Appendix A

RBLC Search Summary for Pertinent Emission Units at Similar Sources

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Sinter Plant

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SIN-101 - MEROS System Vent Stack	Natural Gas	346	T/H	Nitrogen Oxides (NOx)		188.33	LB/H	3 - HR STACK TEST	BACT-PSD	749.88	T/YR		0.495	LB/TON	FINISHED SINTER PRODUCT

U. S. Steel Gary Works
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Sinter Plant

Sulfur Dioxide (SO2)

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Blast Furnace

Nitrogen Oxides (NOx)

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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	

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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	

Sulfur Dioxide (SO2)

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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	1/31/2006	INTEGRATED IRON AND STEEL PLANT	BLAST FURNACE STOVES	BLAST FURNACE GAS	24003	MMSCF/YR	Sulfur Dioxide (SO2)	NO CONTROLS FEASIBLE. COMPLIANCE VERIFICATION VIA CEMS.	14.37	LB/MMMSCF	WHEN B FURNACE OPERATING	BACT-PSD	16.62	LB/MMSCF	WHEN B FURNACE NOT OPERATING	0		
MI-0413	AK STEEL	AK STEEL CORPORATION	MI	182-05C	331111	5/12/2014	Iron and steel manufacturing facility	EUCFURNACE - C Blast Furnace which includes the blast furnace casthouse and stoves.	Nat. gas, BFG, pulv coal, coke	37841	MMCF/YR	Sulfur Dioxide (SO2)		179.65	LB/H	CALENDAR DAY AVG; BAGHOUSE STACK	BACT-PSD	193.6	LB/H	CALENDAR DAY AVG; STOVE STACK	0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/YR		0		

Sulfur Dioxide (SO2)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/H		0		
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	01/31/2006 ACT	INTEGRATED IRON AND STEEL PLANT	C FURNACE CASTHOUSE	PULVERIZED COAL, COKE	6700	T/D	Sulfur Dioxide (SO2)	NO FEASIBLE CONTROLS	14.65	LB/H	AVERAGING TIME PER TEST PROTOCOL	BACT-PSD	0			0		

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Waste Heat Boiler

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	NEW STEEL INTERNATIONAL, INC.	OH	07-00587	331513	5/6/2008	STEEL MINI MILL, WITH 2 ELECTRIC ARC FURNACES AND A PRODUCTION RATE OF 4,409,248 TONS/YEAR. ***THIS FACILITY WAS NOT INSTALLED AS OF 10/09.***	WASTE HEAT BOILERS (6)	PULVERIZED COAL	60	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION AND LOW NOX BURNERS	48.61	LB/H	AS A ROLLING 3-HOUR AVERAGE	BACT-PSD	177.21	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.081	LB/MMBTU	AS A ROLLING 3-HOUR AVERAGE

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Reheat Furnace

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0210	IPSCO STEEL INC.	IPSCO STEEL INC.	AL	503-8065-X003 MOD 1	331111	2/7/2005		REHEAT FURNACE	NATURAL GAS	450	mmbtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS, 12 MONTH NATURAL GAS LIMIT -- 3.69 E+9 CUFT	77.4	LB/H		BACT-PSD	172	LB/MMBTU		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX AND LOW NOX BURNERS	0.085	LB/MMBTU		BACT-PSD	14.37	LB/H		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)	SCR	100	PPMVD	PARTS PER MILLION, VOLUMETRIC DRY	BACT-PSD	3.43	LB/H		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	HOT STRIP MILL (MULTIPLE EMISSION POINTS)	NATURAL GAS	690	T/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS	0.085	LB/MMBTU	EACH FURNACE	BACT-PSD	40.1	LB/H	EACH FURNACE	0		
AR-0085	BLYTHEVILLE MILL	NUCOR-YAMATO STEEL COMPANY	AR	883-AOP-R5	331111	4/6/2005	PRODUCES STEEL BEAMS, PRIMARILY FROM STEEL SCRAP USING THE EAF PROCESS.	#1 REHEAT FURNACE (SN-02)	NATURAL GAS	300	MMBTU/H	Nitrogen Dioxide (NO2)	ULTRA LOW NOX BURNERS	51.3	LB/H		BACT-PSD	224.7	T/YR		0.07	LB/MMBTU	
FL-0283	JACKSONVILLE STEEL MILL	GERDAU AMERISTEEEL	FL	PSD-FL-349A	331513	5/5/2006	EXISTING SCRAP AND IRON AND STEEL RECYCLING (SECONDARY METAL PRODUCTION) FACILITY THAT PRODUCES STEEL REBAR, ROD AND WIRE. MAIN COMPONENTS OF THE PLANT INCLUDE: AN EXISTING FUCHS ELECTRIC ARC FURNACE (EAF); A LADLE METALLURGY FURNACE (LMF); A SCRAP HANDLING BUILDING; A ROKOP CONTINUOUS CASTER; A REBAR BILLET REHEAT FURNACE (BRF): A ROLLING MILL; A ROD MILL; AND, SLAG HANDLING AND STORAGE. PERMITTED CAPACITY IS 1,192,000 TONS PER CONSECUTIVE 12- MONTH OF TAPPED LIQUID STEEEL.	NEW BILLET REHEAT FURNACE	NATURAL GAS	160	T/YR	Nitrogen Oxides (NOx)	FIRING OF NATURAL GAS.	0.08	LB/MMBTU	SEE NOTE	BACT-PSD	0			0		
GA-0142	OSCEOLA STEEL CO.	OSCEOLA STEEL CO.	GA	3312-075-0024-P-01-0	331111	12/29/2010	Osceola Steel Co. plans to construct and operate a micro steel mill capable of producing 430,000 tons of scrape steel annually. The proposed micro steel mill project will include 1 electric arc furnace, 2 horizontal ladle pre-heaters, 1 vertical ladle heater, 2 Tundish pre-heaters, 1 reheat furnace, 2 castings machine torches, and 3 cooling towers. Natural gas will be fired in the electric are furnace, the reheat furnace, both horizontal ladle and Tundish pre-heaters, the vertical ladle heater, and the casting machine torches. The primary sources of emissions from the facility will be from the electric arc furnace and the reheat furnace.	Reheat Furnace	Natural Gas	75	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners with FGR technology and good combustion/operating practices.	0.075	LB/T	3 HOUR STACK TESTING	BACT-PSD	0			0		
IA-0087	GERDAU AMERISTEEL WILTON	GERDAU AMERISTEEL WILTON	IA	PROJECT NUMBER 06-472	331111	5/29/2007	STEEL MINI-MILL THAT PRODUCES MERCHANT STEEL, SBQ BARS, FLATS, ANGLES, AND REBAR.	BILLET REHEAT FURNACE	NATURAL GAS	145.5	MMBTU/H	Nitrogen Oxides (NOx)	24 ULTRA LOW NOX BURNERS	110.23	LB/MMCF	AVG OF THREE (3) TEST RUNS	BACT-PSD	22.45	T/YR	ROLLING 12 MONTH TOTAL	0		
IL-0126	NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	18060014	331111	11/1/2018	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Natural Gas-Fired Reheat Furnace	Natural Gas	125.5	mmBtu/hr	Nitrogen Oxides (NOx)	Good combustion practices and low-NOx burners	0.07	LBS/MMBTU	DAILY (24-HR) AVERAGE	BACT-PSD	11.3	LBS/HR	AVERAGE VALID TEST RUN	0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	6/4/2015	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Shell Reheat Furnace - S04	natural gas	79.7	mm btu/hr	Nitrogen Oxides (NOx)	ULNB	0.075	LB/MM BTU		BACT-PSD	0			0		
MI-0417	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	MI	102-12A	331111	10/27/2014	Steel mill	EUBILLET-REHEAT (Walking Beam Billet Reheat Furnace)	natural gas ultra low NOx burners	260.7	MMBTU/H total burner capacity	Nitrogen Oxides (NOx)	Ultra-Low NOx burners and good combustion practices.	0.07	LB/MMSCF	TEST PROTOCOL	BACT-PSD	18.3	LB/H	TEST PROTOCOL	0		
NJ-0087	GERDAU SAYREVILLE	GERDAU	NJ	18052/BOP150001	331111	3/26/2018	Steel mini-mill	Billet Reheat Furnace	Natural gas	1178	MMSCF/YR	Nitrogen Oxides (NOx)	Low NOx Burners	0.1	LB/MMBTU	AV OF THREE STACK TEST RUNS ANNUALLY	RACT	17.3	LB/H	AV OF THREE STACK TEST RUNS ANNUALLY	0		
OH-0316	V & M STAR	V & M STAR	OH	P0103660	331111	9/23/2008	STEEL MINI-MILL PLANT, EXPANSION OF AN EXISTING PLANT PRODUCTION OF SEAMLESS STEEL TUBES.	BILLET PREHEAT FURNACE	NATURAL GAS	0.18	MMSCF/H	Nitrogen Oxides (NOx)	ULTRA-LOW NOX BURNERS	12.6	LB/H		BACT-PSD	30.4	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.07	LB/MMBTU	
OH-0316	V & M STAR	V & M STAR	OH	P0103660	331111	9/23/2008	STEEL MINI-MILL PLANT, EXPANSION OF AN EXISTING PLANT PRODUCTION OF SEAMLESS STEEL TUBES.	BILLET REHEAT FURNACE	NATURAL GAS	290	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA-LOW NOX BURNERS	29	LB/H		BACT-PSD	89.3	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.1	LB/MMBTU	
OH-0331	AK STEEL CORPORATION MANSFIELD WORKS	AK STEEL CORPORATION	OH	03-17463	331111	1/11/2010	STEEL SHOP USING ELECRIC ARC FUNRACES. SEE A MODIFICATION IN OH-0335.	Slab Reheat Furnace	Natural Gas	1138800	MMBtu/YR	Nitrogen Oxides (NOx)		0.14	LB/MMBTU	CALCULATED FROM AP-42 SECTION 1.4	N/A	79.72	T/YR	PER ROLLING 12 MONTHS	0		
OH-0341	NUCOR STEEL MARION, INC.	NUCOR STEEL	OH	P0105283	331111	12/23/2010	Steel Facility, Non-integrated mini-mill producing carbon steel bar stock, angle reinforcing rod, and highway products. This is a modification to OH-0294.	Reheat furnace for steel billet	Natural gas	184	MMBtu/H	Nitrogen Oxides (NOx)	Low NOx burners	27.6	LB/H		BACT-PSD	120.89	T/YR	PER ROLLING 12 MONTHS	0		

