfur Dioxide	CONTAINING NO MORE THAN 5 GR S/100					
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	AND ANNUAL		134.5	5 ММВТU/Н	(SO2)	DSCF.	1157.44	LB/H	0		_
TX-0354	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		13/ 5	5 ММВТU/Н	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0		
17-0354		1	12/19/2002 & 105p, ACT	AND ANNOAL		154.5		Reduced (TRS)		0.89	цруп	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur Dioxide (SO2)	FOLLOW SPECIFICATIONS OF 40 CFR 60.18 SEE POLLUTANT NOTES.	3665.97	LB/H	0		
			12, 19, 2002 anosp,Act		1		1	Sulfur, Total		5005.57	-5/11	0		
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35	LB/H	0		
				PRODUCT RECOVERY TOWER			1	Sulfur Total	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION,					
TV 0254	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	FUGITIVES				Sulfur, Total Reduced (TRS)	AND REPAIR.	0.01	LB/H	0		

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Heate	rs			
SION 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	0		CALCULATED, USING	
	0.0006	lb/MMBTU	THROUGHPUT	
	0		NOT AVAILABLE	
	0.0006	lb/mmbtu	USING THROUGHPUT	
	0			
	0			
	0			
	0			
	0			
	0			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE
				SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET
	0			CONCENTRATION OF 10 PPMV.
	0			
	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR TO DETERMINE IF ADDITIONAL SO2 ENTROMINED THAT ADDITIONAL SO2 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
	0			
	0			

				Summary of SO ₂ C	Control Detei	rmination per I	EPA's RACT/B	ACT/LAER Data	abase for Combustion of Misc. B	oilers, Furnac	es, & Heate	ers			
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE		PRIMARY FUEL	THROUGHPUT	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
															ALL LOADING FOR POSSIBL
															LOADING OP
															REPAIRED OF
															OPERATIONS OPERATIONS
															SHALL BE PU
															BEFORE ANY
															AND LOADED
															LOADING WI
															SYSTEMS CO SULFOX-TO.
															OPERATIONS
															THE RAILCAR
ł															UNHOOKING
															ACETIC ACID
															BE NEUTRALI
				RAILCAR LOADING/UNLOADING				Sulfur, Total							WASTEWATE
TX-0354	ATOFINA CHEMICALS INCORPORATED	ТХ	12/19/2002 ACT	FUGITIVES				Reduced (TRS)	SEE POLLUTANT NOTES.	0.03	LB/H	0			VENT TO THE
								Culfur Tatal	FOLLOW PRACTICES OF LEAK DETECTION,						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	ISOLATION, AND REPAIR.	0.06	LB/H	0			
			12/13/2002 ((1000))/101					neudeed (mb)		0.00	20,11			EACH,	
									FUEL GAS SHALL BE SWEET NATURAL GAS					CALCULATED	
-		-	10/10/0000 0 1 107	(2) STEAM BOILERS, X-426A AND X-				Sulfur Dioxide				0.000		USING	
TX-0354	ATOFINA CHEMICALS INCORPORATED	IX	12/19/2002 ACT	426B N	ATURAL GAS	15.8	MMBTU/H	(SO2)	NO MORE THAN 5 GR S/100 DSCF. MMP DAY STORAGE TANKS WILL VENT TO		lb/H	0.0006	lb/MMBTU	THROUGHPUT	
									THE MMP BULK						
									STORAGE TANK WHICH WILL VENT TO						
									SULF0X-TO.						
								Sulfur, Total	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION,						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Reduced (TRS)	AND REPAIR.	0.11	IB/H	0			
			,,						MMP DAY STORAGE TANKS WILL VENT TO		/··	-			
									THE MMP BULK						
									STORAGE TANK WHICH WILL VENT TO						
ł									SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION,						
								Sulfur, Total	ISOLATION,						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Reduced (TRS)	AND REPAIR.	0.15	LB/H	0			
									FOLLOW PROCEDURES OF LEAK						
TX-0354	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	DETECTION, ISOLATION, AND REPAIR.	0.02	ID/U	0			
17-0334		17	12/13/2002 @1030,ACT	TOGITIVES				heddeed (113)	FOLLOW PRACTICES OF LEAK DETECTION,	0.02	20/11				
								Sulfur, Total	ISOLATION,						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Reduced (TRS)	AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	ту	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		12/ 5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.80	LB/H	0			
17-0334	ATOTINA CHEMICALS INCORPORATED	17	12/19/2002 &105p,Ac1	SERVICE		134.		Reduced (TRS)	FUEL GAS COMBUSTED IN EACH	0.89	сбутт	0			
									COMBUSTION EMISSION						
									POINT NUMBER SHALL BE SWEET						
								Culfur Disuida	NATURAL GAS						
TX-0354	ATOFINA CHEMICALS INCORPORATED	тх	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		12/1	MMBTU/H	Sulfur Dioxide (SO2)	CONTAINING NO MORE THAN 5 GR S/100 DSCF.		LB/H				
	LIMESTONE ELECTRIC GENERATING		12, 19, 2002 anosp,nei			134.		Sulfur Dioxide		4.21	-3/11				
TX-0359	STATION	тх	05/23/2001 ACT	NO 2 SRU INCINERATOR, V-16				(SO2)	NONE INDICATED	10.48	LB/H	0		NOT AVAILABLE	
TV 0055	LIMESTONE ELECTRIC GENERATING		05/22/2001 0	FLUID CATALYTIC CRACK UNIT				Sulfur Dioxide					DD1 01 (411.011	
TX-0359	STATION LIMESTONE ELECTRIC GENERATING	ТХ	05/23/2001 ACT	REGENERATOR VENT, V-20				(SO2) Sulfur Dioxide	NONE INDICATED	341	lb/H	100	PPMV	1 H AV	
TX-0359	STATION	тх	05/23/2001 ACT	FCCU FLARE				(SO2)	NONE INDICATED	3.46	LB/H	n			
	LIMESTONE ELECTRIC GENERATING			1				Sulfur Dioxide			· ·				
TX-0359	STATION	ТХ	05/23/2001 ACT	HCU FLARE, FL-4			 	(SO2)	NONE INDICATED	0.45	LB/H	0		ļ	
									REFINERY FUEL GAS WITH HOURLY H2S						
									CONTENT NOT TO EXCEED 0.10 GR/DSCF AND ANNUAL						COMPLIANCE
	LIMESTONE ELECTRIC GENERATING							Sulfur Dioxide	AVERAGE H2S NOT TO						BASED ON TH
1		тх	05/23/2001 ACT	BOILER, B-12 RI	EFINERY FUEL	1	1	(SO2)	EXCEED 0.03 GR/DSCF	1	LB/MMBTU	1	LB/MMBTU		ASSUMING 1

& Heate	rs			
AISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	0			POLLUTANT COMPLIANCE NOTES ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
1	0			
I		lb/mmbtu	EACH, CALCULATED USING THROUGHPUT	
	0			
	0			
I	0			
I	0			
	0			
	0			
	0		NOT AVAILABLE	
	100	PPMV	1 H AV	
	0			
	0			
1MBTU	0.0376	lb/mmbtu		COMPLIANCE WITH THE SO2 EMISSION LIMIT SHALL BE BASED ON THE H2S CONTENT OF THE FUEL GAS, ASSUMING 100% CONVERSION OF H2S TO SO2.

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	Summary of SO	2 Control Deter	THROUGHPUT	THROUGHPUT	POLLUTANT	abase for Combustion of Misc. B	EMISSION LIMIT LIMIT 1 UNIT	rs STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
24 0262		T)/						Sulfur Dioxide	USE OF PIPELINE QUALITY SWEET	0.04 1.0/11				
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	HOT AIR DRYERS ENTRY A				(SO2) Sulfur Dioxide	NATURAL GAS.	0.01 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	ТХ	03/22/2000 ACT	RTP DRYER NO. 15				(SO2) Sulfur Dioxide	PIPELINE QUALITY SWEET NATURAL GAS	0.01 LB/H	0		ТН	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	MAT LINE (DRYERS AND CLEANER)				(SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	HOT AIR DRYER NO. 45				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	BOILER NO. 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.04 LB/H	0		NOT AVAILABLE FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
								Sulfur Dioxide						
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	EMERGENCY GENERATOR ENTRY A				(SO2) Sulfur Dioxide	NONE INDICATED	5.51 LB/H	U		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 5 DRYER NOS. 1-5				(SO2) Sulfur Dioxide	NONE INDICATED	0.01 LB/H	0		ТН	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 5 DRYER NO. 6				(SO2)	NONE INDICATED	0.01 LB/H	0)	FA	ILITY NETTED OUT OF PSD REVIEW
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 5 FOREHEARTH MONITOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.02 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 5 CURING OVENS NOS. 1 & amp; 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0		тн	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
		TV						Sulfur Dioxide (SO2)						ILITY NETTED OUT OF PSD REVIEW FOR SO2.
	VETROTEX AMERICA	TX	03/22/2000 ACT	BOILER NO. 3				Sulfur Dioxide	NONE INDICATED	0.03 LB/H	0			
X-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	DIESEL GENERATOR	DIESEL			(SO2)	NONE INDICATED SCRUBBER AND AN ESP. ABATEMENT	0.93 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
								Cultur Disuida	EQUIPMENT IS					
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 5				Sulfur Dioxide (SO2)	BYPASSED FOR MAINTENANCE NO MORE THAN 144 H/YR.	11.4 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	RTP DRYERS ENTRY B				Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY SWEET NATURAL GAS	0.01 LB/H	0			
									SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO					
								Sulfur Dioxide	MORE THAN 144		-			
X-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 3				(SO2)	H/YR. SCRUBBER AND AN ESP. ABATEMENT	6.66 LB/H	0		IH	FACILITY NETTED OUT OF PSD REVIEW.
								Sulfur Dioxide	EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO MORE THAN 286					
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 4				(SO2)	H/YR. SCRUBBER FOLLOWED BY AN ESP.	9.03 LB/H	0		тн	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
								Sulfur Dioxide	ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO					
X-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACES NO. 1				(SO2) Sulfur Dioxide	MORE THAN 286 H/YR.	20.31 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
(-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	PROPANE FLARE				(SO2) Sulfur Dioxide	NONE INDICATED	0.49 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	PROPANE EVAPORATOR NO 1				(SO2)	NONE INDICATED	0.01 LB/H	0)	FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	PROPANE EVAPORATOR ENTRY B				Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0	0	FA	ILIY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE FOREHEARTH ENTRY A				Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE FOREHEARTH NO. 3				Sulfur Dioxide	NONE INDICATED	0.01 LB/H				ILITY NETTED OUT OF PSD REVIEW FOR SO2
				FURNACE FOREHEARTH NO. 4 AND				Sulfur Dioxide			0			
X-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	RTP CHOPPER				(SO2)	NONE INDICATED SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO	0.01 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	FURNACE NO. 2				Sulfur Dioxide (SO2)	MORE THAN 286 H/YR.	20.31 LB/H	0		FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
X-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	HOT AIR DRYER NO. 98				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01 LB/H	0	,	FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2.
	VETROTEX AMERICA	ТХ	03/22/2000 ACT	RTP DRYERS ENTRY A				Sulfur Dioxide (SO2)	NONE INDICATED	0.01 LB/H	0			ILITY NETTED OUT OF PSD REVIEW FOR SO2.
								Sulfur Dioxide			0			
X-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	POST CURING OVEN NO. 1				(SO2)	NONE INDICATED	0.01 LB/H	0	1	FA	ILITY NETTED OUT OF PSD REVIEW FOR SO2

				Summary of SO					abase for Combustion of Misc. I				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	ST/ EN LIN
TX-0362	VETROTEX AMERICA	тх	03/22/2000 ACT	POST CURING OVENS NOS. 2 & amp; 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FOREHEARTH MONITOR, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	CURING OVEN NO 1 & amp; 2 FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(5) HOT AIR DRYERS, FURNACE NO 5	5			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 6, FURNACE 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(6) HOT AIR DRYER NO 31, 32, 33, 34, 35, 36				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	RTP DRYER NO 15				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	MAT LINE (DRYERS & amp; CLEANER)				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 45				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	BOILER NO. 2	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) EMERGENCY GENERATORS NO. 1 & amp; 2	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	PROPANE FLARE				Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	PROPANE EVAPORATOR NO. 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(3) PROPANE EVAPORATORS NO 2, 3, 4				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) FURNACE FOREHEARTHS NO 1 & 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) RTP DRYERS NO 12 & amp; 13				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(3) RTP DRYERS NO 16, 17, 18				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	BOILER NO 3	NAT GAS			Sulfur Dioxide (SO2) Sulfur Dioxide	NONE INDICATED	0.03	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	DIESEL GENERATOR	DIESEL			(SO2)	NONE INDICATED	0.93	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 5	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	11.4	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE FOREHEARTH NO 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 4 FOREHEARTH & RTP CHOPPER				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	HOT AIR DRYER NO 98				Sulfur Dioxide (SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) RTP DRYERS 10 & 11				(SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	POST CURING OVEN NO 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	(2) POST CURING OVENS NO 2 & 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 3	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	6.66	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO. 1	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 2	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	тх	11/13/2000 ACT	FURNACE NO 4	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	9.03	LB/H	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60) MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/M
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED		LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
		FACILITY NETTED OUT OF PSD REVIEW FOR SO2
	NOT AVAILABLE	
	NOT AVAILABLE	
	NOT AVAILABLE	
B/MMBTU	USING THROUGHPUT	
	NOT AVAILABLE	

						_			base for Combustion of Misc. B				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STAND EMISS LIMIT U
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
17-0378			11/03/2001 &hbsp,Act	MONOMENT NO. 2 FLARE				Sulfur Dioxide		0.01	LB/11	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	TRAIN NO. 8 FLARE				(SO2)	NONE INDICATED	0.01	LB/H	0	
TX-0378	LA PORTE POLYPROPYLENE PLANT	тх	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0	
TV 0200		TV		(2) AIR PREHEATERS 1106 & amp;				Sulfur Dioxide		0.01	10/11	0	
TX-0380	SYNTHESIS GAS UNIT	тх	06/01/2001 ACT	1206, F1106SGU &F1206SGU				(SO2) Sulfur Dioxide	NONE INDICATED	0.01	LB/H	0	
TX-0380	SYNTHESIS GAS UNIT	тх	06/01/2001 ACT	FLARE, FS28 THERMAL OIL HEATER, BYPASS	SYNGAS WOOD/NATURAL			(SO2) Sulfur Dioxide	NONE INDICATED	3337.57	LB/H	0	
TX-0403	LOUISIANA-PACIFIC CORPORATION	тх	07/06/1999 ACT	STACK, (2)	GAS			(SO2)	LOW SULFUR FUEL	0.02	LB/H	0	
TX-0403	LOUISIANA-PACIFIC CORPORATION	тх	07/06/1999 ACT	WOOD DRYERS, (5)	WOOD WASTE	1636250	saf/d	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	1.09	LB/H	0	
								Sulfur Dioxide					
TX-0403	LOUISIANA-PACIFIC CORPORATION	TX	07/06/1999 ACT	PRESS		1636250	sqf/D	(SO2) Sulfur Dioxide	LOW SULFUR FUEL REFINERY GAS LIMIT: 160 PPMV	0.01	LB/H	0	
TX-0415	PORT ARTHUR REFINERY	тх	03/04/1999 ACT	FLARE	WASTE GAS			(SO2)	HYDROGEN SULFIDE	0.03	LB/H	0	
TX-0415	PORT ARTHUR REFINERY	тх	03/04/1999 ACT	CRACKING FURNACE, RECYCLE ETHANE	REFINERY GAS	302	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	1.12	LB/H	0.0037	lb/mmb.
TV 0445		T)/						Sulfur Dioxide	REFINERY GAS LIMIT: 160 PPMV			0.0000	1.0./1.41.40
TX-0415	PORT ARTHUR REFINERY	ТХ	03/04/1999 ACT	CRACKING HEATER, FRESH FEED, (8)	REFINERY GAS	441.7	mmbtu/h	(SO2) Sulfur Dioxide	HYDROGEN SULFIDE REFINERY GAS LIMIT: 160 PPMV	1.61	LB/H	0.0036	lb/MMB
TX-0415	PORT ARTHUR REFINERY	тх	03/04/1999 ACT	HEATER, DP REACTOR FEED HEATER, DP REACTOR	REFINERY GAS	62 58	mmbtu/h	(SO2) Sulfur Dioxide	HYDROGEN SULFIDE REFINERY GAS LIMIT: 160 PPMV	0.22	LB/H	0.0035	LB/MMB
TX-0415	PORT ARTHUR REFINERY	тх	03/04/1999 ACT	REGENERATION	REFINERY GAS	21 56	mmbtu/h	(SO2)	HYDROGEN SULFIDE	0.07	LB/H	0.0032	LB/MMB
TX-0415	PORT ARTHUR REFINERY	тх	03/04/1999 ACT	BOILER, AUXILIARY	REFINERY GAS	416	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	1 //	LB/H	0.0035	lb/MMB
								Sulfur Dioxide	REFINERY GAS LIMIT: 160 PPMV				
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	HEATER, CONDENSATE SPLITTER HEATER, STARTUP, MALEIC	REFINERGY GAS	211 07	mmbtu/h	(SO2) Sulfur Dioxide	HYDROGEN SULFIDE PIPELINE QUALITY NATURAL GAS < 2.0 GR	0.73	LB/H	0.0035	LB/MMB
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	ANHYDRIDE REACTOR	NATURAL GAS	160.7	mmbtu/h	(SO2)	S PER 1000 DSCF	0.64	LB/H	0.004	lb/mmb
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	тх	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			Sulfur Dioxide (SO2)		0.05	LB/H	0	
TX-0422	BP TEXAS CITY CHEMICAL PLANT B JASPER ORIENTED STRANDBOARD	ТХ	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS				Sulfur Oxides (SOx) Sulfur Dioxide		7.75	LB/H	0	
TX-0446	MILL	тх	02/09/2004 ACT	THERMAL OIL HEATER BYPASS				(SO2)		0.02	LB/H	0	
TX-0446	JASPER ORIENTED STRANDBOARD MILL	тх	02/09/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		3 24	LB/H	0	
	JASPER ORIENTED STRANDBOARD							Sulfur Dioxide				0	
TX-0446	MILL JASPER ORIENTED STRANDBOARD	тх	02/09/2004 ACT	FIRE WATER PUMP				(SO2) Sulfur Dioxide		1.18	LB/H	0	
TX-0446	MILL	тх	02/09/2004 ACT	DRYER RTOS				(SO2)		2.18	LB/H	0	
TX-0446	JASPER ORIENTED STRANDBOARD MILL	тх	02/09/2004 ACT	PRESS RTO				Sulfur Dioxide (SO2)		0.01	LB/H	0	
	JASPER ORIENTED STRANDBOARD	TV	02/00/2004 8 share 4 CT					Sulfur Dioxide		0.22	10/11	0	
TX-0446	MILL CARHAGE ORIENTED STRANDBOARD	тх	02/09/2004 ACT	PRESS BYPASS				(SO2) Sulfur Dioxide		0.33	LB/H	0	
TX-0447	MILL CARHAGE ORIENTED STRANDBOARD	ТХ	03/16/2004 ACT	DRYER RTOS (2)				(SO2) Sulfur Dioxide		2.68	LB/H	0	
TX-0447	MILL	тх	03/16/2004 ACT	PRESS RTO				(SO2)		0.01	LB/H	0	
TX-0447	CARHAGE ORIENTED STRANDBOARD	тх	03/16/2004 ACT	THERMAL OIL HEATER BYPASS				Sulfur Dioxide (SO2)		0.02	LB/H	0	
	CARHAGE ORIENTED STRANDBOARD							Sulfur Dioxide					
TX-0447	MILL CARHAGE ORIENTED STRANDBOARD	ТХ	03/16/2004 ACT	EMERGENCY GENERATOR				(SO2) Sulfur Dioxide		3.24	LB/H	0	
TX-0447	MILL	тх	03/16/2004 ACT	FIRE WATER PUMP				(SO2)		1.23	LB/H	0	
TX-0448	SID RICHARDSON CARBON BORGER PLANT	тх	03/29/2004 ACT	BOILER STACK, PLANT 1 DRYER, AND PLANT 2 DRYER				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE MINIMIZED BY RESTRICTING THE SULFUR CONTENT OF THE CARBON BLACK FEEDSTOCK OIL TO 3 0% ON AN ANNUAL BASIS AND THE USE OF PIPELINE QUALITY SWEET NATURAL GAS AS THE PRIMARY REACTOR FUEL	3921.6	LB/H	0	
-	SID RICHARDSON CARBON BORGER	t		1	İ		İ	Sulfur Dioxide					

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	NOT AVAILABLE	
	NOT AVAILABLE	
	SEE NOTE	LIMIT APPLIES WHEN BURNING NATURAL GAS ONLY. LIMIT AS LBS/MMBTU NOT AVAILABLE.
		THE EMISSION POINT FOR THIS PROCESS IS THE RTO.
		THE LIMIT CORRESPONDS TO THE EMISSIONS FROM RTO.
.B/MMBTU	CALCULATED	
.B/MMBTU		
.B/MMBTU	CALCULATED	
	SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.

								,	base for Combustion of Misc. I				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION	STANDARD EMISSION LIMIT	ST/ EN LIN
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	тх	03/18/2005 ACT	PILOT PLANT FLARE				Sulfur Dioxide (SO2)		435.27	/ LB/H	0	i.
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	тх	03/18/2005 ACT	PROCESS BAG FILTER				Sulfur Dioxide (SO2)		0.15	5 LB/H	0	
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	тх	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	NATURAL GAS, FUEL OIL, OR FLUE GAS	0.0	MMBTU/H	Sulfur Dioxide			L LB/H		
17-0404	CONTINENTAL CARBON SUNRAY					0.5		Sulfur Dioxide		0.001		0	
TX-0464	PLANT	ТХ	03/18/2005 ACT	OXYGEN PRE HEATER COOPER-BESSEMER ENGINE 3105	NATURAL GAS			(SO2) Sulfur Dioxide		0.01	L LB/H	0	
TX-0465	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	НР		3105	HP	(SO2) Sulfur Dioxide	LEAN COMBUSTION	0.26	5 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER		32.5	ММВТИ/Н	(SO2) Sulfur Dioxide		0.02	2 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	FLARES (2)				(SO2)		50.48	3 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HP TEG FIREBOX				Sulfur Dioxide (SO2)		0.01	L LB/H	0	1
TX-0465	SALT CREEK GAS PLANT	ТХ	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.36	5 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	CLARK ENGINE (2)		2000) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.31	L LB/H	0	l.
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.7	7 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	HOT OIL HEATER		12	MMBTU/H	Sulfur Dioxide (SO2)		0.01	L LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330) HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	3 LB/H	0	
TX-0465	SALT CREEK GAS PLANT	тх	01/31/2003 ACT	GLYCOL REBOILER		2.5	ммвит/н	Sulfur Dioxide (SO2)		0.02	2 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBtu/H	Sulfur Dioxide (SO2)		0.41	L LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBtu/h	Sulfur Dioxide (SO2)		0.38	3 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250	MMBtu	Sulfur Dioxide (SO2)		0.02	2 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	2 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	5 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250	mmbtu/h	Sulfur Dioxide (SO2)		0.38	3 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1057-1062, 1091)	FUEL GAS	250	MMBTU/h	Sulfur Dioxide (SO2)		0.38	3 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	Sulfur Dioxide (SO2)		0.41	L LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1067)				Sulfur Dioxide (SO2)		0.01	L LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1087)				Sulfur Dioxide (SO2)		0.02	2 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR (N7900LJD)	DIESEL			Sulfur Dioxide (SO2)		1.85	5 LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REGENERATION HEATER				Sulfur Dioxide (SO2)			L LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	SECOND STAGE FEED HEATER				Sulfur Dioxide (SO2)			L LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (8003B)				Sulfur Dioxide (SO2)		0.01	L LB/H	0	
TX-0476		тх	04/08/2005 ACT	VACUUM UNIT 51 AND COKER UNIT 50	-			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	6681	L LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)) LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)			5 LB/H	0	
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER			ммвти/н	Sulfur Dioxide (SO2)			LB/H	0	
	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	тх	04/20/2005 ACT	ACID GAS FLARE	1			Sulfur Dioxide			2 LB/H	0	
	CITGO CORPUS CHRISTI REFINERY -		,		REFINERY FUEL			Sulfur Dioxide	1		2 LB/H		

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES

	1	1	1	Summary of SO	2 Control Deter	mination per l	EPA's RACT/B	ACT/LAER Dat	abase for Combustion of Misc. I	Boilers, Furnac	es, & Heate	rs	1		
							THROUGHPUT					STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERA TIME	GE
RBLCID	FACILITY NAME CITGO CORPUS CHRISTI REFINERY -	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	POLLUTANT Sulfur Dioxide	CONTROL METHOD DESCRIPTION	1	LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	
TX-0478	WEST PLANT	тх	04/20/2005 ACT	TAIL GAS INCINERATOR		100	о ммвти/н	(SO2)		22.4	LB/H	0			
-	CITGO CORPUS CHRISTI REFINERY -			MIXED DISTILLATE HYDROHEATER	REFINERY FUEL			Sulfur Dioxide							
TX-0478	WEST PLANT	тх	04/20/2005 ACT	REBOILER HEATER	GAS	82	2 MMBTU/H	(SO2)		5.7	LB/H	0			
	CITGO CORPUS CHRISTI REFINERY -							Sulfur Dioxide							
TX-0478	WEST PLANT	ТХ	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				(SO2)		0.19	LB/H	0			
	CITGO CORPUS CHRISTI REFINERY -							Sulfur Dioxide		1050					
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				(SO2) Sulfur Dioxido		1056	LB/H	0			
TX-0478	WEST PLANT	тх	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
17-0476	ROHM AND HAAS CHEMICALS LLC	1.	04/20/2003 &IIDSP,ACT	DHICHARGER HEATER				Sulfur Dioxide		2.1	цр/п	0			
TX-0487	LONE STAR PLANT	тх	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			(SO2)		0.03	LB/H	0			
	ROHM AND HAAS CHEMICALS LLC		00/2 // 2000 anosp)/ 101					Sulfur Dioxide		0.05	20/11	0			
TX-0487	LONE STAR PLANT	тх	03/24/2005 ACT	N5/6 FLARE				(SO2)		0.11	LB/H	0			
	ROHM AND HAAS CHEMICALS LLC			N-3 BACKUP INSTRUMENT AIR				Sulfur Dioxide			,				
TX-0487	LONE STAR PLANT	тх	03/24/2005 ACT	COMPRESSOR				(SO2)		0.01	LB/H	0			
	ROHM AND HAAS CHEMICALS LLC							Sulfur Dioxide							
TX-0487	LONE STAR PLANT	ТΧ	03/24/2005 ACT	N7/8 PREHEATER				(SO2)		0.01	LB/H	0			
	ROHM AND HAAS CHEMICALS LLC							Sulfur Dioxide							
TX-0487	LONE STAR PLANT	тх	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				(SO2)		0.11	LB/H	0			
	ROHM AND HAAS CHEMICALS LLC							Sulfur Dioxide							
TX-0487	LONE STAR PLANT	тх	03/24/2005 ACT	N-3,4 PREHEATER				(SO2)		0.01	LB/H	0		-	
TV 0407	ROHM AND HAAS CHEMICALS LLC	TV	02/24/2005 8 about CT					Sulfur Dioxide		0.01	1.0./11	0			
TX-0487	LONE STAR PLANT DOW CHEMICAL PLANT B AND	тх	03/24/2005 ACT	N-5/6 PREHEATER				(SO2)		0.01	LB/H	0		-	
	OYSTER CREEK LIGHT							Sulfur Dioxide							
TX-0493	HYDROCARBONS PLA	тх	07/05/2005 ACT	B-7200 UNIT	HYDROCARBONS			(SO2)		201	LB/H	0			
			··/···	TURBINE EXHAUST DUCT BURNER				Sulfur Dioxide			,	-			
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	(3)	NATURAL GAS			(SO2)		0.02	LB/H	0			
								Sulfur Dioxide							
TX-0501	TEXSTAR GAS PROCESS FACILITY	ТХ	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	93	3 MMBTU/H	(SO2)		0.05	LB/H	0			
				TREATED GAS COMPRESSOR											
				ENGINE STACK WITH CATALYTIC				Sulfur Dioxide							
TX-0501	TEXSTAR GAS PROCESS FACILITY	ТХ	07/11/2006 ACT	CONVERTER WAUKESHA L-7042GSI		8/5	5 HP	(SO2) Sulfur Dioxide		0.46	lb/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 & phon ACT	TAIL GAS INCINERATOR STACK				(SO2)		250	LB/H	0			
17-0201	TEXSTAR GAS PROCESS FACILITY	1.	07/11/2006 ACT	TAIL GAS INCINERATOR STACK				Sulfur Dioxide		550	цы/п	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	BOTTOM HEATERS (2)		11	5 ММВТИ/Н	(SO2)		0.01	LB/H	0			
			0771172000 anosp), ter	ALLISON 501KB GAS TURBINE				Sulfur Dioxide		0.01	20/11	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	GENERATOR	NATURAL GAS			(SO2)		0.67	LB/H	0			
								Sulfur Dioxide							
TX-0604	GOLDSMITH GAS PLANT	тх	11/03/2011 ACT	Tail Gas Incinerator	Natural Gas	(D	(SO2)		1521.8	T/YR	0			
				BURNERS, (2) CALCINING HAMMER				Sulfur Dioxide							
VA-0299	UNITED STATES GYPSUM COMPANY	VA	06/19/2006 ACT	MILL	DISTILLATE OIL	60	ОММВТИ/Н	(SO2)		3.1	LB/H	0			EMISS
				DRYING KILN, WET & amp; DRY			1	Sulfur Dioxide							
VA-0299	UNITED STATES GYPSUM COMPANY	VA	06/19/2006 ACT	ZONE BURNERS	DISTILLATE OIL	100	MMBTU/H	(SO2)		5.1	LB/H	0			EMISS
				OFF-MACHINE COATER, DRYER (P51				Sulfur Dioxide		.		_		1.	BACT f
WI-0202	COMBINED LOCKS MILL	WI	08/13/2003 ACT	/ S51) PROCESS HEATER PAPER MACHINE	NATURAL GAS	1256	5 T/D	(SO2)	USE NATURAL GAS	0		0		see note	emissi
MIL 0242		14/1	07/15/2005 8					Sulfur Dioxide		_		~		1	
VVI-0212	SENA - NIAGARA MILL	WI	07/15/2005 ACT	P51 DRYER	NATURAL GAS	35.:	3 MMBTU/H	(SO2)	NATURAL GAS AS FUEL	0		0		1	NO EN

s, & Heate	rs			
EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
B/H	0			
в/н	0			
B/H	0			
В/Н	0			
B/H	0			
B/H	0			
в/н	0			
B/H	0			
B/H	0			
B/H	0			
/YR	0			
в/н	0			EMISSION LIMITS ARE FOR ONE OF TWO BURNERS
B/H	0			EMISSION LIMITS ARE FOR ONE OF TWO BURNERS
	0		see note	BACT for this pollutant is use of natural gas, no emission rate limits
	0			NO EMISSION RATE LIMITS, BACT IS POLLUTION PREVENTION.

	Γ	1	1	Summ	ary of SO ₂ Con	trol Determin	ation per EPA	's RACT/BACT	/LAER Database for Combustion	of Other Sources				
BLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION 1 LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	E POLLUTANT COMPLIANCE NOTES
										00/400.005				SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT
286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333	3 ММВТU/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	GS/100 SCF 2 GAS	0			COMBUSTION DESIGN AND OPERATION OF EACH GAS TURBINE REPRESENTS (BACT) FOR PM/PM10 EMISSIONS.
				TWO 99.8 MMBTU/H GAS-FUELED				Sulfur Dioxide		GS/100 SCF				
286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	AUXILIARY BOILERS TWO GAS-FUELED 10 MMBTU/H	NATURAL GAS	99.8	8 MMBTU/H	(SO2) Sulfur Dioxide		2 GAS GS/100 SCF	0			
286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	PROCESS HEATERS	NATURAL GAS	10	0 ММВТИ/Н	(SO2)		2 GAS	0			
86	FPL WEST COUNTY ENERGY CENTER	E1	01/10/2007 ACT	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS	FUEL OIL			Sulfur Dioxide (SO2)		0.0015 % S FUEL OIL	0			
80	CARBO CERAMICS INC MILLEN		01/10/2007 & mbsp, ACT					Sulfur Dioxide	WET SCRUBBER, USE OF NATURAL GAS	% CONTROL	0			TEST METHOD: METHOD 6 OR 6C
145	FACILITY	GA	04/06/2012 ACT	CALCINER	NATURAL GAS	60	0 ММВТU/Н	(SO2)	AND PROPANT	90 BY WEIGHT	0			40 CFR 60,SUBPART UUU
L45	CARBO CERAMICS INC MILLEN FACILITY	GA	04/06/2012 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	20.2	2 MMBTU/H	Sulfur Dioxide (SO2)		PPM SULFUR 15 IN FUEL	0			40 CFR 60, SUBPART IIII 40 CFR 63, SUBPART ZZZZ
137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	DRYER STACK (EMISSION POINT 59)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	580.25 LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. AI SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), M COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIM PSD-LA-580(M-3) SET LIMITS FOR THE DRYER STACK AT 389 2 (HOURLY MAXIMUM) & 1704 94 TPY (ANNUAL MAXIMUM).
								Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY					*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. AI SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), M COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIM PSD-LA-580(M-3) SET LIMITS FOR THE STEAM BOILER AT 97 0
137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	STEAM BOILER	FEEDSTOCK OIL	1	5 ММВТИ/Н	(SO2)	WEIGHT.	166.17 LB/H	0			(HOURLY MAXIMUM) & 424.91 TPY (ANNUAL MAXIMUM).
)137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	MAIN COMBUSTION STACK	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	2437.79 LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. AN SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), M/ COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL O FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIMU PSD-LA-580(M-3) SET LIMITS FOR THE MAIN COMBUSTION ST/ 2633.15 LB/HR (HOURLY MAXIMUM) & 11,533.21 TPY (ANNUAL MAXIMUM).
137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	DRYER STACK (EMISSION POINT 84)	FEEDSTOCK OIL			Sulfur Dioxide (SO2) Sulfur Dioxide	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT. 30 DAY ROLLING AVERAGE. WILL FIRE ONLY PIPELINE QUALITY NATURAL GAS. NOT OVER 3100	263.12 LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. AN SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), M COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIM PSD-LA-580(M-3) SET LIMITS FOR THE DRYER STACK AT 327 07 (HOURLY MAXIMUM) & 1432 55 TPY (ANNUAL MAXIMUM).
303	MIDLAND COGENERATION	МІ	07/26/2001 ACT	DUCT BURNERS, 2 EACH	NATURAL GAS	400	0 ММВТU/Н	(SO2)	HOURS/YR.	0.8 LB/MMBTU	0.8	lb/MMBTU		
777	DAIMLER CHRYSLER CORPORATION	ОН	08/31/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	<i></i>	0 ММВТU/Н	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	0.03 LB/H	0 0005	lb/mmbtu	FROM NATURA GAS	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE CO L EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL ALL COMBUSTION UNITS NOT TO EXCEED 8 99 T/ROLLING 12:
211			00/31/2004 &IIDSPACT	GAS, 2 UNITS AIR SUPPLY MAKE UP UNITS (40	INAT UNAL GAS	50		(302)	THAN U 5 % SULFUK	0.03 LB/H	0.0006		GAD	*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM
		OH.	09/21/2004 Sabar ACT	UNITS) AND BODY WASHERS (2		~		Sulfur Dioxide		0.06110/11	0.0000			COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL COMBU
	BODY SHOP DAIMLER CHRYSLER CORPORATION BODY SHOP DAIMLER CHRYSLER CORPORATION	ОН	08/31/2004 ACT 08/31/2004 ACT		NATURAL GAS NUMBER 2 FUEL OIL		D MMBTU/H	(SO2) Sulfur Dioxide (SO2) Sulfur Dioxide	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	0.06 LB/H 26 LB/H		LB/MMBTU	FROM #2 FUEL OIL	UNITS NOT TO EXCEED 8 99 T/ROLLING 12-MO. LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE CC EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL ALL COMBUSTION UNITS NOT TO EXCEED 8 99 T/ROLLING 12
278	ROLLING CHASSIS	ОН	08/31/2004 ACT		NATURAL GAS	50	0 ММВТU/Н	(SO2)		0.03 LB/H	0.0006	lb/MMBTU		
	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	ОН	09/02/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	5() MMBTU/H	Sulfur Dioxide (SO2)		0.03 LB/H	0.0006	LB/MMBTU	FROM NATURA	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE CO EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL L THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINA OVENS NOT TO EXCEED 9 01 T/ROLLING 12-MO.