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Reheat Furnace

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
SC-0128	NUCOR STEEL CORPORATION (DARLINGTON PLANT)	NUCOR CORPORATION	SC	0820-0001-DF	331111	12/29/2006	THIS FACILITY PRODUCES BAR PRODUCT PRIMARILY FROM STEEL SCRAP AND SCRAP SUBSTITUTES USING AN ELECTRIC ARC FURNACE.	REHEAT FURNACE NO.2	NATURAL GAS	180	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.075	LB/MMBTU		BACT-PSD	0			0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 2				Nitrogen Oxides (NOx)		1.6	LB/H		BACT-PSD	7.01	T/YR		0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 1				Nitrogen Oxides (NOx)		9.1	LB/H		BACT-PSD	39.86	T/YR		0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 3				Nitrogen Oxides (NOx)		4.22	LB/H		BACT-PSD	18.5	T/YR		0		
TX-0705	STEEL MINIMILL FACILITY	STRUCTURAL METALS INC	TX	PSDTX708M6 8248	331111	7/24/2014	The primary purpose of the permit amendment is to authorize a number of physical and operational changes to increase the annual production rate through the electric arc furnace (EAF) and associated material handling sources at the mill. Specifically, the amendment will increase the melt shop production to 1,300,000 tpy.	Rolling Mill Billet Reheat Furnace	Natural Gas	1300000	tons/year	Nitrogen Oxides (NOx)	Ultra-low NOX burners.	0.073	LB/MMBTU		BACT-PSD	0			0		

Appendix B

Air Permit Summary for Similar Sources

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Sinter Plant						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
USS Gary Works	ISS10379 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	None	95.5 MMSCF	Natural gas usage shall be less than limit in the No. 3 Sinter Plant Sinter Strand Windbox reheat burners ISB001 and ISB003 per twelve (12) consecutive month period	Quench Reactor, Dry Venturi Scrubber	200 lb/hr	
USS Gary Works	ISS30381 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	None	95.5 MMSCF	Natural gas usage shall be less than limit in the No. 3 Sinter Plant Sinter Strand Windbox reheat burners ISB001 and ISB003 per twelve (12) consecutive month period	Quench Reactor, Dry Venturi Scrubber	200 lb/hr	
AM Indiana Harbor East	1959 Sinter Plant 1.4 Mmton/yr input	None	None		None	180 lb/hr	Pursuant to 326 IAC 7-4.1-11(a)(13)
AM Indiana Harbor West	1958 Sinter Plant (not present in 2020 permit mod) 2 Mmton/yr Sinter	None	None		Wet venturi scrubbers	240 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(3)
AM Burns Harbor	1968 Continuous Sintering Process Plant 535 tons sinter/hr	None	None		Venturi scrubber	None	
Nucor St. James	Not constructed Sinter Plant 3.03 Mmtons/yr Natural gas	None	0.495 lb/ton finished sinter	LAC 33:III.509	Lime Spray Drying Scrubber	2000 ppmv	LAC 33:III.1503.C: 3-hr average
						100 mg/DSCM	LAC 33:III.509, BACT
USS Clairton	Facility does not have a sinter plant						
AK Dearborn	Facility does not have a sinter plant						
AK Middleton	Facility does not have a sinter plant						
AM Cleveland	Facility does not have a sinter plant						
USS Edgar Thompson	Facility does not have a sinter plant						
USS East Chicago	Facility does not have a sinter plan						

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Blast Furnace						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150	None	None		None	0.134 lb/MMBtu 93.5 lb/hr total 115 lb/hr	Limit on: Blast Furnace No. 14 Stove Stack Limit on: Blast Furnace No. 14 Stove Stack Limit on: Blast Furnace No. 14 Casthouse Baghouse
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	None	None		None	0.195 lb/MMBtu 162 lb/hr 0.22 lb/ton 50.4 lb/hr	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Casthouse
AM Indiana Harbor West	1953 No. 3 Blast Furnace Comprised of three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	None	None		None	0.29 lb/MMBtu 127.89 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack
	1967 No. 4 Blast Furnace Comprised of three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	None	None		None	0.29 lb/MMBtu 140.94 lb/hr 0.18 lb/ton 69.9 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting
	2 Ladle Burners 36 MMBtu/hr max HI total	None	None		None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None		None	None	
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	None	None		None	None	
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	None	None		None	None	
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT	Low Sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 1	None	None		None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT	Low Sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S)	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 2	None	None		None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
USS Clairton	Facility does not have a blast furnace						
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Low-NOx Stove Technology	25.74 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES baghouse stacks R336.2801 - R336.2804 -- PSD	None	1,188 tpy (12mo rolling)	Limit on: FGB&CFURNACES baghouse and stove stacks R336.2803, R336.2804 -- PSD
	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common		439.2 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES stove stacks R336.2801 - R336.2804 -- PSD			

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Blast Furnace						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	None	None		None	None	
AM Cleveland	P903 Blast Furnace C5	None	0.06 lbs/MMBtu	for furnace stoves	None	33 lb/hr	from the blast furnace casthouse when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
						53 lb/hr	from the blast furnace stoves when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
	P904 Blast Furnace C6	None	0.06 lbs/MMBtu	for furnace stoves	None	33 lb/hr	A maximum of 390 grains of hydrogen sulfide per 100 dry standard cubic feet of coke oven gas, and the daily average not to exceed 33 lbs of SO2 per hour from the blast furnace casthouse when combusting coke oven gas.
						53 lb/hr	Maximum of 390 grains of hydrogen sulfide per 100 dscf of coke oven gas and the daily average not to exceed 53 lbs SO2/hr from the blast furnace stoves when combusting coke oven gas.
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	None	None		None	None	
	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	None	None		None	1. 353.03 lb/hr 2. 108.41 tpy 3. A = 1.7 E^(-0.14)	1. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B) 2. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B) 3. "The permittee shall not operate No. 1 or No. 3 Blast furnace stoves, in such a manner that emission of sulfur oxides, expressed as sulfur dioxide (SO2), exceed the rate determined by the formula: (§2104.03.a.2.B) A = allowable emissions in lbs/Mmbtu of actual heat input E = actual heat input in MMBtu/hr
	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	None	None		None		
	P001c BFG Flare 3 MMcfh BFG	None	None		None		
	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	None	None		None		
USS East Chicago	Facility does not have a blast furnace						

U. S. Steel Gary Works

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix B: Air Permit Summary for Similar Sources

Facility	Emission Unit Description	NOx Controls	NOx Limit	NOx Comments
Strip Mill Reheat Furnace and Waste Heat Recovery Boiler				
USS Gary Works	RMV00504 84 in. Hot Strip Mill Boilers (No. 1 and No. 2) 856 tons metal processing/hr Natural gas	None	None	
USS Gary Works	RB1B0508 Waste Heat boiler No. 1 226 MMBtu/hr max HI (ea.) Natural gas	None	None	
USS Gary Works	RB2B0509 Waste Heat Boiler No. 2 226 MMBtu/hr max HI (ea.) Natural gas	None	None	
USS Gary Works	RMF10500 Reheat Furnace No. 1 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
USS Gary Works	RMF20501 Reheat Furnace No. 2 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
USS Gary Works	RMF30502 Reheat Furnace No. 3 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
USS Gary Works	RMF40503 Reheat Furnace No. 4 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
AM Indiana Harbor East	2001 No. 4 Walking Beam Furnace 720 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	35 lb/MMSCF	Prevention of Significant Deterioration (PSD) and Emission Offset Minor Limit [326 IAC 2-2][326 IAC 2-3]: Total for all furnaces
AM Indiana Harbor East	1995 No. 5 Walking Beam Furnace 685.6 MMBtu/hr max HI (ea.) Natural Gas	None		
AM Indiana Harbor East	1995 No. 6 Walking Beam Furnace 685.6 MMBtu/hr max HI (ea.) Natural Gas	None		
AM Indiana Harbor West	1968 No. 1 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	
AM Indiana Harbor West	1968 No. 2 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	
AM Indiana Harbor West	1968 No. 3 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

Facility	Strip Mill Reheat Furnace and Waste Heat Recovery Boiler			
	Emission Unit Description	NOx		
		Controls	Limit	Comments
AM Burns Harbor	1966 Reheat Furnace No. 1 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	1966 Reheat Furnace No. 2 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	1966 Reheat Furnace No. 3 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	Approved in 2017 - HSM WBF No. 1 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
AM Burns Harbor	Approved in 2017 - HSM WBF No. 2 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
Nucor St. James	Facility as proposed did not have reheat furnaces or waste heat recovery boilers			
USS Clairton	Facility as proposed did not have reheat furnaces or waste heat recovery boilers			
AK Dearborn	1/1/1979 EUREHEATFURN1 - slab reheat furnace 1 oil shall not be used	None	0.11 lbs/MMBtu	R 336.2081 (ee) / 336.2082(4) -- PSD
AK Dearborn	1/1/1974 EUREHEATFURN2 - slab reheat furnace 2 oil shall not be used			
AK Dearborn	1/1/1974 EUREHEATFURN3 - slab reheat furnace 3 oil shall not be used			
AK Middleton	P094 Hot Strip Mill	None	None	
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Strip Mill Reheat Furnace and Waste Heat Recovery Boiler			
	Emission Unit Description	NOx		
		Controls	Limit	Comments
AM Cleveland	P046-P048 80" hot strip mill reheat furnaces 1,2,3 630 MMBtu/hr (each) Natural gas, fuel oil backup	Low NOx burners	0.35 lbs/MMBtu	for each furnace, OAC rule 3745-110-03(N) (as of 5/12/2011)
AM Cleveland	P265 Walking beam furnace 615 MMBtu/hr Natural gas	None	0.4 lbs/MMBtu	shall not exceed the lesser of 0.4 lb/mmBtu of actual heat input and 1.2 times the actual rate as determined by testing
USS Edgar Thompson	Facility does not have reheat furnaces or waste heat recovery boilers			
USS East Chicago	Facility does not have reheat furnaces or waste heat recovery boilers			

Appendix C

Unit-specific Screening Level Cost Summaries for NO_X Emission Control Measures

Appendix C.1

84” Hot Strip Mill Reheat Furnaces No. 1 through No. 4

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.1 - Table C.1-1: Cost Summary
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

NO_x Control Cost Summary (emissions and costs are for each furnace individually)

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	112.7	210.6	$23,010,000	$2,977,781	$14,142

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.1 - Table C.1-2: Summary of Utility, Chemical and Supply Costs
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually **Study Year** 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	600.0	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	323.3				Combined 2028 emissions for all four reheat furnaces, distributed evenly across each furnace
LNB - NO_x Performance	0.10	lb/MMBtu			Vendor estimated burner performance HHV, calculated from LHV factor from vendor
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.1 - Table C.1-3: NO_x Control - Low NOx Burners (LNB)

84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment Total (B)		6,100,000
Installation Total		10,000,000
Total Direct Capital Cost, DC		16,100,000
Total Indirect Capital Costs, IC		6,910,000
Total Capital Investment (TCI) = DC + IC		**23,010,000**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	82,450
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	2,895,331
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,977,781**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis.**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	323.3		0.10	112.7	210.6	14,142
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1. Equipment costs from vendor, installation based on U. S. Steel previous similar project experience
2. Purchased equipment includes 46 low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system and equipment to maintain NFPA compliance per code.
3. Installation includes, but is not limited to: installation of upgraded burner ports including shell and refractory work, natural gas header, combustion air fan and ducts power system modifications, and upgrades/repairs to 50-year old infrastructure
4. Retrofit Costs are intended to address undefined additional costs such as: specific design and space constraints of the facility, structural improvements/repairs that may be necessary, and asbestos/lead paint abatement.
5. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
6. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.1 - Table C.1-3: NOx Control - Low NOx Burners (LNB)

84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**5,000,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equip cost	500,000
Sales Taxes	7.0%	of purchased equip cost	350,000
Freight	5%	of purchased equip cost	250,000
Purchased Equipment Total (B)	22%		**6,100,000**
Installation			
Infrastructure repairs/replacement	50%	of purchased equip cost	2,500,000
Construction & field expenses	100%	of purchased equip cost and infrastructure cost	7,500,000
Installation Total			**10,000,000**
Total Direct Capital Cost, DC			**16,100,000**
Indirect Capital Costs			
Construction Management and Indirects	10%	Equipment, Infrastructure, and Construction Costs	1,500,000
Start-up	1%	of purchased equip cost	50,000
Performance test	1%	of purchased equip cost	50,000
Model Studies	NA	of purchased equip cost	NA
Retrofit costs	30%	of total cost	5,310,000
Total Indirect Capital Costs, IC			**6,910,000**
Total Capital Investment (TCI) = DC + IC			**23,010,000**
Site Preparation, as required		Included above	NA
Buildings, as required		Included above	NA
Site Specific - Other		Included above	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**23,010,000**
Total Capital Investment (TCI)			**23,010,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,395
Supervisor	15%	15% of Operator Costs	1,109
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	36,973
Maintenance Materials	100%	of maintenance labor costs	36,973
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**82,450**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	460,200
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	230,100
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	230,100
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	1,925,461
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,895,331**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,977,781**

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.1 - Table C.1-3: NOx Control - Low NOx Burners (LNB)

84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:

N/A

Replacement Parts & Equipment:

N/A

Electrical Use

N/A

Reagent Use & Other Operating Costs

N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.1	hr/8 hr shift	110	7,395	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,109	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	548	36,973	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,973	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 100% utilization
Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

Appendix C.2

Waste Heat Boiler No. 1

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-1: Cost Summary
Waste Heat Boiler No. 1

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	31.0	58.0	$1,806,740	$355,376	$6,130

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-2: Summary of Utility, Chemical and Supply Costs
Waste Heat Boiler No. 1

Study Year 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	226	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	89.0				Estimated 2028 emissions
LNB - NO_x Performance	0.10	lb/MMBtu			Assuming similar performance to reheat furnace low-NOX burner estimate
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NO_x Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

Desgin Capacity	226	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment Total (B)								492,800
Installation Total								660,000
Total Direct Capital Cost, DC								1,152,800
Total Indirect Capital Costs, IC								653,940
Total Capital Investment (TCI) = DC + IC								**1,806,740**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						82,450
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						272,926
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**355,376**

Emission Control Cost Calculation (Costs are per Furnace)

Pollutant	Baseline Emis. T/yr	Cont. Emis.	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	89.0		0.10	31.0	58.0	6,130
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Equipment and installation costs from U. S. Steel previous similar project experience
2 Purchased equipment includes low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system, power distribution and equipment to maintain NFPA compliance per code.
3 Installation includes, but is not limited to: installation of upgraded burner ports including boiler and refractory work, natural gas header, and upgrades/repairs to 50-year old infrastructure.
4 Retrofit Costs are intended to address undefined additional costs such as: specific design and space constraints of the facility, structural improvements/repairs that may be necessary, and asbestos/lead paint abatement.
5 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
6 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**440,000**
Purchased Equipment Costs			
Instrumentation	0%	Included in purchased equipment cost	0
Sales Taxes	7.0%	of control device cost	30,800
Freight	5%	of control device cost	22,000
Purchased Equipment Total (B)	12%		**492,800**
Installation			
Construction	150%	of purchased equip cost and infrastructure cost	660,000
Installation Total			**660,000**
Total Direct Capital Cost, DC			**1,152,800**
Indirect Capital Costs			
Construction Management and Indirects	15%	Equipment, Infrastructure, and Construction Costs	165,000
Start-up	5%	of purchased equip cost	22,000
Performance test		estimated cost of engineering and performance testing	50,000
Model Studies	NA	of purchased equip cost	NA
Retrofit Costs	30%	of total cost	416,940
Total Indirect Capital Costs, IC			**653,940**
Total Capital Investment (TCI) = DC + IC			**1,806,740**
Site Preparation, as required		Included above	NA
Buildings, as required		Included above	NA
Site Specific - Other		Included above	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,806,740**
Total Capital Investment (TCI)			**1,806,740**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	\$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,395
Supervisor	15%	15% of Operator Costs	1,109
Maintenance (2)			
Maintenance Labor	67.53	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	36,973
Maintenance Materials	100%	of maintenance labor costs	36,973
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**82,450**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	36,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	151,187
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**272,926**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**355,376**

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs
N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.1	hr/8 hr shift	110	7,395	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,109	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	548	36,973	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,973	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 100% utilization
Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

Appendix C.3

Waste Heat Boiler No. 2

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-1: Cost Summary
Waste Heat Boiler No. 2

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	30.0	56.0	$1,806,740	$355,376	$6,344

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-2: Summary of Utility, Chemical and Supply Costs
Waste Heat Boiler No. 2

Study Year 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	226	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	86.0				Estimated 2028 emissions
LNB - NO_x Performance	0.10	lb/MMBtu			Assuming similar performance to reheat furnace LNB.
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: NO_x Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 2

Desgin Capacity	226	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment Total (B)								492,800
Installation Total								660,000
Total Direct Capital Cost, DC								1,152,800
Total Indirect Capital Costs, IC								653,940
Total Capital Investment (TCI) = DC + IC								**1,806,740**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						82,450
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						272,926
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**355,376**

Emission Control Cost Calculation (Costs are per Furnace)

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis.**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	86.0		0.10	30.0	56.0	6,344
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Equipment and installation costs from U. S. Steel previous similar project experience
2 Purchased equipment includes low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system, power distribution and equipment to maintain NFPA compliance per code.
3 Installation includes, but is not limited to: installation of upgraded burner ports including boiler and refractory work, natural gas header, and upgrades/repairs to 50-year old infrastructure.
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6 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**440,000**
Purchased Equipment Costs			
Instrumentation	0%	Included in purchased equipment cost	0
Sales Taxes	7.0%	of control device cost	30,800
Freight	5%	of control device cost	22,000
Purchased Equipment Total (B)	12%		**492,800**
Installation			
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Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,806,740**
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Total Annual Cost (Annualized Capital Cost + Operating Cost)			**355,376**

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.3 - Table C.3-3: NOx Control - Low NOx Burners (LNB)

Waste Heat Boiler No. 2

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs
N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
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Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

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Appendix F

Cokenergy Four-Factor Analysis Submittal

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Cokenergy, LLC
3210 Watling Street MC 2-991
East Chicago, IN 46312

September 30, 2020 Via Electronic Mail

Indiana Department of Environmental Management
Office of Air Quality
100 N. Senate Avenue
Mail Code 61-53, IGCN 1003
Indianapolis, IN 46204 - 2251

Subject: Cokenergy, LLC Regional Haze Four-Factor Analysis Report

Dear Jean:

Attached please find Cokenergy's Regional Haze Four-Factor Analysis Report requested by your office on June 18, 2020. Based on the information presented in this report, Cokenergy's position is that a Four-Factor Analysis should not be required. Notwithstanding and without conceding the applicability of a Regional Haze Four-Factor Analysis, Cokenergy is providing this report to respond to IDEM's request.

Our report also includes a significant discussion on the capital improvements and optimization work Cokenergy has completed over the past several years on our system which support our position that no additional SO2 control measures are necessary for IDEM to meet the Regional Haze Program requirements.

If you have any questions, please contact me at lford@primaryenergy.com or (219) 397-4626.

Sincerely,

Luke E. Ford
Director EH&S
Primary Energy

File: X:\\ 660

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Cokenergy > East Chicago, Indiana

Prepared By:

Cokenergy, LLC
3210 Watling St, MC 2-991
East Chicago, Indiana 46312

TRINITY CONSULTANTS
1717 Dixie Hwy Suite 900
Covington, Kentucky 41011

September 2020

Project 201801.0091

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYM LIST

ArcelorMittal Indiana Harbor Works	Arcelor-IH
Area of Influence	AoI
Calcium	Ca
Calcium Hydroxide	$Ca(OH)_2$
Clean Air Act	CAA
Comprehensive Air Quality Model with Extensions	CAMx
Consent Decree	CD
Continuous Emissions Monitoring System	CEMS
Dry Sorbent Injection	DSI
Electric Generating Utilities	EGU
Emission Tracking System	ETS
Flue Gas Desulfurization	FGD
Heat Recovery Steam Generator	HRSG
Indiana Department of Environmental Management	IDEM
Indiana Harbor Coke Company	IHCC
Induced Draft	ID
Kilometer	km
Kentucky Division for Air Quality	KDAQ
Key Performance Indicators	KPI
Lake Michigan Air Directors Consortium	LADCO
New Source Review	NSR
Particulate Matter	PM
Particulate Matter Source Apportionment Technology	PSAT
Prevention of Significant Deterioration	PSD
Preventive Maintenance and Operation	PMO
Regional Haze	RH
Regional Planning Organization	RPO
Southeastern Air Pollution Control Agencies	SESARM
Spray Dryer Absorber	SDA
State Implementation Plan	SIP
Steam Turbine Generator	STG
Sulfur Dioxide	SO_2
Tons per year	tpy
Uniform Rate of Progress	URP

Visibility Improvement State and Tribal Association	VISTAS
US Environmental Protection Agency	EPA

1. EXECUTIVE SUMMARY

This report was prepared on behalf of Cokenergy, LLC (Cokenergy) in response to the June 2020 Indiana Department of Environmental Management (IDEM) Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis request letter. IDEM requested that Cokenergy prepare a Four-Factor Analysis per Section 169a(g)(1) of the Clean Air Act (CAA) to support IDEM's development of a revised Regional Haze State Implementation Plan (SIP) for the second planning period, 2018 to 2028. The second planning period SIP is due for submission to Region 5 of the US Environmental Protection Agency (EPA) by July 31, 2021.[1]

As detailed in IDEM's Four-Factor Analysis request to Cokenergy, this report provides information related to the sulfur dioxide (SO_2) emissions from the lime spray dryer flue gas desulfurization (FGD) unit Cokenergy operates at its Indiana Harbor heat recovery facility (Facility). In addition, this report discusses the nominal (if any) impact Cokenergy's SO_2 emissions have on the relevant Class I area[2], Mammoth Cave National Park, for which this Regional Haze (RH), analysis is being conducted. This report also discusses the significant SO_2 reductions Cokenergy recently made to optimize its FGD system including the extensive capital costs related to that work, and other important information that Cokenergy suggests being considered as part of IDEM's second planning period SIP report to Region 5. Indeed, Cokenergy's FGD optimization measures have reduced the SO_2 emissions by more than 15%. Based on these factors and the information presented in this report, Cokenergy's view is that no additional SO_2 reductions from the Facility should be required to meet RH requirements.

Cokenergy operates as a contractor[3] at the ArcelorMittal Indiana Harbor Works, Arcelor-IH, facility in East Chicago, Indiana. The Facility is an energy facility that includes the integrated combined heat and power project using waste heat recovered from non-recovery coke batteries[4] owned and operated by Indiana Harbor Coke Company (IHCC). The Facility provides electricity and industrial process steam to the ArcelorMittal integrated steel mill operation. A schematic of the Cokenergy Facility showing its relationship with Arcelor-IH and IHCC is shown in Figure 1-1.