						THROUGHPUT		/LAER Database for Combustion		STANDARD EMISSION	STANDARD EMISSION	STANDARD LIMIT AVERAGE TIME	
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	1 LIMIT 1 UNIT	LIMIT	LIMIT UNIT	CONDITION	POLLUTANT COMPLIANCE NOTES
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	он	09/02/2004 ACT	HOT WATER BOILER, W/ #2 FUEL OIL	#2 FUEL OIL	50 MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	26 I.B/H	0 51	LB/MMBTU	FROM #2 FUEL	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS NOT TO EXCEED 9 01 T/ROLLING 12-MO.
													*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	он	09/02/2004 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	95 MMBTU/H	Sulfur Dioxide (SO2)		0.06 LB/H	0.0006	lb/MMBTU		COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS NOT TO EXCEED 9.01 T/ROLLING 12-MO. LB/H & T/YR LIMITS ARE FOR EACH DRYING OVEN FROM
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	он	09/02/2004 ACT	NAT GAS DRYING OVENS,4,FOR 4 AUTOMOTIVE OFF-LINE REPAIR BOOTHS	NATURAL GAS	5 MMBTU/H EACH	Sulfur Dioxide (SO2)		0.01 LB/H	C			COMBUSTION OF NATURAL GAS, AT 5 MMBTU/H EACH. THE COMBINED SO2 EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS IS NOT TO EXCEED 9.01 T/ROLLING 12- MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	50 MMBTU/H	Sulfur Dioxide (SO2)		0.03 LB/H	0.0006	lb/mmbtu		LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
01 0380	DAIMLER CHRYSLER CORPORATION PAINT SHOP		09/02/2004 ACT	AIR SUPPLY MAKEUP UNITS (30 UNITS)		20 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H	0.0006			LB/H LIMIT FOR EACH UNIT. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
08-0280	PAINT SHOP	ОП	09/02/2004 &110sp,AC1		NATURAL GAS		(302)		0.02 LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	ОН	09/02/2004 ACT	ELECTRODEPOSITION		JOBS/ROLLING 200064 12-MO	Sulfur Dioxide (SO2)		0.01 LB/H	0.0006	LB/MMBTU		COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	ELECTRODEPOSITION OVEN	NATURAL GAS	29.6 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H		LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	AIR SUPPLY MAKE UP UNITS (17 UNITS)	NATURAL GAS	10 MMBTU/H	Sulfur Dioxide (SO2)		0.04 LB/H	0.0006	lb/mmbtu		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	ELECTROSTATIC POWDER PRIMER SPRAY BOOTH OVEN	NATURAL GAS	37.3 MMBTU/H	Sulfur Dioxide (SO2)		0.03 LB/H	0.0006	lb/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO. EMISSIONS FROM THERMAL OXIDIZER CONTROL. *T/ROLLING 12-MO
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	TOPCOAT BOOTHS (TWO) FOR BASECOAT AND CLEARCOAT		JOBS/ROLLING 200064 12-MO	Sulfur Dioxide (SO2)		0.01 LB/H	0.0006	lb/mmbtu		IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	он	09/02/2004 ACT	TOPCOAT DRYING OVEN	NATURAL GAS	66 MMBTU/H	Sulfur Dioxide (SO2) Sulfur Dioxide		0.04 LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	он	05/03/2007 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	20.4 MMBTU/H	(SO2)		0.01 LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	он	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	FUEL OIL #2	20.4 MMBTU/H	Sulfur Dioxide (SO2)		10.4 LB/H	0 51	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOF	он	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (24)	NATURAL GAS	20 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H	0 0006	LB/MMBTU		LIMITS ARE FOR EACH UNIT. 24 AIR SUPPLY MAKE UP UNITS.
	TOLEDO SUPPLIER PARK- PAINT SHOF		05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	28 95 MMBTU/H	Sulfur Dioxide (SO2)		0.02 LB/H		LB/MMBTU		
	TOLEDO SUPPLIER PARK- PAINT SHOF		05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (6)	NATURAL GAS	14 MMBTU/H	Sulfur Dioxide (SO2)		0.01 LB/H		LB/MMBTU		LIMITS ARE FOR EACH UNIT. 6 AIR SUPPLY UNITS.
	LORAINE COUNTY LFG POWER			Reciprocationg Internal Combustion			Sulfur Dioxide			0.0000		1	
	STATION LORAINE COUNTY LFG POWER	ОН	09/14/2011 ACT	Engines (10)	Landfill Gas	2233 HP	(SO2) Sulfur Dioxide		0.28 LB/H	(+	
		ОН	09/14/2011 ACT	Thermal Oxidizer	landfill gas	6 MMBTU/H	(SO2) Sulfur Dioxide		0.09 LB/H				
TX-0371 TX-0371	CORPUS CHRISTI ENERGY CENTER	тх	02/04/2000 EST 02/04/2000 EST		NAT GAS	315 MMBTU/H	(SO2) Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT	48.35 LB/H 9.4 LB/H	0 03	LB/MMBTU	EACH, CALCULATED	SO2 STANDARD EMISSIONS REQUIRED IN LB/MMBTU, CALCULATED FROM MAXIMUM ALLOWABLE RATES IN LB/H AND HEAT INPUT CAPACITY.
	CORPUS CHRISTI ENERGY CENTER	ТХ	02/04/2000 EST	ANNUAL TOTALS FOR TURBINES & amp; AUXILIARY BOILERS	GASEOUS FUEL		Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS.	189.3 T/YR				
	CORPUS CHRISTI ENERGY CENTER	ТХ	01/20/2004 EST	SUBMERGED COMBUSTION	NATURAL GAS		Sulfur Dioxide	FIGEL SOLFOR CONTENT LIMITS. FIRING LOW SULFUR NATURAL GAS IN THE SCVS REPRESENTS BACT FOR SO2 AND PM10.					
TX-0440	CORPUS CHRISTI LNG	тх	01/20/2004 ACT		DIESEL	660 HP	Sulfur Dioxide (SO2)		1.08 LB/H	C			

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STA EN LIN
TX-0440	CORPUS CHRISTI LNG	тх	01/20/2004 ACT	DIESEL FIREWATER BOOSTER PUMP	DIESEL	525	5 HP	Sulfur Dioxide (SO2)		1.35	LB/H	0	
TX-0440	CORPUS CHRISTI LNG	тх	01/20/2004 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	1500		Sulfur Dioxide (SO2)			LB/H	0	
	SHELL OIL DEER PARK					1500		Sulfur Dioxide				0	
TX-0442		тх	07/30/2004 ACT	SR- 3/4 INCINERATOR				(SO2) Sulfur Dioxide			PPMV	0	
TX-0442	SHELL OIL DEER PARK	ТХ	07/30/2004 ACT	EAST PROPERTY FLARE				(SO2) Sulfur Dioxide		300	PPM	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	COKER FLARE	REFINERY FUEL			(SO2) Sulfur Dioxide		300	PPM	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	TWENTY ONE FURNACES	GAS			(SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	FOURTEEN HEATERS				Sulfur Dioxide (SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN			Sulfur Dioxide (SO2)		300	PPMV	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	CO BOILER	CARBON MONOXIDE			Sulfur Dioxide (SO2)		300	РРМ	0	
	SHELL OIL DEER PARK							Sulfur Dioxide (SO2)					
		тх	07/30/2004 ACT	CCU FLARE				Sulfur Dioxide			PPM	0	
TX-0442	SHELL OIL DEER PARK	ТХ	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				(SO2) Sulfur Dioxide		300	PPM	0	
TX-0442	SHELL OIL DEER PARK	ТХ	07/30/2004 ACT	WEST PROPERTY FLARE				(SO2) Sulfur Dioxide		300	PPM	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	THREE FLARES				(SO2)		300	РРМ	0	
TX-0442	SHELL OIL DEER PARK	тх	07/30/2004 ACT	ANALYZER				Sulfur Dioxide (SO2)		300	РРМ	0	
				COMBUSTION UNITS, TANKS, PROCESS VENTS, LOADING, FLARES									
TX-0451	DIAMOND SHAMROCK REFINING VALERO	тх	05/20/2004 ACT	FUGITIVES (4), WASTEWATER, COOLING TOWERS	-			Sulfur Dioxide (SO2)		466.38	ів/н	0	
17-0451	VALLIO		03/20/2004 and sp,Act					(302)	EMISSIONS OF SO2 WILL BE LIMITED BY	400.38	20/11	0	
	DEGUSSA ENGINEERED CARBONS			WASTE GAS COMBUSTION ANNUAL				Sulfur Dioxide	REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN				
TX-0455	ORANGE CARBON BLACK PLANT	ТХ	08/21/2003 ACT	EMISSIONS CAP				(SO2)	ANNUAL BASIS EMISSIONS OF SO2 WILL BE LIMITED BY	5821.2	T/YR	0	
								Cultur Diouido	REDUCING THE CARBON BLACK OIL				
TX-0455	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	тх	08/21/2003 ACT	VOC INCINERATOR, WASTE HEAT BOILER				Sulfur Dioxide (SO2)	FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN ANNUAL BASIS	968.8	LB/H	0	
									EMISSIONS OF SO2 WILL BE LIMITED BY REDUCING THE CARBON BLACK OIL				
	DEGUSSA ENGINEERED CARBONS	TV	08/21/2002 8 share 4 CT					Sulfur Dioxide	FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN	122.2	10/11	0	
TX-0455	ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	BOILER STACK, DRYER 1-4				(SO2)	ANNUAL BASIS EMISSIONS OF SO2 WILL BE LIMITED BY	123.3	LB/H	0	
	DEGUSSA ENGINEERED CARBONS							Sulfur Dioxide	REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN				
TX-0455	ORANGE CARBON BLACK PLANT CITY PUBLIC SERVICE LEON CREEK	тх	08/21/2003 ACT	DRYER FILTER 1-4 GE LM6000 COMBUSTION TURBINE				(SO2) Sulfur Dioxide	ANNUAL BASIS CONTROLLED BY PROPER COMBUSTION	12.3	LB/H	0	
TX-0457	PLANT	тх	06/26/2003 ACT	(4)	NATURAL GAS			(SO2)	OF NATURAL GAS	1.3	LB/H	0	
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	тх	06/26/2003 ACT	EMERGENCY GENERATOR (5)				Sulfur Dioxide (SO2)		2.8	LB/H	0	
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	COMBUSTION TURBINE WITH 550 MMBTU/HR DUCT BURNER	NATURAL GAS			Sulfur Dioxide (SO2)	BURN LOW SULFUR NATURAL GAS	14 5	LB/H	0	
								Sulfur Dioxide	BORN LOW SOLL OR NATORAL GAS				
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	AUXILIARY BOILER	NATURAL GAS	36	5 mmbtu/h	(SO2) Sulfur Dioxide		0.3	LB/H	0	
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	FIRE WATER PUMP ENGINE				(SO2) Sulfur Dioxide		0.5	LB/H	0	
TX-0458	JACK COUNTY POWER PLANT	тх	07/22/2003 ACT	EMERGENCY GENERATOR (6)				(SO2)		1.4	LB/H	0	
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	тх	08/21/2003 ACT	VOC INCINERATOR, WASTE HEAT BOILER	TAIL GAS			Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT IN TAIL GAS	968.8	LB/H	0	
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	тх	08/21/2003 ACT	DRYER FILTER 1-4				Sulfur Dioxide (SO2)	LIMIT SULFUR IN GAS	12.3	LB/H	0	
	DEGUSSA ENGINEERED CARBONS							Sulfur Dioxide				-	
TX-0470	ORANGE CARBON BLACK PLANT DEGUSSA ENGINEERED CARBONS	TX	08/21/2003 ACT	BOILER STACK, DRYER 1-4 WASTE GAS COMBUSTION ANNUAL				(SO2) Sulfur Dioxide	LIMIT SULFUR IN GAS	123.3	ьв/п	0	
TX-0470	ORANGE CARBON BLACK PLANT	тх	08/21/2003 ACT	EMISSIONS CAP				(SO2)		5821.2	T/YR	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES

									LAER Database for Combustion				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANI EMIS LIMIT
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBtu/H	Sulfur Dioxide (SO2)		0.41	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250	MMBtu	Sulfur Dioxide (SO2)		0.02	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056) PYROLYSIS FURNACE (1057-1062,	FUEL GAS	250	mmbtu/h	Sulfur Dioxide (SO2) Sulfur Dioxide		0.38	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	1091)	FUEL GAS	250	MMBTU/h	(SO2) Sulfur Dioxide		0.38	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	(SO2) Sulfur Dioxide		0.41	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1067)				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	FLARE (1087)				(SO2)		0.02	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR (N7900LJD)	DIESEL			Sulfur Dioxide (SO2) Sulfur Dioxide		1.85	lb/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	REGENERATION HEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT	тх	05/09/2005 ACT	SECOND STAGE FEED HEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0475	FORMOSA POINT COMFORT PLANT CITGO CORPUS CHRISTI REFINERY -	тх	05/09/2005 ACT	FLARE (8003B)	REFINERY FUEL			(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	DHT STRIPPER REBOILER	GAS			(SO2) Sulfur Dioxide		1.9	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	(SO2) Sulfur Dioxide		6.6	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	(SO2) Sulfur Dioxide		1.4	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	ACID GAS FLARE	REFINERY FUEL			(SO2) Sulfur Dioxide		0.2	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	NO.3 BOILER	GAS	99	MMBTU/H	(SO2) Sulfur Dioxide		2.2	lb/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	TAIL GAS INCINERATOR MIXED DISTILLATE HYDROHEATER	REFINERY FUEL	100	MMBTU/H	(SO2) Sulfur Dioxide		22.4	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	REBOILER HEATER	GAS	82	ММВТИ/Н	(SO2) Sulfur Dioxide		5.7	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				(SO2) Sulfur Dioxide		0.19	LB/H	0	
TX-0478	WEST PLANT CITGO CORPUS CHRISTI REFINERY -	тх	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				(SO2) Sulfur Dioxide		1056	LB/H	0	
TX-0478	WEST PLANT ROHM AND HAAS CHEMICALS LLC	тх	04/20/2005 ACT	DHT CHARGER HEATER				(SO2) Sulfur Dioxide		2.1	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			(SO2) Sulfur Dioxide		0.03	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N5/6 FLARE N-3 BACKUP INSTRUMENT AIR				(SO2) Sulfur Dioxide		0.11	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	COMPRESSOR				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N7/8 PREHEATER				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				(SO2) Sulfur Dioxide		0.11	lb/H	0	
TX-0487	LONE STAR PLANT ROHM AND HAAS CHEMICALS LLC	тх	03/24/2005 ACT	N-3,4 PREHEATER				(SO2) Sulfur Dioxide		0.01	lb/H	0	
TX-0487	LONE STAR PLANT FLINT HILLS RESOURCES	тх	03/24/2005 ACT	N-5/6 PREHEATER				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0494	INSTALLATION OF BOILERS	тх	01/24/2005 ACT	FLARES 5,6				(SO2) Sulfur Dioxide		942.51	lb/H	0	
TX-0494	INSTALLATION OF BOILERS	тх	01/24/2005 ACT	MARINE VAPOR COMBUSTOR				(SO2) Sulfur Dioxide		0.01	LB/H	0	
TX-0499	SANDY CREEK ENERGY STATION	тх	07/24/2006 ACT	PULVERIZED CAOL BOILER	COAL	8185	ММВТИ/Н	(SO2)		2456	LB/H	0	

STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
	1	

				Sumi	mary of SO ₂ Cor	trol Determin	ation per EPA	A's RACT/BACT	/LAER Database for Combustion	of Other Sources				
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	
								Sulfur Dioxide						
TX-0499	SANDY CREEK ENERGY STATION	ТХ	07/24/2006 ACT	AUXILLARY BOILER	NATURAL GAS	17	5 MMBTU/H	(SO2)		0.11 LB/H	0)		
								Sulfur Dioxide						
TX-0499	SANDY CREEK ENERGY STATION	ТХ	07/24/2006 ACT	PLANT-EMISSION CAP				(SO2)		3585 T/YR	C)		
				TURBINE EXHAUST DUCT BURNER				Sulfur Dioxide						
TX-0501	TEXSTAR GAS PROCESS FACILITY	ТХ	07/11/2006 ACT	(3)	NATURAL GAS			(SO2)		0.02 LB/H	C)		
-		-	07/11/2006 0 1 107					Sulfur Dioxide		0.05110.00				
TX-0501	TEXSTAR GAS PROCESS FACILITY	IX	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	9.	3 MMBTU/H	(SO2)		0.05 LB/H	0		-	
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	TREATED GAS COMPRESSOR ENGINE STACK WITH CATALYTIC CONVERTER WAUKESHA L-7042GSI	1	87	5 НР	Sulfur Dioxide (SO2)		0.46 LB/H	C	þ		
								Sulfur Dioxide						
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	TAIL GAS INCINERATOR STACK				(SO2)		350 LB/H	C)		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	BOTTOM HEATERS (2)		1	5 ММВТU/Н	Sulfur Dioxide (SO2)		0.01 LB/H	C	þ		
TX-0501	TEXSTAR GAS PROCESS FACILITY	тх	07/11/2006 ACT	ALLISON 501KB GAS TURBINE GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)		0.67 LB/H	C)		
	CITY OF HARRISONBURG RESOURCE			RESOURCE RECOVERY - WASTE				Sulfur Dioxide	DRY-DRY FLUE GAS SCRUBBING SYSTEM USING A HYDRATED LIME SORBENT OR OTHER DEQ APPROVED SUITABLE					
VA-0297	RECOVERY FACILITY	VA	11/18/2005 ACT	COMBUSTION	SOLID WASTE	3467	5 tons/year	(SO2)	SORBENT. CEM SYSTEM.	30 PPM @ 7% O2	30	PPM @ 7% O2		
	CITY OF HARRISONBURG RESOURCE			RESOURCE RECOVERY - WASTE				Sulfur Dioxide	GOOD COMBUSTION PRACTICES AND CEM	_				
VA-0297	RECOVERY FACILITY	VA	11/18/2005 ACT	COMBUSTION	NATURAL GAS	43.	2 mmbtu	(SO2)	SYSTEM.	2.19 LB/H	2 03	B LB/MMBTU	CALCULATED	
	CITY OF HARRISONBURG RESOURCE			RESOURCE RECOVERY - WASTE				Sulfur Dioxide						1
VA-0297	RECOVERY FACILITY	VA	11/18/2005 ACT	COMBUSTION	DISTILLATE OIL	1 0	8 MMBTU/H	(SO2)	PROPER OPERATION AND MAINTENANCE.	0.32 LB/H	0.3	B LB/MMBTU		

EMISSION	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LB/H	0			
T/YR	0			
LB/H	0			
LB/H	0			
5 LB/H	0			
LB/H	0			
' LB/H	0			
) PPM @ 7% O	2 30	PPM @ 7% O2		
) LB/H	2 03	lb/mmbtu	CALCULATED	
LB/H	0.3	lb/mmbtu		

APPENDIX B COST CALCULATION DETAILS

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Dispersion (Stack Replacement)

- B1a Annual Cost Factors, Boiler House #1 Dispersion (Stack Replacement)
- B1b Direct and Indirect Installed Costs, Boiler House #1, Dispersion (Stack Replacement)
- B2a Annual Cost Factors, Boiler House #2 Dispersion (Stack Replacement)
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- B3a Annual Cost Factors, HSM Furnaces Dispersion (Stack Replacement)
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Fuel Switching

- B4a Annual Cost Factors, Boiler House #1 Fuel Switching
- B4b Direct and Indirect Installed Costs, Boiler House #1, Fuel Switching
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- B7a Annual Cost Factors, Boiler House #1 Wet Scrubber
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- B10a Annual Cost Factors, Boiler House #1 SDA
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Miscellaneous Calculations

B16 Summary of Operating and Maintenance Costs Based on 2013 Actuals

Cost Item	Factor Cos	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	2,346,68
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	234,66
Instrumentation	0.04 \$	103,25
Sales Taxes	0.06 \$	154,88
Freight	0.05 \$	129,06
Purchased Equipment Cost, PEC	\$	2,968,55
Direct Installation Costs		
Foundations and Supports ²	0.1 \$	258,13
Handling and Erection	0.75 \$	1,929,12
Electrical	0.01 \$	25,81
Piping	0.04 \$	90,34
Ductwork	0.26 \$	671,15
Painting	0.01 \$	13,16
Direct Installation Costs, DC	\$	2,987,73
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	5,976,28
Indirect Costs (Installation)		
Engineering	0.15 \$	445,28
Construction an Field Expenses	0.1 \$	296,85
Contractor Fees	0.1 \$	296,85
Startup	0.006 \$	17,81
Performance Test	0.005 \$	14,84
Model Study	0\$	-
Contingencies	0.1 \$	296,85
Total Indirect Costs, IC	\$	1,368,50
Fotal Installed Cost	\$	7,324,78

Table B1b. Direct and Indirect Installation Costs, Boiler House #1 - Dispersion

¹ Primary equipment includes stack/chimney. Ancillary equipment includes: partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item	Factor	Cost	:
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	\$	28,470
Supervisor	15% of Operator	\$	4,271
Material	5% of total operating	\$	1,637
Maintenance			
Maintenance Employee	General Maintenance	\$	63,489
Supervisor	15% of Maintenance Labor	\$	11,204
Material	100% of Maintenance Labor	\$	74,693
Utilities			
Electricity		\$	137,163
Water		\$	21,024
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	\$	146,496
Property Tax	1% of Total Capital Investment	\$	73,248
Insurance	1% of Total Capital Investment	\$	73,248
Overhead	60% of total Labor and Materials	\$	204,189
Capital Recovery	0.1098 x Total Capital Investment	\$	804,262
Total Annual Cost		\$	1,643,394
20	10 Uncontrolled SO $_2$ Actual Emissions (tpy)		407.35
Ar	nbient Air Quality Impact Reduction (ug/m ³)		13.8
Ca	ontrol Cost Per ug/m ³ Reduction in SO $_2$ Impact	\$	119,259

Table B1a. Annual Cost Factors, Boiler House #1 - Dispersion

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for Boiler House #1 - Dispersion

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Un	nit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required			(Base Year)		Factor	Year Cost	Factor	(Current Year)
												Factor		
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	\$	666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$	104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$	472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	\$	554,774	\$554,774	2014	1	1	1	\$ 554,774
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$	658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$	109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$	70,500	\$70,500	2014	1	1	1	\$ 70,500
8														
9														
10														
21														
														\$ 2,346,681

Notes:

1 New stack cost based on estimate from International Chimney Corporation, ICC File CC-42408-C, February 27, 2014.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 330,130 acfm acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #1 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity				
Fan Electricity	222422			
Flow	330130 ACFM			
Pressure Drop	5 iwc	(4 inches duct, 1 inch stack	()	
Fan Efficiency	0.8 fraction	11 1		
Gas S.G. (Air = 1)	1	Use 1		
Belt Efficiency	1	Typical Efficiencies		
Motor Efficiency	0.95	Motor 1kW - 0.4		
Power (BHP)	325 BHP	Motor 10 kW - 0.87		
Motor Efficiency	95 %	Malas (00/10/ 0.00		
Power (KW)	254.8 KW	Motor 100 kW - 0.92		
Electricity Cost (\$/KW-hr)	\$ 0.06	Belt 1 kW - 0.78		
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88		
Annual Electricity Cost (\$)	\$ 133,930	Belt 100 kW - 0.93		
Duran in a				
Pumping	202			
Pumping Rate	200 gpm			
TDH	200 ft			
Pump Efficiency	75%			
Motor Efficiency	92%			
Annual Hours of Operation	8760 hr/yr			
Electricity Cost (\$/KW-hr)	0.06 \$/Kw-hr			
Brake Horsepower	7.59 BHP			
Annual Electricity Cost	\$ 3,233.48 (\$/year)			
Electricity Other Uses				
Other Costs	0 KW			
Electricity Cost (\$/KW-hr)				
	\$ 0.06 8760 hr			
Hours Operated/Yr	\$ -			
Annual Electricity Cost (\$)	Ş -			
Total Electricity Cost (\$)	\$ 137,163.18			
	<i>t</i>			
2.0 Water Costs				
Partial Quench				
Estimated Partial Quench (gpm)	200	Quench associated with lo	wering tempe	rature of flue gas
Hours Per Year	8760			
Water Cost (\$/kgal)	\$ 0.20			
Annual Water Cost	\$ 21,024			
3.0 Operating Labor Cost				
Quench System	\$ 18,980.00	26 \$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Stack	\$ 9,490.00	26 \$/hr	365	1 hr/day x 365 day/yr
Misc.	\$ -			
Supervision	\$ 4,270.50	Note 1		
Annual Total Operating Labor	\$ 32,740.50			
4.0 Maintenance	ć <u> </u>			
Total Installed Direct Cost	\$ 2,987,735			
Total Maintonance Materials	ć 74.600	Noto 2		
Total Maintenance Materials	\$ 74,693	Note 2		
Total Maintenance Labor	\$ 74,693 \$ 149,387	Note 2		
Total Annual Maintenance Cost	\$ 149,387	Note 3		
TOTAL LABOR AND MATERIALS	\$ 340,314.44			
	÷ • • • • • • • • • • • • • • • • • • •			

5.0 Installed Equipment Costs for Boiler House #1 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	2,504,827
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	250,483
Instrumentation	0.04 \$	110,212.3
Sales Taxes	0.06 \$	165,318.58
Freight	0.05 \$	137,765.49
Purchased Equipment Cost, PEC	\$	3,168,606
Direct Installation Costs		
Foundations and Supports ²	0.1 \$	275,53
Handling and Erection	0.69 \$	1,903,83
Electrical	0.01 \$	27,55
Piping	0.03 \$	95,05
Ductwork	0.25 \$	688,82
Painting	0.01 \$	14,05
Direct Installation Costs, DC	\$	3,004,85
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	6,193,462
Indirect Costs (Installation)		
Engineering	0.15 \$	475,29
Construction an Field Expenses	0.1 \$	316,86
Contractor Fees	0.1 \$	316,86
Startup	0.006 \$	19,01
Performance Test	0.005 \$	15,84
Model Study	0\$	-
Contingencies	0.1 \$	316,86
Total Indirect Costs, IC	\$	1,460,72
Fotal Installed Cost	\$	7,654,18

Table B2b. Direct and Indirect Installation Costs, Boiler House #2 - Dispersion

¹ Primary equipment includes stack/chimney. Ancillary equipment includes: partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item		Factor	Cost	:
Direct Annual Cos	sts, DC			
Opera	ating Labor			
	Operator	General Operating	\$	28,470
	Supervisor	15% of Operator	\$	4,271
	Material	5% of total operating	\$	1,637
Maint	enance			
	Maintenance Employee	General Maintenance	\$	63 <i>,</i> 853
	Supervisor	15% of Maintenance Labor	\$	11,268
	Material	100% of Maintenance Labor	\$	75,121
Utiliti	es			
	Electricity		\$	168,612
	Water		\$	21,024
Indirect Annual C	osts, IC			
Admiı	nistrative Charges	2% of Total Capital Investment	\$	153,084
Prope	erty Tax	1% of Total Capital Investment	\$ \$	76,542
Insura	ance	1% of Total Capital Investment	\$	76,542
Overh	nead	60% of total Labor and Materials	\$	223,572
Capita	al Recovery ¹	0.1098 x Total Capital Investment	\$	840,430
Total Annual Cos	t		\$	1,744,426
	2010	Uncontrolled SO 2 Actual Emissions (tpy)		750.35
	Ambi	ent Air Quality Impact Reduction (ug/m ³)		8.3
	Cont	rol Cost Per ug/m ³ Reduction in SO $_2$ Impact	\$	210,934

Table B2a. Annual Cost Factors, Boiler House #2 - Dispersion

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for Boiler House #2 Dispersion

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	\$ 666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans (2)	4	CS	CS	CUECOST3	1	\$ 712,920	\$712,920	2014	1	1	1	\$ 712,920
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
8													
9													
10													
21													
													\$ 2,504,827

Notes:

1 Estimate for self supporting stack, 12'10" diameter, including aircarft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CEUCOST3, EPA cost model, 1998 basis. Estimate based on duct flow of 330,130 acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

BY: KJ 2-12-14

5.0 Installed Equipment Costs for Boiler House #2 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity Fan Electricity Flow Pressure Drop Fan Efficiency Gas S.G. (Air = 1) Belt Efficiency Power (BHP) Motor Efficiency Power (KW) Electricity Cost (\$/KW-hr)	406355 ACFM iwc 0.8 fraction 1 0.95 400 BHP 95 % 313.6 KW \$ 0.06	(4 inches duct, 1 inch stack) Use 1 <u>Typical Efficiencies</u> Motor <i>1kW</i> - <i>0.4</i> Motor <i>10 kW</i> - <i>0.87</i> Motor <i>100 kW</i> - <i>0.92</i> Belt <i>1 kW</i> - <i>0.78</i>			
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88			
Annual Electricity Cost (\$)	\$ 164,853	Belt 100 kW - 0.93			
Pumping Pumping Rate TDH Pump Efficiency Motor Efficiency Annual Hours of Operation Electricity Cost (\$/KW-hr) Brake Horsepower Annual Electricity Cost	200 gpm 200 ft 75% 92% 8760 hr/yr 0.06 \$/Kw-hr 7.59 BHP \$ 3,233.48 (\$/year)		Base Boil Quencher		acfm Deg. F 540025 550 406355 300
Electricity Other Uses From CEUCOST3	1 KW				
Electricity Cost (\$/KW-hr)	\$ 0.06				
Hours Operated/Yr	8760 hr				
Annual Electricity Cost (\$)	\$ 525.60				
Total Electricity Cost (\$)	\$ 168,612				
2.0 Water Costs Partial Quench Estimated Partial Quench (gpm) Hours Per Year Water Cost (\$/kgal) Annual Water Cost	200 8760 \$ 0.20 \$ 21,024	Quench associated with lowerir	ng temperati	ure of flue	gas
3.0 Operating Labor Cost					
Quench System	\$ 18,980.00	26 \$/hr 73		-	t x 2 shifts x 365 day/yr
Stack	\$ 9,490.00 \$ -	26 \$/hr 36	65	1 hr/day	x 365 day/yr
Misc. Supervision	\$ - \$ 4,270.50	Note 1			
Annual Total Operating Labor	\$ 32,740.50				
4.0 Maintenance Total Installed Direct Cost	\$ 3,004,856				
Total Maintenance Materials	\$ 75,121	Note 2			
Total Maintenance Labor	\$ 75,121	Note 2			
Total Annual Maintenance Cost	\$ 150,243	Note 3			
TOTAL LABOR AND MATERIALS	\$ 372,619.61				

5.0 Installed Equipment Costs for Boiler House #2 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	3,606,75
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	360,67
Instrumentation	0.04 \$	158,69
Sales Taxes	0.06 \$	238,04
Freight	0.05 \$	198,37
Purchased Equipment Cost, PEC	\$	4,562,54
Direct Installation Costs		
Foundations and Supports ²	0.125 \$	495,92
Handling and Erection	0.50 \$	1,977,74
Electrical	0.01 \$	39,67
Piping	0.03 \$	99,18
Ductwork	0.34 \$	1,344,95
Painting	0.01 \$	20,23
Direct Installation Costs, DC	\$	3,977,73
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	8,560,27
Indirect Costs (Installation)		
Engineering	0.15 \$	684,38
Construction an Field Expenses	0.1 \$	456,25
Contractor Fees	0.1 \$	456,25
Startup	0.006 \$	27,37
Performance Test	0.005 \$	22,81
Model Study	0 \$	-
Contingencies	0.1 \$	456,25
Total Indirect Costs, IC	\$	2,103,33
Fotal Installed Cost	\$	10,663,61

Table B3b. Direct and Indirect Installation Costs, HSM Furnaces - Dispersion

¹ Primary equipment includes stack/chimney. Ancillary equipment includes: partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item		Factor	Cost	t
Direct Annual Co	osts, DC			
Ope	rating Labor			
	Operator	General Operating	\$	37,960
	Supervisor	15% of Operator	\$	5,694
	Material	5% of total operating	\$	2,183
Maii	ntenance			
	Maintenance Employee	General Maintenance	\$	84,527
	Supervisor	15% of Maintenance Labor	\$	14,916
	Material	100% of Maintenance Labor	\$	99,443
Utili	ties			
	Electricity		\$	293,997
	Water		\$	42,048
Indirect Annual	Costs, IC			
Adm	ninistrative Charges	2% of Total Capital Investment	\$	213,272
Prop	perty Tax	1% of Total Capital Investment	\$	106,636
Insu	rance	1% of Total Capital Investment	\$	106,636
Ove	rhead	60% of total Labor and Materials	\$	347,151
Capi	tal Recovery ¹	0.1098 x Total Capital Investment	\$	1,170,864
Total Annual Co	ost		\$	2,525,328
	201	0 Uncontrolled SO $_2$ Actual Emissions (tpy)		2240.06
	Am	bient Air Quality Impact Reduction (ug/m ³)		30.5
	Cor	trol Cost Per ug/m ³ Reduction in SO $_2$ Impact	\$	82,934

Table B3a. Annual Cost Factors, HSM Furnaces - Dispersion

¹ Capital Recovery Actor is derived rom EPA Air Pollution control Cost Manual, Xixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for HSM Furnaces Dispersion

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	\$ 833,333	\$833,333	2014	1	1	1	\$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	\$ 104,576	\$209,152	2014	1	1	1	\$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	\$ 472,844	\$945,688	2014	1	1	1	\$ 945,688
4	New Fans	4	CS	CS	Fans (2)	1	\$ 1,000,262	\$1,000,262	2014	1	1	1	\$ 1,000,262
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$ 141,000	\$141,000	2014	1	1	1	\$ 141,000
8													
9													
10													
21													
													\$ 3,606,756

Notes:

1 Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet. Two parallel ducts will be required for this case.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Partial quench system @ 400 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

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5.0 Installed Equipment Costs for HSM Furnaces Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity					
Fan Electricity					
Flow	702269 ACFM				
Pressure Drop	5 iwc	(4 inches duct, 1 inch stack)			
Fan Efficiency	0.8 fraction	(1 mones adde) 1 mon stacky			
Gas S.G. (Air = 1)	1	Use 1			
Belt Efficiency	1	Typical Efficiencies			
Motor Efficiency	0.95	Motor 1kW - 0.4			
Power (BHP)	691 BHP	Motor 10 kW - 0.87			
Motor Efficiency	95 %				
Power (KW)	542.1 KW	Motor 100 kW - 0.92			
Electricity Cost (\$/KW-hr)	\$ 0.06	Belt 1 kW - 0.78			
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88			
Annual Electricity Cost (\$)	\$ 284,902	Belt 100 kW - 0.93			
Annual Electricity Cost (\$)	\$ 284,902	Den 100 kW 0.00			
Dumming					
Pumping	100				
Pumping Rate	400 gpm				acfm Temp (Deg. F)
TDH	200 ft		Base Boil		933279 550
Pump Efficiency	75%		Quenche	ed	702269 300
Motor Efficiency	92%		Fan Outle	et	706890 305 5 Deg F
Annual Hours of Operation	8760 hr/yr				reheat
Electricity Cost (\$/KW-hr)	0.06 \$/Kw-hr				
Brake Horsepower	15.18 BHP				
	\$ 6,466.96 (\$/year)				
Annual Electricity Cost	\$ 0,400.90 (\$/year)				
Electricity Other Uses					
From CEUCOST3	5 KW				
Electricity Cost (\$/KW-hr)	\$ 0.06				
Hours Operated/Yr	8760 hr				
Annual Electricity Cost (\$)	\$ 2,628.00				
Total Electricity Cost (\$)	\$ 293,997				
	+				
2.0 Water Costs					
Partial Quench					
	100				
Estimated Partial Quench (gpm)	400	Quench associated with lowe	ering temperat	ure of flue	gas
Hours Per Year	8760				
Water Cost (\$/kgal)	\$ 0.20				
Annual Water Cost	\$ 42,048				
3.0 Operating Labor Cost					
Quench System	\$ 18,980.00	26 \$/hr	730	1 hr/shif	t x 2 shifts x 365 day/yr
Stack	\$ 18,980.00	26 \$/hr	730	1 nr/day	x 365 day/yr
Misc.	\$ -				
Supervision	\$ 5,694.00	Note 1			
Annual Total Operating Labor	\$ 43,654.00				
4.0 Maintenance					
Total Installed Direct Cost	\$ 3,977,731				
	- 0,0,01				
Total Maintenance Materials	\$ 99,443	Noto 2			
		Note 2			
Total Maintenance Labor	\$ 99,443	Note 2			
Total Annual Maintenance Cost	\$ 198,887	Note 3			
TOTAL LABOR AND MATERIALS	\$ 578,585				

5.0 Installed Equipment Costs for HSM Furnaces Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	6,030,92
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	603,093
Instrumentation	0.04 \$	265,36
Sales Taxes	0.06 \$	398,04
Freight	0.05 \$	331,70
Purchased Equipment Cost, PEC	\$	7,629,12
Direct Installation Costs		
Foundations and Supports	0.05 \$	331,70
Handling and Erection	0.69 \$	4,554,64
Electrical	0.05 \$	331,70
Piping	0.08 \$	530,72
Ductwork	0.02 \$	119,41
Painting	0.01 \$	
Direct Installation Costs, DC	\$	5,902,01
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	13,551,13
Indirect Costs (Installation)		
Engineering	0.15 \$	1,144,36
Construction an Field Expenses	0.1 \$	762,91
Contractor Fees	0.1 \$	762,91
Startup	0.006 \$	45,77
Performance Test	0.007 \$	53,40
Model Study	0 \$	-
Contingencies	0.1 \$	762,91
Two-Week Lost Production at the Blast Furnace	\$	8,031,00
Total Indirect Costs, IC	\$	11,563,28
Total Installed Cost	\$	25,114,41

Table B4b. Direct and Indirect Installation Costs, Boiler House #1 - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Cost Item		Factor	Cost	:
Direct Annual Costs,	, DC			
Operatir	ng Labor			
	Operator	General Operating	\$	18,980
	Supervisor	15% of Operator	\$	2,847
	Material	5% of Total Operating	\$	1,091
Mainten	ance			
	Maintenance Employee	General Maintenance	\$	125,418
	Supervisor	15% of Maintenance Labor	\$	22,133
	Material	100% of Maintenance Labor	\$	147,550
Utilities				
	Annual Fuel Switching C	osts	\$	1,146,110
Indirect Annual Cost	ts, IC			
Adminis	trative Charges	2% of Total Capital Investment	\$	502,288
Property	/ Tax	1% of Total Capital Investment	\$	251,144
Insuranc	e	1% of Total Capital Investment	\$	251,144
Overhea	d	60% of total Labor and Materials	\$	876,115
Capital F	Recovery ¹	0.1098 x Total Capital Investment	\$	2,757,563
Total Annual Cost			\$	6,102,383
	2	2010 Uncontrolled SO $_2$ Actual Emissions (tpy)		407.35
	A	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		50 2 Removal Efficiency		88.62%
		Post-Control Emission Factor (Ib/MMBtu)		0.055
		Control Cost Per Ton SO 2	\$	16,904

Table B4a. Annual Cost Factors, Boiler House #1 - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low Nox burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #1 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year		Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
											Factor		(ear)
1	Burner System	1	CS	CS	North American Combustion, Inc.	20	\$ 235,000	\$4,700,000	2014	1	1	1	\$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,330,927	\$1,330,927	2014	1	1	1	\$ 1,330,927
3													
4													
5													
6													
7													
8													
9													
10													
21													
													\$ 6,030,927

Notes:

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

¹ Burner system includes burner, fuel train/control valves, two (2) blowers, and control panel (I&C).

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

5.1 Baseline Cost of Fuel 1,684,852 MMBtu/yr Baseline SO₂ Emissions Total Rating Baseline NG 69,206 MMBtu/yr Btu/scf NG 0.0006 41 lb/yr Baseline COG 503,315 MMBtu/yr NG HHV 1012 COG 1.431 720,385 lb/yr Baseline BFG 1,112,332 MMBtu/yr BFG HHV 89 BFG 0.08279 92,087 lb/yr 496 812,513 lb/yr Annual Hours Operation 8,760 hrs/yr COG HHV Total Cost NG (\$ per MMBtu) 4.89 (Based on 2010 cost) 406 tpy Ś Cost COG (\$ per MMBtu) \$ 2.92 (Based on 2010 Cost) 1,808,096 (Cost NG and COG) **Baseline Annual Cost** Ś 5.2 Fuel Use After Fuel Switch Post-Fuel Switch SO₂ Emissions 1,684,852 MMBtu/yr **Total Rating** Btu/scf 0.0006 572,521 339 lb/yr Post-Fuel Switch NG MMBtu/yr NG HHV 1012 NG Post-Fuel Switch COG MMBtu/yr BFG HHV 89 COG 1.431 lb/yr Post-Fuel Switch BFG 1,112,332 MMBtu/yr COG HHV 496 BFG 0.082787 92,087 lb/yr 92,426 lb/yr Annual Hours Operation 8,760 hrs/yr Total Cost NG (\$ per MMBtu) 5.16 (Based on average EIA Short-Term Projection for 2014/2015) 46 tpy Future Projected Annual Cost Ś 2,954,207 (Cost NG and COG) Post-Fuel Switch SO₂ Emission Reduction 360.0 tpy Post Control SO₂ Factor: 0.0549 lb/MMBtu 5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost \$ 1,146,110 3.0 Operating Labor Cost Burners 18,980 26 \$/hr 730 1 hr/shift x 2 shifts x 365 day/yr Ś 26 \$/hr Other \$ 0 Ś 18,980 Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost \$ 5,902,010 **Total Maintenance Materials** 147,550 Note 2 \$ **Total Maintenance Labor** Ś 147,550 Note 2 Total Annual Maintenance Cost \$ 295,101 Note 3 1,460,191 TOTAL LABOR AND MATERIALS \$

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO₂ emission factors from 2013 Air Inventory.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

Flow Flow 5% NG 28% COG 67% BFG 100% By: KJ 2-12-14

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	6,090,040
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	609,00
Instrumentation	0.04 \$	267,962.0
Sales Taxes	0.06 \$	401,94
Freight	0.05 \$	334,95
Purchased Equipment Cost, PEC	\$	7,703,90
Direct Installation Costs		
Foundations and Supports	0.05 \$	334,95
Handling and Erection	0.68 \$	4,560,55
Electrical	0.05 \$	334,95
Piping	0.08 \$	535,92
Ductwork	0.02 \$	133,98
Painting	0.01 \$	34,16
Direct Installation Costs, DC	\$	5,934,52
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	13,658,43
Indirect Costs (Installation)		
Engineering	0.15 \$	1,155,58
Construction an Field Expenses	0.1 \$	770,39
Contractor Fees	0.1 \$	770,39
Startup	0.006 \$	46,22
Performance Test	0.02 \$	154,07
Model Study	0\$	-
Contingencies	0.1 \$	770,39
Two-Week Lost Production at the Blast Furnace	\$	8,031,00
Total Indirect Costs, IC	\$	11,698,06
Total Installed Cost	\$	25,356,49

Table B5b. Direct and Indirect Installation Costs, Boiler House #2 - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Cost Item		Factor	Cost	:
Direct Annual Costs, DC				
Operating Labor				
Operato	r	General Operating	\$	18,980
Supervis	or	15% of Operator	\$	2,847
Material		5% of Total Operating	\$	1,091
Maintenance				
Mainten	ance Employee	General Maintenance	\$	126,109
Supervis	or	15% of Maintenance Labor	\$	22,254
Material		100% of Maintenance Labor	\$	148,363
Utilities				
Cost of F	uel Switch (Natural	Gas for COG) 2010 Basis	\$	2,075,812
Indirect Annual Costs, IC				
Administrative Char	ges	2% of Total Capital Investment	\$	507,130
Property Tax		1% of Total Capital Investment	\$	253,565
Insurance		1% of Total Capital Investment	\$	253,565
Overhead		60% of total Labor and Materials	\$	1,434,911
Capital Recovery ¹		0.1098 x Total Capital Investment	\$	2,784,143
Total Annual Cost			\$	7,628,771
	2010	Uncontrolled SO 2 Actual Emissions (tpy)		750
	Allow	ance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		Removal Efficiency		83.80%
	-	Control Emission Factor (Ib/MMBtu)		0.057
		rol Cost Per Ton SO 2	\$	12,133

Table B5a. Annual Cost Factors, Boiler House #2 - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS providing installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #2 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	\$ 235,000	\$4,700,000	2014	1	1	1	\$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,390,046	\$1,390,046	2014	1	1	1	\$ 1,390,046
3													
4													
5													
6													
7													
8													
9													
10													
21													
													\$ 6,090,046

Notes:

1 Burner system includes burner, fuel train/control valves, blower, and control panel (I&C).

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #2 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

```
5.1 Baseline Cost of Fuel -2010
Total Usage
                                                  4,216,399 MMBtu/yr
                                                                                         Btu/scf
Baseline NG
                                                   424,030 MMBtu/yr
                                                                              NG HHV
                                                                                              1012
                                                                                                          NG
                                                                                                                          0.0006
                                                                                                                                        251.40 lbs /yr
Baseline COG
                                                   875,590 MMBtu/yr
                                                                              BFG HHV
                                                                                                89
                                                                                                          COG
                                                                                                                           1 4 3 1
                                                                                                                                   1,253,217.00 lbs /yr
Baseline BFG
                                                  2,916,778 MMBtu/yr
                                                                              COG HHV
                                                                                               496
                                                                                                          BFG
                                                                                                                        0.08279
                                                                                                                                    241,472.12 lbs /yr
                                                                                                                                      1,494,941 lbs /yr
Annual Hours Operation
                                                     8,760 hrs/yr
                                                                                                                   Total
Cost NG
                                                       4.89 (Based on 2010 cost)
                                                                                                                                         747.47 tons /yr
                                       Ś
Cost COG
                                       $
                                                       2.92 (Based on 2010 Cost)
Baseline Annual Cost
                                                 4,630,232 (Cost NG and COG)
                                       Ś
5.2 Fuel Use After Fuel Switch
                                                  4,216,399 MMBtu/yr
                                                                                         Btu/scf
Total Rating
                                                                                                                                        770.53 lbs /yr
                                                                                                                          0.0006
Post Fuel Switch NG
                                                  1,299,621 MMBtu/yr
                                                                              NG HHV
                                                                                              1012
                                                                                                          NG
Post Fuel Switch COG
                                                            MMBtu/yr
                                                                              BFG HHV
                                                                                                89
                                                                                                          COG
                                                                                                                           1.431
                                                                                                                                                lbs /yr
Post Fuel Switch BFG
                                                 2,916,778
                                                            MMBtu/yr
                                                                              COG HHV
                                                                                               496
                                                                                                          BFG
                                                                                                                       0.082787
                                                                                                                                       241,472 lbs /yr
Annual Hours Operation
                                                                                                                                       242,243 lbs /yr
                                                      8,760 hrs/yr
                                                                                                                   Total
Cost NG
                                                       5.16 (Based on average EIA Short-Term Projection for 2014/2015)
                                                                                                                                        121.12 tons /yr
Future Projected Annual Cost
                                      Ś
                                                 6,706,045 (Cost NG and COG)
                                                                                         Post Fuel Switch SO<sub>2</sub> Emission Reduction
                                                                                                                                        626.35 tpy
                                                                                                   Post Control SO<sub>2</sub> Factor:
                                                                                                                                         0 057 lb/MMBtu
5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost
                                      $
                                                  2,075,812
3.0 Operating Labor Cost
Burners
                                       $
                                                    18,980
                                                                           26 $/hr
                                                                                               730
                                                                                                          1 hr/shift x 2 shifts x 365 day/yr
                                       $
Other
                                                                          26 $/hr
                                                                                                 0
Annual Total Operating Labor
                                       Ś
                                                    18,980
4.0 Maintenance
                                       $
Total Installed Direct Cost
                                                  5,934,526
Total Maintenance Materials
                                                   148,363
                                                                       Note 2
Total Maintenance Labor
                                       $
                                                   148,363
                                                                       Note 2
Total Annual Maintenance Cost
                                       $
                                                   296,726
                                                                       Note 3
TOTAL LABOR AND MATERIALS
                                      $
                                                  2,391,519
```

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO₂ emission factors from 2013 Air Inventory.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	13,658,240
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	1,365,82
Instrumentation	0.04 \$	600,96
Sales Taxes	0.06 \$	901,44
Freight	0.05 \$	751,20
Purchased Equipment Cost, PEC	\$	17,277,674
Direct Installation Costs		
Foundations and Supports	0.05 \$	751,20
Handling and Erection	0.45 \$	6,801,70
Electrical	0.056 \$	841,34
Piping	0.07 \$	1,051,68
Ductwork	0.03 \$	450,72
Painting	0.01 \$	76,62
Direct Installation Costs, DC	\$	9,973,28
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	27,270,950
Indirect Costs (Installation)		
Engineering	0.15 \$	2,591,65
Construction an Field Expenses	0.1 \$	1,727,76
Contractor Fees	0.1 \$	1,727,76
Startup	0.006 \$	103,66
Performance Test	0.02 \$	345,55
Model Study	0 \$	-
Contingencies	0.1 \$	1,727,76
Two-Week Lost Production at the HSM	\$	15,600,00
Total Indirect Costs, IC	\$	23,824,17
Total Installed Cost	\$	51,095,12

Table B6b. Direct and Indirect Installation Costs, HSM Furnaces - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement of fuel line to handle added natural gas demand.

Cost Item		Factor	Cos	t
Direct Annual Costs, DC				
Operating Labo	or			
Ор	erator	General Operating	\$	18,980
Sup	pervisor	15% of Operator	\$	2,847
Ma	terial	5% of Total Operating	\$	1,091
Maintenance				
Ma	intenance Employee	General Maintenance	\$	91,953
Sup	pervisor	15% of Maintenance Labor	\$	16,227
Ma	terial	100% of Maintenance Labor	\$	108,180
Utilities				
Fue	el Switch Replacement Co	st	\$	7,765,439
Indirect Annual Costs, IC				
Administrative	Charges	2% of Total Capital Investment	\$	1,021,903
Property Tax		1% of Total Capital Investment	\$	510,951
Insurance		1% of Total Capital Investment	\$	510,951
Overhead		60% of total Labor and Materials	\$	4,800,468
Capital Recove	ry	0.1098 x Total Capital Investment	\$	5,610,245
Total Annual Cost			\$	20,459,236
	2010	Uncontrolled SO 2 Actual Emissions (tpy)		2240.1
	Allow	ance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		Removal Efficiency		99.92%
		Control Emission Factor (lb/MMBtu)		0.0006
		rol Cost Per Ton SO $_2$	\$	<i>9,129</i>

Table B6a. Annual Cost Factors, HSM Furnaces - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001,

January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Fuel Switching

Notes

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1 This option involves replacment of existing COG burners in the boiler house. There are five furnaces, each equipped with multiple natural gas and COG burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This esimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for HSM Fuel Switching

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	•	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	COG to NG Replacement Burners 12.5 MM	1	CS	CS	North American Combustion , Inc.	75	\$ 65,000	\$4,875,000	2014	1	1	1	\$ 4,875,000
2	COG to NG Replacement Burners 17.5 MM	2	CS	CS	North American Combustion , Inc.	80	\$ 80,000	\$6,400,000	2014	1	1	1	\$ 6,400,000
3	Panels and Instrumentation	3	-	-	North American Combustion , Inc.	5	\$ 100,000	\$500,000	2014	1	1	1	\$ 500,000
4	Panels and Instrumentation	4	-	-	North American Combustion , Inc.	5	\$ 100,000	\$500,000	2014	1	1	1	\$ 500,000
5	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,383,240	\$1,383,240	2014	1	1	1	\$ 1,383,240
6													
7													
8													
9													
10													
21													
													\$ 13,658,240

Notes:

1 Burner system includes burner, fuel train/control valves, blower.

2 Burner system includes burner, fuel train/control valves, blower.

3 Panels for Smaller Burners. Actual configuration of panels will depend on detailed systems control analysis.

4 Panels for Larger Burners. Actual configuration of panels will depend on detailed systems control analysis.

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\$ 13,658,240

5.0 Installed Equipment Costs for HSM Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

5.1 Baseline Cost of Fuel -2010								
Total Usage	5,930,934	MMBtu/yr						
Baseline NG	2,801,957	MMBtu/yr	NG HHV	1012	NG	0 0006	1,661.24	lbs /yr
Baseline COG	3,128,978	MMBtu/yr	BFG HHV	89	COG	1.431	4,478,450.16	lbs /yr
Baseline BFG	-	MMBtu/yr	COB HHV	496	BFG	0.08279	-	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	4,480,111	lbs /yr
Cost NG	\$ 4.89	(Based on 2010 cost)					2,240.06	tons/yr
Cost COG	\$ 2.92	(Based on 2010 Cost)				L. L. L. L. L. L. L. L. L. L. L. L. L. L		
Baseline Annual Cost	\$ 22,838,183	(Cost NG and COG)						
5.2 Fuel Use After Fuel Switch								
Total Rating	5,930,934	MMBtu/yr						
Post Fuel Switch NG	, , ,	MMBtu/yr	NG HHV	1012	NG	0 0006	3,516.36	lbs /vr
Post Fuel Switch COG		MMBtu/yr	BFG HHV	89	COG	1.431	-	lbs/yr
Post Fuel Switch BFG		MMBtu/yr	COG HHV	496	BFG	0.082787	-	lbs/yr
Annual Hours Operation		hrs/yr	0001111	450	big	Total		lbs/yr
Cost NG		(Based on average El/	A Short-Terr	n Projection for 20	14/2015)	i o cui	-	tons /yr
Future Projected Annual Cost		(Cost NG and COG)			1,2010)	L	100	
	¢ 50,000,022			Post Fuel Switch	SO ₂ Emission Re	eduction	2,238.3	tov
					2	l	2,20010	(P)
				Post (Control SO ₂ Fact	or:	0 0006	lb/MMBtu
5.3 Baseline Fuel Cost - Fuel Swich Fuel	Cost						0 0000	,
5.5 Baseline Fuel Cost - Fuel Swith Fuel	\$ 7,765,439	1						
	\$ 7,703,433	J						
3.0 Operating Labor Cost								
Burners	\$ 18,980	26	5 \$/hr	730	1 hr/shift	x 2 shifts x 365 d	lav/vr	
Other	\$ -		5 \$/hr	0	-	x 2 311113 x 303 u		
Annual Total Operating Labor	\$ 18,980		, yrm	0				
	Ŷ 10,500	1						
4.0 Maintenance								
Total Installed Direct Cost	¢ / 227 217							
	\$ 4,327,217							
Total Maintenance Materials	\$ 108,180	Note 2						
Total Maintenance Labor	\$ 108,180	Note 2						
Total Annual Maintenance Cost	\$ 216,361	Note 3						
iota / and maintenance cost	÷ 210,301	Note 5						
TOTAL LABOR AND MATERIALS	\$ 8,000,779							

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Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO_2 emission factors from 2013 Air Inventory.

5. Actual rating is 2660 MMBtu/hr. Firing rate adjusted using 2013 emission factors to reach the PTE of 620.6 lb/hr (2713 tpy).

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	19,555,26
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	1,955,52
Instrumentation	0.04 \$	860,431.4
Sales Taxes	0.06 \$	1,290,647.1
Freight	0.05 \$	1,075,539.3
Purchased Equipment Cost, PEC	\$	24,737,40
Direct Installation Costs		
Foundations and Supports ²	0.02 \$	494,74
Handling and Erection	0.68 \$	14,559,58
Electrical	0.011 \$	236,61
Piping	0.01 \$	215,10
Ductwork	0.03 \$	677,589.7
Painting	0.01 \$	107,55
Direct Installation Costs, DC	\$	16,291,20
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC + DC)	\$	41,048,61
Indirect Costs (Installation)		
Engineering	0.15 \$	3,710,61
Construction an Field Expenses	0.1 \$	2,473,74
Contractor Fees	0.1 \$	2,473,74
Startup	0.01 \$	148,42
Performance Test	0.003 \$	74,21
Model Study	0.005 \$	123,68
Contingencies	0.1 \$	2,473,74
Total Indirect Costs, IC	\$	11,478,15
Total Installed Cost	\$	52,526,76

Table B7b. Direct and Indirect Installation Costs, Boiler House #1 - Wet Scrubber

¹ Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

² Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Cost Item	Factor		Cost
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	\$	333,970
Supervisor	15% of Operator	\$	50,096
Material	0.5% of General Operation	\$	1,670
Maintenance			
Maintenance Employe	e General Maintenance	\$	871,858
Supervisor	15% of Maintenance Labor	\$	153,857
Material	100% of Maintenance Labor	\$	1,025,71
Utilities			
Electricity		\$	375,20
Water		\$ \$ \$	21,024
Reagents	Limestone		34,28
Sludge Disposal	Gypsum sludge	\$	61,35
Wastewater Disposal ¹			
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	\$	1,050,53
Property Tax	1% of Total Capital Investment	\$	525,268
Insurance	1% of Total Capital Investment	\$	525,268
Overhead	60% of total Labor and Materials	\$	1,851,024
Capital Recovery ²	0.1098 x Total Capital Investment	\$	5,767,439
Total Annual Cost		\$	12,648,56
201	0 Uncontrolled SO 2 Actual Emissions (tpy)		407.
Allo	wance for Uncontrolled Maint. Outages (tpy) - 15 days		19.
	trol Effectiveness		809
	-Control SO ₂ Emission Factor (lb/MMBtu)		0.02
	Per Ton SO , Removed	\$	40,747

Table B7a. Annual Cost Factors, Boiler House #1 - Wet Scrubber

¹ It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

² Captal Recover Factor is derived from *EPA Air Pollution Control Manual*, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for Boiler House #1 Wet Scrubber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

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4 Installed Equipment Costs for Boiler House #1 Wet Scrubber

Equipment Cost Summary

BY: KJ 2-12-14

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	\$ 666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	\$ 534,266	\$534,266	2014	1	1	1	\$ 534,266
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	\$ 17,229,088	\$17,229,088	2014	1	1	1	\$ 17,229,088
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
9													
10													
20													
	\$ 19,555,26:											\$ 19,555,261	

Notes:

1 New cost based on estimate from International Chimney Corporation, ICC File CC-42408-C, February 27, 2014. Stack is 11' 7" ID, and includes aircraft lighting, stairs, and testing platform. Stack is 213 ft high.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. New fans sized at 254,982 acfm.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

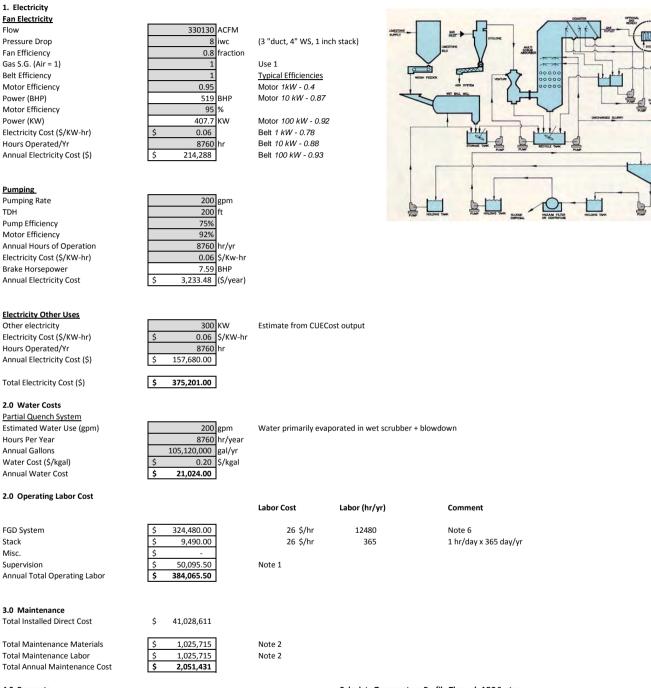
7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 330,130 acfm. The gas leaving the SDA will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F . A 5 Deg. F reheat at the fan is added. SO2 flow is based on 470.2 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for Boiler House #1 Wet Scrubber

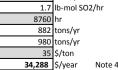
Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14





90 % 470.2 tons/yr



Ś

Calculate Temperature Profile Through APC System

Initial Flow
Scrubber Inlet
Scrubber Outlet
Other APC
Fan Outlet

peratare rionie		,	
-	Flow	Temperatu	re (F)
	438,726	550	
	330,130	300	
t	254,982	127	FGD Quenching effect
	254,982	127	
	257,154	132	ID Fan Reheat = 5 Deg. F

5.0 Installed Equipment Costs for Boiler House #1 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

5.0 Disposal Annual Limestone Use 882 ton/yr Note 5 Impurity 98 ton/yr Waste gypsum + Inerts 1614.48 tons Cost Disposal 38 \$/ton Annual Disposal Cost 61,350 \$/yr

Notes:

- 1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

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Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	22,879,56
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	2,287,95
Instrumentation	0.04 \$	1,006,700.8
Sales Taxes	0.06 \$	1,510,051.2
Freight	0.05 \$	1,258,37
Purchased Equipment Cost, PEC	\$	28,942,64
Direct Installation Costs		
Foundations and Supports ²	0.02 \$	578,852.9
Handling and Erection	0.65 \$	16,453,93
Electrical	0.011 \$	276,842.
Piping	0.01 \$	251,675.2
Ductwork	0.05 \$	1,258,376.0
Painting	0.01 \$	125,837.6
Direct Installation Costs, DC	\$	18,945,51
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC + DC)	\$	47,908,16
Indirect Costs (Installation)		
Engineering	0.15 \$	4,341,39
Construction an Field Expenses	0.1 \$	
Contractor Fees	0.1 \$	2,894,26
Startup	0.01 \$	173,65
Performance Test	0.003 \$	86,82
Model Study	0.005 \$	144,7
Contingencies	0.1 \$	
Total Indirect Costs, IC	\$	13,429,38
Total Installed Cost	\$	61,337,55

Table B8b. Direct and Indirect Installation Costs, Boiler House #2 - Wet Scrubber

¹ Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

² Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Cost Item	Factor		Cost
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	\$	333,970
Supervisor	15% of Operator	\$	50,096
Material	0.5% of General Operation	\$	1,670
Maintenance			
Maintenance Employee	e General Maintenance	\$	1,017,623
Supervisor	15% of Maintenance Labor	\$	179,583
Material	100% of Maintenance Labor	\$	1,197,204
Utilities			
Electricity		\$ \$ \$	457,932
Water		\$	2,52
Reagents	Limestone		27,19
Sludge Disposal	Gypsum sludge	\$	48,664
Wastewater Disposal ¹			
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	\$	1,226,753
Property Tax	1% of Total Capital Investment	\$	613,376
Insurance	1% of Total Capital Investment	\$	613,376
Overhead	60% of total Labor and Materials	\$	2,099,249
Capital Recovery ²	0.1098 x Total Capital Investment	\$	6,734,863
Total Annual Cost		\$	14,604,073
2010) Uncontrolled SO $_2$ Actual Emissions (tpy)		750.
Allov	vance for Uncontrolled Maint. Outages (tpy) - 15 days		15.
	rol Effectiveness		80%
Post	-Control SO ₂ Emission Factor (lb/MMBtu)		0.03
Cost	Per Ton SO , Removed	\$	24,848

Table B8a. Annual Cost Factors, Boiler House #2 - Wet Scrubber

¹ It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

² Captal Recover Factor is derived from *EPA Air Pollution Control Manual*, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for Boiler House #2 Wet Scrubber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

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4 Installed Equipment Costs for Boiler House #2 Wet Scrubber

Equipment Cost Summary

BY: KJ 2-12-14

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	\$ 666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	\$ 607,720	\$607,720	2014	1	1	1	\$ 607,720
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	\$ 20,479,938	\$20,479,938	2014	1	1	1	\$ 20,479,938
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
9													
10													
20													
													\$ 22,879,565

Notes:

1 Estimate for self supporting stack, 12'10" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Flow to fan is 313,972 acfm at 127 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

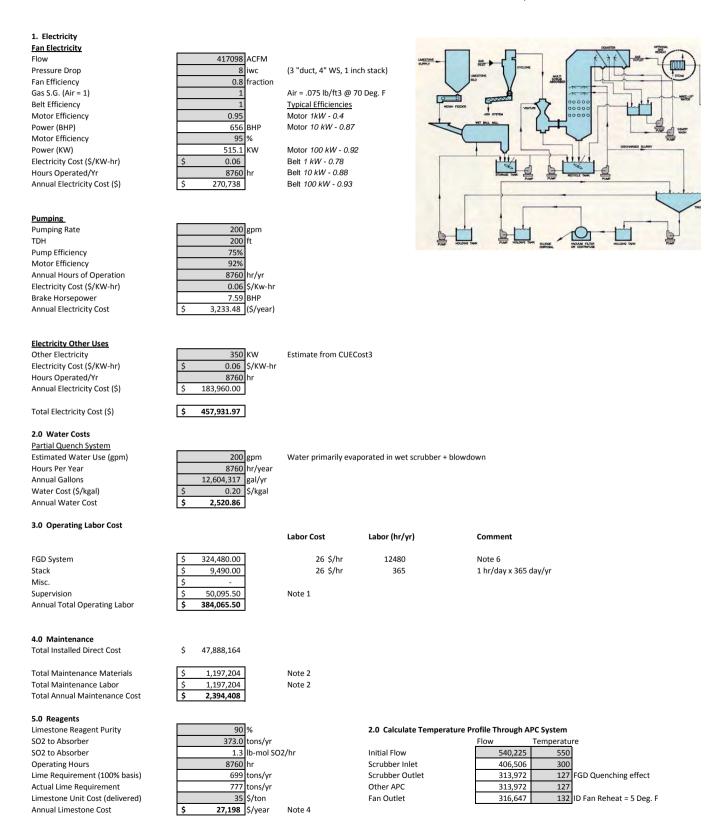
7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 540,025 acfm. The gas leaving the wet scrubber will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F . A 5 Deg. F reheat at the fan is added. SO2 flow is based on 373 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for Boiler House #2 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

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5.0 Installed Equipment Costs for Boiler House #2 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

6.0 Disposal Annual Limestone Use 699 ton/yr Note 5 Impurity 78 ton/yr Waste gypsum + Inerts 1280.63 tons Cost Disposal 38 \$/ton Annual Disposal Cost 48,664 \$/yr

Notes:

- 1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

By: KJ 2-12-14

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	24,846,340
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	2,559,774
Instrumentation	0.04 \$	1,096,245
Sales Taxes	0.06 \$	1,644,367
Freight	0.05 \$	1,370,306
Purchased Equipment Cost, PEC	\$	31,517,031
Direct Installation Costs		
Foundations and Supports ²	0.02 \$	630,340.63
Handling and Erection	0.61 \$	19,243,882
Electrical	0.011 \$	346,687
Piping	0.01 \$	409,721
Ductwork	0.04 \$	1,304,805
Painting	0.01 \$	157,585
Direct Installation Costs, DC	\$	22,093,022
Site Preparation	\$	20,000
Buildings	\$	-
Total Direct Costs (PEC + DC)	\$	53,630,053
Indirect Costs (Installation)		
Engineering	0.15 \$	4,727,555
Construction an Field Expenses	0.1 \$	3,151,703
Contractor Fees	0.1 \$	3,151,703
Startup	0.01 \$	189,102
Performance Test	0.003 \$	94,551
Model Study	0.005 \$	157,585
Contingencies	0.1 \$	3,151,703
Total Indirect Costs, IC	\$	14,623,903
Total Installed Cost	\$	68,253,956

Table B9b. Direct and Indirect Installation Costs, HSM Furnaces - Wet Scrubber

¹ Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

² Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	\$ 333,970
Supervisor	15% of Operator	\$ 50,090
Material	0.5% of General Operation	\$ 1,670
Maintenance		
Maintenance Employee	e General Maintenance	\$ 1,139,214
Supervisor	15% of Maintenance Labor	\$ 201,03
Material	100% of Maintenance Labor	\$ 1,340,25
Utilities		
Electricity		\$ 682,75
Water		\$ 42,04
Reagents	Limestone	\$ 197,82
Sludge Disposal	Gypsum sludge	\$ 353,95
Wastewater Disposal ¹		
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	\$ 1,365,079
Property Tax	1% of Total Capital Investment	\$ 682,540
Insurance	1% of Total Capital Investment	\$ 682,54
Overhead	60% of total Labor and Materials	\$ 2,762,370
Capital Recovery ²	0.1098 x Total Capital Investment	\$ 7,494,284
Total Annual Cost		\$ 17,329,633
2010) Uncontrolled SO $_2$ Actual Emissions (tpy)	2240.
Allow	vance for Uncontrolled Maint. Outages (tpy) - 15 days	111.
	rol Effectiveness	809
	-Control SO ₂ Emission Factor (Ib/MMBtu)	0.04
	Per Ton SO , Removed	\$ 10,17

Table B9a. Annual Cost Factors, HSM Furnaces - Wet Scrubber

¹ It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

² Captal Recover Factor is derived from *EPA Air Pollution Control Manual*, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for HSM Furnaces Wet Scrubber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

KJ 2-12-14

4 Installed Equipment Costs for HSM Furnaces Wet Scrubber

Equipment Cost Summary

BY: KJ 2-12-14

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year		Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	\$ 833,333	\$833,333	2014	1	1	1	\$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	\$ 104,576	\$209,152	2014	1	1	1	\$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	\$ 472,844	\$945,688	2014	1	1	1	\$ 945,688
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	\$ 941,668	\$941,668	2014	1	1	1	\$ 941,668
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	\$ 22,120,076	\$22,120,076	2014	1	1	1	\$ 22,120,076
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
9													
10													
11													
12													
13													L
14	Known Installation Costs to Be Factored In		Amt		Basis								L
15	Chimney and General Facilities (total direct)		\$ 2,500,000		International Chimney Corp.								I
16	New Structural Ductwork (total direct)		\$ 1,782,294		CB&I Estimate								I
17	Wet FGD Scrubber System		\$ 38,046,531		CUECOST (2014 basis)								L
	Tie In to Structural Ductwork		\$ 676,172		CB&I Estimate								ļ
18	Fans (2)		\$ 1,783,218		CUECOST (2014 basis)								I
19	Partial Quench System		\$ 211,000.00		CB&I Estimate								
20													1
													\$ 25,597,738

Notes:

1 Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Flow to fan is 637,017 acfm at 127 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

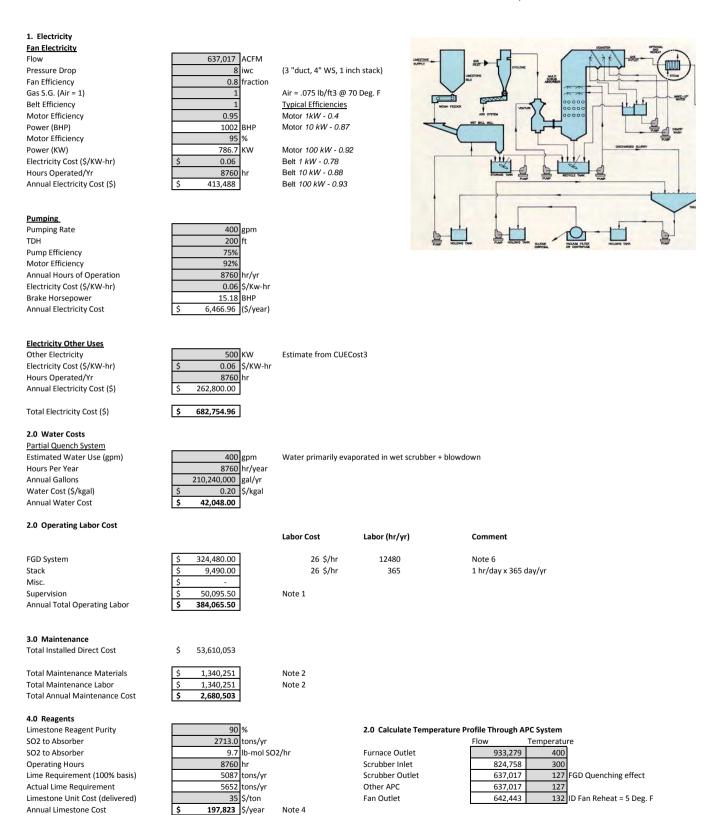
7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 824,758 acfm. The gas leaving the wet scrubber will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F. A 5 Deg. F reheat at the fan is added. SO2 flow is based on 620.9 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO₂ removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for HSM Furnaces Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14



5.0 Installed Equipment Costs for HSM Furnaces Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

Annual Limestone Use	5,087	ton/yr	Note 5
Impurity	565	ton/yr	
Waste gypsum + Inerts	9314.63	tons	
Cost Disposal	38	\$/ton	
Annual Disposal Cost	353,956	\$/yr	

TOTAL LABOR AND MATERIALS

\$ 4,603,950

Notes:

- 1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of
- Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

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Cost Item	Factor	Factor Co	ost
Direct Costs			
Purchased Equipm	ient Costs		
Primar	y Equipment ¹	\$	16,765,66
	ary Equipment	\$	-
Allowa	nce for Unforseen	\$	1,676,56
Instrur	nentation	0.04 \$	737,689.4
Sales T	axes		1,106,534.1
Freight	:	0.05 \$	
	Purchased Equipment Cost, PEC	\$	21,208,57
Direct Installation	Costs ²		
Found	ations and Supports	0.03 \$	461,05
Handli	ng and Erection	0.70 \$	12,930,72
Electri	cal	0.009 \$	165,98
Piping		0.01 \$	221,30
Ductw	ork	0.05 \$	922,11
Paintir	-	0.01 \$	92,21
	Direct Installation Costs, DC	\$	14,793,38
Site Preparation		\$	20,00
Buildings		\$	-
Total Direct Costs	(PEC + DC)	\$	36,021,95
Indirect Costs (Inst	callation)		
Engine	ering	0.15 \$	3,181,28
Constr	uction an Field Expenses	0.1 \$	2,120,85
Contra	ctor Fees	0.1 \$	2,120,85
Startu)	0.01 \$	127,25
Perfor	mance Test	0.003 \$	63,62
Model	Study	0.005 \$	106,04
Contin	gencies	0.1 \$	2,120,85
	Total Indirect Costs, IC	\$	9,840,77
Total Installed Cost		\$	45,862,73

Table B10b. Direct and Indirect Installation Costs, Boiler House #1 - Spray Dryer Absorber

¹ Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

² Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Cost Item		Factor		Cost
Direct Annual Costs, I	DC			
Operating	g Labor			
	Operator	General Operating	\$	336,830
	Supervisor	15% of Operator	\$	50,525
	Material	0.5% of General Operation	\$	1,684
Maintena	nce			
	Maintenance Employee	General Maintenance	\$	765,042
	Supervisor	15% of Maintenance Labor	\$	135,007
	Material	100% of Maintenance Labor	\$	900,049
Utilities				
	Electricity		\$	71,832
	Water		\$	2,521
Reagents		Lime	\$	101,612
Solids Dis	posal	Gypsum solids from FFBH	\$	64,026
Indirect Annual Costs	, IC			
Administr	ative Charges	2% of Total Capital Investment	\$	917,255
Property	Tax	1% of Total Capital Investment	\$	458,627
Insurance		1% of Total Capital Investment	\$	458,627
Overhead		60% of total Labor and Materials	\$	1,454,953
Capital Re	ecovery ¹	0.1098 x Total Capital Investment	\$	5,035,728
Total Annual Cost			\$	10,754,317
	2010	Uncontrolled SO 2 Actual Emissions (tpy)		407.4
	Allov	vance for Uncontrolled Maint Outages (tpy) - 15 days		19.3
		Removal Efficiency		80%
	-	Control Emission Factor (lb/MMBtu)		0.026
		rol Cost Per Ton SO 2	Ś	34,644

Table B10a. Annual Cost Factors, Boiler House #1 - Spray Dry Absorber

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 °F. The primary SDA components include: Lime/reagent feed system, SO₂ removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

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4 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack	1	-	-	International Chimney Corp.	1	\$ 666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	\$-	\$0	2014	1	1	1	\$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 108,570	\$108,570	2011	593	600	1	\$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	\$ 11,793,535	\$11,793,535	2014	1	1	1	\$ 11,793,535
8	New FFBH for SDA system	8	-	-	CUECOST	1	\$ 3,181,523	\$3,181,523	2014	1	1	1	\$ 3,181,523
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
10													
11													
	\$ 16,765,6										\$ 16,765,668		

Notes:

1 Estimate for self supporting stack, 11'7" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 263,670 acfm at 152 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 330130 acfm. The gas leaving the SDA will approach saturation temperature . The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added. Control costs are based on a SO2 loading of 470 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CEUCOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 263670 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4. An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity					
<u>Fan Electricity</u> Flow	330130 ACFM				
Pressure Drop	15 iwc	(3 inches duct, 5 inche	SDA Gir	chos EERH 1 inch s	tack)
Fan Efficiency	0.8 fraction	(5 menes duct, 5 mene	5 JDA, 0 II	iches ir bii, 1 ilicii s	lack)
Gas S.G. (Air = 1)	1	Use 1			
Belt Efficiency	1	Typical Efficiencies			
Motor Efficiency	0.95	Motor 1kW - 0.4			
Power (BHP)	974 BHP	Motor 10 kW - 0.87			
Motor Efficiency	95 %				
Power (KW)	764.4 KW	Motor 100 kW - 0.92			
Electricity Cost (\$/KW-hr)	\$ 0.06	Belt 1 kW - 0.78			
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88			
Annual Electricity Cost (\$)	\$ 401,789	Belt 100 kW - 0.93			
	+				
Electricity Other Uses					
From CUECOST3	120 KW	Costing from CUECOS	T model fo	r FFBH	
Electricity Cost (\$/KW-hr)	\$ 0.06				
Hours Operated/Yr	8760 hr				
Annual Electricity Cost (\$)	\$ 63,072.00				
Total Electricity Cost (\$)	\$ 71,832.00				
2.0 Water Costs					
SDA System					
Estimated Water Use (gpm)	200 gpm	Water primarly evapo	rated in SC	10	
Hours Per Year	8760	water primariy evapo	rateu ili SL	A	
Annual Gallons	12,604,317 gal/yr				
Water Cost (\$/kgal)	\$ 0.20				
Annual Water Cost	\$ 2,520.86				
2.0 Operating Labor Cost					
		Labor Cost	Labor (hr		Comment
Quench System	\$ 18,980	26 \$/hr	73		1 hr/shift x 2 shifts x 365 day/yr
SDA System	\$ 270,400	26 \$/hr	1040		Note 6
Stack	\$ 9,490	26 \$/hr	36		1 hr/day x 365 day/yr
Baghouse	\$ 37,960	26 \$/hr	146	0	Inspect 2/shift x 2 * 365
Misc.	\$ -				
Supervision	\$ 50,525	Note 1			
Annual Total Operating Labor	\$ 387,355				
3.0 Maintenance	¢ 00 001 050				
Total Installed Direct Cost	\$ 36,001,958			Calculate Tempe	rature Profile Through APC System
Tabal Majadana ang Madanjala	<u> </u>	No. 4 2			Flow Temperature
Total Maintenance Materials	\$ 900,049	Note 2		Absorber Inlet	330,130 300
Total Maintenance Labor	\$ 900,049	Note 2		Absorber Outlet	263,670 147 SDA quenching effect
Total Annual Maintenance Cost	\$ 1,800,098			FFBH Outlet	263,670 147 265,842 152 ID Fan Reheat = 5 Deg F
4.0 Reagents				Fan Outlet	265,842 152 ID Fan Reheat = 5 Deg F
4.0 Reagents Reagent Purity	90			Note: Flow prior	to quench is 438,726 acfm at 550 Deg. F
				Note: Flow prior	to quencii is 450,720 aciiii al 550 Deg. F
SO ₂ to Absorber	470.2 tons/yr				
Operating Hours	8760 hr				
Lime Requirement (100% basis)	494 tons/yr				
Actual Lime Requirement	549 tons/yr				
Lime Unit Cost	185 \$/ton				
Annual Lime Cost	\$ 101,612 \$/year	Note 4			
5.0 Disposal					
CaO + SO2 + 1/2 O2 + 2H2O> CaSO4*2	H20				
Annual Lime Use	494 ton/yr	Note 5			
Impurity	55 ton/yr				
Waste gypsum + Inerts	1685 tons				
Cost Disposal	38 S/ton				
Cost Disposal Annual Disposal Cost	38 \$/ton 64.026 \$/vr				
Cost Disposal Annual Disposal Cost	38 \$/ton 64,026 \$/yr				

TOTAL LABOR AND MATERIALS

\$ 2,424,921.64

5.0 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

Ву: КЈ 2-12-14

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Cost Item	Factor	Factor C	ost
Direct Costs			
Purchased E	quipment Costs		
I	Primary Equipment ¹		\$ 17,901,564
	Ancilliary Equipment		\$ -
,	Allowance for Unforseen	2	\$ 1,790,156
I	nstrumentation	0.04	\$ 787,668.8
2	Sales Taxes		\$ 1,181,503.2
I	Freight	0.05	\$ 984,58
	Purchased Equipment Cost, PEC	:	\$ 22,645,479
Direct Instal	lation Costs ²		
I	Foundations and Supports	0.03	\$ 590,75
I	Handling and Erection	0.697	. , ,
I	Electrical	0.009	
I	Piping	0.01	\$ 196,91
I	Ductwork	0.05	\$ 984,58
I	Painting	0.01	
	Direct Installation Costs, DC	:	\$ 15,776,13
Site Prepara	tion		\$ 20,00
Buildings		:	\$ -
Total Direct	Costs (PEC + DC)	:	\$ 38,441,61
Indirect Cos	ts (Installation)		
I	Engineering	0.15	\$ 3,396,82
(Construction an Field Expenses	0.1	\$ 2,264,54
(Contractor Fees	0.1	\$ 2,264,54
2	Startup	0.01	\$ 135,87
I	Performance Test	0.003	· ,
I	Model Study	0.005	\$ 113,22
(Contingencies	0.1	\$ 2,264,54
	Total Indirect Costs, IC		\$ 10,507,50
Total Installed Cost			\$ 48,949,11

Table B11b. Direct and Indirect Installation Costs, Boiler House #2 - Spray Dryer Absorber

¹ Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

² Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Direct Annual Costs, DC Operating Labor Operator Supervisor Material Maintenance Employee Maintenance Employee Maintenance Employee Supervisor Material Material Material Material Material Material D0% of Maintenance Labor Material D0% of Maintenance Labor Material Mater		Cost
OperatorGeneral OperatingSupervisor15% of OperatorMaterial0.5% of General OperationMaintenanceGeneral MaintenanceSupervisor15% of Maintenance LaborMaterial100% of Maintenance LaborMaterial100% of Maintenance LaborUtilitiesElectricityWaterLimeSludge DisposalGypsum sludgeIndirect Annual Costs, ICJ% of Total Capital InvestmentProperty Tax1% of Total Capital InvestmentNoverhead60% of total Labor and MaterialsCapital Recovery ¹ 0.1098 x Total Capital InvestmentTotal Annual Cost		
Supervisor 15% of Operator Material 0.5% of General Operation Maintenance General Maintenance Maintenance Employee General Maintenance Supervisor 15% of Maintenance Labor Material 100% of Maintenance Labor Utilities Electricity Water Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment		
Material0.5% of General OperationMaintenanceGeneral MaintenanceMaintenance EmployeeGeneral MaintenanceSupervisor15% of Maintenance LaborMaterial100% of Maintenance LaborUtilitiesElectricityKeagentsElectricitySludge DisposalGypsum sludgeIndirect Annual Costs, ICSignal CostAdministrative Charges2% of Total Capital InvestmentProperty Tax1% of Total Capital InvestmentInsurance1% of Total Capital InvestmentOverhead60% of total Labor and MaterialsCapital Recovery10.1098 x Total Capital InvestmentTotal Annual Cost	\$	336,830
Maintenance Maintenance Employee General Maintenance Supervisor 15% of Maintenance Labor Material 100% of Maintenance Labor Utilities Electricity Water Electricity Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC X Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost Z2010 Uncontrolled SO 2 Actual Emissions (tpy)	\$	50,525
Maintenance Employee General Maintenance Supervisor 15% of Maintenance Labor Material 100% of Maintenance Labor Utilities Electricity Water Electricity Water Electricity Water Group Solution Gypsum sludge Indirect Annual Costs, IC Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost	\$	1,684
Supervisor 15% of Maintenance Labor Material 100% of Maintenance Labor Utilities Electricity Water Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost		
Material 100% of Maintenance Labor Utilities Electricity Water Lime Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment	\$	816,459
Utilities Electricity Water Lime Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment	\$	144,081
Electricity Water Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment	\$	960,540
Water Water Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Property Tax 2% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment		
Reagents Lime Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment	\$	471,735
Sludge Disposal Gypsum sludge Indirect Annual Costs, IC Administrative Charges Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO 2 Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	2,521
Indirect Annual Costs, IC Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO ₂ Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	80,606
Administrative Charges 2% of Total Capital Investment Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment	\$	50,790
Property Tax 1% of Total Capital Investment Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO 2 Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days		
Insurance 1% of Total Capital Investment Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO ₂ Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	978,982
Overhead 60% of total Labor and Materials Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO 2 Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	489,491
Capital Recovery ¹ 0.1098 x Total Capital Investment Total Annual Cost 2010 Uncontrolled SO ₂ Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	489,491
Total Annual Cost 2010 Uncontrolled SO ₂ Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	1,746,940
2010 Uncontrolled SO ₂ Actual Emissions (tpy) Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$	5,374,613
Allowance for Uncontrolled Maint Outages (tpy) - 15 days	\$ 1	11,995,290
		750.4
		15.3
SO 2 Removal Efficiency		80%
Post-Control Emission Factor (lb/MMBtu)		0.037
Control Cost Per Ton SO 2	\$	20,400