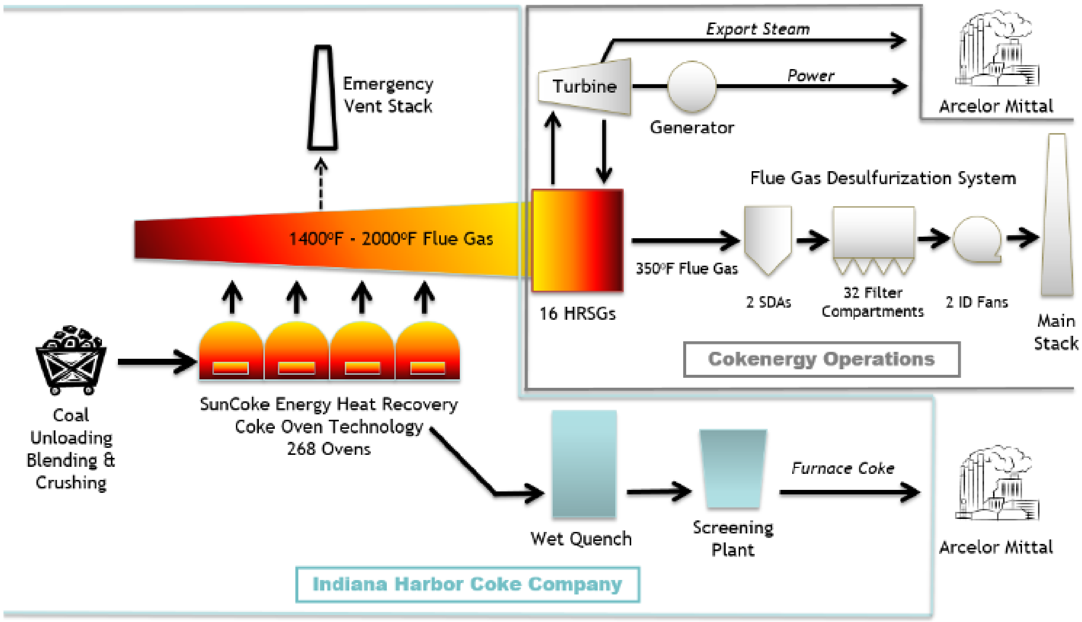
[1] 40 CFR 51.308(f)

[2] Class I areas are designated by the CAA which gave special air quality and visibility protection to national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the CAA was amended in 1977.

[3] Cokenergy leases the property necessary for its operations from Arcelor-IH.

[4] Cokenergy does not combust any fuel within its physical boundaries. The design of the non-recovery coke batteries operated by IHCC completely exhausts all heating value from the coal in the coke oven.

Figure 1-1. Schematic of Cokenergy, IHCC, and Arcelor-IH Process Flow



IDEM indicated during a webinar specifically held for Indiana facilities, that IDEM would request Cokenergy to conduct a Four-Factor Analysis. IDEM's request specified that Cokenergy conduct this analysis for SO_2 emissions from the FGD unit operated at the Facility. IDEM's four-factor selection rankings identified iron/steel mills, cement manufacturing kilns, and two other non-electric generating utilities (EGUs) industrial sources as the source categories for analysis of control measures during this second RH implementation period.

IDEM based inclusion of sources in this second implementation period of RH planning on a ratio of 2018 actual annual emissions of visibility-affecting pollutants (determined to be NO_X and SO_2 for Indiana), known as "Q" in tons per year (tpy), and distance to Class I area, known as "d" in kilometers (km). IDEM has selected the cautious ratio criteria of "Q/d > 5.0" to identify the facilities for which four-factor analyses were requested. Based on this screening approach, IDEM calculated the "Q/d" ratio to be 10.695[5] for Cokenergy (i.e., the SO_2 emissions from FGD unit), which led to IDEM's request that Cokenergy develop a Four-Factor Analysis.

However, as detailed in Section 2-1, a more comprehensive analysis which included air modeling was conducted by another state agency and a Regional Haze Planning Organization (RPO), that indicated Cokenergy has no visibility impact on Mammoth Cave, the Class I area nearest the Facility.

In 2014 Cokenergy contracted with an engineering firm to conduct a study to evaluate and optimize the existing FGD system that controls the SO_2 emissions from the process. The coke oven flue gas enters the heat recovery steam generators (HRSGs) operated by Cokenergy that produce process steam and electricity for the Arcelor-IH facility from heat recovered from the coke ovens. The flue gas is then directed to the FGD system, which consists of two (2) spray dryer absorbers (SDAs) where the flue gas mixes with sorbent to

[5] Actual 2018 sitewide SO_2 emissions of 5,398 tpy with a distance of 505 km to Mammoth Cave NP (5,398, Q / 505 d = 10.695).

remove SO_2 then the flue gas goes through two (2) pulse jet, fabric filter baghouses to remove particulate. The recommended strategy to optimize the existing FGD was to operate the dual SDAs in parallel rather than one SDA being a backup/standby unit. After the 2014 engineering study was completed, Cokenergy refined the design to operate both SDAs in parallel in a second engineering study completed in 2015.

This report provides a comprehensive review of the already completed FGD improvements resulting in SO_2 reductions at Cokenergy. These already-realized SO_2 reductions from the optimization of the existing FGD system are well documented for incorporation of the SO_2 reductions into a recent Consent Decree entered in late 2018 (the CD) and/or IDEM's SIP validating that Cokenergy's FGD is achieving higher SO_2 removal than prior to the CD.[6] IDEM has incorporated portions of the CD in Cokenergy's Title V operating permit, T089-41033-00383, Section D.1.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-7] [Consent Decree, Civil Action No. 18cv-35] [326 IAC 2-7-10.5(b)(2)].

Importantly, Cokenergy invested approximately $9.3 million between 2014 and 2018 to optimize the FGD system as well as $32 million to retube the HRSGs between 2010 and 2015. Cokenergy has continued to monitor performance and engage in practices to demonstrate good operating, engineering, and air pollution control practice for minimizing air emissions and ensuring continual compliance with all Title V operating permit and the CD requirements.[7]

In addition to information presented herein, the following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered, in accordance with instructions in the Four-Factor Analysis request provided by IDEM in mid-June 2020 and supports Cokenergy's position that no additional actions are required by Cokenergy to address the impact of RH on Mammoth Cave:

- Identification of technically feasible options (not included by IDEM, but appropriate initial step to eliminate and document options that are not technically feasible)
- Costs of implementation[8] (Statutory Factor 1)
- Time necessary for implementation[8] (Statutory Factor 2)
- Energy and non-air quality environmental impacts[8] (Statutory Factor 3)
- Remaining useful life[8] (Statutory Factor 4)

Based on the extensive capital, employee and consultant hours already invested in reducing SO_2 emissions from Cokenergy's FGD, RH program guidance, physical limitations, and other data and factors detailed in this report, no control devices were deemed technically feasible to evaluate through the four statutory factors. This position is also supported by the minimal impact that Cokenergy's emissions have on Mammoth Cave.

[6] Cokenergy has complied with the required milestones of the CD process. All documentation is publicly available on Indiana Harbor Coke/Cokenergy Consent Decree website.

[7] The CD required Cokenergy to develop and submit a preventive maintenance and operation plan (PMO Plan) per IV. Compliance Requirements D. 23. a. Cokenergy submitted a PMO on December 13, 2018.

[8] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. See 40 CFR 51.308(f)(2)(i). Technical feasibility, control effectiveness and emissions reductions information are required to assess the cost of implementation.

2. REGIONAL HAZE BACKGROUND

2.1 Regional Haze Program

Pursuant to 40 CFR 51.308(d), each state must address RH in each mandatory Class I Federal area located within or outside of the state if affected by interstate emissions. States must establish reasonable progress goals which provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period. The RH program is within the second planning period (2018 to 2028).

2.2 IDEM's Request to Cokenergy

IDEM sent Cokenergy a Four-Factor Request Letter, via email, on June 18, 2020 which included the list of emission units to be included in the Four-Factor Analysis. IDEM's request of Cokenergy included SO_2 emissions from Stack 201, the exhaust stack of the FGD system.

IDEM described their selection methodology to request Four-Factor Analyses for facilities in Indiana during the June 3, 2020 webinar. To summarize the information presented, IDEM selected steel mills[9], cement kilns[10], and non-EGU sources with a "Q/d" greater than 5.0 to complete or request completion of a Four-Factor Analysis. IDEM indicated the "Q/d" approach was chosen to include a reasonable number of sources to be evaluated and for consistency with other Lake Michigan Air Directors Consortium (LADCO) states. LACDO is a RPO and includes Indiana, Illinois, Ohio, Wisconsin, and Michigan.

The "Q/d" selection criterion is the least complicated technique offered in the guidance memorandum by EPA on RH SIP for the Second Implementation Period.[11] The additional selection criteria suggested by EPA in the guidance memo are, ranked in order of least to most complicated:

- Emissions divided by distance ("Q/d") – Ratios SO_2 and NO_X emissions with distance to Class I areas.
- Trajectory analyses – Examines the wind direction on individual days.
- Residence time analyses – A trajectory-based analysis technique that combine emissions, ambient particulate data, and trajectory information.
- Photochemical modeling (zero-out and/or source apportionment) – The only air modeling technique suggested by EPA. Photochemical modeling quantifies source or source sector visibility impacts.

Although the "Q/d" selection technique is easy to implement, it does not include as much information as the three (3) more complex selection techniques suggested by EPA. The more sophisticated techniques account for detailed information on particulate (PM) and PM species impacts but are more resource intensive. EPA allowed each state to choose their own Four-Factor Analysis selection techniques and did allow states to use other reasonable techniques as appropriate.

IDEM's "Q/d >5.0" selection criterion does not account for the data analyzed (i.e., photochemical modeling) and summarized by RPOs. Based on the RPO modeling results conducted by the Visibility Improvement

[9] Cokenergy operates as a contractor within the Arcelor-IH site, an integrated steel mill, but is not in itself a steel mill.

[10] IDEM requested Four-Factor Analyses for the two cement facilities in Indiana with a "Q/d > 5.0" (Lehigh Cement Company and Lone Star Industries Inc).

[11] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

State and Tribal Association of the Southeast (VISTAS), Cokenergy's SO_2 emissions do not have a sulfate or nitrate impact on Mammoth Cave greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the twenty (20) percent most impaired days. This criterion is used to include or exclude, in Cokenergy's case, emissions from a point source as within the Area of Influence (AoI) of a Class I area.

2.3 VISTAS Class I Impacts Outside Region

Cokenergy reviewed publicly available guidance documents from the VISTAS to investigate any potential visibility impact Cokenergy may have on Class I areas. As noted previously, Mammoth Cave is in Kentucky. The VISTAS, a subcommittee of the Southeastern Air Pollution Control Agencies (SESARM), conducted technical analyses to help states identify sources that significantly impact visibility impairment for Class I areas within and outside of the VISTAS region (i.e., VA, WV, NC, SC, GA, FL, AL, TN, MI, KY, GA). VISTAS conducted an AoI analysis to identify sources to "tag" for PM Source Apportionment Technology (PSAT) modeling which was implemented with the Comprehensive Air Quality Model with Extensions (CAMx) to identify emissions sources which strongly contribute to RH.[12] VISTAS identified three (3) impactful sources[13] in Indiana as a result of this analysis that did not include Cokenergy.[14] Therefore, the VISTAS modeling efforts support Cokenergy's position that the Facility was not a source shown to have a significant sulfate or nitrate impact on a Class I area.

In addition, VISTAS updated 2028 CAMx modeling with actual observations through 2018 and revised future projections based on reasonable progress.[15] As indicated in Figure 2-1, Mammoth Cave is below the target uniform rate of progress (URP) glidepath line. Therefore, additional emission reductions beyond those already planned are not required to meet the 2028 uniform progress goal for visibility at Mammoth Cave.

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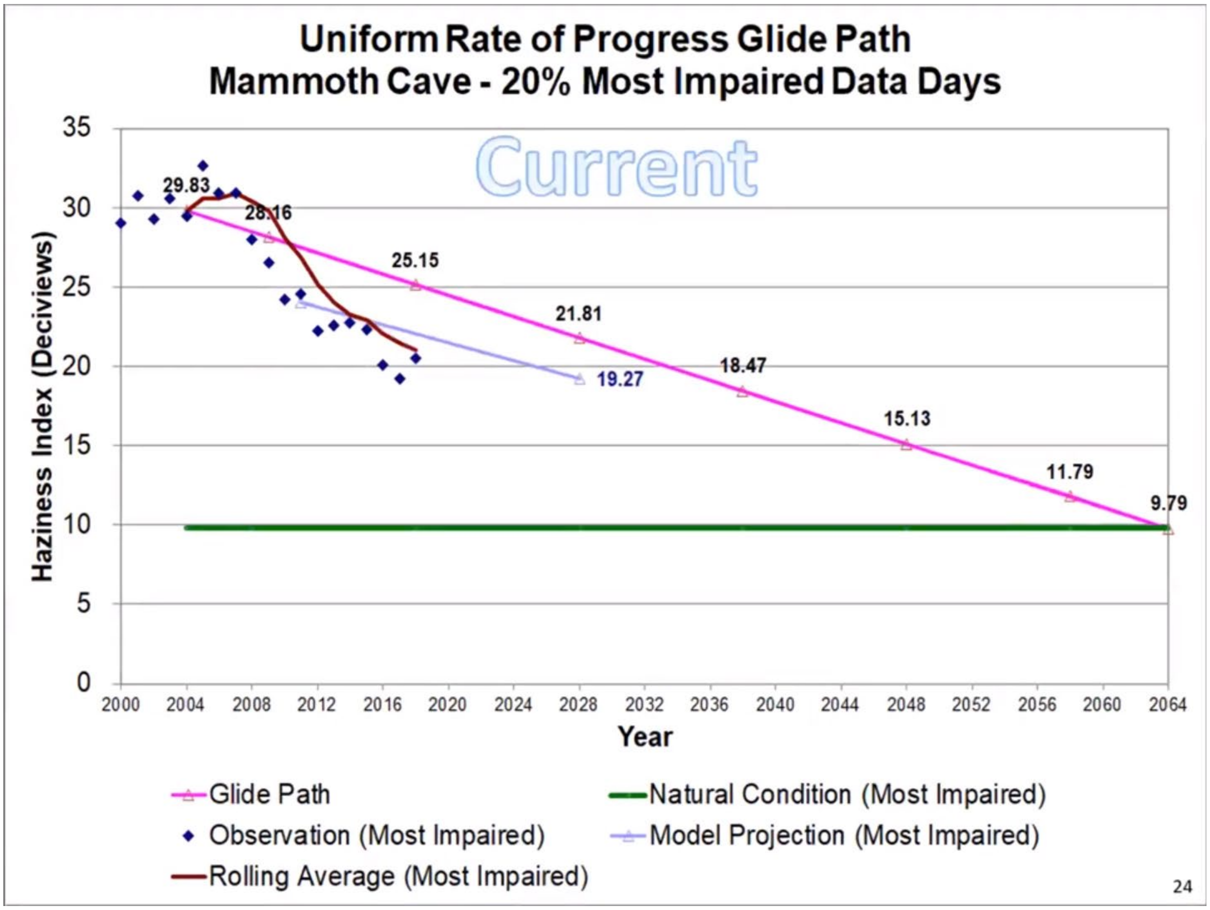
[12] Sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00% of the total sulfate plus nitrate point source visibility impairment on the 20% most impaired days for each Class I area

[13] VISTAS identified Indianapolis Power & Light Petersburg (18125-73624111), Gibson (18051-7363111), and Indiana Michigan Power DBA AEP Rockport (18147-9017211) as the Indiana sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00 percent of total sulfate plus nitrate point source visibility impairment on the 20 percent most impaired days for each Class I area.

[14] VISTAS Letter- Request for Regional Haze Reasonable Progress Analyses for Indiana Sources Impacting VISTAS Class I Areas, June 2020.

[15] VISTAS presentation- Regional Haze Project Update- EPA, FLM, RPO Briefing https://youtu.be/FN83NmV0JWQ , August 2020.

Figure 2-1. VISTAS Haziness Index Modeling Results – Mammoth Cave Class I Area

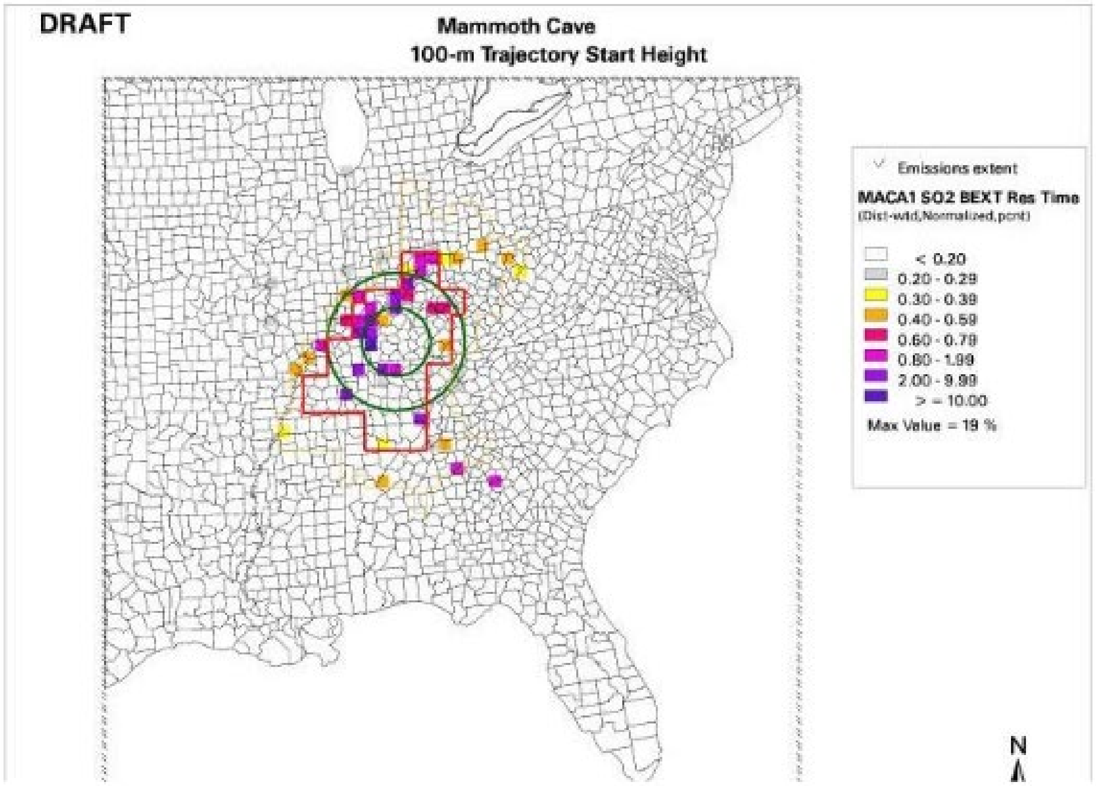


2.4 Kentucky Division of Air Quality-Area of Influence for Mammoth Cave

Kentucky Energy and Enviroment Cabinet-Kentucky Division for Air Quality (KDAQ) released a SIP Revision: Regional Haze 5-Year Periodic Report 2008-2013[16] for Kentucky's Class I Federal Area. The closest Class I area to Cokenergy is Mammoth Cave located in Kentucky. Mammoth Cave is the only Class I area IDEM indicated Cokenergy address in this Four-Factor Analysis. Figure 2-2 illustrates the sulfate extinction-weighted residence time plot for Mammoth Cave. Cokenergy is well outside the AoI of SO_2 for Mammoth Cave with the residence time being less than 0.20 percent.

[16] KDAQ SIP Revision for Kentucky's Regional Haze Periodic Report, September 2014.

Figure 2-2. SO_2 Area of Influence for Mammoth Cave, KY



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time $\geq$ 10%.
Orange line perimeter indicate Area of Influence with Residence Time $\geq$ 5%.

2.5 Cokenergy's Summary of Facility's Regional Haze Impact

The data presented and detailed in this report, from VISTAS and KDAQ support Cokenergy's view that SO_2 emissions from Cokenergy's Facility do not impact Mammoth Cave. Therefore, Cokenergy's position is that a Four-Factor Analysis should not be required for the facility. Notwithstanding and without conceding the applicability of RH Four Factor Analysis requirements to the Facility, Cokenergy is responding to IDEM's request by submitting this four-factor report, although no current data indicates the Facility's emissions impact Class I visibility.

In addition, Cokenergy has undergone numerous studies and projects in the last several years, additional details in Section 3, that reduced SO_2 emissions through optimization of the exisitng FGD system.

3. COKENERGY FACILITY HISTORY

3.1 Facility Description

The Arcelor-IH facility[17] was established as an integrated steel mill more than 100 years ago. In 1998, Primary Energy (Primary) began operating Cokenergy within the Arcelor-IH facility. The Cokenergy facility is a first-of-a-kind combined heat and power system that uses the waste heat in the flue gas from IHCC's metallurgical coke facility to produce steam and power for the Arcelor-IH facility.