Table B11a. Annual Cost Factors, Boiler House #2 - Spray Dry Absorber

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 °F. The primary SDA components include: Lime/reagent feed system, SO₂ removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

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4 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack	1	-	-	International Chimney Corp.	1	\$ 666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	\$-	\$0	2014	1	1	1	\$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 108,570	\$108,570	2011	593	600	1	\$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	\$ 12,477,234	\$12,477,234	2014	1	1	1	\$ 12,477,234
8	New FFBH for SDA system	8	-	-	CUECOST	1	\$ 3,633,720	\$3,633,720	2014	1	1	1	\$ 3,633,720
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
10													
11													
	\$ 17,901											\$ 17,901,564	

Notes:

1 Estimate for self supporting stack, 12'10" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 324,550 acfm at 147 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 406,355 acfm. The gas leaving the SDA will approach saturation temperature . The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added. Control costs are based on a SO2 loading of 373 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CEUCOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 324,550 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4. An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity Fan Electricity Flow Pressure Drop Fan Efficiency Gas S.G. (Air = 1) Belt Efficiency Motor Efficiency Power (BHP) Motor Efficiency Power (KW) Electricity Cost (\$/KW-hr) Hours Operated/Yr Annual Electricity Cost (\$)	324550 ACFM 15 iwc 0.8 fraction 1 1 0.95 957 957 BHP 95 % 751.5 KW \$ 0.06 8760 hr \$ 394,998	(3 inches duct, 5 inches SDA, Use 1 <u>Typical Efficiencies</u> Motor <i>1kW</i> - <i>0.4</i> Motor <i>10 kW</i> - <i>0.87</i> Motor <i>100 kW</i> - <i>0.92</i> Belt <i>1 kW</i> - <i>0.78</i> Belt <i>10 kW</i> - <i>0.78</i> Belt <i>100 kW</i> - <i>0.93</i>	5 inches FFBH, 1 inch :	stack)
Electricity Other Uses From CEUCOST3 Electricity Cost (\$/KW-hr) Hours Operated/Yr Annual Electricity Cost (\$)	146 KW \$ 0.06 8760 hr \$ 76,737.60	Costing from CUECOST mode	L	
Total Electricity Cost (\$) 2.0 Water Costs SDA System Estimated Water Use (gpm) Hours Per Year Annual Gallons Water Cost (\$/kgal) Annual Water Cost	\$ 471,735.49 200 gpm 8760 12,604,317 gal/yr \$ 0.20 \$ 2,520.86	Water primarly evaporated ir	SDA	
2.0 Operating Labor Cost Quench System SDA System Stack Baghouse Misc. Supervision Annual Total Operating Labor	\$ 18,980 \$ 270,400 \$ 9,490 \$ 37,960 \$ - \$ 50,525 \$ 387,355	26 \$/hr 26 \$/hr 10 26 \$/hr	(hr/yr) 730 0400 365 1460	Comment 1 hr/shift x 2 shifts x 365 day/yr Note 6 1 hr/day x 365 day/yr Inspect 2/shift x 2 * 365
3.0 Maintenance Total Installed Direct Cost Total Maintenance Materials Total Maintenance Labor Total Annual Maintenance Cost 4.0 Reagents Reagent Purity SO2 to Absorber Operating Hours	\$ 38,421,613 \$ 960,540 \$ 960,540 \$ 1,921,081 90 373 tons/yr 8760 hr	Note 2 Note 2	Absorber Inlet Absorber Outlet FFBH Outlet Fan Outlet	erature Profile Through APC System Flow Temperature 330,130 300 263,670 147 265,842 152 ID Fan Reheat = 5 Deg F r to quench is 438726 acfm at 550 Deg. F
Lime Requirement (100% basis) Actual Lime Requirement Lime Unit Cost Annual Lime Cost	392 tons/yr 436 tons/yr 185 \$/ton \$ 80,606 \$/year	Note 4		
5.0 Disposal CaO + SO2 + 1/2 O2 + 2H2O> CaSO4*2 Annual Lime Use Impurity Waste gypsum + Inerts Cost Disposal Annual Disposal Cost	2H20 392 ton/yr 44 ton/yr 1337 tons 38 \$/ton 50,790 \$/yr	Note 5		

TOTAL LABOR AND MATERIALS

\$ 2,911,567.28

5.0 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

Ву: КЈ 2-12-14

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Cost Item	Factor	Factor Co	st
Direct Costs			
Purchased Equipm	nent Costs		
Primai	y Equipment ¹	\$	24,907,54
	ary Equipment	\$	-
Allowa	nce for Unforseen	\$	2,490,75
Instru	nentation	0.04 \$	1,095,93
Sales 1	axes	0.06 \$	1,643,89
Freigh	t	0.05 \$	1,369,91
	Purchased Equipment Cost, PEC	\$	31,508,03
Direct Installation	Costs ²		
Found	ations and Supports	0.02 \$	630,16
Handli	ng and Erection	0.700 \$	19,191,88
Electri	cal	0.009 \$	246,58
Piping		0.01 \$	273,98
Ductw	ork	0.05 \$	
Paintir	ng	0.01 \$	136,99
	Direct Installation Costs, DC	\$	21,849,52
Site Preparation		\$	20,00
Buildings		\$	-
Total Direct Costs	(PEC + DC)	\$	53,377,56
Indirect Costs (Ins	tallation)		
Engine	ering	0.15 \$	4,726,20
Constr	uction an Field Expenses	0.1 \$	3,150,80
Contra	ctor Fees	0.1 \$	3,150,80
Startu	0	0.01 \$	189,04
Perfor	mance Test	0.003 \$	94,52
Model	•	0.005 \$,
Contin	gencies	0.1 \$	
	Total Indirect Costs, IC	\$	14,619,73
Total Installed Cost		ې	67,977,29

Table B12b. Direct and Indirect Installation Costs, HSM Furnaces - Spray Dryer Absorber

¹ Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

² Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Direct Annual C Ope	Costs, DC			
Ope				
	erating Labor			
	Operator	General Operating	\$	336,830
	Supervisor	15% of Operator	\$	50,525
	Material	0.5% of General Operation	\$	1,684
Mai	intenance			
	Maintenance Employe	e General Maintenance	\$	1,133,848
	Supervisor	15% of Maintenance Labor	\$	200,091
	Material	100% of Maintenance Labor	\$	1,333,939
Util	ities			
	Electricity		\$	953,604
	Water		\$	5,042
Rea	igents	Lime	\$	586,288
Soli	ds Disposal	Gypsum solids from FFBH	\$	369,420
Indirect Annual	l Costs, IC			
Adn	ninistrative Charges	2% of Total Capital Investment	\$	1,359,546
Pro	perty Tax	1% of Total Capital Investment	\$	679,773
Insu	urance	1% of Total Capital Investment	\$	679,773
Ove	erhead	60% of total Labor and Materials	\$	2,978,726
Сар	ital Recovery ¹	0.1098 x Total Capital Investment	\$	7,463,906
Total Annual C	ost		\$	18,132,994
	20	010 Uncontrolled SO ₂ Actual Emissions (tpy)		2240.0
	A	lowance for Uncontrolled Maint Outages (tpy) - 15 days		111.7
		C₂ Removal Efficiency		80%
		pst-Control Emission Factor (lb/MMBtu)		0.046
		ontrol Cost Per Ton SO 2	Ś	10,650

Table B12a. Annual Cost Factors, HSM Furnaces - Spray Dry Absorber

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Summary of Equipment Included in Estimate

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 °F. The primary SDA components include: Lime/reagent feed system, SO₂ removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

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4 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	New Stack	1	-	-	International Chimney	1	\$ 833,333	\$833,333	2014	1	1	1	\$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	\$ 104,576	\$209,152	2014	1	1	1	\$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	\$ 472,844	\$945,688	2014	1	1	1	\$ 945,688
4	New Fans	4	CS	CS	Included with SDA	1	\$-	\$0	2014	1	1	1	\$-
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 108,570	\$108,570	2011	593	600	1	\$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	\$ 16,550,960	\$16,550,960	2014	1	1	1	\$ 16,550,960
8	New FFBH for SDA system	8	-	-	CUECOST	1	\$ 5,821,883	\$5,821,883	2014	1	1	1	\$ 5,821,883
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$ 70,500
10													
11													
													\$ 24,907,540

Notes:

1 Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 658,721 acfm at 147 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 824,758 acfm. The gas leaving the SDA will approach saturation temperature . The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added. Control costs are based on a SO2 loading of 2713 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CUECOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 658,721 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4. An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14 1. Electricity Fan Electricity Flow 658721 ACFM (3 inches duct, 5 inches SDA, 6 inches FFBH, 1 inch stack) Pressure Drop 15 iwc Fan Efficiency 0.8 fraction Gas S.G. (Air = 1) 1 Use 1 Belt Efficiency 1 Typical Efficiencies Motor 1kW - 0.4 Motor Efficiency 0.95 Motor 10 kW - 0.87 Power (BHP) 1943 BHP Motor Efficiency 95 Power (KW) Motor 100 kW - 0.92 1525.3 KW Electricity Cost (\$/KW-hr) Belt 1 kW - 0.78 0.06 Ś Belt 10 kW - 0.88 Hours Operated/Yr 8760 hr Annual Electricity Cost (\$) 801,705 Belt 100 kW - 0.93 Electricity Other Uses From CUECOST3 289 KW Costing from CUECOST model. Electricity Cost (\$/KW-hr) 0.06 Hours Operated/Yr 8760 Annual Electricity Cost (\$) Ś 151,898.40 Total Electricity Cost (\$) Ś 953,603.54 2.0 Water Costs SDA System 400 gpm Estimated Water Use (gpm) Water primarly evaporated in SDA Hours Per Year 8760 Annual Gallons 25,208,633 gal/yr Water Cost (\$/kgal) Ś 0.20 5,041.73 Annual Water Cost Ś 2.0 Operating Labor Cost Labor (hr/yr) Labor Cost Comment 18 980 1 hr/shift x 2 shifts x 365 day/yr Quench System 26 \$/hr 730 SDA System 270.400 26 \$/hr 10400 Note 6 Ś Stack 9,490 26 \$/hr 365 1 hr/day x 365 day/yr \$ Baghouse 37,960 26 \$/hr 1460 Inspect 2/shift x 2 * 365 Ś Misc. Ś 50,525 Supervision Ś Note 1 Annual Total Operating Labor Ś 387,355 3.0 Maintenance Total Installed Direct Cost \$ 53,357,561 Calculate Temperature Profile Through APC System Flow Temperature **Total Maintenance Materials** 1,333,939 Note 2 Absorber Inlet 824,758 300 147 SDA quenching effect Total Maintenance Labor 1,333,939 Absorber Outlet Ś Note 2 658,721 Total Annual Maintenance Cost Ś 2,667,878 FFBH Outlet 658,721 147 Fan Outlet 664,147 152 ID Fan Reheat = 5 Deg F 4.0 Reagents Note: Flow prior to quench is 933,279 acfm at 550 Deg. F Reagent Purity 90 SO2 to Absorber 2713 tons/yr **Operating Hours** 8760 hr Lime Requirement (100% basis) 2852 tons/yr Actual Lime Requirement 3169 tons/yr Lime Unit Cost 185 \$/ton Annual Lime Cost \$ 586,288 \$/year Note 4 5.0 Disposal CaO + SO2 + 1/2 O2 + 2H20 --> CaSO4*2H20 Annual Lime Use 2,852 ton/yr Note 5 Impurity 317 ton/yr Waste gypsum + Inerts 9722 tons 38 \$/ton Cost Disposal Annual Disposal Cost 369,420 \$/yr

TOTAL LABOR AND MATERIALS

\$ 4,964,544.02

5.0 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

- Notes: 1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
- 5. Cost based on \$38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
- 6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	8,144,61
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	814,46
Instrumentation	0.04 \$	358,363.2
Sales Taxes	0.06 \$	537,544.8
Freight	0.05 \$	447,95
Purchased Equipment Cost, PEC	\$	10,302,94
Direct Installation Costs		
Foundations and Supports ²	0.1 \$	895,90
Handling and Erection	0.66 \$	5,902,51
Electrical	0.015 \$	134,38
Piping	0.03 \$	268,77
Ductwork	0.09 \$	806,31
Painting	0.01 \$	45,69
Direct Installation Costs, DC	\$	8,053,58
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	18,376,52
Indirect Costs (Installation)		
Engineering	0.15 \$	1,545,44
Construction an Field Expenses	0.1 \$	1,030,29
Contractor Fees	0.1 \$	1,030,29
Startup	0.007 \$	72,12
Performance Test	0.005 \$	51,51
Model Study	0 \$	-
Contingencies	0.1 \$	1,030,29
Total Indirect Costs, IC	\$	4,759,96
Fotal Installed Cost	\$	23,136,48

Table B13b. Direct and Indirect Installation Costs, Boiler House #1 - Dry Sorbent Injection

¹ Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item		Factor	Cost	t
Direct Annual Costs	, DC			
Operatii	ng Labor			
	Operator	General Operating	\$	120,510
	Supervisor	15% of Operator	\$	18,077
	Material	5% of Operation	\$	6,929
Mainter	ance			
	Maintenance Employee	General Maintenance	\$	171,139
	Supervisor	15% of Maintenance Labor	\$	30,201
	Material	100% of Maintenance Labor	\$	201,340
Utilities				
	Electricity		\$	414,195
	Water		\$	24,528
Reagent		Trona	\$ \$ \$	68,083
Ash Disp	oosal		\$	11,777
Indirect Annual Cos	ts, IC			
Adminis	trative Charges	2% of Total Capital Investment	\$	462,730
Property	у Тах	1% of Total Capital Investment	\$	231,365
Insuranc	ce	1% of Total Capital Investment	\$	231,365
Overhea	ad	60% of total Labor and Materials	\$	635,910
Capital F	Recovery ¹	0.1098 x Total Capital Investment	\$	2,540,386
Total Annual Cost			\$	5,168,534
	2	2010 Uncontrolled SO $_2$ Actual Emissions (tpy)		407.35
	A	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		19.3
		SO 2 Removal Efficiency		50%
		Post-Control SO ₂ Emission Factor (Ib/MMBtu)		0.057
		Control Cost Per Ton SO ,	\$	26,640

Table B13a. Annual Cost Factors, Boiler House #1 - Dry Sorbent Injection

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Notes

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1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Exte	ended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Cur	rrent Year)
											Factor			
1	New Chimney/stack	1	-	-	International Chimney	1	\$ 666,667	\$666,667	2014	1	1	1	\$	666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$ 104,576	\$104,576	2014	1	1	1	\$	104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$ 472,844	\$472,844	2014	1	1	1	\$	472,844
4	New Fans	4	CS	CS	Included with baghouse	1	\$-	\$0	2014	1	1	1	\$	-
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$	366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$	111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	\$ 2,678,702	\$2,678,702	2014	1	1	1	\$	2,678,702
8	New Baghouse for DIS system	8	-	-	CUECOST3	1	\$ 3,674,010	\$3,674,010	2014	1	1	1	\$	3,674,010
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$	70,500
10														
11														
													\$	8,144,619

Notes:

1 Estimate for self supporting stack, 11'7" ID, including aircraft warning lights, ladder, and tesitng platform. Pricing for 213 ft stack from International Chimney Corporation, ICC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 330,130 acfm acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 470.2 tons of SO2 per year was factored based on a total heat input of 250 MMBtu/hr. Calculated SO2 emission factor of 107.36 lb/hr/250MMBtu/hr = 0.429 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 330130 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity Fan Electricity Flow Pressure Drop Fan Efficiency Gas S.G. (Air = 1) Belt Efficiency Motor Efficiency Power (BHP) Motor Efficiency Power (KW) Electricity Cost (\$/KW-hr) Hours Operated/Yr Annual Electricity Cost (\$)	330130 ACFM 12 iwc 0.8 fraction 1 1 0.95 779 95 611.6 \$ 0.06 8760 hr \$ 321,431	(3 inches duct, 2 inches DSI, 6 inches FFBH, Use 1 <u>Typical Efficiencies</u> Motor 1 <i>kW</i> - 0.4 Motor 10 <i>kW</i> - 0.87 Motor 100 <i>kW</i> - 0.92 Belt 1 <i>kW</i> - 0.78 Belt 10 <i>kW</i> - 0.93	acfm Deg. F Boiler Flow 438,726 550 Post Quench 330,130 300 Post DSI 330,130 300 Post FFBH 330,130 300 IDF Outlet 332,302 305
Pumping Pumping Rate TDH Pump Efficiency Motor Efficiency Annual Hours of Operation Electricity Cost (\$/KW-hr) Brake Horsepower Annual Electricity Cost	200 gpm 200 ft 75% 92% 8760 hr/yr 0.06 \$/Kw-hr 7.59 BHP \$ 3,233.48 (\$/year)		
Electricity Other Uses Other Electricity Cost (\$/KW-hr) Hours Operated/Yr Annual Electricity Cost (\$) Total Electricity Cost (\$)	170.34 KW \$ 0.06 8760 hr \$ 89,530.70 \$ 414,195.46	Costing from CEUCOST model - FFBH + DSI	
2.0 Water Costs Partial Quench Estimated Partial Quench (gpm) Hours Per Year Water Cost (\$/kgal) Annual Water Cost Annual Water Cost	200 8760 \$ 2.00 \$ 3,504.00 \$ 24,528.00	Quench associated with lowering tempera	ture of flue gas
3.0 Operating Labor Cost Quench System DSI System Stack Baghouse Misc. Supervision Annual Total Operating Labor	\$ 18,980.00 \$ 54,080.00 \$ 9,490.00 \$ 37,960.00 \$ - \$ 18,076.50 \$ 138,586.50	26 \$/hr 730 26 \$/hr 4160 26 \$/hr 365 26 \$/hr 1460 Note 1	1 hr/shift x 2 shifts x 365 day/yr 1 operator x 2 shifts x 365 days/yr 1 hr/day x 365 day/yr Inspect 2/shift x 2 * 365
4.0 Maintenance Total Installed Direct Cost Total Maintenance Materials Total Maintenance Labor Total Annual Maintenance Cost	\$ 8,053,585 \$ 201,340 \$ 201,340 \$ 402,679	Note 2 Note 2 Note 3	
5.0 Reagents Trona Reagent	68,083	Note 4	

5.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

6.0 Disposal Trona Disposal	\$ 11,777	Note 5	Ву: КЈ 2-12-14
TOTAL LABOR AND MATERIALS	\$ 1,059,849.23		

Notes:

- 1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on a basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- 4. Trona cost based on EPA Cost Model, IPM Model, August 20, 2010 . Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO2 removal.
- 5. Cost based on \$38/ton disposal cost.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	8,508,67
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	850,86
Instrumentation	0.04 \$	374,381.7
Sales Taxes	0.06 \$	561,572.5
Freight	0.05 \$	467,97
Purchased Equipment Cost, PEC	\$	10,763,474
Direct Installation Costs		
Foundations and Supports ²	0.1 \$	935,954
Handling and Erection	0.66 \$	6,192,89
Electrical	0.015 \$	140,39
Piping	0.03 \$	280,78
Insulation for Ductwork	0.09 \$	842,35
Painting	0.01 \$	47,73
Direct Installation Costs, DC	\$	8,440,11
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	19,223,590
Indirect Costs (Installation)		
Engineering	0.15 \$	1,614,52
Construction an Field Expenses	0.1 \$	1,076,34
Contractor Fees	0.1 \$	1,076,34
Startup	0.006 \$	64,58
Performance Test	0.005 \$	53,81
Model Study	0\$	-
Contingencies	0.1 \$	1,076,34
Total Indirect Costs, IC	\$	4,961,96
Total Installed Cost	\$	24,165,55

Table B14b. Direct and Indirect Installation Costs, Boiler House #2 - Dry Sorbent Injection

¹ Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item		Factor	Cost	t
Direct Annual Costs	, DC			
Operatir	ng Labor			
	Operator	General Operating	\$	120,510
	Supervisor	15% of Operator	\$	18,077
	Material	5% of Operation	\$	6,929
Mainten	ance	or erator General Operating bervisor 15% of Operator interial 5% of Operation intenance Employee General Maintenance bervisor 15% of Maintenance Labor iterial 100% of Maintenance Labor iterial 100% of Maintenance Labor ctricity iter Charges 2% of Total Capital Investment 1% of Total Capital Investment 1% of Total Capital Investment 1% of Total Capital Investment 60% of total Labor and Materials erry 0.1098 x Total Capital Investment 2010 Uncontrolled SO 2 Actual Emissions (tpy) Allowance for Uncontrolled Maint. Outages (tpy) - 15 days SO 2 Removal Efficiency Post-Control SO 2 Emission Factor (lb/MMBtu)		
	Maintenance Employee	General Maintenance	\$	179,352
	Supervisor	15% of Maintenance Labor	\$	31,650
	Material	100% of Maintenance Labor	\$	211,003
Utilities				
	Electricity		\$	503,434
	Water		\$	24,528
Reagent	S	Trona	\$	53,984
Solids Di	sposal		\$	9,338
Indirect Annual Cost	ts, IC			
Adminis	trative Charges	2% of Total Capital Investment	\$	483,311
Property	/ Tax	1% of Total Capital Investment	\$	241,656
Insuranc	ce	1% of Total Capital Investment	\$	241,656
Overhea	d	60% of total Labor and Materials	\$	691,126
Capital F	Recovery	0.1098 x Total Capital Investment	\$	2,653,378
Total Annual Cost			\$	5,469,930
	2	2010 Uncontrolled SO $_2$ Actual Emissions (tpy)		750
	A	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		15.3
				50%
				0.087
	(Control Cost Per Ton SO 2	\$	14,890

Table B14a. Annual Cost Factors, Boiler House #2 - Dry Sorbent Injection

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Notes

KJ 2-12-14

1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Equipment Cost Summary

BY: KJ 2-12-14

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	l	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required			(Base Year)		Factor	Year Cost	Factor	(Current Year)
												Factor		
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	\$	666,667	\$666,667	2014	1	1	1	\$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	\$	104,576	\$104,576	2014	1	1	1	\$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	\$	472,844	\$472,844	2014	1	1	1	\$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	\$	-	\$0	2014	1	1	1	\$-
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$	658	\$361,900	2011	593	600	1	\$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$	109,852	\$109,852	2011	593	600	1	\$ 111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	\$	2,508,522	\$2,508,522	2014	1	1	1	\$ 2,508,522
8	New Baghouse for DSI system	8	-	-	CUECOST3	1	\$	4,208,246	\$4,208,246	2014	1	1	1	\$ 4,208,246
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$	70,500	\$70,500	2014	1	1	1	\$ 70,500
10														
11														
														\$ 8,508,675

Notes:

1 New stack calculated from CUECOST3, EPA cost model, 2014 basis. Stack sizing based on 409,029 acfm at 305 Deg. F

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 406,355 acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 373 tons of SO2 per year was factored based on a total heat input of 1000 MMBtu/hr. Calculated SO2 emission factor of 85.15 lb/hr/1000MMBtu/hr = 0.0815 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 406355 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity						
Fan Electricity	405255 4.0514					
Flow	406355 ACFM					
Pressure Drop	12 iwc	(3 inches duct, 2 inches	s DSI, 6 inches FFBF	I, 1 Inch stack)		
Fan Efficiency	0.8 fraction					
Gas S.G. (Air = 1)	1	Use 1			acfm	Deg. F
Belt Efficiency	1	Typical Efficiencies		Boiler Flow	540,025	550
Motor Efficiency	0.95	Motor 1kW - 0.4		Post Quench	406,355	300
Power (BHP)	959 BHP	Motor 10 kW - 0.87		Post DSI	406,355	300
Motor Efficiency	95 %			Post FFBH	406,355	300
Power (KW)	752.8 KW	Motor 100 kW - 0.92		IDF Outlet	409,029	305
Electricity Cost (\$/KW-hr)	\$ 0.06	Belt 1 kW - 0.78				
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88				
Annual Electricity Cost (\$)	\$ 395,648	Belt 100 kW - 0.93				
Pumping						
Pumping Rate	200 gpm					
TDH	200 ft					
Pump Efficiency	75%					
Motor Efficiency	92%					
Annual Hours of Operation	8760 hr/yr					
Electricity Cost (\$/KW-hr)	0.06 \$/Kw-hr					
Brake Horsepower	7.59 BHP					
Annual Electricity Cost	\$ 3,233.48 (\$/year)					
Electricity Other Uses						
Other	198.92 KW	Costing from CEUCOST	model - FFBH +DSI			
Electricity Cost (\$/KW-hr)	\$ 0.06	•				
Hours Operated/Yr	8760 hr					
Annual Electricity Cost (\$)	\$ 104,552.35					
Total Electricity Cost (\$)	\$ 503,433.63					
2.0 Water Costs						
Partial Quench						
Estimated Partial Quench (gpm)	200	Quench associated wit	h lowering tempera	ature of flue gas		
Hours Per Year	8760					
Water Cost (\$/kgal)	\$ 2.00					
Annual Water Cost	\$ 3,504.00					
Annual Water Cost	\$ 24,528.00					
3.0 Operating Labor Cost						
Quench System	\$ 18,980.00	26 \$/hr	730	1 hr/shift x 2 shifts x 3	365 day/yr	
DSI System	\$ 54,080.00	26 \$/hr	4160	1 operator x 2 shifts x	365 days/yr	
Stack	\$ 9,490.00	26 \$/hr	365	1 hr/day x 365 day/yr	•	
Baghouse	\$ 37,960.00	26 \$/hr	1460	Inspect 2/shift x 2 * 3	65	
Misc.	\$ -					
Supervision	\$ 18,076.50	Note 1				
Annual Total Operating Labor	\$ 138,586.50					

4.0 Maintenance	
Total Installed Direct Cost	\$ 8,440,116

Total Maintenance Materials

\$ 211,003

Note 2

5.0 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

Total Maintenance Labor Total Annual Maintenance Cost	\$ 211,003 \$ 422,006	Note 2 Note 3	Ву: КЈ 2-12-14
5.0 Reagents Trona Reagent	53,984	Note 4	
6.0 Disposal Trona Disposal	\$ 9,338	Note 5	
TOTAL LABOR AND MATERIALS	\$ 1,151,876		

Notes:

- Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on CUECOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Trona cost based on EPA Cost Model, IPM Model, August 20, 2010.
 Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO2 removal.

5. Cost based on \$38/ton disposal cost.

Cost Item	Factor Co	ost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	13,029,043
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	1,302,90
Instrumentation	0.04 \$	573,277.8
Sales Taxes	0.06 \$,
Freight	0.05 \$	716,59
Purchased Equipment Cost, PEC	\$	16,481,73
Direct Installation Costs		
Foundations and Supports ²	0.06 \$	859,91
Handling and Erection	0.69 \$	9,834,41
Electrical	0.01 \$	143,31
Piping	0.02 \$	214,97
Ductwork	0.10 \$	1,361,53
Painting	0.01 \$	73,09
Direct Installation Costs, DC	\$	12,487,25
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	28,988,99
Indirect Costs (Installation)		
Engineering	0.15 \$	2,472,26
Construction an Field Expenses	0.1 \$, ,
Contractor Fees	0.1 \$	1,648,17
Startup	0.006 \$	98,89
Performance Test	0.005 \$	
Model Study	0 \$	
Contingencies	0.1 \$	1,648,17
Total Indirect Costs, IC	\$	7,598,08
Fotal Installed Cost	\$	36,587,07

Table B15b. Direct and Indirect Installation Costs, HSM Furnaces - Dry Sorbent Injection

¹ Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instillation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Cost Item		Factor	Cost								
Direct Annual Costs, DC											
Operat	ting Labor										
	Operator	General Operating	\$	120,510							
	Supervisor	15% of Operator	\$	18,077							
	Material	5% of Operation	\$	6,929							
Mainte	enance										
	Maintenance Employee	General Maintenance	\$	265,354							
	Supervisor	15% of Maintenance Labor	\$	46,827							
	Material	100% of Maintenance Labor	\$	312,181							
Utilitie	-										
	Electricity		\$	958,465							
	Water		\$	42,048							
Reager		Trona	\$	394,334							
Solids	Disposal		\$	68,209							
Indirect Annual Co	osts, IC										
Admin	istrative Charges	2% of Total Capital Investment	\$	731,742							
Proper	ty Tax	1% of Total Capital Investment	\$	365,871							
Insurai	nce	1% of Total Capital Investment	\$	365,871							
Overhe	ead	60% of total Labor and Materials	\$	1,335,603							
Capita	l Recovery ¹	0.1098 x Total Capital Investment	\$	4,017,261							
Total Annual Cost			\$	9,049,282							
	2	2010 Uncontrolled SO 2 Actual Emissions (tpy)		2240							
	,	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		111.7							
		SO ₂ Removal Efficiency		50%							
	ŀ	Post-Control SO ₂ Emission Factor (lb/MMBtu)		0.101							
	(Control Cost Per Ton SO 2	\$	8,081							

Table B15a. Annual Cost Factors, HSM Furnaces - Dry Sorbent Injection

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

Notes

KJ 2-12-14

1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Exter	nded Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)	
											Factor			
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	\$ 833,333	\$833,333	2014	1	1	1	\$	833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	\$ 104,576	\$209,152	2014	1	1	1	\$	209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	\$ 472,844	\$945,688	2014	1	1	1	\$	945,688
4	New Fans	4	CS	CS	Included with baghouse	1	\$-	\$0	2014	1	1	1	\$	-
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	\$ 658	\$361,900	2011	593	600	1	\$	366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	\$ 109,852	\$109,852	2011	593	600	1	\$	111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	\$ 4,410,255	\$4,410,255	2014	1	1	1	\$ ·	4,410,255
8	New Baghouse for DIS system	8	-	-	CUECOST3	1	\$ 6,082,793	\$6,082,793	2014	1	1	1	\$	6,082,793
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	\$ 70,500	\$70,500	2014	1	1	1	\$	70,500
10														
11														
	\$ 13,029,041											3,029,041		

Notes:

1 Estimate for self supporting column (concrete with block lining), 16'10" ID, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 702,269 acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 2713 tons of SO2 per year was factored based on a total heat input of 2660 MMBtu/hr. Calculated SO2 emission factor of 620.6 lb/hr/2660 MMBtu/hr = 0.2333 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 702269 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity						
Fan Electricity						
Flow	702,269 ACFM					
	12 iwc	(2 inches dust 2 inches D	CL 6 inches FFDU	1 inch stack)		
Pressure Drop		(3 inches duct, 2 inches D	SI, O IIICHES FFBH,	I IIICH SLOCK)		
Fan Efficiency	0.8 fraction		-		(D F
Gas S.G. (Air = 1)	1	Air = .075 lb/ft3 @ 70 Deg	g. F		acfm	Deg. F
Belt Efficiency	1	Typical Efficiencies		HSM Furnace Flow	933,279	550
Motor Efficiency	0.95	Motor 1kW - 0.4		Post Quench	702,269	300
Power (BHP)	1657 BHP	Motor 10 kW - 0.87		Post DSI	702,269	300
Motor Efficiency	95 %			Post FFBH	702,269	300
Power (KW)	1300.9 KW	Motor 100 kW - 0.92		IDF Outlet	706,890	305
Electricity Cost (\$/KW-hr)	\$ 0.06	Belt 1 kW - 0.78				
Hours Operated/Yr	8760 hr	Belt 10 kW - 0.88				
Annual Electricity Cost (\$)	\$ 683,765	Belt 100 kW - 0.93				
Pumping						
Pumping Rate	200 gpm					
TDH	200 ft					
Pump Efficiency	75%					
Motor Efficiency	92%					
Annual Hours of Operation	8760 hr/yr					
Electricity Cost (\$/KW-hr)	0.06 \$/Kw-hr					
Brake Horsepower	7.59 BHP					
Annual Electricity Cost	\$ 3,233.48 (\$/year)					
Electricity Other Uses	516 10 1011	0				
Other	516.49 KW	Costing from CUECOST mo	odel - FFBH + DSI.			
Electricity Cost (\$/KW-hr)	\$ 0.06					
Hours Operated/Yr	8760 hr					
Annual Electricity Cost (\$)	\$ 271,467.14					
Total Electricity Cost (\$)	\$ 958,465.28					
2.0 Water Costs						
Partial Quench						
Estimated Partial Quench (gpm)	400	Quench associated with lo	owering temperat	ure of flue gas		
Hours Per Year	8760	Quench associated with it	Sweinig temperat	ure of flue gas		
Water Cost (\$/kgal)	\$ 0.20 \$ 42,048					
Annual Water Cost	\$ 42,048					
Other						
Estimated (gpm)	0	Miscellaneous use.				
Hours Per Year	8760					
Water Cost (\$/kgal)	\$ 0.20					
Annual Water Cost	\$ -					
Annual Water Cost	\$ 42,048.00					
3.0 Operating Labor Cost						
Quench System	\$ 18,980.00	26 \$/hr	730	1 hr/shift x 2 shifts x 3	365 day/yr	
DSI System	\$ 54,080.00	26 \$/hr	8320	2 operator x 2 shifts x	365 days/yr	
Stack	\$ 9,490.00	26 \$/hr	365	1 hr/day x 365 day/yr		
Baghouse	\$ 37,960.00	26 \$/hr	1460	Inspect 2/shift x 2 * 3	65	
Misc.	\$ -					
Supervision	\$ 18,076.50	Note 1				
Annual Total Operating Labor	\$ 138,586.50					

5.0 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

By: KJ 2-12-14

Utilities, Materials, Reagents, Waste Streams, O&M

4.0 Maintenance Total Installed Direct Cost	\$ 12,487,257	
Total Maintenance Materials Total Maintenance Labor	\$ 312,181 \$ 312,181	Note 2 Note 2
Total Annual Maintenance Cost	\$ 624,363	Note 3
Trona Reagent 6.0 Disposal Trona Disposal	394,334 \$ 68,209	Note 4 Note 5
nona Disposar	\$ 68,209	Note 5
TOTAL LABOR AND MATERIALS	\$ 2,226,006	

Notes:

- 1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
- 2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
- 3. Total maintenance cost estimated based on CUECOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
- Trona cost based on EPA Cost Model, IPM Model, August 20, 2010.
 Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO2 removal.
- 5. Cost based on \$38/ton disposal cost.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	6,030,92
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	603,093
Instrumentation	0.04 \$	265,36
Sales Taxes	0.06 \$	398,04
Freight	0.05 \$	331,70
Purchased Equipment Cost, PEC	\$	7,629,12
Direct Installation Costs		
Foundations and Supports	0.05 \$	331,70
Handling and Erection	0.69 \$	4,554,64
Electrical	0.05 \$	331,70
Piping	0.08 \$	530,72
Ductwork	0.02 \$	119,41
Painting	0.01 \$	
Direct Installation Costs, DC	\$	5,902,01
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	13,551,13
Indirect Costs (Installation)		
Engineering	0.15 \$	1,144,36
Construction an Field Expenses	0.1 \$	762,91
Contractor Fees	0.1 \$	762,91
Startup	0.006 \$	45,77
Performance Test	0.007 \$	53,40
Model Study	0 \$	-
Contingencies	0.1 \$	762,91
Two-Week Lost Production at the Blast Furnace	\$	8,031,00
Total Indirect Costs, IC	\$	11,563,28
Total Installed Cost	\$	25,114,41

Table B16b. Direct and Indirect Installation Costs, Boiler House #1 - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Cost Item		Factor	Cost	:
Direct Annual Costs,	DC			
Operatin	g Labor			
	Operator	General Operating	\$	18,980
	Supervisor	15% of Operator	\$	2,847
	Material	5% of Total Operating	\$	1,091
Mainten	ance			
	Maintenance Employee	General Maintenance	\$	125,418
	Supervisor	15% of Maintenance Labor	\$	22,133
	Material	100% of Maintenance Labor	\$	147,550
Utilities				
	Annual Fuel Switching C	Costs	\$	1,844,586
Indirect Annual Cost	s, IC			
Administ	rative Charges	2% of Total Capital Investment	\$	502,288
Property	Тах	1% of Total Capital Investment	\$	251,144
Insuranc	e	1% of Total Capital Investment	\$	251,144
Overhea	d	60% of total Labor and Materials	\$	1,295,200
Capital R	ecovery ¹	0.1098 x Total Capital Investment	\$	2,757,563
Total Annual Cost			\$	7,219,944
	2	2010 Uncontrolled SO $_2$ Actual Emissions (tpy)		407.35
	/	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		SO 2 Removal Efficiency		88.62%
		Post-Control Emission Factor (Ib/MMBtu)		0.055
		Control Cost Per Ton SO $_2$	\$	19,999

Table B16a. Annual Cost Factors, Boiler House #1 - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low Nox burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #1 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year		Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
											Factor		(ear)
1	Burner System	1	CS	CS	North American Combustion, Inc.	20	\$ 235,000	\$4,700,000	2014	1	1	1	\$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,330,927	\$1,330,927	2014	1	1	1	\$ 1,330,927
3													
4													
5													
6													
7													
8													
9													
10													
21													
													\$ 6,030,927

Notes:

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

¹ Burner system includes burner, fuel train/control valves, two (2) blowers, and control panel (I&C).