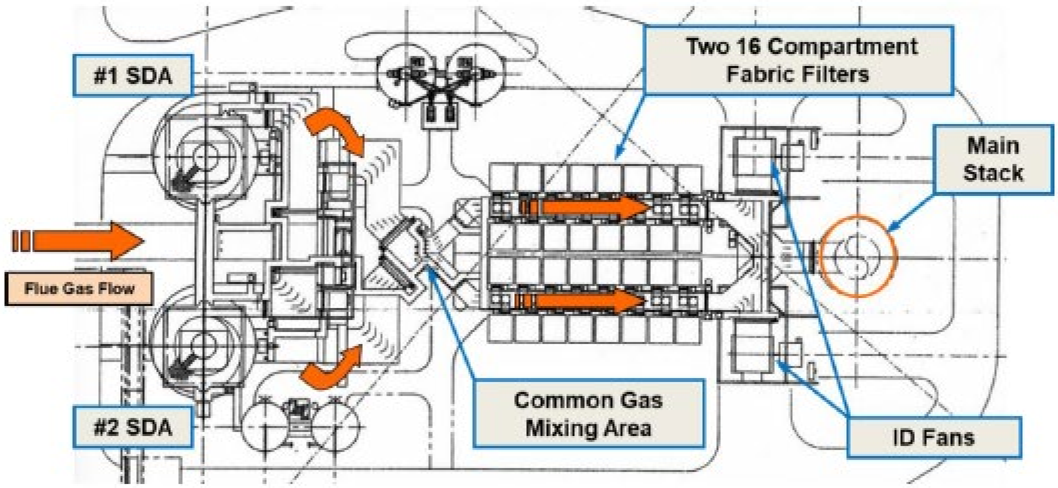
Cokenergy's sixteen HRSGs, arranged four per oven battery, receive and recover heat from the coke oven flue gas, producing power-grade steam and cooling the gas in the process. The superheated steam is used to generate electricity in an industrial condensing/extraction steam turbine. With the steam and power generated in this process, Cokenergy supplies electricity as well as high-pressure process steam to Arcelor-IH. After the flue gas passes through the HRSGs, Cokenergy's FGD system environmentally treats the cooled flue gas to remove SO_2 and particulate emissions. The inter-relationship among Cokenergy, Arcelor-IH, and IHCC is graphically shown in Figure 1-1.

Figure 3-1 provides a basic schematic of Cokenergy's FGD:

- Sixteen (16) HRSGs, four (4) per coke oven battery. The HRSGs recover heat from the coke oven flue gas.
- Flue gas ductwork to manifold the flue gas from the HRSGs to Cokenergy's FGD system.
- Two (2) SDA. The mixing of flue gas with sorbent material to environmentally treat, or remove, SO_2 from the flue gas.
- Two (2) individual sixteen (16) compartment pulse jet, fabric filter baghouse, which removes particulate emissions from the flue gas.
- Two (2) induced draft (ID) fans, which pull draft through the entire flue gas system from the coke ovens to the ID fans.
- One (1) extraction/condensing steam turbine generator (STG). The STG accepts the steam generated by the HRSGs and includes a six (6)-cell cooling tower, boiler feedwater heater, two (2) deaerators.

[17] The current Arcelor-IH facility has had various owners since beginning operation, ArcelorMittal USA LLC took ownership in 2002.

Figure 3-1. Schematic of Cokenergy's FGD



Particulate emissions are not included in IDEM's Four-Factor Analysis request; therefore, this report exclusively provides information related to the SO_2 effective and reasonable control measures considering the costs of compliance for Cokenergy's FGD system.

3.2 Review of FGD Optimization Projects and Milestones

The FGD system at Cokenergy became fully operational in 1998 with the original system design being similar to FGDs for coal-fired EGUs. The original FGD system, as installed, did contain the same equipment as listed in Section 3.1 where the original design called for operating one SDA train (SDA, SDA bypass duct, and ID fan) and the other SDA train was run in standby mode. Beginning in 2010 Cokenergy began the process of investigating potential means to increase the FGD system's SO_2 control rates to reduce emissions and ensure the reliability of the FGD system.

Cokenergy began engineering studies in 2012 to optimize the FGD system. Prior to beginning the engineering studies, the re-tubing of the sixteen (16) HRSGs had begun. The retubing projects in themselves significantly reduced SO_2 emissions through the reduction in bypass venting. The notable milestones of the Facility's FGD optimization[18] are:

- 2010 to 2015 – Retubed all sixteen (16) HRSGs
- 2012 – Consultant identified a series of FGD improvement options
- 2014 – First engineering study began
  - Evaluate and understand original FGD design and capabilities
  - Determine any intrinsic design issues
  - Develop and evaluate SDA models
  - Identify possible FGD enhancements for existing FGD system
- 2014 to 2015 – Engineering feasibility study
  - Refine and select FGD optimization projects
  - Improve reliability and enhancement of FGD equipment

[18] These steps did include reducing PM as well as SO_2, which is the pollutant of focus for Cokenergy's Four-Factor Analysis.

- 2015 to 2016 – Implement FGD upgrade projects
- 2016 – Employed the approach temperature optimization program
- January 2018 – Consent Decree lodged
- Continuing optimization of FGD system through performance monitoring program

Since the beginning of the FGD optimization project in 2012 Cokenergy has invested tremendous resources to achieve the overarching goal of reducing SO_2 emissions from the FGD system. These projects have reduced the SO_2 emissions from the FGD by **more than 15 percent (%)**. A summary of the actual SO_2 emissions and percent reduction of SO_2 prior to and after the extensive projects completed by Cokenergy are detailed in Table 3-1.

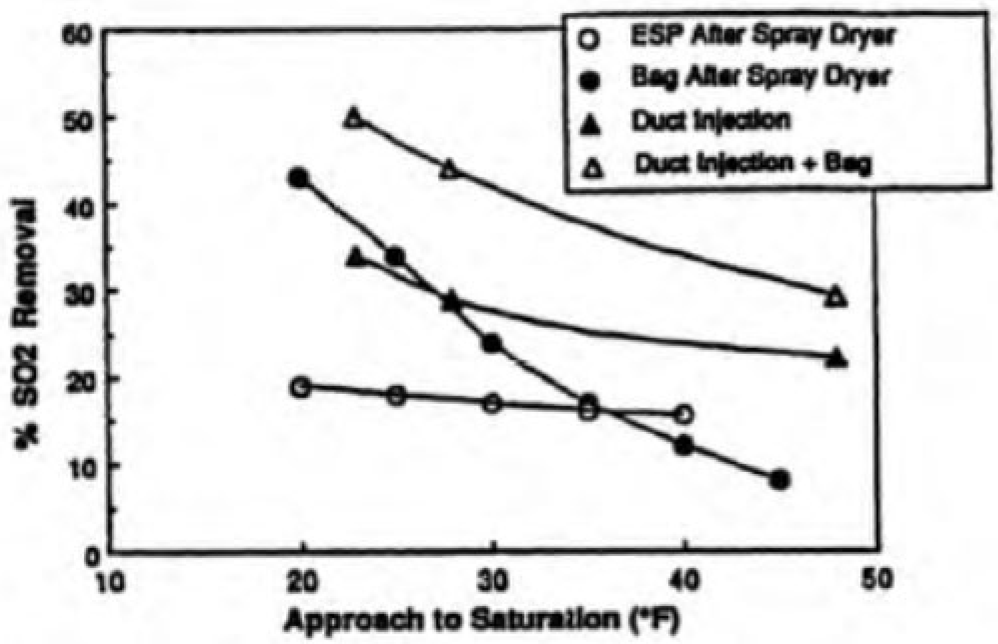
3.2.1 Key Factors to Enhancement of FGD System

The following factors were important considerations to the FGD optimization projects and were studied in detail during the engineering studies completed by Cokenergy. Each factor that was considered is described below, and the meaningful impact to SO_2 is summarized as well.

- HRSG Retubing
  - Completed retubing of all 16 of the HRSGs that allowed for a reduction in the amount of over-scrubbing required by the FGD, reduced the pressure drop by using finned tubes, and reduced venting from the emergency bypass vent stacks.
- Reduce Flue Gas Volume
  - Replaced dampers and reduced air in-leakage rates to lower the high flue gas volumetric flow rate at the inlet of the SDA. The flue gas flow rates to the SDA were too high and resulted in a reduced capture efficiency of the SDA.
  - With the reduction of flue gas flow into the SDA increased overall performance by allowing the SDA to capture more gas volume.
- Increase Gas Temperature
  - Increased flue gas temperature into the SDA was achieved by reducing the false air (i.e. in-leakage from the ambient environment that is not flue gas) entering the SDA.
  - A higher flue gas temperature allows for a higher water/lime slurry injection rate; therefore, increasing the SO_2 capture and control effectiveness. Controlling the water/slurry lime slurry injection rate as the desired ratio allowed for more consistent SDA performance.
- Increase Calcium to Sulfur Ratio
  - An increase in the calcium (Ca) injection ratio was achieved by reducing the flue gas volume.
  - SO_2 removal is directly associated with a higher Ca/sulfur ratio into the SDA.
- Increase Residence Time
  - A reduction in flue gas volume allowed for a longer residence time, or amount of time the flue gas is inside the SDA, for SO_2 absorption into the evaporating slurry droplets. The absorption of SO_2 into slurry droplets is the mechanism in which SO_2 is captured or removed from flue gas. The captured SO_2 droplets exit the SDA as solids.
  - The increased residence time has a direct influence on higher SO_2 capture during spray droplet evaporation.
- Increase SO_2 Removal with Approach to Dew Point
  - Cokenergy installed instrumentation and controls to improve the removal efficiency of the SDA by controlling the approach temperature to allow for optimal scrubbing.

- This theory is defined as approach to dew point or saturation temperature. The closer the SDA operates to the saturation temperature, the higher the final SO_2 removal as shown in Figure 3-2.[19]
- SO_2 removal rate is influenced by the relationship between the final flue gas temperatures and moisture content.

Figure 3-2. SO_2 Removal Efficiency Related to "Approach to Dew Point"



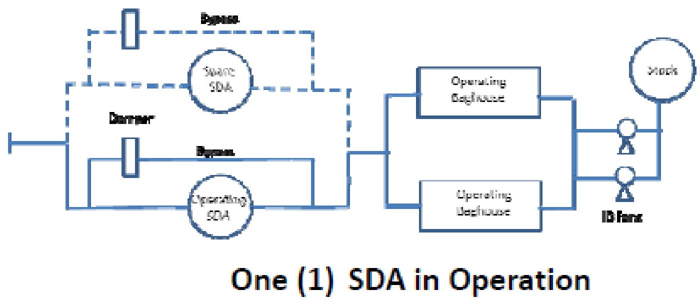
3.2.2 Enhanced FGD Scenarios Evaluated in 2014 Study

The following four (4) scenarios described below were studied in detail by Burns and Roe Enterprises, Inc. and summarized in a report from June 9, 2014. Additionally, a stand-alone additional FGD system that contains one SDA was also evaluated as a means of assuring 100% availability but was deemed inappropriate due to the high estimated capital cost relative to any emissions reductions, increased maintenance, expected chemical usage, and difficulties related to positioning and available footprint.

► One (1) SDA in Operation Scenario - Figure 3-3
  - This was the current configuration at the time of the study such that the second SDA was operating as a backup or in standby mode. In this study, it was concluded this option means approximately 38% of the flue gas needs to be bypassed as to not exceed the design retention time of ten (10) seconds. This configuration requires an SO_2 removal efficiency of 80.3% to achieve the current Title V permit limit of 1,656 lb/hr.

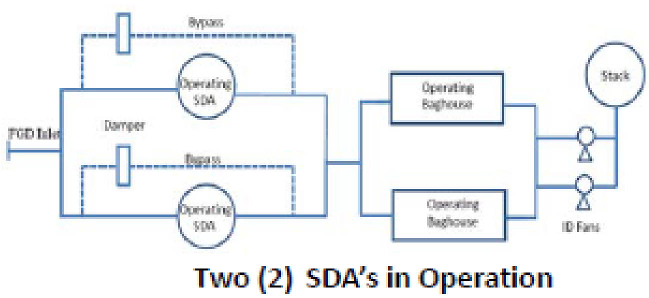
[19] "Dry Scrubbing Technologies for Flue Gas Desulfurization," Ohio Coal Research Consortium, 1998.

Figure 3-3. One (1) SDA in Operation Scenario from 2014 Study



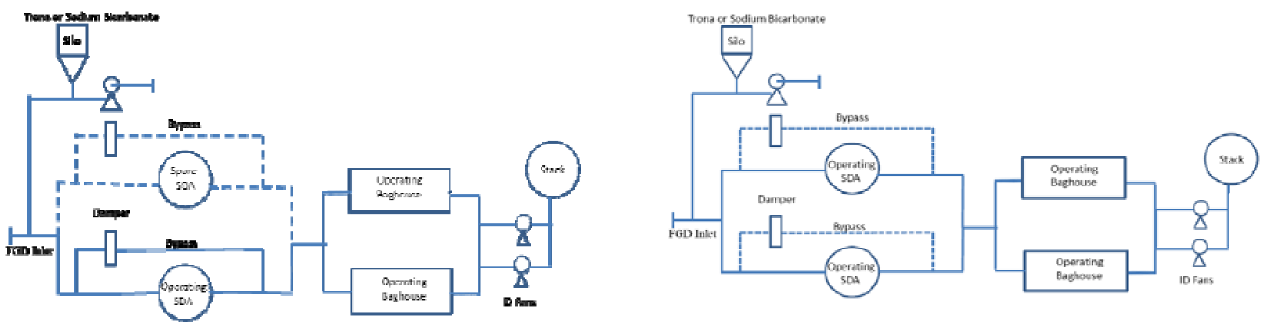
- Two (2) SDAs Operating in Parallel Scenario - Figure 3-4
  - This was the overall optimal option found during the study. This option can accommodate the full flue gas volume with a residence time of 12.4 seconds, which was longer than the first scenario allowing for longer reaction time to increase SO_2 removal rates.

Figure 3-4. Two (2) SDAs in Operation Scenario from 2014 Study



- Dry Sorbent Injection (DSI) with Trona with One (1) or Two (2) SDAs in Operation Scenarios - Figure 3-5
  - The option of adding a DSI upstream of both the single SDA and dual SDA configurations was considered. The SO_2 removal capability of the FGD system with DSI of Trona is significantly enhanced for single SDA operation and marginally increased during operation with two SDA's. However, the added capital cost and annual operating cost relative to any emissions reductions, and the environmental concerns of sodium in the by-product, significantly detract from the overall benefits of DSI.

Figure 3-5. DSI with Trona Scenarios from 2014 Study



DSI Stand Alone System with Trona
One (1) SDA in Operation

DSI with Trona
Two (2) SDA's in Operation

3.2.3 Phase 2 Study Highlights

The Phase 2 study by POWER Burns and Roe summarized in the May 25, 2015, report focused on determining the best means of revitalizing the existing FGD system to accommodate current and future operating conditions which included the following:

- Implementation of dual SDA operation
- Procurement of fourth atomizer
- Replace the original SDA upstream and downstream isolation dampers
- Consider implementation of upstream gas conditioning system
- Optimization of baghouse cleaning
- Optimization of SDA exit temperature
- Upgrades to redundant atomizer chiller system
- Continue to address air infiltration throughout the oven/HRSG/FGD system

3.2.4 Comparison of 2014 and 2020 Emissions to Show Improvements

The combined SO_2 limit in Cokenergy's and IHCC's Title V permits is 1,656 lb/hr. The combined emission rate for both plants is determined by summing SO_2 emissions from the IHCC emergency bypass vent stacks with the emissions from Cokenergy Stack 201 using the emission tracking system (ETS) in coordination with the Cokenergy Continuous Emissions Monitoring System (CEMS). ETS uses coke production data, HRSG steam production, vent lid status, and coal analytical data to calculate the potential SO_2 emissions from venting using a material balance. Cokenergy provides the actual SO_2 data from the stack CEMS.

Table 3-1 provides a summary of this ETS output with additional calculations to demonstrate the impact of the FGD enhancements made in recent years on improved SO_2 removal efficiency. A six (6) month period from November 2014 to April 2015 was selected to represent the pre-FGD enhancements timeframe. The most recent semiannual period, January 2020 through June 2020, was used to demonstrate the post-FGD enhancement timeframe.

The ETS input variables of stack SO_2 emissions, bypass SO_2 emissions, total SO_2 emissions, coal charge, coal sulfur content, coke production, and sulfur content of the finished coke were used to estimate SO_2 input and output to and from the FGD system which estimates the FGD SO_2 control efficiency.

As demonstrated in Table 3-1, the semiannual average control efficiency pre-FGD enhancement was approximately 43% whereas the semiannual average control efficiency post-FGD enhancement was approximately 61%.

$$Raw\ SO_2\ Input\ to\ FGD = [Coal\ Charge\ (tons)\ x\ Coal\ Sulfur\ Content\ (\%)] -$$

$$[Coke\ Production\ (tons)\ x\ Coke\ Sulfur\ Content\ (\%)]\ x\ \frac{2000\ lbs}{ton}\ x\ \frac{64\ \frac{lb}{lbmol} SO_2}{32\ \frac{lb}{lbmol}\ S}\ x\ \frac{1\ day}{24\ hours}$$

$$SO_2\ \ Input\ to\ the\ SDAs = Stack\ SO_2\ \ emissions - Raw\ SO_2\ \ Input\ to\ FGD$$

$$SDA\ SO_2\ Control\ Efficiency = 100\ x\ \frac{SO_2\ \ Input\ to\ SDAs - Stack\ SO_2}{Raw\ SO_2\ \ Input\ to\ FGD}$$

Table 3-1. Summary of Cokenergy SO_2 Emissions Pre and Post FGD Enhancements [a]

		Monthly Average Stack SO2 Emissions (lb/hr)	Monthly Average Bypass Stack SO2 Emissions (lb/hr)	Monthly Average Total SO2 Emissions (lb/hr)	Monthly Average Coal Charge (ton/day)	Monthly Average Coal Sulfur Content	Monthly Average Coke Production (ton/day)	Monthly Average Coke Sulfur Content (%)	Monthly Average SO2 Input to FGD (lb/hr)	Monthly Average SO2 Input to SDA (lb/hr)	Monthly Average SDA SO2 Control Efficiency (%)	Semiannual Average SDA SO2 Control Efficiency (%)
Pre-FGD Enhancement Timeframe	Nov-14	1,413	152	1,565	4,351	0.84	2,872	0.61	3,172	3,020	49%	43%
	Dec-14	1,529	21	1,551	4,266	0.81	2,815	0.60	2,943	2,922	46%	
	Jan-15	1,505	35	1,540	3,670	0.81	2,454	0.60	2,501	2,466	35%	
	Feb-15	1,540	15	1,555	3,707	0.80	2,443	0.60	2,499	2,484	37%	
	Mar-15	1,414	115	1,530	3,814	0.79	2,528	0.59	2,535	2,420	42%	
	Apr-15	1,399	179	1,578	4,284	0.81	2,753	0.61	2,985	2,805	46%	
Post-FGD Enhancement Timeframe	Jan-20	1,175	181	1,356	5,074	0.93	3,325	0.71	3,952	3,771	64%	61%
	Feb-20	1,175	173	1,347	4,957	0.89	3,084	0.73	3,569	3,396	60%	
	Apr-20	1,312	72	1,384	4,998	0.89	3,315	0.66	3,736	3,664	63%	
	May-20	1,364	5	1,369	4,965	0.90	3,302	0.68	3,674	3,669	60%	
	Jun-20	1,218	156	1,373	4,855	0.89	3,177	0.69	3,561	3,404	59%	

a. March 2020 data is not included herein due to low daily coal charge weights.

3.2.5 Ongoing Optimization of FGD System

Cokenergy practices various other emissions minimization steps such as proactive monitoring of the HRSG tube health data to assess when re-tubing may be necessary, routine inspections, cleaning, preventative maintenance schedules, maintain critical spare parts in inventory for repairs, and following best practice for equipment start-up and shutdowns.

Cokenergy has been working with Primex[20] for over 5 years to monitor and optimize utilizing their FGD Performance Assurance Program.

- Monthly tasks completed by Primex
  - Provide and analyze corrosion coupons.
  - Publish monthly report with key performance indicators (KPI) and progress towards goals.
  - Obtain data, analyze performance, and interpret change.
  - Identify potential safety, reliability, and efficiency issues.
  - Perform first layer of troubleshooting.

[20] Primex is an engineering consultant firm specializing in optimization of FGDs.

  - Provide actions and recommendations.
  - Conference call with Cokenergy team to review findings.

- Quarterly tasks completed by Primex
  - Analyze pebble lime and lime slurry samples.
  - On-site meeting with Cokenergy team.
  - Identify and agree on improvement opportunities.
  - Prioritization of actions and assignment of resources.
  - Update strategy and action plan.

- Current action plan between Cokenergy and Primex
  - Evaluating the inlet temperature effects on SDA residence calculation.
  - Determining the best method to automatically control approach temperature based on atomizer(s) conditions.
  - Evaluating:
    - Sorbent preparation control system.
    - Long-term ash moisture testing options for approach temperature control.

4. TECHNICAL FEASIBLITY – FOUR-FACTOR ANALYSIS

A Four-Factor Analysis for any emission source, such as Cokenergy's FGD system begins with an assessment of technical feasibility in order to determine which emission control measures to reasonably consider with respect to emission-related factors and cost. This aligns with EPA's guidance which states:[21]

> *The first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment. Identification of these measures does not create a presumption that one of them will be determined to be necessary to make reasonable progress. A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set.*

Based on this guidance, Cokenergy has provided background information throughout this report and below which identifies actions already completed at Cokenergy to support the increased effectiveness of existing control techniques that are the most technically feasible and reasonable methods for Cokenergy's FGD system. As noted throughout this report, Cokenergy has already implemented FGD optimization measures at extensive capital cost which have resulted in significant SO_2 reductions.

Consequently, to the extent any additional controls of SO_2 may be considered to meet the RH program reasonable progress requirements, Cokenergy has already implemented those controls through the FGD optimization measures and the realized SO_2 emission reductions.

4.1 Current Baseline Control Scenario

At present, the Cokenergy FGD system at the Arcelor-IH facility consists of two (2) SDAs and two (2) fabric filter baghouses, additional details and description of the system are in Section 3.1. The current permit limits and actual emissions for 2018 for Stack 201, the exhaust of FGD system, are presented in Table 4-1.

Table 4-1. Cokenergy FGD Permit Limits and Annual Emissions

Unit	Pollutant	Limit[a]	Actual Emissions (TPY)[b]
			2018
FGD Stack 201	SO_2	Combined with the sixteen (16) vents from the IHCC of a twenty-four (24) hour average emission rate of one thousand six hundred fifty-six (1,656) pounds per hour	5,398

a. Condition D.1.2(a) T089-41033-00383 issued May 8, 2019.
b. Actual emissions as submitted in 2018 Annual Emission Inventory.