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

5.1 Baseline Cost of Fuel 1,684,852 MMBtu/yr Baseline SO₂ Emissions Total Rating Baseline NG 69,206 MMBtu/yr Btu/scf NG 0.0006 41 lb/yr Baseline COG 503,315 MMBtu/yr NG HHV 1012 COG 1.431 720,385 lb/yr Baseline BFG 1,112,332 MMBtu/yr BFG HHV 89 BFG 0.08279 92,087 lb/yr 496 812,513 lb/yr Annual Hours Operation 8,760 hrs/yr COG HHV Total Cost NG (\$ per MMBtu) 4.89 (Based on 2010 cost) 406 tpy Ś Cost COG (\$ per MMBtu) \$ 2.92 (Based on 2010 Cost) 1,808,096 (Cost NG and COG) **Baseline Annual Cost** Ś 5.2 Fuel Use After Fuel Switch Post-Fuel Switch SO₂ Emissions 1,684,852 MMBtu/yr **Total Rating** Btu/scf 0.0006 572,521 339 lb/yr Post-Fuel Switch NG MMBtu/yr NG HHV 1012 NG Post-Fuel Switch COG MMBtu/yr BFG HHV 89 COG 1.431 lb/yr Post-Fuel Switch BFG 1,112,332 MMBtu/yr COG HHV 496 BFG 0.082787 92,087 lb/yr 92,426 lb/yr Annual Hours Operation 8,760 hrs/yr Total Cost NG (\$ per MMBtu) 6.38 (Based on average historical USS natural gas prices) 46 tpy Future Projected Annual Cost Ś 3,652,682 (Cost NG and COG) Post-Fuel Switch SO₂ Emission Reduction 360.0 tpy Post Control SO₂ Factor: 0.0549 lb/MMBtu 5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost \$ 1,844,586 3.0 Operating Labor Cost Burners 18,980 26 \$/hr 730 1 hr/shift x 2 shifts x 365 day/yr Ś 26 \$/hr Other \$ 0 Ś 18,980 Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost \$ 5,902,010 **Total Maintenance Materials** 147,550 Note 2 \$ **Total Maintenance Labor** Ś 147,550 Note 2 Total Annual Maintenance Cost \$ 295,101 Note 3 2,158,666 TOTAL LABOR AND MATERIALS \$

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO₂ emission factors from 2013 Air Inventory.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

Flow Flow 5% NG 28% COG 67% BFG 100% By: KJ 2-12-14

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	6,090,046
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	609,005
Instrumentation	0.04 \$	267,962.04
Sales Taxes	0.06 \$	401,943
Freight	0.05 \$	334,953
Purchased Equipment Cost, PEC	\$	7,703,909
Direct Installation Costs		
Foundations and Supports	0.05 \$	334,953
Handling and Erection	0.68 \$	4,560,550
Electrical	0.05 \$	334,95
Piping	0.08 \$	535,92
Ductwork	0.02 \$	133,98
Painting	0.01 \$	34,16
Direct Installation Costs, DC	\$	5,934,526
Site Preparation	\$	20,000
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	13,658,434
Indirect Costs (Installation)		
Engineering	0.15 \$	1,155,586
Construction an Field Expenses	0.1 \$	770,393
Contractor Fees	0.1 \$	770,393
Startup	0.006 \$	46,22
Performance Test	0.02 \$	154,07
Model Study	0 \$	-
Contingencies	0.1 \$	
Two-Week Lost Production at the Blast Furnace	\$	8,031,00
Total Indirect Costs, IC	\$	11,698,06
Total Installed Cost	\$	25,356,49

Table B17b. Direct and Indirect Installation Costs, Boiler House #2 - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Cost Item		Factor	Cos	t
Direct Annual Cost	s, DC			
Operati	ing Labor			
	Operator	General Operating	\$	18,980
	Supervisor	15% of Operator	\$	2,847
	Material	5% of Total Operating	\$	1,091
Mainte	nance			
	Maintenance Employee	General Maintenance	\$	126,109
	Supervisor	15% of Maintenance Labor	\$	22,254
	Material	100% of Maintenance Labor	\$	148,363
Utilities	5			
	Cost of Fuel Switch (Natu	ıral Gas for COG) 2010 Basis	\$	3,661,350
Indirect Annual Cos	sts, IC			
Admini	strative Charges	2% of Total Capital Investment	\$	507,130
Propert	ty Tax	1% of Total Capital Investment	\$	253,565
Insuran	ce	1% of Total Capital Investment	\$	253,565
Overhe	ad	60% of total Labor and Materials	\$	2,386,234
Capital	Recovery ¹	0.1098 x Total Capital Investment	\$	2,784,143
Total Annual Cost			\$	10,165,632
	20	010 Uncontrolled SO ₂ Actual Emissions (tpy)		750
	Al	llowance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		C₂ Removal Efficiency		83.80%
		ost-Control Emission Factor (lb/MMBtu)		0.057
		ontrol Cost Per Ton SO 2	\$	16,168

Table B17a. Annual Cost Factors, Boiler House #2 - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS providing installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #2 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	\$ 235,000	\$4,700,000	2014	1	1	1	\$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,390,046	\$1,390,046	2014	1	1	1	\$ 1,390,046
3													
4													
5													
6													
7													
8													
9													
10													
21													
													\$ 6,090,046

Notes:

1 Burner system includes burner, fuel train/control valves, blower, and control panel (I&C).

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #2 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

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By: KJ 2-12-14
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5.1 Baseline Cost of Fuel -2010		I	D: ((
Total Usage	, ,	MMBtu/yr	Btu/scf		
Baseline NG	,	MMBtu/yr NG HHV	1012	NG	0.0006 251.40 lbs /yr
Baseline COG		MMBtu/yr BFG HHV	89	COG	1.431 1,253,217.00 lbs /yr
Baseline BFG		MMBtu/yr COG HHV	496	BFG	0.08279 241,472.12 lbs /yr
Annual Hours Operation	,	hrs/yr			Total 1,494,941 lbs /yr
Cost NG		(Based on 2010 cost)			747.47 tons /yr
Cost COG		(Based on 2010 Cost)			
Baseline Annual Cost	\$ 4,630,232	(Cost NG and COG)			
5.2 Fuel Use After Fuel Switch					
Total Rating	4,216,399	MMBtu/yr	Btu/scf		
Post Fuel Switch NG	1,299,621	MMBtu/yr NG HHV	1012	NG	0.0006 770.53 lbs /yr
Post Fuel Switch COG	-	MMBtu/yr BFG HHV	89	COG	1.431 - Ibs /yr
Post Fuel Switch BFG	2,916,778	MMBtu/yr COG HHV	496	BFG	0.082787 241,472 lbs /yr
Annual Hours Operation	8,760	hrs/yr			Total 242,243 lbs /yr
Cost NG	\$ 6.38	(Based on average historical	USS natural gas	prices)	121.12 tons /yr
Future Projected Annual Cost	\$ 8,291,583	(Cost NG and COG)			
5.3 Baseline Fuel Cost - Fuel Swich Fue	el Cost \$ 3,661,350	I	Ро	st Control S	O ₂ Factor: 0 057 lb/MMBtu
		Ι	Ро	st Control S	O ₂ Factor: 0 057 lb/MMBtu
5.3 Baseline Fuel Cost - Fuel Swich Fue 3.0 Operating Labor Cost Burners] 26 \$/hr	Po 730		iO ₂ Factor: 0 057 lb/MMBtu
3.0 Operating Labor Cost	\$ 3,661,350 \$ 18,980	26 \$/hr 26 \$/hr 26 \$/hr			
3.0 Operating Labor Cost Burners	\$ 3,661,350	+	730		
3.0 Operating Labor Cost Burners Other	\$ 3,661,350 \$ 18,980 \$ -	+	730		
3.0 Operating Labor Cost Burners Other	\$ 3,661,350 \$ 18,980 \$ -	+	730		
3.0 Operating Labor Cost Burners Other Annual Total Operating Labor	\$ 3,661,350 \$ 18,980 \$ -	+	730		
 3.0 Operating Labor Cost Burners Other Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost 	\$ 3,661,350 \$ 18,980 \$ - \$ 18,980 \$ 5,934,526	26 \$/hr	730		
 3.0 Operating Labor Cost Burners Other Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost Total Maintenance Materials 	\$ 3,661,350 \$ 18,980 \$ - \$ 18,980 \$ 5,934,526 \$ 148,363	26 \$/hr Note 2	730		
 3.0 Operating Labor Cost Burners Other Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost Total Maintenance Materials Total Maintenance Labor 	\$ 3,661,350 \$ 18,980 \$ - \$ 18,980 \$ 5,934,526 \$ 148,363 \$ 148,363	26 \$/hr Note 2 Note 2	730		
 3.0 Operating Labor Cost Burners Other Annual Total Operating Labor 4.0 Maintenance Total Installed Direct Cost Total Maintenance Materials 	\$ 3,661,350 \$ 18,980 \$ - \$ 18,980 \$ 5,934,526 \$ 148,363	26 \$/hr Note 2	730		

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO_2 emission factors from 2013 Air Inventory.

Cost Item	Factor Co	st
Direct Costs		
Purchased Equipment Costs		
Primary Equipment ¹	\$	13,658,240
Ancilliary Equipment	\$	-
Allowance for Unforseen	\$	1,365,82
Instrumentation	0.04 \$	600,96
Sales Taxes	0.06 \$	901,44
Freight	0.05 \$	751,20
Purchased Equipment Cost, PEC	\$	17,277,674
Direct Installation Costs		
Foundations and Supports	0.05 \$	751,20
Handling and Erection	0.45 \$	6,801,70
Electrical	0.056 \$	841,34
Piping	0.07 \$	1,051,68
Ductwork	0.03 \$	450,72
Painting	0.01 \$	76,62
Direct Installation Costs, DC	\$	9,973,28
Site Preparation	\$	20,00
Buildings	\$	-
Total Direct Costs (PEC +DC)	\$	27,270,950
Indirect Costs (Installation)		
Engineering	0.15 \$	2,591,65
Construction an Field Expenses	0.1 \$	1,727,76
Contractor Fees	0.1 \$	1,727,76
Startup	0.006 \$	103,66
Performance Test	0.02 \$	345,55
Model Study	0 \$	-
Contingencies	0.1 \$	1,727,76
Two-Week Lost Production at the HSM	\$	15,600,00
Total Indirect Costs, IC	\$	23,824,17
Total Installed Cost	\$	51,095,12

Table B18b. Direct and Indirect Installation Costs, HSM Furnaces - Fuel Switching

¹ Primary equipment includes : replacement low NOx burner systems. Also included is replacement of fuel line to handle added natural gas demand.

Cost Item		Factor	Cos	t
Direct Annual Costs,	DC			
Operatin	g Labor			
	Operator	General Operating	\$	18,980
	Supervisor	15% of Operator	\$	2,847
	Material	5% of Total Operating	\$	1,091
Maintena	ance			
	Maintenance Employee	General Maintenance	\$	91,953
	Supervisor	15% of Maintenance Labor	\$	16,227
	Material	100% of Maintenance Labor	\$	108,180
Utilities				
	Fuel Switch Replacement	Cost	\$	15,001,179
Indirect Annual Costs	s, IC			
Administ	rative Charges	2% of Total Capital Investment	\$	1,021,903
Property	Тах	1% of Total Capital Investment	\$	510,951
Insurance	2	1% of Total Capital Investment	\$	510,951
Overhead	b	60% of total Labor and Materials	\$	9,141,912
Capital R	ecovery	0.1098 x Total Capital Investment	\$	5,610,245
Total Annual Cost			\$	32,036,420
	20	10 Uncontrolled SO 2 Actual Emissions (tpy)		2240.1
	All	owance for Uncontrolled Maint. Outages (tpy) - 15 days		0.0
		2 Removal Efficiency		99.92%
		st-Control Emission Factor (lb/MMBtu)		0.0006
		ntrol Cost Per Ton SO $_2$	\$	14,295

Table B18a. Annual Cost Factors, HSM Furnaces - Fuel Switching

¹ Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001,

January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing COG burners in the boiler house. There are five furnaces, each equipped with multiple natural gas and COG burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This esimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for HSM Fuel Switching

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	•	Basis For Estimate	No.	Unit Cost	Extended Cost	Base Year	Base Cost	Current	Material	Extended Cost
				Materials		Required		(Base Year)		Factor	Year Cost	Factor	(Current Year)
											Factor		
1	COG to NG Replacement Burners 12.5 MM	1	CS	CS	North American Combustion , Inc.	75	\$ 65,000	\$4,875,000	2014	1	1	1	\$ 4,875,000
2	COG to NG Replacement Burners 17.5 MM	2	CS	CS	North American Combustion , Inc.	80	\$ 80,000	\$6,400,000	2014	1	1	1	\$ 6,400,000
3	Panels and Instrumentation	3	-	-	North American Combustion , Inc.	5	\$ 100,000	\$500,000	2014	1	1	1	\$ 500,000
4	Panels and Instrumentation	4	-	-	North American Combustion , Inc.	5	\$ 100,000	\$500,000	2014	1	1	1	\$ 500,000
5	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	\$ 1,383,240	\$1,383,240	2014	1	1	1	\$ 1,383,240
6													
7													
8													
9													
10													
21													
													\$ 13,658,240

Notes:

1 Burner system includes burner, fuel train/control valves, blower.

2 Burner system includes burner, fuel train/control valves, blower.

3 Panels for Smaller Burners. Actual configuration of panels will depend on detailed systems control analysis.

4 Panels for Larger Burners. Actual configuration of panels will depend on detailed systems control analysis.

BY: KJ 2-12-14

\$ 13,658,240

5.0 Installed Equipment Costs for HSM Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

5.1 Baseline Cost of Fuel -2010 5,930,934 MMBtu/yr Total Usage NG HHV 1012 Baseline NG 2,801,957 MMBtu/yr NG 0 0006 1,661.24 lbs /yr Baseline COG 3,128,978 MMBtu/yr BFG HHV 89 COG 1.431 4.478.450.16 lbs /vr Baseline BFG MMBtu/yr COB HHV 496 BFG 0.08279 lbs /yr 8,760 hrs/yr 4,480,111 lbs /yr Annual Hours Operation Total Cost NG 4.89 (Based on 2010 cost) 2,240.06 tons/yr Cost COG \$ 2.92 (Based on 2010 Cost) Baseline Annual Cost 22,838,183 (Cost NG and COG) Ś 5.2 Fuel Use After Fuel Switch **Total Rating** 5,930,934 MMBtu/yr Post Fuel Switch NG 5,930,934 MMBtu/yr NG HHV 1012 NG 0 0006 3,516.36 lbs /yr COG Post Fuel Switch COG MMBtu/yr BEG HHV 89 1 4 3 1 lbs /vr Post Fuel Switch BFG MMBtu/yr COG HHV 496 BFG 0.082787 lbs /yr 3,516 lbs /yr 8,760 hrs/yr Annual Hours Operation Total Cost NG 6.38 (Based on average historical USS natural gas prices) 1.76 tons /yr Future Projected Annual Cost 37,839,362 (Cost NG and COG) Ś Post Fuel Switch SO₂ Emission Reduction 2,238.3 tpy Post Control SO₂ Factor: 0 0006 lb/MMBtu 5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost \$ 15,001,179 3.0 Operating Labor Cost 18,980 1 hr/shift x 2 shifts x 365 day/yr 26 \$/hr 730 Burners \$ 26 \$/hr Other Ś 0 18,980 Annual Total Operating Labor Ċ 4.0 Maintenance Total Installed Direct Cost 4,327,217 Ś **Total Maintenance Materials** 108,180 Note 2 \$ Total Maintenance Labor 108,180 Note 2 Ś Ś Total Annual Maintenance Cost 216,361 Note 3 15,236,519 TOTAL LABOR AND MATERIALS \$

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983,

prepared for Ohio EPA, Table 5-1.

2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.

3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

4. Fuel SO₂ emission factors from 2013 Air Inventory.

5. Actual rating is 2660 MMBtu/hr. Firing rate adjusted using 2013 emission factors to reach the PTE of 620.6 lb/hr (2713 tpy).

Reasonably Available Control Technology (RACT) Analysis.

RACT analysis for the control of sulfur dioxide (SO₂) emissions for the River Rouge and Trenton Channel Power Plants.

DTE Electric Company River Rouge and Trenton Channel Power Plants

April, 2014

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Executive Summary

This document is a reasonably available control technology (RACT) analysis for the control of sulfur dioxide (SO₂) emissions from the coal-fired electric generating units at the River Rouge and Trenton Channel Power Plants. This RACT analysis evaluated eight control technologies in a "top-down" analysis, including wet and dry flue gas desulfurization (FGD), two options for dry sorbent injection, and low sulfur fuels, including natural gas, distillate fuel oil, low sulfur subbituminous coals, and a blend of low sulfur subbituminous and bituminous coals. With respect to natural gas and distillate fuel oil, these fuels are not technically feasible control technologies because the use of these fuels would change the fundamental nature of the affected coal-fired electric generating units and redefine the source. The following table summarizes the control options and the average cost effectiveness for each technically feasible control technology at the River Rouge and Trenton Channel Power Plants.

Control Technology Option	Achievable Emission Rate ^a ,	Average Cor \$ per	
	lb/mmBtu	RR2, RR3, TCHS ^b	TC9
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	\$7,230 to \$11,610	\$5,080
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	\$8,460 to \$13,260	\$6,020
3. Sorbent Injection (optimized for SO ₂ control).	0.48 0.72 ^c	\$7,210 to \$10,980	\$6,750
 Sorbent Injection (MATS Compliance). 	0.72 1.02 ^c	\$15,530 to \$31,030	\$12,720
5. Low Sulfur Subbituminous Coal.	0.8	\$1,970 to \$2,240	\$3,800 to \$5,060
 Low Sulfur Subbituminous / Bituminous Coal Blend. 	1.2		
Current Allowable	1.67		

SO₂ control technologies and costs for the River Rouge and Trenton Channel Power Plants.

Footnotes

a. The achievable emission rate is based on a 12-month average.

- b. RR2 means River Rouge Unit 2; RR3 means River Rouge Unit 3; TCHS means the Trenton Channel High Side Boilers 16, 17, 18, and 19; TC9 means Trenton Channel Unit 9.
- c. The first emission rate for sorbent injection is for RR2, RR3, and TCHS based on reductions from low sulfur subbituminous coal (Option 5); the second rate is for TC9 based on reductions from the coal blend (Option 6).

Based on this RACT analysis, DTE Electric Company has concluded that an emission rate equal to the use of low sulfur subbituminous coal (which is the lowest SO₂ emitting coal available) is technically and economically feasible for the River Rouge Units 2 and 3, and for the Trenton Channel High Side Boilers 16, 17, 18, and 19. However, because Trenton Channel Unit 9 cannot achieve full capacity when firing only low sulfur subbituminous coal, the costs of this reduced electric output would range from \$3,800 to \$5,060 per ton of SO₂ controlled. In the individual years from 2016 to 2022, these costs may be more than \$11,200 per ton of SO₂ controlled. Based on these high costs, DTE Electric Company has concluded that the use of only low sulfur subbituminous coals is not economically feasible for Trenton Channel Unit 9.

Based on this RACT analysis, the following sulfur dioxide (SO₂) limits represent RACT for the River Rouge and Trenton Channel Power Plants.

Units	RACT Emission Limits
River Rouge Unit 2	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Unit 3	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Units 2 and 3 Combined	77.22 tons per day, based on a 24-hour or daily basis.
Trenton Channel Boilers 16 - 19	0.8 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Unit 9	1.2 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Boilers 16 - 19 and Unit 9	117.83 tons per day, based on a 24-hour or daily basis.

Proposed SO₂ RACT limits for the River Rouge and Trenton Channel Power Plants.

The proposed long term limit of 0.8 lb/mmBtu would result in a 52% reduction in the allowable emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The proposed long term limit of 1.2 lb/mmBtu would result in a 28% reduction in the allowable emissions for Trenton Channel Unit 9. The reductions in potential SO_2 emissions based on these limits are summarized in the following table.

Comparison of the current potential SO_2 emissions to the potential emissions based on the proposed RACT limits.

11	Potential to Emit, tons per year	
Unit	Current	Proposed
River Rouge Unit 2	15,768	7,989
River Rouge Unit 3	18,433	9,356
Trenton Channel Boilers 16, 17, 18, and 19	22,112	10,593
Trenton Channel Unit 9	33,134	23,810
Total	89,447	51,747

Sulfur Dioxide (SO₂) RACT Analysis

DTE Electric Company - River Rouge and Trenton Channel Power Plants

Although wet and dry FGD systems can reduce SO_2 emissions by 90 to 95%, the costs for both wet and dry FGD systems exceed \$5,080 per ton of SO_2 controlled for all of the units at their expected utilization equal to a 55% capacity factor. The high costs for wet and dry FGD systems reflect the high capital costs of these technologies. For both power plants, these costs are estimated at \$865 million for wet limestone forced oxidation (wet FGD) systems, and \$990 million for lime spray dry FGD systems. Based on these high costs, wet or dry FGD systems are not economically feasible control technologies.

This analysis included two levels of reduction for sorbent injection. The first level is based on the use of sorbent injection optimized for SO_2 control. This option is expected to achieve an SO_2 control efficiency of at least 40%. However, the use of sorbent injection optimized for SO_2 control is also not economically feasible, with average costs exceeding \$6,750 per ton of SO_2 controlled for all of the units at their expected utilization equal to a 55% capacity factor. These power plants will require the use of sorbent injection to comply with the Mercury and Air Toxics Standards (MATS) under 40 CFR 63, Subpart UUUUU beginning in 2016. Therefore, the second level of control represents the SO_2 reduction which may occur using sorbent injection to achieve the MATS standards. The use of sorbent injection to reduce hydrogen chloride (HCl) emissions for MATS compliance is expected to achieve a 10% incidental reduction in SO_2 emissions. However, the cost effectiveness for the control of SO_2 emissions based on the reduction achieved through the use of sorbent injection for MATS compliance is also not economically feasible, with costs exceeding \$12,720 per ton of SO_2 controlled for all units.

The River Rouge and Trenton Channel Power Plants currently utilize a blend of low sulfur bituminous and low sulfur subbituminous coals. The use of only low sulfur subbituminous coal (which is the lowest SO_2 emitting coal available) would further reduce SO_2 emissions from these power plants. For the River Rouge Units 2 and 3, and the Trenton Channel High Side Boilers 16, 17, 18, and 19, an SO_2 emission rate equal to the rate achieved using only low sulfur subbituminous coal is technically and economically feasible, and is expected to reduce SO_2 emissions to less than 0.8 lb/mmBtu based on a 12-month average, and a mass emission rate for each boiler is based on the mass emission rate for the boiler, expressed in tons per day. This form of the short term emission limit is consistent with the current SO_2 emission limits for these power plants.

Trenton Channel Unit 9, like the other units, was designed to fire bituminous coals. However, Trenton Channel Unit 9 cannot achieve full capacity when firing only low sulfur subbituminous coal. Because low sulfur subbituminous coals have a much lower heat value than bituminous coals, firing only low sulfur subbituminous coals in this unit would reduce the steam output of the boiler and reduce the maximum electric generating capacity or derate the unit by approximately 50 MW. The costs of this reduced electric output would include capacity costs and replacement power costs. For the Trenton Channel Unit 9, the average cost effectiveness for the use of only subbituminous coal would range from \$3,800 to \$5,060 per ton of SO₂ controlled. This cost is not economically feasible for Unit 9.

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Attachments

1. CUECost - Air Pollution Control Systems Economics Spreadsheet for the River Rouge and Trenton Channel Power Plants. Analysis based on 55% utilization for each unit.

On June 3, 2010, EPA revised the primary sulfur dioxide (SO₂) National Ambient Air Quality Standard (NAAQS) by establishing a new 1-hour standard of 75 parts per billion (ppb). EPA must designate areas as "nonattainment," "attainment," or "unclassifiable" for this standard. On February 6, 2013, EPA sent a letter to the State of Michigan with its intended designations. This letter indicated a proposed nonattainment area including portions of Wayne County, Michigan. DTE Energy's River Rouge and Trenton Channel Power Plants are located within the recommended nonattainment area.

The nonattainment area plan provisions under section 172(c) of the Clean Air Act (CAA) set out the planning requirements for areas not meeting a NAAQS. One plan requirement is the application of reasonably available control technology (RACT) controls on existing sources in the nonattainment area. Section 172(c)(1) of the CAA states: "Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the National Primary Ambient Air Quality Standards." The U.S. EPA states that RACT means devices, systems, process modifications, or other apparatus or techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain the NAAQS and the social, environmental, and economic impact of such controls.

This RACT analysis for the control of sulfur dioxide (SO_2) emissions from the River Rouge and Trenton Channel Power Plants provides specific information on SO_2 reduction strategies that are available and technologically feasible for the affected coal-fired electric generating units. Evaluated technologies include fuel switching or cleaning, and post combustion control systems including wet and dry flue gas desulfurization (FGD), and dry sorbent injection. Each technology examined includes an estimate of the SO_2 reduction in tons per year, and also includes a cost evaluation for each technically feasible reduction strategy, expressed in dollars per ton of pollutant controlled.

With respect to low sulfur containing fuels, this RACT analysis includes an evaluation of low sulfur coal, as well as low sulfur distillate fuel oil and natural gas as new primary fuels. However, the use of distillate fuel oil and natural gas as primary fuels are not technically feasible control technologies, since the use of these fuels would change the fundamental nature of the affected coal-fired boilers and redefine the source. The U.S. EPA has a long standing policy that the requirement to apply BACT or RACT is not a means to redefine the source. In the U.S. EPA guidance document *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA-457/B-11-001, March 2011, page 29, EPA states: "For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit."

Chapter 2. Affected Power Plants.

2.1 River Rouge Power Plant.

The River Rouge Power Plant is located in the City of River Rouge, Wayne County and operates under renewable operation permit (ROP) No. MI-ROP-B2810-2012. The River Rouge Power Plant has three electric generating units. Unit 1 has a 2,400 mmBtu per hour natural gas-fired boiler which is not part of this analysis. Units 2 and 3 are solid fuel-fired boilers rated at 2,280 and 2,670 mmBtu per hour, respectively. Units 2 and 3 have nameplate electric generating capacities of 292 and 358 MW, respectively. Both of these boilers are permitted to fire pulverized coal, natural gas, blast furnace gas, and coke oven gas. Units 2 and 3 are exhausted to separate stacks. The stack dimensions are included in Table 1.

Table 2 is a summary of the current potential or allowable SO_2 emissions based on the current emission limits in ROP MI-ROP-B2810-2012. Past actual SO_2 emissions from the U.S. EPA's Air Market's Program database are summarized in Table 3. From Tables 2 and 3, the actual SO_2 emissions in 2013 were 9,214 tons per year, as compared to a current allowable rate of 33,638 tons per year.

The River Rouge Power Plant also has four (4) distillate fuel oil-fired generators rated at 2.75 MW each. ROP No. MI-ROP-B2810-2012 limits SO₂ emissions to 120 parts per million (ppm) by volume at 50% excess air, equal to an SO₂ emission rate of 0.27 lb/mmBtu. These generators are not part of this analysis.

Boiler	Stack Height feet
EU-Boiler#2	385
EU-Boiler#3	425

TABLE 2.	Potential SO	emissions fo	or the River	Rouge Power	Plant Units 2 and 3.

Boiler	Boiler Rating	Allowable SO ₂	Emission Rate	Potential Emissions
Boller	mmBtu/hour	lb/mmBtu	ton/day	ton/year
EU-Boiler#2	2,280	1.67	43.20	15,768
EU-Boiler#3	2,670	1.67	50.50	18,432
TOTAL			93.70	34,200

Unit ID	Voor	Actual SO ₂ Emissions		
Unit ID	Year	lb/mmBtu (annual ave.)	ton/year	
2		0.71	4,355	
3	2013	0.85	4,859	
TOTAL		0.78	9,214	
2		0.75	3,705	
3	2012	0.68	4,497	
TOTAL		0.71	8,202	
2		0.86	5,893	
3	2011	0.75	4,757	
TOTAL	7	0.80	10,650	

TABLE 3. Actual SO₂ emissions for the River Rouge Power Plant Units 2 and 3.

FIGURE 1. River Rouge Power Plant located at 1 Belanger Park Drive, River Rouge.



2.2 Trenton Channel Power Plant.

The Trenton Channel Power Plant is located in the city of Trenton, Wayne County, and operates under ROP No. 199600204. The Trenton Channel Power Plant consists of five coal and oil fired boilers, and five oil-fired Slocum peaker generating units. Boilers 16, 17, 18, and 19 are similar, tangentially fired, coal-fired boilers with a combined heat input capacity of 3,023 mmBtu per hour for all four boilers. Boiler 9A is a coal-fired boiler with a rated heat input capacity of 4,530 mmBtu per hour. This boiler serves an electric generator with a nameplate capacity of 520 MW(e). Boilers 16, 17, 18, and 19 are exhausted to a common stack which is 559 feet above grade. Boiler 9A is exhausted to a separate dedicated stack which is 561 feet above grade. The stack dimensions are included in Table 4.

In accordance with ROP No. 199600204, Table F-1.2, the sulfur content of the coal as fired in boilers 16, 17, 18, 19, and 9A shall not exceed 0.83 pounds per mmBtu of heat input (i.e., an emission limit of 1.67 lb SO_2 /mmBtu), based on a monthly average. In addition, SO_2 emissions may not exceed 151.36 tons per day and 55,246.4 tons per year from all boilers combined. Table 5 is a summary of the current potential or allowable SO_2 emissions based on the current emission limits in ROP No. 199600204. Past actual SO_2 emissions for the Trenton Channel Power Plant from the U.S. EPA's Air Market's Program database are summarized in Table 6.

Boiler	Stack Height	
	feet	
Boiler#16, 17, 18, and 19	559	
Boiler #9A	561	

TABLE 4. Boiler stack data for the Trenton Channel Power Plant.

TABLE 5. Potential SO ₂ emissions for the Trenton Channel High Side and Unit 9.
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Boiler	Boiler Rating Allowable SO ₂ Emission		Emission Rate	Potential Emissions
Donor	mmBtu/hour	lb/mmBtu	ton/day	ton/year
Boilers 16, 17, 18, and 19	3,023	1.67	60.58	22,112
Unit 9A	4,530	1.67	90.78	33,134
TOTAL			151.36	55,246

	No T	Actual SO ₂ Em	Actual SO ₂ Emissions		
Unit ID	Unit ID Year	lb/mmBtu (annual ave.)	ton/year		
16		0.79	766		
17		0.79	1,096		
18	2012	0.78	852		
19	2013	0.79	1,023		
9A		1.18	16,254		
TOTAL		1.08	19,992		
16		1.13	1,252		
17		1.20	1,508		
18	2012	1.12	1,221		
19	2012	1.18	1,445		
9A		1.22	16,999		
TOTAL		1.21	22,426		
16		1.29	1,669		
17		1.29	1,478		
18	2011	1.29	1,333		
19	2011	1.29	1,818		
9A		1.22	16,421		
TOTAL		1.24	22,720		

TABLE 6. Actual SO₂ emissions for the Trenton Channel Power Plant.

FIGURE 2. Trenton Channel Power Plant located at 4695 Jefferson Ave., W Trenton.



Sulfur Dioxide (SO₂) RACT Analysis DTE Electric Company – River Rouge and Trenton Channel Power Plants

RTP Environmental Associates, Inc. April 2014

Chapter 3. RACT Analysis Methodology.

3.1 Reasonably Available Control Technology (RACT).

The nonattainment area plan provisions under section 172(c) of the Clean Air Act (CAA) require the application of Reasonably Available Control Technology (RACT) for the control of air emissions for existing sources located in areas that are not meeting national ambient air quality standards (NAAQS). EPA has defined RACT as: "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). The RACT process determines, and then requires the use of reasonable available control requirements to reduce or limit emissions. These requirements identify the lowest emission limit that a source is capable of meeting after considering technological and economic feasibility.

3.2 Top Down Control Technology Analysis Methodology.

The U.S. EPA recommends a "top-down" approach in conducting a BACT or LAER control technology review. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

- 1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
- 2. Eliminate all technically infeasible control technologies;
- 3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
- 4. Evaluate most effective controls and document results; and
- 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The most important issue of the BACT review is generally the economic impact. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

Because this review methodology is a well-accepted method for evaluating controls for emission sources, this top down control technology analysis methodology has been used in this RACT analysis.

3.3 New Versus Modified Facilities.

There can be significant differences in the technical and economic feasibility of retrofitting controls on existing units, versus the use of these same controls on new units. In addition, a given control technology may not be able to achieve the same level of control when retrofitted onto existing units as the same control technology can achieve on new units. Retrofitting controls on existing units can also have significantly different costs as compared to the use of these same technologies on new units. Retrofitting controls on existing units can have numerous issues, including site constraints and room for the new controls, demolition requirements for existing controls, and unit down time during construction and interconnection of the new systems.

3.4 Technical Feasibility.

Step 2 of the RACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed at full scale and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

Under the U.S. EPA's top down BACT analysis methodology, the technology must be commercially available for it to be considered as a potential control option. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. A technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in physical and chemical gas stream characteristics.

3.5 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology.

As noted above, EPA has defined RACT as: "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). U.S. EPA guidance from 1994 indicates that cost effectiveness should be within \$160 to \$1,300 per ton of pollutant controlled¹. Based on the U.S. Bureau of Labor Statistics Consumer Price Index (CPI) Calculator, available at http://www.bls.gov/data/inflation calculator.htm, \$1.00 in 1994 is equal to \$1.58 in 2014. *Therefore, the equivalent cost effectiveness, expressed in 2014 dollars, is \$250 to \$2,050 per ton of pollutant controlled*.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

Average Cost Effectiveness	Control option annualized cost
(\$ per ton removed)	Baseline emission rate – Control option emissions rate

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. The baseline emission rate represents uncontrolled emissions for the source. However, cost effectiveness may be estimated based *on the realistic operation of the emissions unit in question*. In the EPA's New Source Review Manual, page B.37, the EPA states "In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. *For this reason, costs in this analysis are calculated based on the expected normal utilization of these units of 55%*.

In the cost analyses presented in this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) *are based on a project life of 7 years*. A 7 year project life is used because the River Rouge Units 2 and 3 were constructed in 1954 and 1955, the Trenton Channel Highside Boilers 16 – 19 were constructed in 1948 – 1949, and the Trenton Channel Boiler 9A was constructed in 1965. These electric generating units are therefore from 49 to 66 years old. The construction of post combustion wet and dry FGD systems would require at least 3 years to complete after project approval; the construction of sorbent injection systems will require at least 2 years to complete. Therefore, at the end of a 7-year project cost recovery period, these units would be from 58 to 75 years old. A longer project recovery period is simply not compatible with the age of these units.

¹ From the U.S. EPA memorandum *Cost-Effective Nitrogen Oxides (NOx) Reasonably Available Control Technology (RACT)*, from D. Kent Berry, Acting Director Air Quality Management Division (MD-15), March 16, 1994, available at <u>http://www.epa.gov/ttn/caaa/t1/memoranda/costcon.pdf</u>.

Chapter 4. Potential SO₂ Control Technologies.

Step 1 of this RACT analysis involves the identification of all available potential control technologies for the control of sulfur dioxide (SO₂) emissions from fossil fuel-fired electric generating units.

 SO_2 emissions from fossil fuel-fired electric generating units result from the oxidation of sulfur compounds in the fuel. During combustion, the majority of the fuel sulfur is emitted as SO_2 . A small portion of the sulfur is further oxidized to sulfur trioxide (SO_3). When the flue gas temperature drops below the dew point temperature, sulfur trioxide is converted to sulfuric acid (H_2SO_4). Therefore, control technologies which control SO_2 emissions also reduce sulfuric acid mist emissions to varying degrees. A portion of the SO_2 and SO_3 in the flue gas may react with alkaline products in the ash to form filterable particulate matter. A portion of the sulfur compounds are also bound with bottom ash and are removed in the bottom ash. In this control technology review, all controls are evaluated based on the assumption that 100% of the sulfur in the fuel is converted to SO_2 .

Potential sulfur dioxide (SO_2) control technologies include pre-combustion controls such as low sulfur fuels, and post combustion controls, such as flue gas desulfurization. The following references were used to identify potential SO₂ control technologies: *Controlling SO₂ Emissions: A Review of Technologies* (EPA-600/R-00-093, October 2000), the U.S. EPA's RACT/BACT /LAER Clearinghouse (RLBC), the U.S. EPA's National Coal-Fired Utility Projects Spreadsheet Updated July 2007, and numerous air permits issued by states and the U.S. EPA. Technologies identified to control SO₂ emissions from pulverized coal-fired EGUs are summarized below.

Fuel Cleaning	 Coal Washing Low Sulfur Fuels Low Sulfur Coal Natural Gas Distillate Fuel Oil Biomass
Post Combustion Controls	 Wet Flue Gas Desulfurization (FGD) Dry and Semi-Dry FGD Circulating Fluidized Bed (CFB) Dry FGD Sorbent Injection Emerging Control Technologies.

Potential available SO₂ control technologies.

Chapter 5. Technically Feasible SO₂ Control Technologies.

Step 2 of this RACT analysis involves the evaluation of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source of comparable size, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option. In addition, the technology must be commercially available for it to be considered technically feasible. Finally, technologies which fundamentally redefine a source are also not technically feasible control options.

5.1 Low Sulfur Fuels.

Because SO_2 emissions occur from the oxidation of sulfur in the fuel, SO_2 emissions may be reduced directly by reducing the sulfur content of the fuel. Potential low sulfur fuels include low sulfur coal(s), low sulfur distillate fuel oil, natural gas, and biomass fuels.

5.1.1 Low Sulfur Coal.

All of the affected coal-fired boilers, including the River Rouge Boilers 2 and 3, and the Trenton Channel Boilers 16, 17, 18, 19, and 9A, are subject to the MDEQ rule R 336.1401, Emission of sulfur dioxide from power plants. The applicable requirement for these boilers in R 336.1401, Table 41 is an SO₂ limit of 1.67 pounds of SO₂ per million Btu of heat input. This limit is expressed on a 24-hour basis for the River Rouge Boilers 2 and 3, and is based on a monthly average for the Trenton Channel Boilers 16, 17, 18, 19, and 9A. Low sulfur coal is available and technically feasible for these boilers. However, the use of 100% low sulfur subbituminous coals can have adverse effects on these boilers, including reduced maximum output capabilities or derating due to the lower heat content of these low sulfur coals. There is also inherent variability in sulfur content since coal from one mine or area can have a significantly different sulfur content than from another mine or area in the same region.

5.1.2 Natural Gas, Low Sulfur Fuel Oil, and Biomass Fuels.

All of the affected coal-fired boilers, including the River Rouge Boilers 2 and 3, and the Trenton Channel Boilers 16, 17, 18, 19, and 9A, were designed and constructed as coal-fired electric generating units. The purpose of these units is to provide baseload electric generating capacity from the use of coal as the primary fuel. These units were not designed to burn natural gas or low sulfur distillate fuel oil to generate a meaningful portion of the unit load. These units were designed to utilize coal as the primary fuel, which

is clearly evident by the complex and advanced material handling systems and air quality control systems which are installed on these boilers.

The U.S. EPA has a long standing policy that the requirement to apply BACT or RACT is not a means to redefine the source. The U.S. EPA prepared a guidance document for greenhouse gases titled *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA-457/B-11-001, March 2011, page 29 to assist permit writers and permit applicants in addressing the PSD permitting requirements for greenhouse gases. On page 29, EPA states:

The CAA includes "clean fuels" in the definition of BACT.⁷¹ Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.*, coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit." (*emphasis added*)

Based on U.S. EPA policies and guidance, the switching to a different primary fuel type is not an available control alternative for this project, since the use of a different primary fuel such as natural gas or distillate fuel oil would redefine the project.

There may be other reasons that repowering with natural gas or fuel oil may be technically infeasible, including the availability of the fuel at the plant location. For example, the fuel oil required to replace 100% of the heat input for one of the River Rouge units would be at least 16,200 gallons per hour, or about 2 to 4 semi tanker trucks per hour. This extremely high oil consumption rate may be infeasible to implement at these power plants as a permanent replacement fuel.

With respect to biomass fuels, while biomass fuels have low sulfur contents, the use of biomass would redefine the design and purpose of these units. The design of these boilers would need to be fundamentally changed in order to allow the utilization of biomass in these units in place of pulverized coal. In addition, there is not a sufficient amount of biomass available in southeastern Michigan to provide the fuel requirements for these units.

5.1.3 Conclusions Regarding Low Sulfur Fuels.

Low sulfur coals are an available control technology for the coal-fired boilers at the River Rouge and Trenton Channel Power Plants. However, the use of natural gas, low sulfur fuel oil, or biomass as a means of reducing SO_2 emissions would result in a significant change to both the design and the purpose of these boilers. Therefore, the use of natural gas, low sulfur fuel oil, and biomass fuels are not technically feasible SO_2 control options for these boilers.

5.2 Fuel Cleaning.

Coal is a mineral consisting of a heterogeneous mixture of organic and inorganic matter. The impurities associated with coal may be classified as inherent or extraneous. Inherent impurities cannot be physically separated from coal. However, extraneous impurities such as rocks, scrap iron, and pyrite (iron disulfide, FeS_2) can be physically separated to varying degrees through coal cleaning. Sulfur is generally present in coal in three forms: pyritic, sulfate, or organic. The pyritic portion of sulfur in coal may vary from 10% to 80% of the total sulfur content. Large pyrite particles can be removed by physical cleaning. Sulfate forms of sulfur are usually calcium or iron sulfates, and generally account for less than 0.1% of the coal sulfur content. Organic sulfur is chemically bound to the coal and cannot be separated by coal cleaning. Therefore, fuel cleaning is only effective for coals containing high percentages of sulfur as pyrite.

In the coal cleaning process, "run-of-mine" coal is first cleaned of trash, crushed, and screened. The coal is then cleaned by gravity separation. In the gravity separation process, the desirable coal organic fraction floats in a separating fluid (usually an aqueous suspension of magnetite in water), while pyrite, soil, rock, and shale debris sink. The floating organic fraction is transferred to a dewatering system. Dewatering is a key cleaning step, since the reduction of water reduces shipping costs and improves the coal heating value. Nearly all of the bituminous coals from Illinois and Appalachia are washed before being shipped from the mine.

While coal cleaning can achieve substantial sulfur reductions on some coals (for example, 20 to 30% for Illinois bituminous coals), not all coals can be effectively washed. In particular, subbituminous coals have low sulfur, low ash and small coal particle sizes. Washing of subbituminous coals is not technically feasible because of the minimal improvement in sulfur content and the high energy requirements needed to effectively dewater the coal.

5.2.1 Technical Feasibility

Fuel cleaning is a technically feasible control option to reduce the sulfur content of Illinois and Appalachia bituminous coals with relatively high percentages of sulfur as pyrite. Fuel cleaning is not technically feasible for subbituminous coals because of the minimal improvement in sulfur content and the high energy requirements needed to effectively dewater the coal. In this RACT analysis, the use of low sulfur coals is effective, and in some cases the use of low sulfur coals may include fuel cleaning as part of the achieved low sulfur coal. However, fuel cleaning will not be considered separately from the use of low sulfur coal.

5.3 Flue Gas Desulfurization.

Flue Gas Desulfurization (FGD) technologies used for coal-fired boilers may be broadly classified as "wet" and "dry" systems. Wet FGD systems are characterized by low flue gas outlet temperatures, saturated or wet flue gas conditions, and a wet sludge reaction product which is dewatered before reuse or disposal. For most coals and boiler types, the flue gas saturation temperature is about 130 °F. In wet FGD applications, the primary particulate matter control system is typically located *upstream* of the wet FGD system so that the fly ash and FGD system reaction products are collected *separately*. This is

necessary to avoid saturated conditions in the PM control system which would plug a fabric filter baghouse or dry ESP. This can also be advantageous for the beneficial reuse of fly ash and the wet FGD reaction products such as gypsum, since the ash and gypsum can be collected separately. Wet FGD systems are also characterized by relatively high water use as compared to dry FGD systems.

Conversely, dry FGD systems are characterized by outlet flue gas temperatures about 20 to 50 °F above the saturation point, or about 150 to 180 °F. In dry FGD applications, the particulate control system is located *downstream* of the dry FGD system so that the fly ash and the FGD reaction product are *commingled* into a single byproduct or waste stream. However, in retrofit applications such as the River Rouge and Trenton Channel boilers which already have dry ESPs, the semi-dry FGD system can be installed downstream of the dry ESP systems, so that the fly ash and FGD system reaction products may be collected *separately* much like a conventional wet FGD system. Finally, dry FGD systems are characterized by reduced water use as compared to wet FGD systems.

5.4 Wet Flue Gas Desulfurization.

Wet FGD is a well demonstrated technology for the control of SO_2 emissions from coal-fired electric generating units utilizing pulverized coal-fired boilers. In a wet FGD system, the flue gas is exposed to an alkaline reagent which reacts with SO_2 to form a solid. There are several alkaline reagents used in wet FGD systems, including water-based slurries of lime or limestone, liquors containing dissolved sodium or magnesium salts, or amine based liquors including ammonia. Most wet FGD systems use lime or limestone as the alkaline reagent and produce calcium sulfite and / or calcium sulfate (gypsum). A typical modern wet flue gas desulfurization system absorber tower is shown in Figure 3.

Regardless of the wet FGD design, the flue gas leaving the absorber will be saturated with water, and the stack will have a highly visible condensed moisture plume. The conditions downstream of the absorber are highly corrosive, requiring corrosion-resistant materials for the downstream ductwork and stack. Equipment is also needed to manage the condensation that occurs on the downstream ductwork and in the stack. The wet FGD reaction products also require dewatering, usually by a combination of hydroclones and vacuum filters. Relatively large areas are needed to manage the reagent processing and the byproduct dewatering and storage operations. These factors contribute to the capital and operating costs of wet FGD systems. Note that the FGD systems do not normally have bypass stacks. Therefore, the wet FGD systems must be operational when the units are firing coal to prevent damage to the stacks.

5.4.1 Wet Limestone with Forced Oxidation.

In recent years, the WFGD market has turned almost completely to the use of wet lime or limestone with forced oxidation on pulverized coal-fired boilers because it improves SO_2 control, reduces chemical scale formation, and produces gypsum, a stable and potentially valuable byproduct. Wet limestone with forced oxidation (LSFO) is a modification of the conventional wet limestone FGD process. A conventional wet limestone system forms a scrubber product composed mostly of calcium sulfite (CaSO₃). The LSFO process further oxidizes calcium sulfite to calcium sulfate dihydrate (gypsum, or CaSO₄·2H₂O). The gypsum content of the scrubber sludge is typically 95% on a dry basis, making the sludge easier to dewater and much more valuable. Gypsum is a naturally occurring mineral that is mined around the

world for use as a raw material in the manufacture of plaster, wallboard, Portland cement, agricultural soil conditioners, and various other products.

In a typical LSFO process, flue gas exits the primary particulate matter pollution control system such as an electrostatic precipitator at approximately 300 °F and enters a spray tower where an alkaline slurry consisting of limestone (calcium carbonate), calcium sulfite, and calcium sulfate is contacted with the flue gas. Through a series of reactions, SO₂ in the flue gas reacts with calcium carbonate in the limestone to form CaSO₃. The flue gas exits the absorption tower through a series of chevron mist eliminators to remove entrained moisture droplets. The calcium sulfite remains in the slurry which drains into a recirculation tank located at the bottom of the spray tower. By injecting air into the slurry using fans or blowers, the calcium sulfite is oxidized to CaSO₄·2H₂O. A portion of the slurry in the recirculation tank is pumped back into the spray tower, and a portion is removed. The removed slurry is dewatered and stockpiled for transport offsite. The overall FGD reaction is:

$$CaCO_{3}(s) + SO_{2}(g) + \frac{1}{2}O_{2}(g) + 2H_{2}O \longrightarrow CaSO_{4} \cdot 2H_{2}O(s) + CO_{2}(g)$$

The LSFO process can achieve high levels of control on pulverized coal-fired boilers. Recent BACT determinations put the level of control in the 95-97% range. However, the same performance principle for any SO₂ control system is also true for the LSFO – as the boiler outlet SO₂ concentration decreases, the ability to achieve high control efficiencies also decreases. As a result, the higher level of performance for LSFO systems stated as a percentage reduction can only be achieved when the boiler is firing higher sulfur content fuels.

5.4.2 Advanced Wet FGD Designs.

The first FGD systems in the U.S. were installed largely in response to the 1971 Clean Air Act. Most of these original FGD systems were calcium based wet FGD systems. About half of these early systems were lime and the other half limestone. Many of the original FGD systems were plagued with operational issues that included scaling, plugging, and low SO_2 removal efficiency - generally less than 90%. These first wet FGD systems utilized spray tower absorbers, often without a perforated plate tray, as the method for contacting the flue gas with the alkaline reagent.

FGD systems installed in the 1990's were 2^{nd} and 3^{rd} generation systems which generally achieved greater than 90% SO₂ removal with improved reliability. The limestone systems installed during this time were mostly forced oxidation systems which demonstrated the ability to achieve similar performance and reliability as lime systems. The SO₂ removal efficiencies of the 2^{nd} and 3^{rd} generation systems were improved primarily by improving gas to liquid contact. These improvements include absorption trays with perforated plates and multiple levels of interspatial reagent spray nozzles.

FGD system suppliers have introduced several new designs to further improve the flue gas-to-liquid reagent contact and minimize operating costs. Designs such as the Jet Bubbling Reactor developed by Chiyoda and Alstom's Flowpac systems were developed to improve the gas-to-liquid contact by forcing the flue gas to bubble through the liquid reagent using a gas sparger design rather than spraying the alkaline slurry into the gas stream. Mitsubishi developed the Double Contact Flow Scrubber (DCFS)

which uses 'fountains' of slurry to contact the flue gas. Babcock Power Environmental Inc. utilizes bidirectional sprays and wall rings to maximize contact between the flue gas and liquid reagent.

5.4.3 Technical Feasibility

As noted above, WFGD is a well demonstrated, technically feasible control technology for the control of SO_2 emissions from pulverized coal-fired boilers. Wet FGD is typically used on boilers combusting higher sulfur eastern bituminous coals, while dry FGD systems have typically used on boilers firing low sulfur western subbituminous coals.

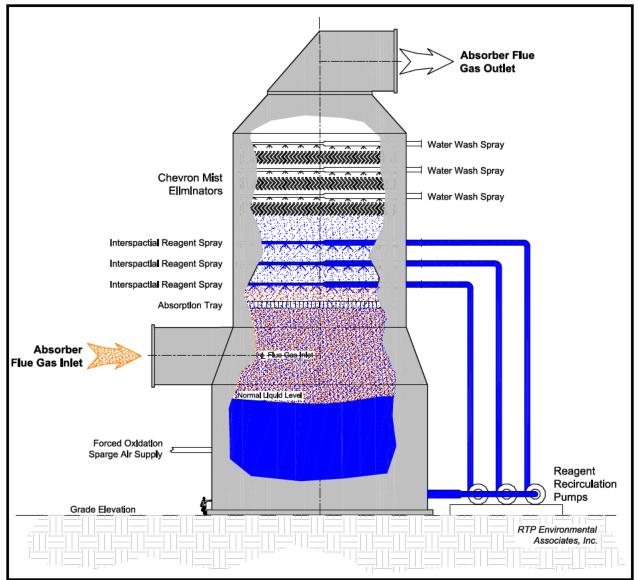


FIGURE 3. Typical modern wet flue gas desulfurization system absorber tower.

5.5 Dry or Semi-Dry Flue Gas Desulfurization.

Dry or semi-dry FGD is a well demonstrated technology for the control of SO₂ emissions from coal-fired electric generating units. Like wet FGD systems, dry FGD systems can be divided into several types. Dry FGD systems involve injecting a dry sorbent into the furnace or flue gas duct; the by-product solids are normally collected with the boiler fly ash. In semi-dry FGD systems, the sorbent is introduced as an aqueous slurry or a humidified dry powder to improve SO₂ control efficiency. The water content is controlled so that the reaction by-products are dry solids. While the flue gas temperature in both dry and semi-dry FGD remains above the adiabatic saturation temperature, the semi-dry systems have lower flue gas exit temperatures and a closer approach to the saturation temperature. The primary PM control system for dry FGD applications is normally a fabric filter baghouse since this PM control technology can provide higher reagent utilization. In this type of application, the baghouse acts much like a fixed bed reactor, allowing for intimate contact between unreacted reagent and SO₂ gas in the filter cake.

Dry and semi-dry FGD systems do not have a saturated plume and therefore do not require the same design elements related to a saturated and corrosive plume as with wet FGD systems. Since the FGD reaction products are also dry, there is no need for dewatering equipment or a wastewater discharge. The reaction product is primarily calcium sulfite, with smaller amounts of calcium sulfate. Because of the calcium sulfite content, the dry FGD byproduct is usually unstable and will undergo pozzolanic (cementitious) reactions when wetted. This material has limited commercial value and is typically landfilled or used for mine fill.

5.5.1 Lime Spray Drying Absorber.

One of the most widely used semi-dry FGD technologies is the lime spray dry absorber (LSDA). The LSDA is a semi-dry FGD technology that is often used in low sulfur pulverized coal-fired boiler applications. The LSDA process employs a spray dryer absorber (SDA) and a downstream PM control device. The SDA introduces a lime or limestone slurry and flue gas at the top of an absorber vessel. Rotary atomizers or dual fluid nozzles are used to create a spray of atomized slurry droplets which are dispersed in the flue gas stream. The water in the slurry droplets evaporates as the flue gas passes through the absorber, cooling and humidifying the flue gas stream and rapidly drying the slurry to a powder. In practice, water is added to control the SDA outlet temperature to approximately 155° F, or an approach temperature approximately 25° F above the saturation temperature. SO₂ in the flue gas reacts with calcium hydroxide to form solid calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄) according to the following overall equations:

$2Ca(OH)_2(s) + 2SO_2(g) + 2H_2O(g)$	$\rightarrow 2(CaSO_3 \bullet 2H_2O)$
$2Ca(OH)_2(s) + 2SO_2(g) + 2H_2O(g)$	$+O_2 \rightarrow 2(CaSO_4 \bullet 2H_2O)$

Fly ash, reaction products, and unreacted lime are captured downstream of the LSDA in the PM control system. A portion of the collected material in the PM control system is recycled back to the SDA to improve reagent utilization.

5.5.2 Advanced Semi-Dry FGD Systems.

Advanced Semi-Dry FGD systems include circulating fluidized bed (CFB) systems, hydrated lime injection systems such as Turbosorp, circulating dry scrubbers (CDS), and flash dry absorbers, also called novel integrated desulphurization system (NIDS). These systems are often utilized in circulating fluidized bed (CFB) boiler applications where excess lime (CaO) produced in the CFB boiler can be used to further reduce SO₂ emissions. The ash captured in the fabric filter baghouse which contains excess lime is hydrated to form calcium hydroxide (Ca(OH)₂). This hydrated ash is then reinjected into the flue gas in a reactor or vessel upstream of the baghouse.

These advanced semi-dry systems may be contrasted with conventional LSDA systems in that the ash is humidified but remains a free-flowing solid, as opposed to being hydrated to a slurry as in the LSDA process. This lower water content eliminates the need for slurry handling, atomization, and a large reactor or absorber vessel. Reinjecting a dry solid also allows the reagent to disperse rapidly in the flue gas. These systems may also be contrasted with conventional SDA systems in that the solids recirculation rate is 30 to 100 times, compared to 3-5 times in a conventional SDA system.

These semi-dry FGD systems have demonstrated the ability to achieve SO_2 emission reductions equivalent to or even greater than that achieved by conventional dry FGD systems and LSDA systems. For example, the CFB semi-dry FGD process uses lime, water and recycled solids from the CFB boiler and fabric filter baghouse in a fluidized bed reactor to form calcium sulfite and calcium sulfate as described above. In a CFB system, flue gas is introduced into the bottom of a vessel at high velocity through a venturi nozzle and is mixed with water, hydrated lime, recycled fly ash, and FGD reaction byproducts. The mixture of flue gas, water, and solids traverses the reactor in a highly turbulent fluidized bed. SO_2 in the flue gas reacts with calcium hydroxide in the reactor or on the fabric filter bags to form solid calcium sulfite and calcium sulfate. The injected water humidifies and cools the flue gas. By the time the particles leave the reactor, they are dry particulate matter which is captured in the PM control system.

5.5.3 Technical Feasibility.

Dry FGD systems, including lime spray drying absorbers, circulating fluidized bed semi-dry systems, hydrated lime injection systems, circulating dry scrubbers, and flash dryer absorbers, are all demonstrated, technically feasible control technologies for the control of SO₂ emissions from coal-fired boilers. Although advanced semi-dry systems are primarily used in fluidized bed boiler applications, not pulverized coal-fired boilers, these dry and semi-dry FGD systems are nevertheless technically feasible control options.

5.6 Sorbent Injection.

Sorbent injection systems are dry FGD systems in which a powdered sorbent is injected into the furnace or into downstream ductwork. Several types of sorbent injection systems are available, including furnace sorbent injection and duct or dry sorbent injection. Dry sorbent injection (DSI) is a dry FGD system. In a typical DSI system, the sorbents are either sodium or calcium-based materials which are injected either in the furnace, or in the downstream ductwork prior to the PM control system. Calcium-based sorbents include limestone and hydrated quicklime; sodium-based sorbents include sodium bicarbonate, and trona (sodium sesquicarbonate or $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Fly ash, sorbent reaction products, and unused sorbent are collected and commingled in the PM control system. DSI has typical SO₂ removal efficiencies of 10 to 50%, although removal efficiencies of up to 90% have been reported at very high molar ratio sorbent injection rates and for short test durations. However, this very high level of removal has not been demonstrated on a continuous basis.

Furnace sorbent injection is also a dry system. Sorbents such as limestone or hydrated lime are injected into the boiler furnace. The injection point is selected based on the temperature window that is required for the reagent, typically around 1,000 - 1,500°F. The reaction product and fly ash are collected in the PM collection system. Furnace sorbent injection systems designed specifically for SO₂ control may achieve SO₂ removal efficiencies of 25 to 50%. However, for fluidized bed boilers, furnace sorbent injection is capable of achieving 90% removal in high sulfur coal applications.

Sorbent injection systems may also be used for the control of acid gases which are also hazardous air pollutants (HAPs), such as hydrogen chloride (HCl). For example, trona reacts with acid gases including HCl, HF, SO₂, NO_x, and SeO₂ (selenium dioxide) to form solid salts according to the following example overall reactions:

Pollutant	Sorbent	Oxygen	Reaction Product	Water	Carbon Dioxide
3HCl +	$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$		\rightarrow 3NaCl	$+ 4H_2O$	+ 2CO ₂
3HF +	$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$		\rightarrow 3NaF	$+ 4H_2O$	+ 2CO ₂
$3SO_2 +$	2 $[Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O]$	$+ \frac{3}{2}O_2$	\rightarrow 3Na ₂ SO ₄	$+ 5H_2O$	$+ 4CO_2$
6NO ₂ +	2 $[Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O]$	$+ {}^{3}/_{2}O_{2}$	\rightarrow 6NaNO ₃	$+ 5H_2O$	$+ 4CO_2$
$3SeO_2$ +	2 $[Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O]$	$+ {}^{3}/_{2}O_{2}$	\rightarrow 3Na ₂ SeO ₄	$+ 5H_2O$	$+ 4CO_2$

DSI designed specifically for SO_2 control has typical SO_2 removal efficiencies of 25 to 50%, and typical HCl and HF control efficiencies of 80 – 90% or even higher, depending on the sorbent injection rate.

The coal-fired boilers at both the River Rouge and Trenton Channel Power Plants will be subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) From Coal and Oil-Fired Electric Utility Steam Generating Units, 40 CFR Part 63, Subpart UUUUU, published in the Federal Register on February 16, 2012. This subpart established Mercury and Air Toxics Standards (MATS) for coal and oil-fired electric utility steam generating units. Under 40 CFR § 63.10042, *Electric utility steam generating unit* (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and

electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. These standards include emission limits for:

- a. Filterable particulate matter or limits on individual HAP metals,
- b. Hydrogen chloride (HCl) or, for FGD controlled units, limits on SO₂ emissions, and
- c. Mercury.

The use of sorbent injection may be used to comply with these MATS standards at both River Rouge and Trenton Channel. To achieve the MATS limit of 0.002 lb/mmBtu and an uncontrolled HCl emission rate of 0.004 to 0.03 lb/mmBtu (depending on the coal actually fired), the HCl reduction would need to be from 50% to approximately 95%. The sorbent injection required to achieve this HCl reduction is expected to achieve a 5% to 20% reduction in SO_2 emissions, depending on the coal fired and HCl reduction required.

From the Code of Federal Regulations TABLE 2 TO SUBPART UUUUU OF PART 63 — EMISSION LIMITS FOR EXISTING EGUS

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
	a. Filterable particulate matter (PM)	0.03 lb/MMBtu or 0.3 lb/MWh
Coal-fired unit not	OR	OR
low rank virgin coal	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh
(> 8,300 Btu/lb)	OR	OR
	Individual HAP metals:	
	Antimony (Sb)	0.8 lb/TBtu or 0.008 lb/GWh
	Arsenic (As)	1.1 lb/TBtu or 0.020 lb/GWh
	Beryllium (Be)	0.2 lb/TBtu or 0.002 lb/GWh
	Cadmium (Cd)	0.3 lb/TBtu or 0.003 lb/GWh
	Chromium (Cr)	2.8 lb/TBtu or 0.030 lb/GWh
	Cobalt (Co)	0.8 lb/TBtu or 0.008 lb/GWh
	Lead (Pb)	1.2 lb/TBtu or 0.020 lb/GWh
	Manganese (Mn)	4.0 lb/TBtu or 0.050 lb/GWh
	Nickel (Ni)	3.5 lb/TBtu or 0.040 lb/GWh
	Selenium (Se)	5.0 lb/TBtu or 0.060 lb/GWh
	b. Hydrogen chloride (HCl)	0.002 lb/MMBtu or 0.02 lb/MWh
	OR	OR
	Sulfur dioxide (SO ₂)	0.2 lb/MMBtu or 1.5 lb/MWh
	c. Mercury (Hg)	1.2 lb/TBtu or 1.3E-2 lb/GWh

[As stated in § 63.9991, you must comply with the following applicable emission limits]

5.6.1 Technical Feasibility.

Dry sorbent injection into the ductwork is a technically feasible control option for the affected boilers at the River Rouge and Trenton Channel Power Plants.

Chapter 6. Ranking of the Technically Feasible SO₂ Control Technologies.

6.1 Wet Flue Gas Desulfurization.

Modern wet FGD designs can be designed to achieve 98 - 99% SO₂ removal on an initial performance guarantee basis. However, while modern wet FGD systems can be designed to achieve 98 - 99% SO₂ removal on an initial performance guarantee basis when firing high sulfur eastern bituminous coals, it is not technically feasible to achieve this high level of control on a continuous basis.

Based on the performance for existing coal-fired units using wet FGD systems, including DTE Energy's Monroe Power Plant, we have concluded that the use of wet FGD on the River Rouge and Trenton Channel coal-fired boilers could achieve SO_2 emission rates of 0.08 lb/mmBtu based on a 24-hour or daily basis, and 0.06 lb/mmBtu, based on a 12-month rolling average. This long term emission rate represents an average SO_2 emission reduction of 92.5% from the low sulfur subbituminous coal uncontrolled emission rate, and 95% reduction from the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9.

6.2 Dry Flue Gas Desulfurization.

Modern dry FGD spray dryer designs can achieve 90 - 95% SO₂ removal on an initial performance guarantee basis. Based on the performance for existing subbituminous coal-fired units using dry FGD systems, we have concluded that the use of dry FGD on the River Rouge and Trenton Channel Power Plant coal-fired boilers could achieve SO₂ emission rates of 0.12 lb/mmBtu based on a 24-hour basis, and 0.08 lb/mmBtu, based on a 12-month rolling average. This long term emission rate represents an average SO₂ emission reduction of 90% from the low sulfur subbituminous coal uncontrolled emission rate, and 93.3% reduction from the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9.

6.3 Sorbent Injection.

Sorbent injection systems are expected to achieve an SO_2 control efficiency of 10% to as much as 50%, depending on the injection rate. In this control ranking, we have identified two control levels for sorbent injection. The first sorbent injection control level is based on a sorbent injection system designed and optimized for SO_2 control. This control technology would have a high sorbent injection rate which would be required to achieve a 40% reduction in the SO_2 emission rate from the uncontrolled coal emission rate. For the low sulfur subbituminous coal, this would result in a controlled SO_2 emission rate of 0.48 lb/mmBtu. For the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9, this would result in a controlled SO_2 emission rate of 0.72 lb/mmBtu.

The second control level is based on the sorbent injection rate which is necessary to achieve the applicable Mercury and Air Toxics Standards (MATS) for coal-fired electric utility steam generating

units 40 CFR Part 63, Subpart UUUUU. Low sulfur subbituminous coal has an uncontrolled HCl emission rate of approximately 0.004 to 0.010 lb/mmBtu. The low sulfur bituminous coals have a typical HCl emission rate of approximately 0.10 lb/mmBtu. Based on an 80% subbituminous/20% low sulfur bituminous coal blend, the coal blend would have an uncontrolled HCl emission rate of approximately 0.02 to 0.03 lb/mmBtu. To achieve the MATS limit of 0.002 lb/mmBtu, the HCl reduction would need to be from 50% to 80% for subbituminous coals, and 90% to 95% for the coal blend. This level of sorbent injection is expected to achieve a 5 - 10% reduction from the uncontrolled coal emission rate for subbituminous coal, and a 10 to 20% SO₂ reduction for the coal blend². The use of sorbent injection for MATS compliance would utilize less sorbent than the sorbent injection system designed and optimized for SO₂ control, and it may utilize a different sorbent which is optimized for HCl removal.

For the low sulfur subbituminous coal, the residual SO_2 reduction achieved through the use of sorbent injection for HCl control would result in a controlled SO_2 emission rate of less than 0.72 lb/mmBtu on a 12-month basis. For the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9, the residual SO_2 reduction achieved through the use of sorbent injection for HCl control would result in a controlled SO_2 emission rate of 1.02 lb/mmBtu on a 12-month basis.

6.4 Low Sulfur Coal.

6.4.1 Low Sulfur Western Subbituminous Coals.

The lowest SO₂ emitting coals which are commercially available for the River Rouge and Trenton Channel Power Plants is low sulfur western subbituminous (Powder River Basin or PRB) coals. PRB coals have heat values in the range of 8,200 to 9,400 Btu per pound, and sulfur contents in the range of 0.3 to 0.7%. The current commercially available PRB coals have typical uncontrolled SO₂ emission rates ranging from 0.5 to more than 1.6 lb/mmBtu. According to the document *Coal Quality and Major*, *Minor, and Trace Elements in the Powder River, Green River, and Williston Basins, Wyoming and North Dakota*, Open-File Report 2007-1116, U.S. Department of the Interior, U.S. Geological Survey, Table 3, all PRB samples have a mean sulfur content of 0.29%, with a standard deviation of 0.35%, and a mean heating value of 9,250 mmBtu per pound. Based on these analyses, PRB coals have a mean potential SO₂ combustion concentration of 0.63 lb/mmBtu, with a 2 standard deviation high of 2.1 lb/mmBtu. For this analysis, these low sulfur coals are expected to achieve SO₂ emission rates which are less than 0.8 lb/mmBtu on an annual basis, and less than 1.3 lb/mmBtu on a daily basis. However, because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is actually the *mass* emission rate for the boiler, expressed in tons per day.

6.4.2 Low Sulfur Eastern Bituminous Coals.

Low sulfur eastern bituminous coals are also commercially available. The U.S. Department of Energy's Energy Information Administration provides data for coal reserves in the following sulfur content ranges:

² From *Combined Treatment of HCl and SO₂: Independent Study Shows Selectivity and Effectiveness of Sodium Dry Sorbent Injection*, Y. Kong, M. Wood, Solvay Chemicals, Inc. From Figure 6, for HCl control efficiencies of 50 - 80%, SO₂ control efficiency range from 5 - 15%. At a 90% reduction, SO₂ removal may range from 10 - 20%.

Category	Sulfur Content, Ib S/mmBtu	SO2 Emission Rate, Ib SO₂/mmBtu
Low Sulfur	\leq 0.60	≤ 1.20
Medium	0.61 - 1.67	1.21 - 3.34
High Sulfur	≥ 1.68	≥ 3.36

U.S. DOE coal reserve categories of sulfur content in coal

Most of the high Btu, low sulfur bituminous coals are from the Appalachian region. However, these coals represent less than 6% of US coal reserves³.

6.4.3 Low Sulfur Subbituminous / Bituminous Coal Blends.

The River Rouge and Trenton Channel Power Plants currently burn a blend of low sulfur subbituminous and bituminous coals. A blend of bituminous and subbituminous coals is used because subbituminous coals have a lower heating value than the design eastern bituminous coals for the River Rouge and Trenton Channel boilers. As a result, the use of only low sulfur subbituminous coals can reduce the total heat input to the boilers which also reduces the steam output from the boilers and thereby "derates" or reduces the net electric output of the units. This unit derating is of particular concern for the River Rouge Unit 3 and Trenton Channel Unit 9. To minimize SO₂ emissions but maintain the maximum electric output of the units, the River Rouge and Trenton Channel Power Plants currently burn a blend of low sulfur subbituminous coal with a low sulfur eastern bituminous coal. When optimized for SO₂ reductions, this blend of low sulfur coals is expected to have an SO₂ emission rate which is less than 1.2 lb/mmBtu on a daily basis.

For much of the operating time, the derating of the River Rouge Unit 3 and Trenton Channel Unit 9 are not a serious concern, since a small reduction in electric output can be economically replaced by other available electric generating units in the region. However, during periods of peak electric demand, this derating can have a significant impact to electric generation costs.

³ U.S. Coal Reserves: An Update by Heat and Sulfur Content, February 1993, DOE/EIA-0529(92), Energy Information Administration, <u>Table ES1 Estimates of the Demonstrated Reserve Base of Coal in the United States by</u> <u>Btu/Sulfur Ranges and Regions</u>.

6.5 Ranking of the Technically Feasible Control Options.

Table 7 is a summary of the ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 2 and the Trenton Channel High Side Boilers 16, 17, 18, and 19 based on the above analysis of available technologies. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 – 19, the long term uncontrolled SO_2 emission rate for all options is based on the use of only low sulfur subbituminous coals. That is, the reduction of SO_2 emissions for post combustion control systems is based on the reduction from the uncontrolled subbituminous coal emission rate.

Table 8 is a summary of the ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 3 and the Trenton Channel Unit 9 based on the above analysis. Because these units may be significantly derated through the use of only low sulfur subbituminous coals, the long term uncontrolled SO_2 emission rate for all options is based on the use of a blend of low sulfur western subbituminous coals and low sulfur eastern bituminous coals which is expected to have a long term SO_2 emission rate of 1.2 lb/mmBtu, and a maximum daily SO_2 emission rate of up to 1.5 lb/mmBtu.

6.5.1 Achievable Short Term Emission Rates.

In Tables 7 and 8, the achievable short term SO_2 emission rate expressed on a 24-hour or daily basis is stated on a pound per million Btu (lb/mmBtu) basis. However, because of the natural variability of sulfur in coal, an unexpected coal shipment with an elevated sulfur content could result in emissions above the achievable emission rate when expressed on a lb/mmBtu basis, even if the mass emission rate of SO_2 emissions is relatively small. Since it is the mass of SO_2 emissions which can cause high ambient air concentrations, the short term achievable emission rate for each boiler is the *mass* emission rate for the boiler, expressed in tons per day. For example, for the River Rouge Unit 2, the short term achievable emission rate for subbituminous coal combustion is:

Achievable Emission Rate = $(2,280 \text{ mmBtu/hr})(1.3 \text{ lb } \text{SO}_2/\text{mmBtu})(24 \text{ hr/day})(\text{ton}/2,000 \text{ lb})$ Achievable Emission Rate = $35.57 \text{ tons } \text{SO}_2/\text{day}$

When the achievable emission rate is expressed in tons per day, plant management can reduce load or take other actions to limit SO_2 mass emissions to meet the achievable emission rates. These emission limits are consistent with the current SO_2 emission limits for these power plants. Further, because these units are equipped with SO_2 continuous emissions monitoring systems (SO_2 CEMS) which measure SO_2 mass emissions for each hour of operation in accordance with the federal Acid Rain Program in 40 CFR Part 75, demonstrating compliance with a mass emission limit is straightforward and easy to accomplish in practice.

TABLE 7. Ranking of the technically feasible SO₂ control technologies for the River Rouge Unit 2 and the Trenton Channel High Side Boilers 16, 17, 18, and 19.

Control Toobnology	Expected Emissio	Expected Emission Rate, Ib/mmBtu			
Control Technology	24-hour Ave.	12-mo Ave.			
1. Wet Flue Gas Desulfurization (wet FGD).	0.08	0.06			
2. Dry Flue Gas Desulfurization (dry FGD).	0.12	0.08			
3. Sorbent Injection (Optimized for SO ₂ control).	0.78	0.48			
4. Sorbent Injection (MATS Compliance) and Subbit coal.	1.17	0.72			
5. Low Sulfur Subbituminous Coal.	1.3	0.8			
6. Bituminous/Low Sulfur Subbituminous Coal Blend.	1.5	1.2			

Footnotes

Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is the *mass* emission rate for the boiler, expressed in tons per day.

TABLE 8. Ranking of the technically feasible SO₂ control technologies for the River Rouge Unit 3 and the Trenton Channel Unit 9.

Control Technology	Expected Emissio	Expected Emission Rate, Ib/mmBtu			
Control Technology	24-hour Ave.	12-mo Ave.			
1. Wet Flue Gas Desulfurization (wet FGD).	0.08	0.06			
2. Dry Flue Gas Desulfurization (dry FGD).	0.12	0.08			
3. Sorbent Injection (Optimized for SO ₂ control).	0.90	0.72			
4. Sorbent Injection (MATS Compliance) and Coal Blend.	1.28	1.02			
5. Low Sulfur Subbituminous Coal.	1.3	0.8			
6. Bituminous/Low Sulfur Subbituminous Coal Blend.	1.5	1.2			

Footnotes

Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is the *mass* emission rate for the boiler, expressed in tons per day.

Chapter 7. Evaluate the Most Effective Controls.

7.1 Rank No. 1: Wet Flue Gas Desulfurization.

7.1.1 Environmental and Energy Impacts.

The most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants is the use of wet FGD systems. Based on the above analysis, a wet FGD system has the potential to reduce SO_2 emissions to 0.06 lb/mmBtu based on a 12-month rolling average, and to 0.08 lb/mmBtu based on a 24-hour or daily average. The use of wet FGD systems on these units is also expected to reduce other acid gases, including HCl emissions.

However, the use of wet FGD systems on the River Rouge and Trenton Channel Power Plants would have other adverse environmental effects. Wet FGD systems consume large amounts of water and create new wastewater discharge streams. Wet FGD systems create a significant waste stream of calcium sulfite or calcium sulfate which would likely require disposal. The use of wet FGD systems would require new stacks designed for saturated flue gas conditions, and the stack plume would have a distinct visual plume which may adversely impact the local urban areas. A wet FGD system will also require substantial auxiliary electric power requirements to operate slurry pumps, sludge dewatering, and for the induced draft fan requirements to overcome the wet FGD system pressure drop. This increased auxiliary power requirement reduces overall plant efficiency and would increase the emission rate of other pollutants when stated on an equivalent net electric output basis.

7.1.2 Economic Feasibility.

The costs for retrofitting wet FGD on the River Rouge and Trenton Channel Power Plants would include capital costs for the wet FGD system absorber tower and associated equipment, and other necessary equipment including new fiberglass lined stacks, limestone slurry production equipment, gypsum dewatering equipment, limestone and gypsum material handling systems, and a wastewater treatment facility. Wet FGD system operating costs would include labor, additional auxiliary power requirements, lime or limestone reagent, gypsum handling and disposal costs, maintenance costs, and administrative costs. Both the River Rouge and Trenton Channel Power Plants are located in urban areas and have constrained plant layouts and boundaries, so that the installation of this equipment would be very difficult at either site.

7.1.2.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

Average Cost Effectiveness (\$ per ton removed) = Control option annualized cost Baseline emission rate – Control option emissions rate

For this economic analysis, the capital and operating (O&M) costs for the retrofitting op wet FGD systems on the River Rouge and Trenton Channel Power Plants has been estimated using the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software, Version 1, revised as CUECOST3. Attachment 1 of this RACT analysis includes the CUECOST input and output data for this analysis. For the River Rouge Units 2 and 3 and for Trenton Channel Unit 9, the wet FGD costs are based on one absorber tower for each unit. For the Trenton Channel High Side Boilers 16, 17, 18, and 19, the wet FGD costs have been evaluated based on one wet FGD absorber tower which would serve all four boilers.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the emission rate which can be achieved by utilizing 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).

The capital costs for new wet FGD systems at the River Rouge and Trenton Channel Power Plants would be \$412 million and \$452 million, respectively. The annual operating costs for wet FGD systems would include fixed and variable O&M costs, and capital recovery costs. Fixed O&M costs include costs such as labor and certain maintenance costs. Variable O&M costs include reagent costs, and maintenance costs which are related to plant utilization. As noted on page 15 of this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) *are based on a project life of 7 years for all capital costs*. A 7 year project life is used because the River Rouge Units 2 and 3 were constructed in 1954 and 1955, the Trenton Channel Highside Boilers 16 – 19 were constructed in 1948 – 1949, and the Trenton Channel Boiler 9A was constructed in 1965. These electric generating units are therefore from 49 to 66 years old. The construction of post combustion wet and dry FGD systems would require at least 2 years to complete. Therefore, at the end of a 7-year project cost recovery period, these units would be from 58 to 75 years old. A longer project recovery period is simply not compatible with the age of these units.

It is also important to note that all of these units are expected to operate at levels well below 100% capacity factor (i.e., well below their maximum rated output for 8,760 hours per year). The maximum utilization of these units is expected to be approximately 55% for at least the next 4 - 5 years. Therefore, the cost effectiveness in this analysis are based on a maximum expected utilization of each unit equal to 55% capacity factor. Tables 9, 10, 11, and 12 summarize the costs of the control options based on a utilization of 55% for each unit.

Control Ontion	Achievable SO ₂ Emission Rate ^{1, 2}		Emission Reduction ³ , ton/year		Capital Cost ⁴	Total Annual Cost	Cost Effectiveness
Control Option	lb/mmBtu	ton/year	From Low Sulfur Coal	From Current Allowable		\$/year	\$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	330	4,064	15,438	\$195,555,000	\$47,189,400	\$11,610
 Dry Flue Gas Desulfurization (dry FGD). 	0.08	439	3,955	15,329	\$215,627,000	\$52,431,200	\$13,260
 Sorbent Injection (optimized for SO₂ control). 	0.48	2,636	1,758	13,132	\$11,680,000	\$19,292,600	\$10,980
 Sorbent Injection (for MATS Compliance). 	0.72	3,955	439	11,813	\$11,680,000	\$13,635,300	\$31,030
5. Low Sulfur Subbituminous Coal.	0.8	4,394	0	11,374			
 Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend. 	1.2	6,591	0	9,177			
Current Allowable Emissions	1.67	15,768					

TABLE 9. SO₂ control technologies, achievable emission rates, costs, and cost effectiveness for the River Rouge Unit 2.

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.

2. The achievable annual emissions for RR2 are based on a boiler rating of 2,280 mmBtu per hour, and a capacity factor of 55%.

3. The emission reduction for determining cost effectiveness is from the Low Sulfur Subbituminous Coal (Option 5).

4. The capital and annual costs are detailed in Attachment 1.

5. Because the River Rouge Unit 2 is currently 60 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

Control Ontion	Achievable SO ₂ Emission Rate ^{1, 2}		Emission Reduction ³ , ton/year		Capital Cost⁴	Total Annual Cost	Cost Effectiveness
Control Option	lb/mmBtu	ton/year	From Coal Blend	From Current Allowable		\$/year	\$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	386	7,333	18,046	\$217,194,000	\$52,991,600	\$7,230
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	515	7,204	17,917	\$247,673,000	\$60,942,300	\$8,460
 Sorbent Injection (optimized for SO₂ control). 	0.72	4,631	3,087	13,801	\$15,400,000	\$25,437,100	\$8,240
 Sorbent Injection (for MATS Compliance). 	1.02	6,561	1,158	11,871	\$15,400,000	\$17,978,000	\$15,530
5. Low Sulfur Subbituminous Coal.	0.8	5,146	1,048	13,286	-	\$2,066,700 to \$2,347,500	\$1,970 to \$2,240
 Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend. 	1.2	7,718	0	10,714			
Current Allowable Emissions	1.67	18,432					

TABLE 10. SO₂ control technologies, achievable emission rates, costs, and cost effectiveness for the River Rouge Unit 3.

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.

2. The achievable annual emissions for RR3 are based on a boiler rating of 2,670 mmBtu per hour, and a capacity factor of 55%.

3. The emission reduction for determining cost effectiveness is from the Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.

4. The capital and annual costs are detailed in Attachment 1.

5. Because the River Rouge Unit 3 is currently 59 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

TABLE 11. SO₂ control technologies, achievable emission rates, costs, and cost effectiveness for the Trenton Channel High Side Boilers 16, 17, 18, and 19.

Control Option	Achievable SO ₂ Emission Rate ^{1, 2}		Emission Reduction ³ , ton/year		Capital Cost⁴	Total Annual Cost	Cost Effectiveness
	lb/mmBtu	ton/year	From Low Sulfur Coal	From Current Allowable		\$/year	\$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	437	5,389	21,675	\$195,482,000	\$46,858,900	\$8,700
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	583	5,243	21,529	\$215,633,000	\$52,379,600	\$9,990
 Sorbent Injection (optimized for SO₂ control). 	0.48	3,496	2,330	18,616	\$14,400,000	\$16,810,700	\$7,210
4. Sorbent Injection (for MATS Compliance).	0.72	5,243	583	16,869	\$14,400,000	\$12,160,800	\$20,870
5. Low Sulfur Subbituminous Coal.	0.8	5,826	0	16,286			
 Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend. 	1.2	8,739	0	13,373			
Current Allowable Emissions	1.67	22,112					

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.

2. The achievable annual emissions for the TC High Side boilers are based on a total boiler rating of 3,023 mmBtu per hour, and a capacity factor of 55%.

3. The emission reduction for determining cost effectiveness is from the Low Sulfur Subbituminous Coal (Option 5).

4. The capital and annual costs are detailed in Attachment 1.

5. Because the TC High Side boilers are currently at least 65 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

Control Ontion	Achievable SO ₂ Emission Rate ^{1, 2}		Emission Reduction ³ , ton/year		Capital Cost⁴	Total Annual Cost	Cost Effectiveness
Control Option	lb/mmBtu	ton/year	From Coal Blend	From Current Allowable		\$/year	\$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	655	12,441	32,480	\$257,000,000	\$63,169,600	\$5,080
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	873	12,222	32,262	\$312,372,000	\$73,633,700	\$6,020
 Sorbent Injection (optimized for SO₂ control). 	0.72	7,857	5,238	25,278	\$21,400,000	\$35,347,800	\$6,750
 Sorbent Injection (for MATS Compliance). 	1.02	11,131	1,964	22,004	\$21,400,000	\$24,982,500	\$12,720
5. Low Sulfur Subbituminous Coal.	0.8	8,730	558	24,405	-	\$2,122,400 to \$2,824,500	\$3,800 to \$5,060
 Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend. 	1.2	13,095	0	20,040			
Current Allowable Emissions	1.67	33,135					

TABLE 12. SO₂ control technologies, achievable emission rates, costs, and cost effectiveness for the Trenton Channel Unit 9.

Footnotes

6. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.

7. The achievable annual emissions for TC9 are based on a boiler rating of 4,530 mmBtu per hour, and a capacity factor of 55%.

8. The emission reduction for determining cost effectiveness is from the Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.

9. The capital and annual costs are detailed in Attachment 1.

1. Because the TC Unit 3 is currently 49 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

Table 13 is a summary of the cost analysis for wet FGD for the River Rouge and Trenton Channel Power Plants. The cost effectiveness based on a maximum expected utilization of 55% for each unit and a project cost recovery period of 7 years range from \$5,080 per ton for Trenton Channel Unit 9, to \$11,610 per ton for River Rouge Unit 2.

Unit	Emission Reduction ton/year	Capital Cost	Total Annual Cost \$/year	Cost Effectiveness \$ per ton
River Rouge Unit 2	4,064	\$195,555,000	\$47,189,400	\$11,610
River Rouge Unit 3	7,333	\$217,194,000	\$52,991,600	\$7,230
Trenton Channel Boilers 16, 17, 18, and 19	5,389	\$195,482,000	\$46,858,900	\$8,700
Trenton Channel Unit 9	12,441	\$257,000,000	\$63,169,600	\$5,080

TABLE 13. Summary of the cost effectiveness for the use of wet flue gas desulfurization.

7.1.3 Conclusions.

Wet FGD systems are the most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants. Based on the above analysis, a wet FGD system has the potential to reduce SO_2 emissions by 92.5 to 95%, and the use of wet FGD systems would also reduce other acid gases, including HCl emissions. However, the costs for the use of wet FGD systems on the River Rouge and Trenton Channel Power Plants range from \$5,080 to \$11,610 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of wet FGD systems for the control of SO_2 emissions is not a reasonable available control technology for the affected coalfired electric generating units.

7.2 Rank No. 2: Dry Flue Gas Desulfurization.

7.2.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry FGD systems on the existing River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.08 lb/mmBtu based on a 12-month rolling average, and to 0.12 lb/mmBtu based on a 24-hour or daily average. Like wet FGD systems, the use of dry or semi-dry FGD systems on these units is also expected to reduce other acid gases, including HCl emissions.

However, as with wet FGD systems, the use of dry FGD systems on the River Rouge and Trenton Channel Power Plants would have other adverse environmental effects. Dry and semi-dry FGD systems also consume large amounts of water and also require substantial auxiliary electric power requirements to operate reagent slurry pumps and for the induced draft fan requirements to overcome the dry FGD system pressure drop. This increased auxiliary power requirement would reduce overall plant efficiency and would increase the emission rate of other pollutants when stated on an equivalent net electric output basis. Dry FGD systems will also create a large waste stream which will require landfill disposal.

7.2.2 Economic Feasibility.

The costs for retrofitting dry FGD on the River Rouge and Trenton Channel Power Plants would include capital costs for the dry FGD system absorber tower and associated equipment, and other necessary equipment. It is important to note that dry FGD systems are normally operated with fabric filter baghouse air quality control systems. The use of fabric filter baghouses improves SO_2 control efficiency since much of the SO_2 removal occurs in the filter cake of the baghouse. In addition, these units may not be able to comply with the applicable PM emission limits without the addition of new fabric filter baghouses if dry or semi-dry FGD systems were installed on these units. In this analysis, new fabric filter baghouses increased the total capital cost for dry FGD systems by \$60 to \$110 million per dry FGD system.

For this economic analysis, the capital and operating (O&M) costs for the retrofitting of wet FGD systems on the River Rouge and Trenton Channel Power Plants has been estimated using the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software, Version 1, revised as CUECOST3. Attachment 1 of this RACT analysis includes the CUECOST input and output data for this analysis. In this analysis, the costs are based on the use of dry FGD Lime Spray Dry (LSD) systems. For the River Rouge Units 2 and 3 and for Trenton Channel Unit 9, the dry FGD costs are based on one absorber tower for each unit. For the Trenton Channel High Side Boilers 16, 17, 18, and 19, the dry FGD costs have been evaluated based on one wet FGD absorber tower which would serve all four boilers. In addition, the costs for new fabric filter baghouses have also been included in this analysis.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur

bituminous coal blend option (Option 6). The capital costs for new dry or semi-dry FGD systems at the River Rouge and Trenton Channel Power Plants would be \$463 million and \$528 million, respectively.

The annual operating costs for dry or semi-dry FGD systems would include fixed and variable O&M costs, and capital recovery costs. Fixed O&M costs include costs such as labor and certain maintenance costs. Variable O&M costs include reagent costs, and maintenance costs which are related to plant utilization. As noted on page 15 of this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) *are based on a project life of 7 years for all capital costs*.

In addition, because these units are expected to operate at levels well below 100% capacity factor (i.e., well below their maximum rated output for 8,760 hours per year), the maximum utilization of these units is expected to be approximately 55% for at least the next 4 - 5 years. Therefore, the cost effectiveness in this analysis is based on a maximum expected utilization of each unit equal to 55% capacity factor.

Table 14 is a summary of the cost analysis for dry or semi-dry FGD for the River Rouge and Trenton Channel Power Plants. The cost effectiveness based on a maximum expected utilization of 55% for each unit and a project cost recovery period of 7 years range from \$6,020 per ton for Trenton Channel Unit 9, to \$13,260 per ton for River Rouge Unit 2.

Unit	Emission Reduction	Capital Cost	Total Annual Cost	Cost Effectiveness
	ton/year		\$/year	\$ per ton
River Rouge Unit 2	3,955	\$215,627,000	\$52,431,200	\$13,260
River Rouge Unit 3	7,204	\$247,673,000	\$60,942,300	\$8,460
Trenton Channel Boilers 16, 17, 18, and 19	5,243	\$215,633,000	\$52,379,600	\$9,990
Trenton Channel Unit 9	12,222	\$312,372,000	\$73,633,700	\$6,020

TABLE 14. Summary of the cost effectiveness for the use of dry flue gas desulfurization.

7.2.3 Conclusions.

Dry or semi-dry FGD systems are the second most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants. Based on the above analysis, a dry FGD system has the potential to reduce SO_2 emissions by 90 to 93.3%, and the use of dry FGD systems would also reduce other acid gases, including HCl emissions. However, the costs for the use of dry FGD systems on the River Rouge and Trenton Channel Power Plants range from \$6,020 to \$13,260 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry or semi-dry FGD systems for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.3 Rank No. 3: Sorbent Injection Optimized for SO₂ Control.

7.3.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry sorbent injection systems designed to optimize SO_2 removal on the existing River Rouge Unit 2 and the Trenton Channel High Side Boilers 16 to 19 has the potential to reduce SO_2 emissions to 0.48 lb/mmBtu based on a 12-month rolling average, and to 0.72 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 40% reduction from the low sulfur subbituminous coal (Option 5). For the River Rouge Unit 3 and the Trenton Channel Unit 9, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 0.90 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 40% reduction from the low sulfur subbituminous coal/low sulfur bituminous coal blend (Option 6).

Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. The use of sorbent injection designed to optimize SO_2 removal will also create a significant increase of material requiring landfill disposal.

7.3.2 Economic Feasibility.

The costs for the use of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants are substantially less than those for wet and dry or semi-dry FGD systems, and include primarily the sorbent injection equipment, storage silo(s), and other ancillary equipment.

For this economic analysis, the capital and operating (O&M) costs for the installation and operation of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants has been estimated based on the report *IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology, FINAL*, August 2010, Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy. This analysis was prepared to update the U.S. EPA's economic analysis of sorbent injection costs. These costs include a total project (capital cost) of \$40 per kW of installed electric generating capacity, a fixed O&M cost of \$0.59 per kW of capacity, and a variable O&M cost of \$7.92 per MWhr of electric generation. When optimized for SO2 reductions, the variable O&M costs for the operation of the sorbent injection system have been estimated to be 50% higher than the costs for MATS compliance. A sorbent injection system using high sorbent injection rates for optimized SO₂ removal would likely require the addition of fabric filter systems to meet MATS particulate matter emission limits. Fabric filter baghouse systems would increase capital cost by \$60 million to \$110 million per unit. However, the costs for new fabric filter baghouses have NOT been included in this analysis.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).

From Tables 9, 10, 11, and 12, the capital costs for sorbent injection systems at the River Rouge and Trenton Channel Power Plants would be \$27 million and \$36 million, respectively. These capital costs are much less than the capital costs for wet and dry FGD systems, and reflect the primary advantage of sorbent injection – low capital costs. However, the annual operating costs at 55% capacity factor for sorbent injection systems at the River Rouge and Trenton Channel Power Plants would be \$45 and \$52 million, respectively which reflects the primary disadvantage of sorbent injection – high operating costs. The cost effectiveness, again based on 55% utilization, range from \$6,750 per ton of SO₂ controlled for Trenton Channel Unit 9, to \$10,980 per ton for River Rouge Unit 2.

Table 15 is a summary of the cost analysis for the use of sorbent injection systems optimized for SO_2 control for the River Rouge and Trenton Channel Power Plants. Note that if fabric filter baghouses would be required for particulate matter control at high sorbent injection rates, this change would significantly increase the capital cost requirements for sorbent injection.

Unit	Emission Reduction ton/year	Capital Cost	Total Annual Cost \$/year	Cost Effectiveness \$ per ton
River Rouge Unit 2	1,758	\$11,680,000	\$19,292,600	\$10,980
River Rouge Unit 3	3,087	\$15,400,000	\$25,437,100	\$8,240
Trenton Channel Boilers 16, 17, 18, and 19	2,330	\$14,400,000	\$16,810,700	\$7,210
Trenton Channel Unit 9	5,238	\$21,400,000	\$35,347,800	\$6,750

TABLE 15. Summary of the cost effectiveness for the use of dry sorbent injection optimized for SO_2 control.

7.3.3 Conclusions.

Based on the above analysis, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions by 40% from the uncontrolled emission rate. Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. However, the costs for the use of dry sorbent injection systems designed to optimize SO_2 removal on the River Rouge and Trenton Channel Power Plants range from \$6,750 to \$10,980 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry sorbent injection systems designed to control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.4 Rank No. 4: Sorbent Injection for MATS Compliance.

7.4.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry sorbent injection systems designed and utilized for MATS Compliance on the existing River Rouge Unit 2 and the Trenton Channel High Side Boilers 16 to 19 has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 1.08 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 10% reduction from the low sulfur subbituminous coal (Option 5). For the River Rouge Unit 3 and the Trenton Channel Unit 9, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions to 1.02 lb/mmBtu based on a 12-month rolling average, and to 24-hour or daily average. This reduction from the low sulfur subbituminous coal lb/mmBtu based on a 12-month rolling average, and to 1.28 lb/mmBtu based on a 24-hour or daily average. This reduction from the low sulfur subbituminous coal blend (Option 6).

Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. The use of sorbent injection designed to optimize SO_2 removal will also create a significant increase of material requiring landfill disposal.

Based on the above analysis, the use of dry sorbent injection systems designed for MATS compliance on the existing River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 1.10 lb/mmBtu based on a 24-hour or daily average. The use of sorbent injection on these units would be installed to reduce HCl emissions to comply with the utility boiler MATS requirements.

7.4.2 Economic Feasibility.

As noted in the previous section, the costs for the use of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants are substantially less than those for wet and dry or semi-dry FGD systems, and include primarily the sorbent injection equipment, storage silo(s), and other ancillary equipment. For this economic analysis, the capital and operating (O&M) costs for the installation and operation of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants has been estimated based on the report *IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology, FINAL*, August 2010, Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy. This analysis was prepared to update the U.S. EPA's economic analysis of sorbent injection costs. These costs include a total project (capital cost) of \$40 per kW of installed electric generating capacity, a fixed O&M cost of \$0.59 per kW of capacity, and a variable O&M cost of \$7.92 per MWhr of electric generation.

As with the analysis for wet and dry FGD systems, the average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).

Table 16 is a summary of the cost analysis for the use of sorbent injection systems designed and operated for MATS compliance for the River Rouge and Trenton Channel Power Plants. Note that the cost effectiveness of sorbent injection is much less dependent on the utilization of the unit, since most of the annual cost of sorbent injection is due to variable O&M (i.e., sorbent) costs, while for wet and dry FGD, much of the cost is the cost of capital for the installation of controls.

Unit	Emission Reduction ton/year	eduction Capital Cost		Cost Effectiveness \$ per ton
River Rouge Unit 2	439	\$11,680,000	\$13,635,300	\$31,030
River Rouge Unit 3	1,158	\$15,400,000	\$17,978,000	\$15,530
Trenton Channel Boilers 16, 17, 18, and 19	583	\$14,400,000	\$12,160,800	\$20,870
Trenton Channel Unit 9	1,964	\$21,400,000	\$24,982,500	\$12,720

TABLE 16. Summary of the cost effectiveness for the use of dry sorbent injection for MATS compliance.

7.4.3 Conclusions.

Based on the above analysis, the use of dry sorbent injection systems designed for MATS Compliance has the potential to reduce SO_2 emissions by 10% from the uncontrolled emission rate when burning 100% low sulfur subbituminous coals, and by 15% when burning a low sulfur subbituminous/low sulfur bituminous coal blend. This sorbent injection would be specifically designed to primarily reduce HCl emissions. However, the costs for the use of dry sorbent injection systems designed for MATS Compliance on the River Rouge and Trenton Channel Power Plants range from \$12,720 to \$31,030 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry sorbent injection systems designed for MATS Compliance for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.5 Rank No. 5: Low Sulfur Subbituminous Coal.

7.5.1 Environmental and Energy Impacts.

Based on the above analysis, an emission limit equal to the rate which can be achieved by the use of only low sulfur subbituminous or Powder River Basin (PRB) in the River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.8 lb/mmBtu based on a 12-month rolling average, and 1.3 lb/mmBtu on a 24-hour or daily average. As noted above, because of the natural variability of sulfur in coal, an unexpected coal shipment with an elevated sulfur content could result in emissions above the achievable emission rate when expressed on a lb/mmBtu basis, even if the mass emission rate of SO_2 emissions is relatively small. Therefore, the short term achievable emission rate for each boiler is the *mass* emission rate for the boiler, expressed in tons per day. Expressing the achievable emission rate in tons per day is consistent with the current SO_2 emission limits for these power plants.

7.5.2 Economic Feasibility.

Only the River Rouge Unit 3 and Trenton Channel Unit 9 are considered in the following analysis, because these units cannot burn 100% low sulfur subbituminous coal without a significant derating of the electric output of the units. The River Rouge Unit 3 is expected to be reduced by 20 MW, and the Trenton Channel Unit 9 is expected to be reduced by 50 MW if only low sulfur subbituminous coals were fired in these units. This derating would occur because the low sulfur subbituminous coals have a lower heating value than the design bituminous coals for these boilers. Because the boilers are limited in how many tons of coal they can fire in an hour, the lower heating value will reduce the steam output of the boiler and consequently reduce the maximum electric generating capacity of the unit.

The costs of the reduced electric output of these units would include a capacity derating which is typically expressed in \$ per MW. This is a payment received simply to be available to generate electric power when requested. In addition, during peak load conditions which normally occur in the summer months, the reduced output will also result in a cost for the required purchase of additional electricity during these peak load periods. This replacement power cost will be higher than the cost of generation at these units, since the replacement power is normally only needed during peak periods when the cost of peak electric generating capacity is very high.

The costs for the use of 100% low sulfur subbituminous coal as compared to the use of an optimized low sulfur subbituminous coal/ low sulfur bituminous coal blend for River Rouge Unit 3 and Trenton Channel Unit 9 are summarized in Table 17. The values in Table 17 represent the annual average costs for the 7-year period from 2016 to 2022. These costs are based on projections which were made using the Ventyx PROMOD model. PROMOD is a widely used electric utility market simulation software package which incorporates generating unit operating characteristics, transmission grid constraints, unit commitment and operating conditions, and market system operations to forecast or predict electric generating unit utilization in the future. PROMOD IV performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts. PROMOD IV forecasts hourly energy and loss prices, unit generation, revenues and fuel consumption, external market transactions, transmission flows.

The costs for this same control option, but based on a possible future electric generating capacity shortfall are summarized in Table 18. The costs in Table 18 reflect potential variability in the electric market conditions which can have a large impact on capacity costs. This volatility must be considered when assessing these costs because changes in the market can have large effects on the cost of utilizing only low sulfur western coals.

From Table 17, the use of 100% low sulfur subbituminous coal would have an average annual cost of \$2.07 million for River Rouge Unit 3, and would result in an SO₂ reduction of 1,048 tons per year, resulting in an average cost effectiveness of \$1,970 per ton. For Trenton Channel Unit 9, the use of 100% low sulfur subbituminous coal would also have an annual cost of \$2.12 million, but would result in an SO₂ reduction of only 558 tons per year, resulting in an average cost effectiveness of \$3,800 per ton. From Table 18, based on the potential for a tighter electric generating capacity market, the use of 100% low sulfur subbituminous coal would have an annual cost of \$2.35 million for River Rouge Unit 3. For a similar SO₂ reduction of 1,048 tons per year, would result in a cost effectiveness of \$2,240 per ton. For Trenton Channel Unit 9, the use of 100% low sulfur subbituminous coal would have an annual cost of \$2.35 million for River Rouge Unit 3. For a similar SO₂ reduction of 1,048 tons per year, would result in a cost effectiveness of \$2,240 per ton. For Trenton Channel Unit 9, the use of 100% low sulfur subbituminous coal and the potential tighter capacity market would have an annual cost of \$2.82 million. For an SO₂ reduction of only 558 tons per year, this annual cost would result in an average cost effectiveness of \$5,060 per ton. It is also important to note that for Trenton Channel Unit 9, the cost effectiveness in the individual years from 2016 to 2022 can be much more variable, ranging from \$1,870 to more than \$11,200 per ton of SO₂ controlled.

TABLE 17. Costs for the use of 100% low sulfur subbituminous coal as compared to the use of a low sulfur subbituminous/low sulfur bituminous coal blend.

Unit	Capacity Reduction	Capacity	Annual Costs, \$			SO ₂ Emission Reductions	Cost Effectiveness
onit	MW		Capacity	Generation	Total	ton/year	\$/ton
River Rouge 3	20	50%	\$622,300	\$1,444,400	\$2,066,700	1,048	\$1,970
Trenton 9	50	49%	\$1,555,700	\$566,700	\$2,122,400	558	\$3,800

TABLE 18. Costs for the use of 100% low sulfur subbituminous coal as compared to the
use of a low sulfur subbit/low sulfur bit coal blend based on a tighter capacity market.

Unit	Capacity Reduction	Capacity	Annual Costs, \$			SO ₂ Emission Reductions	Cost Effectiveness
onit	MW Factor	Factor	Capacity	Generation	Total	ton/year	\$/ton
River Rouge 3	20	50%	\$903,100	\$1,444,400	\$2,347,500	1,048	\$2,240
Trenton 9	50	49%	\$2,257,800	\$566,700	\$2,824,500	558	\$5,060

7.5.3 Conclusion.

For River Rouge Unit 3, the average cost effectiveness for the use of only subbituminous coal would range from \$1,970 to \$2,240 per ton of SO₂ controlled. As noted on page 15 of this analysis, U.S. EPA guidance from 1994 indicates that cost effectiveness should be within \$160 to \$1,300 per ton of pollutant controlled, equal to \$250 to \$2,050 per ton of pollutant controlled today. Although these costs are therefore at the upper end of the feasible costs for RACT, DTE Electric Company believes these costs are economically feasible for the River Rouge Unit 3. However, the costs for the use of the use of only low sulfur subbituminous coals in Trenton Channel Unit 9 would range from \$3,800 to \$5,060 per ton of SO₂ controlled. Furthermore, because of highly variable capacity prices in the future, the cost effectiveness in individual years can also be much more variable, ranging from \$1,870 to more than \$11,200 per ton of SO₂ controlled. This high cost is not economically feasible for Trenton Channel Unit 9.

Because the use of only low sulfur subbituminous coal in Trenton Channel Unit 9 would result in significant capacity deratings and significant costs but only moderate SO_2 reductions, an emission limitation based on the use of only 100% low sulfur subbituminous coals is not a reasonably available control technology for the control of SO_2 emissions from Trenton Channel Unit 9.

Chapter 8. Proposed SO₂ RACT Determination.

Based on this analysis, DTE Electric Company has concluded that an SO₂ emission rate equal to the use of low sulfur subbituminous coal is a reasonably available control technology (RACT) for the control of SO₂ emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The River Rouge and Trenton Channel Power Plants currently utilize a blend of low sulfur bituminous and low sulfur subbituminous coals. An emission rate equal to the use of only low sulfur subbituminous coal (which is the lowest SO₂ emitting coal available) would further reduce SO₂ emissions from these power plants. The use of low sulfur subbituminous coal is expected to reduce SO₂ emissions to 0.8 lb/mmBtu based on a 12-month average, and 1.3 lb/mmBtu based on a 24-hour or daily average. Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is based on the mass emission rate for the boiler, expressed in tons per day. This change represents more than a 50% reduction from the current allowable emission rate for these units.

Because the use of only low sulfur subbituminous coal in Trenton Channel Unit 9 would result in a significant capacity derating of the unit and significant adverse economic costs, the use of only low sulfur subbituminous coals in Trenton Channel Unit 9 is not RACT for this unit. If only subbituminous coals are used in this unit, the maximum electric output would be reduced by approximately 50 MW. For the Trenton Channel Unit 9, the average cost effectiveness for the use of only subbituminous coal would range from \$3,800 to \$5,060 per ton of SO₂ controlled. Furthermore, because of highly variable capacity prices in the future, the cost effectiveness in individual years can also be much more variable, ranging from \$1,870 to more than \$11,200 per ton of SO₂ controlled. This high cost is not economically feasible. Based on this analysis, the use of a low sulfur subbituminous coal and bituminous coal blend is RACT for the control of SO₂ emissions from the Trenton Channel Unit 9. The use of this coal blend is expected to reduce SO₂ emissions to 1.2 lb/mmBtu based on a 12-month average, and 1.5 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 29% reduction from the current allowable emission rate for this unit.

Other available control technologies are not economically feasible control options. Although wet and dry FGD systems can reduce SO₂ emissions by 90 to 95%, the costs for both wet and dry FGD systems exceed \$5,080 per ton of SO₂ controlled for all units at their expected utilization equal to a 55% capacity factor. The high costs for wet and dry FGD systems reflect the high capital costs of these technologies. For the River Rouge and Trenton Channel Power Plants, these costs are estimated at \$865 million for wet limestone forced oxidation (wet FGD) systems, and \$990 million for lime spray dry FGD systems. Based on these high capital and operating costs, wet or dry FGD systems are not economically feasible and do not represent RACT for these units.

This analysis included two levels of reduction for the use of sorbent injection for SO₂ control. The first level of control is based on the use of sorbent injection optimized for SO₂ control. This control option is expected to achieve an SO₂ control efficiency of 40%. However, the use of sorbent injection optimized for SO₂ control is also not economically feasible, with average costs exceeding \$6,750 per ton of SO₂ controlled. Because these power plants will require the use of sorbent injection for compliance with the Mercury and Air Toxics Standards (MATS) for coal-fired units under 40 CFR 63, Subpart UUUUUU after the year 2016, the second level of control represents the SO₂ reduction expected to achieve the MACT standards. The use of sorbent injection to reduce hydrogen chloride (HCl) emissions for MATS compliance is expected to achieve a 10 to 15% reduction in the SO₂ emission rate, depending on the coal or coal blend used. However, the cost effectiveness for the control of SO₂ emissions based on the SO₂ reduction achieved through the use of sorbent injection for MATS compliance is also not economically feasible, with costs exceeding \$12,720 per ton of SO₂ controlled.

Based on this RACT analysis, we have concluded that the sulfur dioxide (SO_2) limits in the following table represent RACT for the River Rouge and Trenton Channel Power Plants. The long term limit of 0.8 lb/mmBtu would result in a 52% reduction in the potential or allowable emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The long term limit of 1.2 lb/mmBtu would result in a 28% reduction in the potential or allowable emissions for Trenton Channel Unit 9.

Units	RACT Emission Limits
River Rouge Unit 2	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Unit 3	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Units 2 and 3 Combined	77.2 tons per day, based on a 24-hour or daily basis.
Trenton Channel Boilers 16, 17, 18, and 19	0.8 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Unit 9	1.2 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Boilers 16 - 19 and Unit 9 <i>Combined</i>	117.8 tons per day, based on a 24-hour or daily basis.

Proposed sulfur dioxide (SO₂) RACT emission limits for the River Rouge and Trenton Channel Power Plants.

CUECost - Air Pollution Control Systems Economics Spreadsheet For the River Rouge and Trenton Channel Power Plants.

Capital and Operation Costs for New Wet Flue Gas Desulfurization Systems and New Dry Flue Gas Desulfurization Systems.

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A1. Analysis of the cost effectiveness of the post combustion SO₂ control technology options for River Rouge Unit 2.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.48	0.72	0.80
Heat Input Capacity, mmBtu/hr	2,280	2,280	2,280	2,280	2,280
Utilization, %	55%	55%	55%	55%	55%
Actual SO ₂ Emissions, tons per year	330	439	2,636	3,955	4,394
Total Capital Requirement, \$	\$195,555,000	\$215,627,000	\$11,680,000	\$11,680,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, \$/yr	\$38,854,900	\$42,843,000	\$2,320,700	\$2,320,700	n/a
Annual O&M Cost, \$/yr	\$8,334,500	\$9,588,200	\$16,971,900	\$11,314,600	n/a
Total Annual Cost, \$/yr	\$47,189,400	\$52,431,200	\$19,292,600	\$13,635,300	
Average Annual Cost, \$/yr	\$47,189,400	\$52,431,200	\$19,292,600	\$13,635,300	
Average SO ₂ Reduction, tons per year	4,064	3,955	1,758	439	
Average Cost per Ton Reduced, \$ per ton	\$11,610	\$13,260	\$10,980	\$31,030	

Footnotes

1. The Controlled Emission Rate is from the RACT analysis, Table 7.

2. The Actual SO 2 Emissions are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti

3. The Total Capital Requirement is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.

4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$
 where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.

6. The Average Annual Cost is the Total Annual Cost of the control option.

7. The Average SO $_2$ Reduction is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.

8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO₂ Reduction of the control option:

Average Cost Effectiveness (\$ per ton removed) = $\frac{\text{Control option annual cost}}{\text{seline emission rate} - \text{Control option emissions rate}}$

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A2. Analysis of the cost effectiveness of the post combustion SO₂ control technology options for River Rouge Unit 3.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.72	1.02	1.20
Heat Input Capacity, mmBtu/hr	2,670	2,670	2,670	2,670	2,670
Utilization, %	55%	55%	55%	55%	55%
Actual SO ₂ Emissions, tons per year	386	515	4,631	6,561	7,718
Total Capital Requirement, \$	\$217,194,000	\$247,673,000	\$15,400,000	\$15,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, \$/yr	\$43,154,400	\$49,210,300	\$3,059,800	\$3,059,800	n/a
Annual O&M Cost, \$/yr	\$9,837,200	\$11,732,000	\$22,377,300	\$14,918,200	n/a
Total Annual Cost, \$/yr	\$52,991,600	\$60,942,300	\$25,437,100	\$17,978,000	
Average Annual Cost, \$/yr	\$52,991,600	\$60,942,300	\$25,437,100	\$17,978,000	
Average SO ₂ Reduction, tons per year	7,333	7,204	3,087	1,158	
Average Cost per Ton Reduced, \$ per ton	\$7,230	\$8,460	\$8,240	\$15,530	

Footnotes

1. The Controlled Emission Rate is from the RACT analysis, Table 7.

2. The Actual SO 2 Emissions are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti

3. The *Total Capital Requiremen* t is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.

4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$
 where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.

6. The Average Annual Cost is the Total Annual Cost of the control option.

7. The Average SO $_2$ Reduction is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.

8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO₂ Reduction of the control option:

Average Cost Effectiveness (\$ per ton removed) = $\frac{\text{Control option annual cost}}{\text{seline emission rate} - \text{Control option emissions rate}}$

CUECost - Air Pollution Control Systems Spreadsheet

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.48	0.72	0.80
Heat Input Capacity, mmBtu/hr	3,023	3,023	3,023	3,023	3,023
Utilization, %	55%	55%	55%	55%	55%
Actual SO ₂ Emissions, tons per year	437	583	3,496	5,243	5,826
Total Capital Requirement, \$	\$195,482,000	\$215,633,000	\$14,400,000	\$14,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, \$/yr	\$38,840,400	\$42,844,200	\$2,861,100	\$2,861,100	n/a
Annual O&M Cost, \$/yr	\$8,018,500	\$9,535,400	\$13,949,600	\$9,299,700	n/a
Total Annual Cost, \$/yr	\$46,858,900	\$52,379,600	\$16,810,700	\$12,160,800	
Average Annual Cost, \$/yr	\$46,858,900	\$52,379,600	\$16,810,700	\$12,160,800	
Average SO ₂ Reduction, tons per year	5,389	5,243	2,330	583	
Average Cost per Ton Reduced, \$ per ton	\$8,700	\$9,990	\$7,210	\$20,870	

TABLE A3. Analysis of the cost effectiveness of the post combustion SO₂ control technology options for the Trenton Channel Boilers 16, 17, 18, and 19.

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.

2. The Actual SO 2 Emissions are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti

3. The Total Capital Requirement is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.

4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]} \qquad \begin{array}{l} \text{where:} \\ \text{i} = \text{annual interest rate} = 9.0\% \\ \text{n} = \text{project life, years} = 7 \end{array}$$

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.

6. The Average Annual Cost is the Total Annual Cost of the control option.

Average Cost Effectiveness (\$ per ton removed) =

7. The Average SO₂ Reduction is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.

8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO₂ Reduction of the control option:

Control option annual cost

seline emission rate – Control option emissions rate

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A4. Analysis of the cost effectiveness of the post combustion SO₂ control technology options for the Trenton Channel Unit 9.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal Blend
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.72	1.02	1.20
Heat Input Capacity, mmBtu/hr	4,530	4,530	4,530	4,530	4,530
Utilization, %	55%	55%	55%	55%	55%
Actual SO ₂ Emissions, tons per year	655	873	7,857	11,131	13,095
Total Capital Requirement, \$	\$257,000,000	\$312,372,000	\$21,400,000	\$21,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, \$/yr	\$51,063,500	\$62,065,400	\$4,252,000	\$4,252,000	n/a
Annual O&M Cost, \$/yr	\$12,106,100	\$11,568,300	\$31,095,800	\$20,730,500	n/a
Total Annual Cost, \$/yr	\$63,169,600	\$73,633,700	\$35,347,800	\$24,982,500	
Average Annual Cost, \$/yr	\$63,169,600	\$73,633,700	\$35,347,800	\$24,982,500	
Average SO ₂ Reduction, tons per year	12,441	12,222	5,238	1,964	
Average Cost per Ton Reduced, \$ per ton	\$5,080	\$6,020	\$6,750	\$12,720	

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.

2. The Actual SO 2 Emissions are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti

3. The Total Capital Requirement is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.

4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$
 where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.

6. The Average Annual Cost is the Total Annual Cost of the control option.

Average Cost Effectiveness (\$ per ton removed) =

7. The Average SO₂ Reduction is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.

8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO₂ Reduction of the control option:

Control option annual cost

seline emission rate – Control option emissions rate

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Conoral Plant Tashnical Inputs					
General Plant Technical Inputs					
Location - State	Abbrev.	MI	MI	MI	MI
MW Equivalent of Flue Gas to Control System	MW	292	385	240	535
Net Plant Heat Rate	Btu/kWhr	10,300	10,300	12,600	10,300
Plant Capacity Factor	%	55%	55%	55%	55%
Total Air Downstream of Economizer	%	120%	120%	120%	120%
Air Heater Leakage	%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	300	300	300	300
Inlet Air Temperature	°F	45	45	45	45
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013
Ash Split:	-				
Fly Ash	%	80%	80%	80%	80%
Bottom Ash	%	20%	20%	20%	20%
Seismic Zone	Integer	1	1	1	1
Retrofit Factor	Integer	2.2	2.2	2.2	2.2
(1.0 = new, 1.3 = medium, 1.6 = difficult)	U				
Select Coal	Integer	1	1	1	1
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	Yes	Yes	Yes
Economic Inputs					
Cost Basis -Year Dollars	Year	2013	2013	2013	2013
Sevice Life (levelization period)	Years	20	20	20	20
Inflation Rate	%	3.0%	3.0%	3.0%	3.0%
After Tax Discount Rate (current \$'s)	%	9.2%	9.2%	9.2%	9.2%
AFDC Rate (current \$'s)	%	10.8%	10.8%	10.8%	10.8%
First-year Carrying Charge (current \$'s)	%	22.3%	22.3%	22.3%	22.3%
Levelized Carrying Charge (current \$'s)	%	16.9%	16.9%	16.9%	16.9%
First-year Carrying Charge (constant \$'s)	%	15.7%	15.7%	15.7%	15.7%
Levelized Carrying Charge (constant \$'s)	%	11.7%	11.7%	11.7%	11.7%
Sales Tax	%	6.0%	6.0%	6.0%	6.0%
Escalation Rates:					
Consumables (O&M)	%	3%	3%	3%	3%
Capital Costs:			- / -		- / -
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Inde:	Integer	593.8	593.8	593.8	593.8
If "No" input escalation rate.	%	3%	3%	3%	3%
Construction Labor Rate	\$/hr	\$35	\$35	\$35	\$35
Prime Contractor's Markup	%	3%	3%	3%	3%
Operating Labor Rate	\$/hr	\$30	\$30	\$30	\$30
Power Cost	Wills/kWh	25	25	25	25
	\$/1000 lbs	3.5	3.5	3.5	3.5

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Limestone Forced Oxidation (LSFO)	Inputs				
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.0	5.8		
SO2 Removal Required	%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2
Adiabatic Saturation Temperature	°F	127	127	127	127
Reagent Feed Ratio (Mole CaCO3 / Mole SO2	Factor	1.05	1.05	1.05	1.05
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	2	2	2	2
(1 = stacking, 2 = lanfill, 3 = wallboard)					
Number of Absorbers	Integer	1	1	1	1
(Max. Capacity = 700 MW per absorber)					
Absorber Material $(1 = alloy, 2 = RLCS)$	Integer	1	1	1	1
Absorber Pressure Drop	in. H2O	6	6	6	6
Reheat Required ? $(1 = yes, 2 = no)$	Integer	1	1	1	1
Amount of Reheat	°F	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60
Reagent Cost (delivered)	\$/ton	\$22	\$22	\$22	\$22
Landfill Disposal Cost	\$/ton	\$30	\$30	\$30	\$30
Stacking Disposal Cost	\$/ton	\$6	\$6	\$6	\$6
Credit for Gypsum Byproduct	\$/ton	\$2	\$2	\$2	\$2
Maintenance Factors by Area (% of Installed C	Cost)				
Reagent Feed	%	5%	5%	5%	5%
SO2 Removal	%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost	t)				
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Lime Spray Dryer (LSD) Inputs					
SO2 Removal Required	%	93.3%	93.3%	93%	93%
Adiabatic Saturation Temperature	°F	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147
Reagent Feed Ratio	Factor	0.95	0.95	0.95	0.95
(Mole CaO / Mole Inlet SO2)					
Recycle Rate	Factor	30	30	30	30
(lb recycle / lb lime feed)					
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2
(Max. Capacity = 300 MW per spray dry	ver)				
Absorber Material	Integer	1	1	1	1
(1 = alloy, 2 = RLCS)					
Spray Dryer Pressure Drop	in. H2O	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60
Reagent Cost (delivered)	\$/ton	\$65	\$65	\$65	\$65
Dry Waste Disposal Cost	\$/ton	\$30	\$30	\$30	\$30
Maintenance Factors by Area (% of Installe	ed Cost)				
Reagent Feed	%	5%	5%	5%	5%
SO2 Removal	%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed C	Cost)				
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed C	Cost)				
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation		RR Unit 2	RR Unit 3	TC High	TC Unit 9
LSFO Equipment Capital	Costs				
Co	st Basis (Year)	<u>2013</u>	<u>2013</u>	<u>2013</u>	<u>2013</u>
	<u>Sizing Criteria</u>				
Reagent Feed System	kpph Reag.	\$11,340,729	\$11,477,008	\$11,343,086	\$11,691,398
Ball Mill & Hydroclone System	TPH Reag.	\$2,914,804	\$2,939,125	\$2,915,220	\$2,978,537
DBA Acid Tank (pump, heater, a	gpm DBA	\$0	\$0	\$0	\$0
SO2 Removal System	kpph SO2	\$3,057,789	\$3,102,123	\$3,058,552	\$3,172,917
Absorber Tower	kACFM	\$18,063,667	\$21,110,855	\$18,119,134	\$25,421,794
Spray Pumps	slurry gpm	\$2,154,830	\$2,854,024	\$2,161,818	\$3,800,939
Flue Gas Handling System	*	\$7,986,613	\$9,094,721	\$8,006,719	\$10,608,724
ID Fans	ACFM	\$2,423,194	\$2,927,827	\$2,432,226	\$3,668,423
Waste / Byproduct Handling System	kpph SO2	\$1,301,823	\$1,338,764	\$1,302,459	\$1,397,673
Thickener System	TPH solids	\$225,802	\$241,877	\$226,077	\$267,858
Support Equipment	MW	\$2,565,555	\$2,761,316	\$2,446,963	\$3,038,347
Chimney	ACFM	\$5,924,674	\$6,497,683	<u>\$5,935,442</u>	<u>\$7,253,569</u>
TOTAL		\$57,959,480	\$64,345,322	\$57,947,696	\$73,300,179
* Based on flue gas flow and reheat	temperature.				
Capital Costs with Retrofit Factors					
Reagent Feed System		\$24,949,603	\$25,249,417	\$24,954,789	\$25,721,076
Ball Mill & Hydroclone System		\$6,412,569	\$6,466,075	\$6,413,484	\$6,552,781
DBA Acid Tank (pump, heater, a	gitator)	\$0	\$0	\$0	\$0
SO2 Removal System		\$6,727,136	\$6,824,671	\$6,728,814	\$6,980,416
Absorber Tower		\$39,740,067	\$46,443,881	\$39,862,096	\$55,927,946
Spray Pumps		\$4,740,626	\$6,278,852	\$4,756,000	\$8,362,065
Flue Gas Handling System		\$17,570,548	\$20,008,387	\$17,614,782	\$23,339,193
ID Fans		\$5,331,026	\$6,441,219	\$5,350,898	\$8,070,531
Waste / Byproduct Handling System		\$2,864,012	\$2,945,281	\$2,865,410	\$3,074,881
Thickener System		\$496,763	\$532,130	\$497,369	\$589,287
Support Equipment		\$5,644,221	\$6,074,895	\$5,383,319	\$6,684,364
Chimney		<u>\$13,034,284</u>	<u>\$14,294,902</u>	<u>\$13,057,972</u>	<u>\$15,957,853</u>
TOTAL		\$127,510,855	\$141,559,709	\$127,484,931	\$161,260,393
General Facilities		¢2 404 040	¢0.504.040	¢2 405 470	¢0 570 100
Reagent Feed System		\$2,494,960 \$641,257	\$2,524,942	\$2,495,479 \$641,348	\$2,572,108
Ball Mill & Hydroclone System	citator)	\$641,257 \$0	\$646,608 \$0	\$641,348 \$0	\$655,278 \$0
DBA Acid Tank (pump, heater, a	gitator)	\$0 \$672,714	\$0 \$682.467	\$0 \$672 881	\$0 \$608.042
SO2 Removal System Absorber Tower			\$682,467 \$4,644,388	\$672,881 \$3.086.210	\$698,042 \$5,502,705
Spray Pumps		\$3,974,007 \$474,063	\$4,644,388 \$627,885	\$3,986,210 \$475,600	\$5,592,795 \$836,207
		\$474,063 \$1,757,055	\$627,885 \$2,000,839	\$475,600 \$1,761,478	\$836,207 \$2,333,919
Flue Gas Handling System ID Fans		\$1,737,033	\$2,000,839 \$644,122	\$535,090	\$2,555,919 \$807,053
Waste / Byproduct Handling System		\$333,103 \$286,401	\$044,122 \$294,528	\$335,090 \$286,541	\$807,033 \$307,488
Thickener System		\$280,401 \$49,676	\$294,328 \$53,213	\$49,737	\$507,488 \$58,929
Support Equipment		\$564,422	\$607,490	\$538,332	\$668,436
Chimney		<u>\$1,303,428</u>	<u>\$1,429,490</u>	\$338,332 <u>\$1,305,797</u>	\$008,430 <u>\$1,595,785</u>
Chining		<u>φ1,303,420</u>	<u>φ1,427,470</u>	<u>\$1,303,777</u>	<u>\$1,373,703</u>

DTE Electric Company - River Rouge and Trenton Channel Power Plant SO₂ RACT Analysis Attachment 1: CUECost Air Pollution Control System Costs.

CUECost - Air Pollution Control Systems Spreadsheet

\$12,751,086 \$2,494,960 \$641,257 \$0	\$14,155,971 \$2,524,942 \$646,608	\$12,748,493	\$16,126,039
\$641,257 \$0		¢0.405.450	
\$641,257 \$0		CO 405 470	
\$0	\$646.608	\$2,495,479	\$2,572,108
	+	\$641,348	\$655,278
* ·= * * ·	\$0	\$0	\$0
\$672,714	\$682,467	\$672,881	\$698,042
\$3,974,007	\$4,644,388	\$3,986,210	\$5,592,795
\$474,063	\$627,885	\$475,600	\$836,207
\$1,757,055	\$2,000,839	\$1,761,478	\$2,333,919
\$533,103	\$644,122	\$535,090	\$807,053
\$286,401	\$294,528	\$286,541	\$307,488
\$49,676	\$53,213	\$49,737	\$58,929
\$564,422	\$607,490	\$538,332	\$668,436
\$1,303,428	\$1,429,490	\$1,305,797	\$1,595,785
\$12,751,086	\$14,155,971	\$12,748,493	\$16,126,039
\$4,989,921	\$5,049,883	\$4,990,958	\$5,144,215
			\$1,310,556
			\$0
			\$1,396,083
			\$11,185,589
			\$1,672,413
			\$4,667,839
			\$1,614,106
			\$614,976
			\$117,857
			\$1,336,873
			<u>\$3,191,571</u>
\$25,502,171	\$28,311,942	\$25,496,986	\$32,252,079
\$178.515.197	\$198.183.593	\$178,478,904	\$225,764,551
			\$232,537,487
\$181,192,925	\$201,156,347	\$181,156,087	\$225,830,307
\$9.639 821	\$10,701,914	\$9,637,861	\$24,761,330
			\$250,591,637
			\$6,280,155
\$70,004	\$92,300	\$70,386	\$128,334
\$195 555 186	\$217 104 111	\$195 481 031	\$257,000,126
\$ 193,333,480 \$670	\$217,19 4 ,111 \$564	\$815	\$480
\$16,330.650	\$16.526.891	\$16.334.043	\$16,835,614
	\$474,063 \$1,757,055 \$533,103 \$286,401 \$49,676 \$564,422 <u>\$1,303,428</u> \$12,751,086 \$4,989,921 \$1,282,514 \$0 \$1,345,427 \$7,948,013 \$948,125 \$3,514,110 \$1,066,205 \$572,802 \$99,353 \$1,128,844 <u>\$2,606,857</u> \$25,502,171 \$178,515,197 \$183,870,653 \$181,192,925 \$9,639,821 \$190,832,746 \$4,652,735 \$70,004 \$195,555,486	\$474,063 \$627,885 \$1,757,055 \$2,000,839 \$533,103 \$644,122 \$286,401 \$294,528 \$49,676 \$53,213 \$564,422 \$607,490 <u>\$1,303,428</u> <u>\$1,429,490</u> \$12,751,086 \$14,155,971 \$4,989,921 \$5,049,883 \$1,282,514 \$1,293,215 \$0 \$0 \$1,345,427 \$1,364,934 \$7,948,013 \$9,288,776 \$948,125 \$1,255,770 \$3,514,110 \$4,001,677 \$1,066,205 \$1,288,244 \$572,802 \$589,056 \$99,353 \$106,426 \$1,128,844 \$1,214,979 <u>\$2,606,857</u> <u>\$2,858,980</u> \$25,502,171 \$28,311,942 \$178,515,197 \$198,183,593 \$4 \$183,870,653 \$204,129,101 \$181,192,925 \$201,156,347 \$9,639,821 \$10,701,914 \$190,832,746 \$211,858,261 \$4,652,735 \$5,243,550 \$70,004 \$92,300 \$195,555,486 \$217,194,111 \$670 \$564	\$474,063 \$627,885 \$475,600 \$1,757,055 \$2,000,839 \$1,761,478 \$533,103 \$644,122 \$535,090 \$286,401 \$294,528 \$286,541 \$49,676 \$53,213 \$49,737 \$564,422 \$607,490 \$538,332 \$1,303,428 \$1,429,490 \$1,305,797 \$12,751,086 \$14,155,971 \$12,748,493 \$4,989,921 \$5,049,883 \$4,990,958 \$1,282,514 \$1,293,215 \$1,282,697 \$0 \$0 \$0 \$1,345,427 \$1,364,934 \$1,345,763 \$7,948,013 \$9,288,776 \$7,972,419 \$948,125 \$1,255,770 \$951,200 \$3,514,110 \$4,001,677 \$3,522,956 \$1,066,205 \$1,288,244 \$1,070,180 \$572,802 \$589,056 \$573,082 \$99,353 \$106,426 \$99,474 \$1,128,844 \$1,214,979 \$1,076,664 \$2,606,857 \$2,858,980 \$2,611,594 \$25,502,171 \$28,311,942 \$25,496,986 \$178,515,197 \$198,183,593

DTE Electric Company - River Rouge and Trenton Channel Power Plant SO₂ RACT Analysis Attachment 1: CUECost Air Pollution Control System Costs.

Wet FGD Limestone Forced Oxidation	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Ball Mill & Hydroclone System	\$4,197,318	\$4,232,340	\$4,197,917	\$4,289,093
DBA Acid Tank (pump, heater, agitator)	\$0	\$0	\$0	\$0
SO2 Removal System	\$4,403,217	\$4,467,057	\$4,404,315	\$4,569,000
Absorber Tower	\$26,011,680	\$30,399,631	\$26,091,553	\$36,607,383
Spray Pumps	\$3,102,955	\$4,109,794	\$3,113,018	\$5,473,352
Flue Gas Handling System	\$11,500,722	\$13,096,399	\$11,529,675	\$15,276,563
ID Fans	\$3,489,399	\$4,216,071	\$3,502,406	\$5,282,529
Waste / Byproduct Handling System	\$1,874,626	\$1,927,820	\$1,875,541	\$2,012,649
Thickener System	\$325,154	\$348,303	\$325,551	\$385,715
Support Equipment	\$3,694,399	\$3,976,295	\$3,523,627	\$4,375,220
Chimney	\$8,531,531	\$9,356,663	<u>\$8,547,036</u>	\$10,445,140
TOTAL	\$83,461,651	\$92,657,264	\$83,444,682	\$105,552,257
First Year Maintenance Costs				
Reagent Feed System	\$816,532	\$826,345	\$816,702	\$841,781
Ball Mill & Hydroclone System	\$209,866	\$211,617	\$209,896	\$214,455
DBA Acid Tank (pump, heater, agitator)	\$0	\$0	\$0	\$0
SO2 Removal System	\$220,161	\$223,353	\$220,216	\$228,450
Absorber Tower	\$1,300,584	\$1,519,982	\$1,304,578	\$1,830,369
Spray Pumps	\$155,148	\$205,490	\$155,651	\$273,668
Flue Gas Handling System	\$575,036	\$654,820	\$576,484	\$763,828
ID Fans	\$174,470	\$210,804	\$175,120	\$264,126
Waste / Byproduct Handling System	\$93,731	\$96,391	\$93,777	\$100,632
Thickener System	\$16,258	\$17,415	\$16,278	\$19,286
Support Equipment	\$184,720	\$198,815	\$176,181	\$218,761
Chimney	\$426,577	\$467,833	\$427,352	\$522,257
TOTAL	\$4,173,083	\$4,632,863	\$4,172,234	\$5,277,613

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation	RR Unit 2	RR Unit 3	TC High	TC Unit 9
LSFO O&M Data and Costs				
Cost Basis (Year)	2013	2013	2013	2013
Parameters	2013	2015	2015	2015
Reagent Required	4,419	5,827	4,444	8,102
Reagent Required	1.469	1.469	4,444 1.469	1.469
DBA Required	0.0	0.0	0.0	0.0
Percent SO2 Removal	95%	95%	95%	95%
FGD Sludge to Disposal	7,314	9,643	7,354	13,408
Steam to FGD System	36,157	47,673	36,354	66,284
Total FGD Power Consumption	5,840	7,700	4,800	10,706
FGD Byproduct	0	0	0	0
Fixed O&M Costs				
Number of Operators	20	24	17	29
(40 hrs/week)				
Operating Labor Cost **	\$1,218,971	\$1,470,176	\$1,067,267	\$1,838,112
Maint. Labor & Matls. Cost	\$4,173,083	\$4,632,863	\$4,172,234	\$5,277,613
Admin. & Support Labor	\$866,461	\$996,996	\$820,848	\$1,184,747
TOTAL	\$6,258,515	\$7,100,036	\$6,060,350	\$8,300,472
Variable Operating Costs **				
Reagent Costs	\$234,223	\$308,822	\$235,501	\$429,383
DBA Costs	\$0	\$0	\$0	\$0
Disposal Costs	\$528,576	\$696,923	\$531,458	\$968,995
Credit for Byproduct	\$0	\$0	\$0	\$0
Steam Costs	\$609,720	\$803,911	\$613,044	\$1,117,750
Power Costs	\$703,428	<u>\$927,465</u>	\$578,160	\$1,289,538
TOTAL	\$2,075,947	\$2,737,121	\$1,958,163	\$3,805,665
TOTAL O&M COSTS	\$8,334,462	\$9,837,157	\$8,018,513	\$12,106,137

** These costs assume inputs are in current dollars (no escalation included).

CUECost - Air Pollution Control Systems Spreadsheet

dry FGD Lime Spray Dry (LSD) System		RR Unit 2	RR Unit 3	TC High	TC Unit 9
LSD Equipment Capit	al Costs				
	st Basis (Year)	2013	<u>2013</u>	2013	2013
	Sizing Criteria			<u> </u>	
Reagent Feed System	*	\$6,684,122	\$6,916,648	\$6,688,146	\$7,284,853
SO2 Removal System	Wt. % S	\$2,214,137	\$2,214,137	\$2,214,137	\$2,214,137
Spray Dryers	kACFM	\$20,449,054	\$23,853,138	\$20,515,688	\$27,255,792
Flue Gas Handling System	kACFM	\$3,842,151	\$4,498,106	\$3,854,054	\$5,432,546
ID Fans	ACFM	\$1,792,841	\$2,161,670	\$1,799,439	\$2,703,455
Waste / Byproduct Handling System	kpph SO2	\$1,605,753	\$1,605,753	\$1,605,753	\$1,605,753
Support Equipment	MW	\$3,123,706	\$3,391,903	\$2,959,773	\$3,757,571
Chimney	ACFM	\$6,131,262	\$6,717,380	\$6,142,264	\$7,492,051
TOTAL		\$45,843,026	\$51,358,734	\$45,779,254	\$57,746,158
* Based on lbs/hr of lime feed and G	PM of lime slurr	у.			
Capital Costs with Retrofit Factors					
Reagent Feed System		\$14,705,069	\$15,216,625	\$14,713,922	\$16,026,676
SO2 Removal System		\$4,871,101	\$4,871,101	\$4,871,101	\$4,871,101
Spray Dryers		\$44,987,918	\$52,476,904	\$45,134,513	\$59,962,743
Flue Gas Handling System		\$8,452,732	\$9,895,833	\$8,478,919	\$11,951,602
ID Fans		\$3,944,250	\$4,755,674	\$3,958,767	\$5,947,600
Waste / Byproduct Handling System		\$3,532,657	\$3,532,657	\$3,532,657	\$3,532,657
Support Equipment		\$6,872,154	\$7,462,187	\$6,511,500	\$8,266,657
Chimney		<u>\$13,488,776</u>	\$14,778,236	<u>\$13,512,981</u>	<u>\$16,482,512</u>
TOTAL		\$100,854,657	\$112,989,216	\$100,714,359	\$127,041,548
General Facilities					
Reagent Feed System		\$1,470,507	\$1,521,663	\$1,471,392	\$1,602,668
SO2 Removal System		\$487,110	\$487,110	\$487,110	\$487,110
Spray Dryers		\$4,498,792	\$5,247,690	\$4,513,451	\$5,996,274
Flue Gas Handling System		\$845,273	\$989,583	\$847,892	\$1,195,160
ID Fans		\$394,425	\$475,567	\$395,877	\$594,760
Waste / Byproduct Handling System		\$353,266	\$353,266	\$353,266	\$353,266
Support Equipment		\$687,215	\$746,219	\$651,150	\$826,666
Chimney		<u>\$1,348,878</u>	<u>\$1,477,824</u>	<u>\$1,351,298</u>	<u>\$1,648,251</u>
TOTAL		\$10,085,466	\$11,298,922	\$10,071,436	\$12,704,155
Engineering Fees					
Reagent Feed System		\$1,470,507	\$1,521,663	\$1,471,392	\$1,602,668
SO2 Removal System		\$487,110	\$487,110	\$487,110	\$487,110
Spray Dryers		\$4,498,792	\$5,247,690	\$4,513,451	\$5,996,274
Flue Gas Handling System		\$845,273	\$989,583	\$847,892	\$1,195,160
ID Fans		\$394,425	\$475,567	\$395,877	\$594,760
Waste / Byproduct Handling System		\$353,266	\$353,266	\$353,266	\$353,266
Support Equipment		\$687,215	\$746,219	\$651,150	\$826,666
Chimney		<u>\$1,348,878</u>	<u>\$1,477,824</u>	<u>\$1,351,298</u>	<u>\$1,648,251</u>
TOTAL		\$10,085,466	\$11,298,922	\$10,071,436	\$12,704,155

DTE Electric Company - River Rouge and Trenton Channel Power Plant SO₂ RACT Analysis Attachment 1: CUECost Air Pollution Control System Costs.

dry FGD Lime Spray Dry (LSD) System	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Contingency				
Reagent Feed System	\$2,941,014	\$3,043,325	\$2,942,784	\$3,205,335
SO2 Removal System	\$974,220	\$974,220	\$974,220	\$974,220
Spray Dryers	\$8,997,584	\$10,495,381	\$9,026,903	\$11,992,549
Flue Gas Handling System	\$1,690,546	\$1,979,167	\$1,695,784	\$2,390,320
ID Fans	\$788,850	\$951,135	\$791,753	\$1,189,520
Waste / Byproduct Handling System	\$706,531	\$706,531	\$706,531	\$706,531
Support Equipment	\$1,374,431	\$1,492,437	\$1,302,300	\$1,653,331
Chimney	<u>\$2,697,755</u>	\$2,955,647	\$2,702,596	\$3,296,502
TOTAL	\$20,170,931	\$22,597,843	\$20,142,872	\$25,408,310
Total Plant Cost (TPC)	\$141,196,520	\$158,184,902	\$141,000,102	\$177,858,167
Total Plant Cost (TPC) w/ Prime Contractor's Mark	\$145,432,415	\$162,930,449	\$145,230,105	\$183,193,912
Total Cash Expended (TCE)	\$143,314,468	\$160,557,676	\$143,115,104	\$177,909,970
Allow. for Funds During Constr. (AFDC)	\$7,624,612	\$8,541,985	\$7,614,006	\$19,507,069
Total Plant Investment (TPI)	\$150,939,080	\$169,099,660	\$150,729,109	\$197,417,039
Preproduction Costs	\$3,771,090	\$4,296,464	\$3,750,019	\$5,100,831
Inventory Capital	\$117,160	\$154,475	\$117,799	\$214,780
TOTAL CAPITAL REQUIREMENT (TCR)	\$154,827,330	\$173,550,599	\$154,596,927	\$202,732,650
	\$530	\$451	\$644	\$379

dry FGD Lime Spray Dry (LSD) System	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Maintenance Cost by Area	Case 1	Case 2	Case 3	Case 4
TPC w/o Retrofit Factor				
Reagent Feed System	\$9,625,136	\$9,959,973	\$9,630,931	\$10,490,188
SO2 Removal System	\$3,188,357	\$3,188,357	\$3,188,357	\$3,188,357
Spray Dryers	\$29,446,637	\$34,348,519	\$29,542,590	\$39,248,341
Flue Gas Handling System	\$5,532,698	\$6,477,272	\$5,549,838	\$7,822,867
ID Fans	\$2,581,691	\$3,112,805	\$2,591,193	\$3,892,975
Waste / Byproduct Handling System	\$2,312,284	\$2,312,284	\$2,312,284	\$2,312,284
Support Equipment	\$4,498,137	\$4,884,340	\$4,262,072	\$5,410,903
Chimney	\$8,829,017	\$9,673,028	\$8,844,860	\$10,788,553
TOTAL	\$66,013,957	\$73,956,578	\$65,922,126	\$83,154,468
First Year Maintenance Costs				
Reagent Feed System	\$481,257	\$497,999	\$481,547	\$524,509
SO2 Removal System	\$159,418	\$159,418	\$159,418	\$159,418
Spray Dryers	\$1,472,332	\$1,717,426	\$1,477,130	\$1,962,417
Flue Gas Handling System	\$276,635	\$323,864	\$277,492	\$391,143
ID Fans	\$129,085	\$155,640	\$129,560	\$194,649
Waste / Byproduct Handling System	\$115,614	\$115,614	\$115,614	\$115,614
Support Equipment	\$224,907	\$244,217	\$213,104	\$270,545
Chimney	\$441,451	\$483,651	\$442,243	\$539,428
TOTAL	\$3,300,698	\$3,697,829	\$3,296,106	\$4,157,723

TOTAL OPERATING COSTS

CUECost - Air Pollution Control Systems Spreadsheet

ry FGD Lime Spray Dry (LSD) System	RR Unit 2	RR Unit 3	TC High	TC Unit
SD OF M Data and Costa				
LSD O&M Data and Costs	2012	2012	2012	2012
Cost Basis (Year)	<u>2013</u>	<u>2013</u>	<u>2013</u>	<u>2013</u>
Parameters	2 502	2 201	0 517	4 500
Reagent Required	2,503 0.832	3,301	2,517 0.832	4,589
	0.000-	0.832	0.00-	0.832
Percent SO2 Removal	93%	93%	93%	93%
FGD Solids - dry	22,113	29,155	22,233	40,537
- wetted	27,641	36,444	27,792	50,672
Fresh Water to FGD	16	22	17	30
Blowdown Water to FGD	309	398	311	543
Total FGD Power Consumption	2,044	2,695	1,680	3,747
Fixed O&M Costs				
Number of Operators	16	18	14	21
(40 hrs/week)				
Operating Labor Cost **	\$969,047	\$1,126,368	\$863,382	\$1,315,305
Maint. Labor & Matls. Cost	\$3,300,698	\$3,697,829	\$3,296,106	\$4,157,723
Admin. & Support Labor	<u>\$686,798</u>	\$781,650	\$654,547	\$893,518
TOTAL	\$4,956,542	\$5,605,847	\$4,814,036	\$6,366,54
Variable Operating Costs **				
Reagent Costs	\$391,998	\$516,847	\$394,136	\$718,619
Disposal Costs	\$1,598,080	\$2,107,058	\$1,606,794	\$2,929,631
Credit for Byproduct	\$0	\$0	\$0	\$0
Steam Costs	\$0	\$0	\$0	\$0
Fresh Water Costs	\$2,861	\$3,772	\$2,877	\$5,245
Power Costs	<u>\$246,200</u>	<u>\$324,613</u>	\$202,356	<u>\$451,338</u>
TOTAL	\$2,239,139	\$2,952,290	\$2,206,163	\$4,104,833

\$7,195,682

\$8,558,136

\$7,020,198

\$10,471,380

Fabric Filter Baghous	e	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Flue Gas, Upstream of Fabric Filter					
Temperature	°F	300	300	300	300
Pressure	in. H2O	-12	-12	-12	-12
Flow Rate	SCFM	748,881	987,395	752,965	1,372,863
Flow Rate	ACFM	1,148,302	1,514,029	1,154,564	2,105,090
CO2	lb/hr	642,148	846,668	645,650	1,177,198
N2	lb/hr	2,339,668	3,084,836	2,352,426	4,289,124
SO2	lb/hr	2,703	3,563	2,717	4,954
02	lb/hr	187,835	247,660	188,860	344,343
HCl	lb/hr	38	50	38	69
Other Gases	lb/hr	817	1,077	821	1,497
H2O	lb/hr	258,299	340,565	259,707	473,518
Fly Ash	lb/hr	16,263	21,443	16,352	29,814
Total (gas only)	lb/hr	3,431,507	4,524,418	3,450,218	6,290,704
Total Fabric Required	Ft ²	328,086	432,580	329,875	601,454
Surface Area per Bag	Ft^2	31.4	31.4	31.4	31.4
Required No. of Bags (no spare com	partments)	10,443	13,769	10,500	19,145
Final No. of Bags		11,488	15,146	11,550	21,059
No. of Casings		1	1	1	2
Fabric Filter Dimensions (per Casi	Ft^2	11,278	14,870	11,339	10,337
Length	Ft	150	172	151	144
Width	Ft	75	86	75	72

CUECost - Air Pollution Control Systems Spreadsheet

Fabric Filter Baghou	lse	RR Unit 2	RR Unit 3	TC High	TC Unit 9	
Capital Cost		Case 1	Case 2	Case 3	Case 4	
(Cost Basis (Year)	<u>2013</u>	<u>2013</u>	<u>2013</u>	<u>2013</u>	
Fabric Filter	¢	\$7,126,070	\$8,668,846	\$7,153,590	\$13,399,123	
Bags	\$ \$	\$926,147	\$1,221,118	\$931,197	\$1,697,830	
÷		\$920,147 \$629,314	\$723,500	\$630,926	\$1,097,830	
Ash Handling System ID Fan(s)	\$. ,	\$1,082,304		\$1,327,244	
Equipment Cost Subtotal	\$ \$	<u>\$912,055</u> \$9,593,586	<u>\$1,082,304</u> \$11,695,768	<u>\$915,130</u> \$9,630,844	<u>\$1,527,244</u> \$17,299,914	
Instruments & Controls		\$9,393,380 \$191,872	\$233,915	\$9,030,844 \$192,617	\$17,299,914 \$345,998	
	\$					
Taxes	\$	\$575,615	\$701,746	\$577,851 \$481,542	\$1,037,995	
Freight	\$	<u>\$479,679</u>	<u>\$584,788</u>	<u>\$481,542</u>	<u>\$864,996</u>	
Purchased Equipment Cost Sub		\$10,840,752	\$13,216,218	\$10,882,854	\$19,548,903	
Installation	\$	<u>\$7,263,304</u>	<u>\$8,854,866</u>	<u>\$7,291,512</u>	<u>\$13,097,765</u>	
Total Direct Cost	\$	\$18,104,055	\$22,071,084	\$18,174,365	\$32,646,668	
Total Direct Cost with Retrofit	F \$	\$39,828,922	\$48,556,385	\$39,983,604	\$71,822,671	
General Facilities	\$	\$3,982,892 \$3,982,892	\$4,855,638	\$3,998,360	\$7,182,267	
Engineering Fees	\$		\$4,855,638	\$3,998,360	\$7,182,267	
Contingency	\$	\$7,965,784	\$9,711,277	\$7,996,721	\$14,364,534	
Total Plant Cost (TPC)	\$	\$55,760,490	\$67,978,939	\$55,977,045	\$100,551,739	
Total Plant Cost (TPC) w/ Prime (\$57,433,305	\$70,018,307	\$57,656,357	\$103,568,291	
Total Cash Expended (TCE)	\$	\$56,596,898	\$68,998,623	\$56,816,701	\$102,060,015	
Allow. for Funds During Constr. (\$3,011,066	\$3,670,863	\$3,022,760	\$5,429,794	
Total Plant Investment (TPI)	\$	\$59,607,964	\$72,669,485	\$59,839,462	\$107,489,809	
Preproduction Costs	\$	\$1,192,159	\$1,453,390	\$1,196,789	\$2,149,796	
Inventory Capital	\$ \$	\$1,192,139 \$0	\$1,433,390 \$0	\$1,190,789 \$0	\$2,149,790 \$0	
				4	4	
TOTAL CAPITAL REQUIREME		\$60,800,123	\$74,122,875	\$61,036,251	\$109,639,605	
	\$/kW	\$208.2	\$192.5	\$254.3	\$204.8	
O&M Data and Costs		Case 1	Case 2	Case 3	Case 4	
	Cost Basis (Year)	<u>2013</u>	<u>2013</u>	<u>2013</u>	<u>2013</u>	
Power Required Excluding ID I		493	644	496	885	
ID Fan Power for FF Delta P	kW	<u>1,160</u>	<u>1,529</u>	<u>1,166</u>	<u>2,126</u>	
Total Power	kW	1,653	2,173	1,662	3,011	
Power Cost **	\$/yr	\$199,076	\$407,746	\$311,828	\$565,011	
Maintenance Costs	\$/yr	\$1,267,284	\$1,544,976	\$1,272,206	\$2,285,267	
Periodic Replacement Items	\$/yr	\$926,147	\$1,221,118	\$931,197	\$1,697,830	
First Year Cost. Bags Replaced	•	5 Years	5 Years	5 Years	5 Years	
TOTAL OPERATING COSTS		¢2 202 507	¢2 172 010	¢2 515 220	¢1 510 100	
IUIAL OFERAIING COSIS		\$2,392,507	\$3,173,840	\$2,515,230	\$4,548,108	

** These costs assume inputs are in current dollars (no escalation included).

Reasonably Available Control Technology EES Coke Battery, LLC

EES Coke Battery, LLC River Rouge, Michigan

March 31, 2014

EXECUTIVE SUMMARY

EES Coke Battery, LLC (EES Coke) is submitting a Reasonably Achievable Control Technology (RACT) analysis for its existing coke battery located on Zug Island, River Rouge, Michigan. This analysis has been requested by the Michigan Department of Environmental Quality (MDEQ) as part of its effort to develop a State Implementation Plan (SIP) to achieve compliance with the 1-hr SO₂ National Ambient Air Quality Standard (NAAQS) in the newly designated non-attainment area in Wayne County. EES Coke's RACT analysis evaluates both flue gas and Coke Oven Gas (COG) desulfurization. Flue gas desulfurization is determined to be technically infeasible at EES Coke's natural draft battery. COG desulfurization is determined to be economically infeasible costing \$14,002 per ton of SO₂ removed and slightly over \$1.75 million per ppb of ambient concentration reduced.

EES Coke does not cause a violation of the NAAQS at either the Southwest High School ambient monitor or at its point of highest ambient impact (i.e., hot spot), even when all the coke oven gas generated by the battery is consumed in EES Coke combustion sources (Underfire and COG Flare). Further, EES Coke's ambient impacts are relatively insignificant compared to other nearby sources. EES Coke is not the cause of the nonattainment status for the area and should not be the focus of the mitigating measures.

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APPENDICES

Appendix A	COG Desulfurization Control Costs
Appendix B	COG Desulfurization Total Capital Investment Summary

1.0 INTRODUCTION

EES Coke Battery, LLC (EES Coke) is submitting a Reasonably Achievable Control Technology (RACT) analysis for the existing coke battery facility located at 1400 Zug Island Rd., River Rouge, Michigan. EES Coke is located in the newly designated non-attainment area which encompasses a portion of in Wayne County, which is currently in attainment with all National Ambient Air Quality Standards (NAAQS), with the exception of the 2010 primary sulfur dioxide (SO₂) NAAQS. U.S. Environmental Protection Agency (EPA) designated the area nonattainment for SO₂ on October 4, 2013. The Clean Air Act (CAA) directs areas designated nonattainment (i.e., failing to meet the NAAQS) to undertake certain planning and pollution control activities to attain the NAAQS as expeditiously as practicable. Thus, as part of Michigan's State Implementation Plan (SIP), which must provide for attainment of the SO₂ NAAQS, Michigan Department of Environmental Quality (MDEQ) has requested that EES Coke submit a RACT analysis for SO₂ emissions.

U.S. EPA defines RACT as:

The lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility (44 FR 53762).

1.1 Process Description

The EES Coke No. 5 Coke Battery produces coke from the heating of metallurgical coal, in the absence of oxygen, to vaporize volatile constituents and concentrate the carbon. The coke is used as a raw material in a blast furnace to produce iron. EES Coke operates one (1) coke battery consisting of eighty-five (85), six (6)-meter high ovens that produce coke. The ovens are situated in rows and enclosed between heating walls. The ovens are equipped with four (4) lids on the top of each oven and doors on the two (2) external sides that do not face neighboring ovens. During the "charging" step, coal is taken from storage bins and loaded into a "larry car." The larry car then moves to the empty oven where it unloads coal into the oven. The coal is leveled in the oven using a leveling bar to create a space for waste gas to collect and be drawn off the coal mass undergoing "coking." The coal within each oven is heated for approximately 17-18 hours, in the absence of oxygen, by means of underfire combustion to a temperature of around 1,800-2,200 °F, until the volatile matter, water, and coal-tar in the coal mass are vaporized and driven off. This volatile matter leaves the battery oven as raw coke oven gas (COG) and is sent to the No. 3 By-products Plant for further processing. In order to minimize emissions, staged heating and recirculation flow technologies are utilized on the No. 5 Coke Battery.

Following the "coking" process, both doors are removed and a pushing machine pushes the coke out of the oven into a quench car. Fugitive emissions from the quench car are collected and exhausted through the Pushing Emission Control System (PECS) Baghouse. The quench car is moved along the length of the battery, until it reaches the quench tower where it is quenched with water to cool the coke prior to screening and shipment of the coke.

The No. 3 By-products Plant refines the raw COG and separates tars and light oils by passing the raw gas and process fluids through a series of process decanters, condensers, heat exchangers, and stills. The conditioned COG is then used as a fuel to heat the coke battery, a portion is sent to U.S. Steel for use in several processes, and a portion is sold to offsite sources. Excess COG is flared in an open flare located adjacent to the battery.

1.2 Significant Sources of Sulfur Dioxide (SO₂) Emissions

Coke is produced from the heating of metallurgical coal, in the absence of oxygen, to vaporize volatile constituents and concentrate the carbon. A by-product of the process is coke oven gas (COG), which is recovered in the by-products plant, cleaned, and used as a fuel for heating the ovens. SO_2 is emitted from underfire combustion as a result of the thermal oxidation of the sulfur compounds in the fuel. EES Coke currently collects fuel samples to determine the hydrogen sulfide (H₂S) content of the COG and operates a continuous emissions monitoring system (CEMS) for SO_2 to demonstrate continuous compliance with the current permit emission limits.

In addition to SO₂ emissions from underfire combustion, SO₂ is emitted from combustion of excess COG in the COG flare (worst-case Battery Underfire and Flare SO₂ emissions total 3,846 tpy). The COG flare is a control device used to combust COG that is not used to underfire the battery, used at other on-site sources, or sold offsite.

These EES Coke emissions sources do not cause a violation of the NAAQS at either the Southwest High School (SWHS) ambient monitor or at their point of highest ambient impact (i.e., hot spot). The maximum ambient 1-hr SO2 concentration resulting from EES Coke emission sources is 26 ppb, approximately one-third of the 75 ppb NAAQS. At 17.8 ppb, EES Coke's maximum impact at the SWHS monitor is less than one-quarter of the NAAQS, and only slightly greater than the prevailing background SO2 concentration of 15 ppb. Further, EES Coke's ambient impacts are insignificant compared to other nearby sources. It should be noted when EES Coke sources are modeled in combination with other sources in the area, EES's contribution to the overall ambient impact is minimal as the maximum impact is the result of other nearby sources. EES Coke's emissions do not cause a violation of the NAAQS.

Although SO₂ can be controlled in various types of combustion sources using several techniques, there are considerable limitations associated with retrofitting emission controls on an existing coke battery. Since the coke oven operates at temperatures in excess of 1,800°F and cannot be cooled once operation begins, the logistics of any retrofit project are very difficult to arrange. In addition, because EES Coke is a natural draft combustion source, the addition of post-combustion controls generally requires a complete rebuild of the facility.

The following section contains a RACT analysis for emissions of SO_2 at the No. 5 Coke Battery and No. 3 By-products Plant.

2.0 CONTROL TECHNOLOGY REVIEW

As outlined in Section 1.0, EES Coke is submitting a RACT analysis for the existing coke battery facility as requested by MDEQ. The following sections outline this control technology analysis.

2.1 Reasonably Achievable Control Technology (RACT) Analysis

RACT is defined by U.S. EPA as:

The lowest **emission limitation** that a particular source is capable of meeting by the application of control technology that is **reasonably available** considering **technological** and **economic feasibility** (44 FR 53762). [emphasis added]

This RACT analysis is broken down into five (5) steps. The steps coincide with the definition of RACT:

- 1. Identify All Reasonably Available Control Technologies;
- 2. Evaluate All Control Technologies and Eliminate All Technologically Infeasible Options;
- 3. Discuss Remaining Control Technologies;
- 4. Evaluate Remaining Control Technologies Based on Economic Feasibility; and
- 5. Propose RACT Emission Limit.

EES Coke has reviewed current permits for coke ovens, and other relevant information, for comparison to the emission limits proposed as RACT for this project. It is important to note that coke oven emissions can vary considerably based on the equipment technology and the age of the process equipment. The majority of recently permitted coke batteries are of the heat recovery variety. This technology oxidizes all of the volatiles emitted from the ovens, rather than recovering useful byproducts downstream. Oven design between the two technologies differs greatly as heat recovery ovens are kept at negative pressure, and by-products recovery ovens are kept at positive pressure. Since the EES Coke battery is of the by-product recovery type, emission rates are not easily comparable; therefore this RACT review incorporates only the control technologies applicable to a by-product recovery coke battery.

The sections that follow provide detailed RACT analyses for SO₂ emissions from EES Coke.

2.1.1 Identify All Reasonably Available Control Technologies - STEP 1

Control options for SO₂ consist of pre-combustion COG desulfurization and post-combustion flue gas desulfurization. The only emissions reduction alternative at a flare is to minimize the sulfur content of the waste gases being flared (i.e., COG desulfurization). Potential SO₂ control technologies are as follows:

Underfire Combustion

- 1. Flue Gas Desulfurization
- 2. COG Desulfurization

COG Flare

1. COG Desulfurization

2.1.2 Eliminate Technologically Infeasible Options – STEP 2

The following technologies are considered to be technically infeasible for operation at the EES Coke by-products recovery coke battery plant and are therefore eliminated from further review.

Flue Gas Desulfurization (FGD) - Flue gas desulfurization (FGD) is a post-combustion control technology that uses a scrubbing media to absorb SO_2 present in the exhaust gas stream. FGD is most often used to control emissions from coal-fired boilers. Traditionally designed as a wet system, FGD uses a scrubbing liquid containing an alkali reagent such as lime or limestone for the absorption of SO_2 . Exhaust gas enters the absorber and travels up through the absorption zone where it contacts the absorbent slurry or solution that is passing down through the absorber. SO_2 dissolves into the slurry where it reacts with the alkaline reagent. Treated exhaust gas then passes through a mist eliminator to remove any entrained slurry droplets before exiting the absorber. The process can be regenerative (slurry is recycled back into the system) or non-regenerative (slurry is disposed of or used as a by-product).

The installation of a FGD system would require redesigning and reconstructing the facility in a manner never attempted for any by-products recovery coke battery. The EES Coke battery and other by-products recovery coke batteries rely on natural draft to draw air into the combustion system for proper operation. FGD necessarily quenches the flue gas with sprays to capture SO₂. This cooling of the gas would greatly diminish this natural draft and in turn compromise the combustion system. For this reason we consider this alternative to be technically infeasible.

2.1.3 Discussion of Technologically Feasible Options – STEP 3

The only technologically feasible control option for reducing SO₂ emissions due to COG combustion in the battery underfire or flare is COG desulfurization.

<u>COG Desulfurization</u> - COG desulfurization involves chemical and physically treating the COG to remove sulfur prior to combustion. COG desulfurization requires the design and construction of a major chemical facility to handle the volumes of COG generated at EES Coke.

2.1.4 Evaluate Remaining Control Technologies based on Economic Feasibility – STEP 4

COG desulfurization is the only technologically feasible and available control option for minimizing SO₂ emissions at the EES Coke battery underfire and flare. However, implementing a COG sulfur reduction strategy would require excessive economic costs, beyond what is required by RACT and especially when the source is not causing a NAAQS violation at the SWHS monitor or at its own point of maximum impact (hot spot). The economic feasibility of COG desulfurization is outlined below.

COG Desulfurization

<u>Capital Costs</u> - EES Coke solicited JNE Consulting and Engineering ("JNE") for a preliminary COG desulfurization budgetary cost estimate specific to EES Coke's operating parameters. These parameters included COG production rates consistent with the maximum dry coal charge with sufficient short-term over-capacity to account for upset conditions, reduced efficiency over time, and allowable sulfur content of COG. Costs for infrastructure support facilities as well as modification costs that would be incurred from upgrades at the waste water treatment plant were included in this analysis.

JNE's 2013 estimate was \$111.9 million but excluded certain indirect costs and interest during construction. EES Coke has adjusted the capital estimate at 2.5% annually to convert it into 2015 dollars, added interest during construction, and added 25% to cover certain indirect costs not included in the JNE estimate and contingency. Note: this estimate does not include costs associated with potential lost production. See Appendix B for details.

<u>Operating Costs</u> - COG desulfurization operating expenses were estimated by internal engineers located at the EES Coke battery. Average annual operating costs are estimated to be approximately \$25.1 million and are generally inflated annually at 2.5%. See Appendix A for details.

<u>Cost of Capital</u> - In order to annualize the capital costs associated with the investment, EES Coke calculated a capital recovery factor assuming a 15 year project life and a 7% interest rate. The capital recovery factor was calculated to be 0.1098, resulting in annual capital recovery costs of approximately \$18.0 million.

<u>Tons of SO2 Removed</u> - EES Coke has the capacity to generate up to approximately 3,846 tons of SO2 annually (2,568 from underfire and 1,278 from flare). Assuming a 90% removal efficiency and 89% up-time, 3,082 tons of SO2 is expected to be removed as a result of the COG desulfurization investment. The estimated dollar per ton removal cost of COG desulfurization is estimated to be \$14,002 per ton. See Appendix A for details.

2.1.5 Propose RACT Emission Limit – STEP 5

The proposed RACT emission limits and/or work practice standards are discussed in this section for the EES Coke battery.

COG Combustion –SO₂ Emission Limit

RACT for emissions of SO_2 from EES Coke is determined to be continued compliance with the existing emission limits for the coke oven battery underfire. There are no additional technologically or economically feasible control options reasonably available for SO_2 reduction at EES Coke. Appendix A

COG Desulfurization Control Costs				
Operating Costs (\$000's)				
Variable Costs:				
Steam (500,000 mmlbs/yr)	\$4,258			
Electricity (29,000 mwh/yr)	3,425			
Nitrogen (400,000 ccf/yr)	86			
Service Water (31,500 mgal/yr)	43			
Caustic Soda (1,400 tons/yr)	1,100			
Fixed Costs:	\$8,911			
Sewer	\$517			
Annual Maintenance	2,248			
Labor	923			
Administrative Charges (2% of Capital Investment)	3,291			
Property Taxes (1% of Capital Investment)	1,646			
Insurance (1% of Capital Investment)	1,646			
Overhead (60% of Labor and Materials)	5,901			
	\$16,172			
Total Operating Costs:	\$25,083			
Capital Recovery (\$000's) \$18,0				
COG Desulfurization SO2 Removal				
Annual Production (tons dry coal charged (000's)	1,365			
COG Generation (mmBtu/ton dry coal)	7.25			
COG Heat Content (Btu/scf)	500			
COG Sulfur Content (grains H2S/scf)	2.64			
Annual Underfire COG Consumption (mmBtu)	3,617,250			
Annual Flare COG consumption (mmBtu)	1,800,000			
Uncontrolled SO2 Emissions (tons/yr)	3,846			
SO2 Removal Rate	90%			
Annual Desulf Facility Outage Days	40			
Facility Availability	89%			
Controlled SO2 Emissions (ton/yr)	3,082			
COG Desulfurization Control Costs				
Total Annualized Costs (\$000's)	\$43,151			
Annual SO2 Removed (tons)	3,082			
Control Costs (\$/ton)	14,002			

Appendix B

EES Coke **Desulfurization Total Project Summary** Funding Request Installation Cost Estimate Work Breakdown Structure Engrd Equip -Engr Equip -Mech Process Engr Equip - PC Project Direct Costs Instrumentation Installation Total Equipment / Auto Elect Primary Cooling \$ 2,819,000 \$ \$ \$ 601,000 \$ \$ 10,370,000 \$ 13,790,000 3,385,200 970,000 \$ \$ \$ 615,000 17,230,000 \$ 22,284,200 Cooling Water System \$ \$ -84.000 \$ Scrubbing \$ 1,487,000 \$ \$ -\$ 197,000 \$ _ \$ 5,595,000 \$ 7,279,000 Distillation \$ 3,647,600 \$ \$ 337,000 \$ \$ 11,745,000 \$ 15,819,600 90,000 \$ --\$ Sulfur Recovery Units \$ 4,255,800 \$ 580,000 \$ -\$ 733,000 \$ -\$ 15,125,000 20,693,800 Power \$ 680,000 \$ \$ \$ \$ 5,095,000 \$ 5,775,000 \$ --\$ Automation \$ \$ \$ \$ \$ \$ BioPlant \$ \$ \$ \$ \$ 1,101,000 \$ \$ 2,500,000 3,601,000 ----Sub-Total Project Direct Costs \$ \$ 16,695,600 \$ \$ 1,952,000 \$ 615,000 \$ 67,660,000 \$ -89,242,600 2.320.000 \$ Project Indirect Costs Total Indirect Costs \$ 22,682,540

Total Project					\$ 111,925,140
			•		
2 Years of Inflation					5,666,210
Other Indirect Costs + Contingency					29,397,838

Interest During Construction

Total Capital Investment Used in RACT Analysis

17,575,545

\$ 164,564,733