4.2 Technical Feasibility Assessment of Additional SO_2 Control Measures

In Cokenergy's response to IDEM's request to complete a Four-Factor Analysis for the Facility, four (4) SO_2 reduction options for its FGD system were evaluated to determine technical feasibility.

[21] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

- Additional FGD system.
- Complete replacement of existing FGD system.
- Addition of end-of-pipe controls to existing FGD system.
- Federally enforceable SO_2 limit.

The technical feasibility of these options is detailed below.

4.2.1 Addition of Second FGD System

As part of the two (2) detailed and comprehensive engineering studies previously completed by Cokenergy an initial review of an additional FGD system that contained one (1) SDA was evaluated as part of a comprehensive site-specific engineering evaluation.

Based on the exorbitantly high capital costs, increased maintenance requirements, expected chemical/reagent usage, difficulties related to physical space and positioning of an additional FGD system, and lack of available footprint at Cokenergy[22] it was determined that the addition of a second FGD system is a technically infeasible option. Indeed, the physical space limitations, among other things, were extensively discussed as part of the negotiations with EPA and IDEM to resolve the Consent Decree. Figure 4-1 shows Cokenergy's property boundaries to illustrate the limited space and challenges that would arise with the addition to control devices.

None of the parameters used to eliminate an additional FGD as technically feasible during the previous engineering studies have changed; therefore, the addition of a second FGD system remains technically infeasible.

[22] Cokenergy operates on a small leased portion, less than one (1) percent of the total acreage of Arcelor-IH's expansive facility and is not contractually allowed to expand outside of established physical boundaries.

Figure 4-1. Cokenergy Property Boundaries

4.2.2 Complete Replacement of FGD System

The EPA Four-Factor Analysis guidelines do not require EGUs with existing FGD systems to remove existing controls and replace them with new controls, but the guidelines do state that coal fired EGUs with existing SO_2 controls achieving removal efficiencies of less than 50% should consider constructing a new FGD system in addition to evaluating the suite of upgrade options. For EGUs, the suite of available "upgrades" may not be sufficient to remove significant SO_2 emissions in a cost-effective manner, and States may determine that these EGUs should be retrofitted with new FGD systems.[23]

Cokenergy is not an EGU but has already undergone extensive enhancements to the existing FGD system and now achieves SO_2 control of more than 50%, as shown in Table 3-1. As Cokenergy's existing enhanced FGD system achieves SO_2 removal efficiency greater than the EPA Four-Factor Analysis guidelines for EGUs, a complete replacement of the FGD system is not evaluated further. Additionally, as the flue gas from IHCC is variable by nature, a new FGD system may not achieve more than nominal SO_2 removal efficiency over the existing, fully optimized, FGD system Cokenergy currently operates.

Accordingly, a complete replacement of the existing FGD system at the Facility is unnecessary and technically infeasible.

[23] 70 FR 39122.

4.2.3 Addition of End-of-Pipe Controls to Existing FGD System

The two categories of control technologies that are used to control flue gas containing SO_2 are wet FGD and dry FGD. The technical feasibility of each control technology category is assessed.

4.2.3.1 Addition of Wet FGD after Existing FGD System

Within the wet FGD control technology category a possible device is a wet scrubbing system, wet scrubber, which utilizes a ground alkaline agent, such as lime or limestone, in slurry (i.e., scrubbing liquid) to remove SO_2 from stack gas via absorption into droplets of slurry which are sprayed countercurrent to flue gas flow via low pressure, large orifice spray nozzles into a reactor vessel. The spent scrubbing liquid is sent to hydroclones to separate gypsum from the recirculated liquor and the hydroclone underflow is sent to a drum filter or belt press to separate solids. Water and the spent solids, consisting of reaction products such as calcium sulfate when lime or limestone is utilized, would be sold or landfilled after dewatering. Recovered water is typically reused to blend new slurry for the wet scrubber along with makeup water to maintain optimal scrubber design removal efficiency. Wet systems typically have greater space requirements and can produce aerosol emissions of entrained PM. Key wet scrubbing operating parameters include residence time and pressure differential in the reactor vessel, liquid flow rate for target liquid-to-gas ratio, scrubber liquid pH and specific gravity, and surface area.

4.2.3.2 Addition of Dry FGD after Existing FGD System

An industry standard dry FGD technology is DSI. A DSI system involves injection of dry alkaline sorbent/reagent into a flue gas stream in exhaust ductwork to create contact between the solid reagent and acid gases. Calcium hydroxide [$Ca(OH)_2$] otherwise known as hydrated lime, is involved in the following chemical reactions:

$$Ca(OH)_2 + SO_2 + 0.5O_2 \rightarrow CaSO_4 + H_2O$$
$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O$$

The gaseous pollutants are bound to the surface of the introduced solid, forming a reaction product, which is separated from the flue gas as PM via capture in a fabric filter after the scrubbing process. Dust cake on the bags acts as a second scrubbing stage in which residual acids receive a final step of scrubbing. Factors affecting the efficiency of the absorption process include flue gas temperature, concentration of SO_2 in the exhaust stream, particle size/surface area of the hydrate, flue gas moisture, and stoichiometric ratio of reagent to SO_2 (Ca/S molar ratio).

4.2.3.3 Technical Feasibility of Additional End-of-Pipe Controls to Existing FGD

The addition of any add-on controls to the existing optimized FGD system is not technically feasible. During previously conducted engineering studies and continuing optimization of the FGD by Primex no additional controls have been identified as viable or feasible.

Both the wet and dry FGD control options are deemed technically infeasible for the provided reasons:

- No physical space to install additional control devices. Cokenergy operates as a contractor to Arcelor-IH and there is no room for expansion as Cokenergy is surrounded by Arcelor-IH processes or other on-site contractors with limited space (e.g., IHCC).

- Cokenergy would likely need to install a dedicated wastewater treatment facility to process the waste streams for any end-of-pipe control additions. The capital costs and physical area restrictions deem this infeasible.[24]
- Addition of end-of-pipe controls could impact the current control efficiency achieved by the FGD system Cokenergy operates. It is undeterminable if additional controls could be added before or after the baghouse system already in place. Extensive retrofitting would need to be conducted for either placement option.

4.2.4 Federally Enforceable SO_2 Limit

Accepting a federally enforceable emissions limitation for SO_2 is an EPA-accepted approach to preclude triggering a Four-Factor Analysis and thereby show reasonable progress for the impacted Class I Areas. However, a new federally enforceable emissions limitation is inappropriate.

First as discussed above, using the PSAT modeling data generated by VISTAS, states identified sources shown to have a sulfate or nitrate impact on one or more Class I areas that is greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the most impaired days for that Class I area. This analysis did not identify Cokenergy as a point source that meets the criteria in the VISTAS PSAT modeling. Consequently, VISTAS modeling does not indicate an additional SO_2 limit at Cokenergy would improve visibility at Mammoth Cave or is otherwise required to meet RH regulations.

In addition, there already is a federally enforceable limit of 1,656 lb SO_2/hr in Title V, T089-41033-00383, permit condition D.1.2(a) and additional federally enforceable SO_2 limits raise significant feasibility issues. A federally enforceable limit restricting annual venting (and thereby reducing SO_2 emissions) was accepted as a result of extensive, multi-year CD negotiations and was ultimately incorporated into both Cokenergy's Title V permit and the Indiana SIP. The limit represented the emissions reductions EPA and IDEM believed were feasible while taking into account the need for operational flexibility and routine and non-routine maintenance needs.

Thus, it was understood by all parties that maintaining the 1,656 lb SO_2/hr emission limit is a vital aspect of the Cokenergy Facility's ability to maintain compliance with its Title V permit under a variety of operating conditions.

[24] Cokenergy does not have access to Arcelor-IH wastewater treatment.

5. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS

Based on the analysis above, Cokenergy's view is that no additional controls are necessary or technically feasible. Throughout this report and below, the Facility has provided details, as applicable, to the four-statutory RH factors. The preceding sections of this analysis document the optimization projects Cokenergy has undertaken beginning in 2010 with re-tubing the HRSGs and continues through the present with the ongoing support Primex provides the Facility. These projects, the resources expended to implement the projects, and the impact of the projects on the Facility's SO_2 emissions should be considered in IDEM's RH reasonable progress analysis to be submitted to EPA Region 5. In addition, the fact that there is no visibility impact from the Facility's SO_2 emissions on Mammoth Cave should also be considered in IDEM's RH reasonable progress analysis to be submitted to EPA Region 5.

5.1 Cost of Compliance (Statutory Factor 1)

A cost of compliance analysis was not conducted for this report as additional controls are unnecessary and infeasible. As previously noted, Cokenergy made a substantial capital investment exceeding $41 million to optimize the company's FGD system, which resulted in significant SO_2 reductions. In addition, Cokenergy could not accommodate the additional space required for additional control equipment, storage of reagents that would be required for additional control equipment, additional electric power needed, or disposal/treatment of blowdown wastewater.

In addition, as part of this Four-Factor Analysis, Cokenergy reviewed the EPA Air Pollution Control Cost Manual Section 5 Chapter 1 – Wet Scrubbers for Acid Gas for SO_2 (the Manual). The Manual has been utilized throughout Indiana and nationally as a screening tool for Statutory Factor 1. The input parameters for both wet and dry FGD require data that are not applicable to Cokenergy, as fuel is not combusted as part of Cokenergy's process. Cokenergy receives only waste heat from IHCC. Additionally, the coal that IHCC uses to produce coke is elementally different from coal typically combusted at EGUs which disallows the usage of default coal factors (e.g., lignite, subbituminous, anthracite) from the Manual.

Representative inputs in the Manual:

- Higher heating value of fuel blend
- Nameplate maximum heat input to boiler
- Net plant heat rate of system
- Fuel type combusted and coal type, as applicable

As noted previously in this report, Cokenergy engaged in an extensive engineering review which included cost information before selecting an option to optimize the Facility's FGD system. EPA and IDEM agreed with this determination in the course of CD negotiations. Conducting an additional cost of compliance analysis at this time using the Manual is infeasible in the allotted time given the unique, site specific factors involved. Cokenergy would require additional time from IDEM to develop a site-specific cost estimate that would require contracting with an engineering design firm. Nevertheless, as discussed throughout this report, any additional control technologies for Stack 201 are unnecessary and technically infeasible for all the reasons stated herein.

5.2 Time Necessary for Implementation (Statutory Factor 2)

As no controls are considered technically feasible for Cokenergy, implementation of the controls is not an applicable step. If additional SO_2 control was required for RH visibility reasonable progress, Cokenergy would engage contractors for further engineering analysis/study, which would take several years.

5.3 Energy & Non-Air Quality Environmental Impacts (Statutory Factor 3)

As no controls are considered technically feasible for Cokenergy, an in-depth analysis of energy and non-air quality environmental impacts was not conducted.

5.4 Remaining Useful Life (Statutory Factor 4)

As no controls are considered technically feasible for Cokenergy, there is no add-on control technology life to consider.

6. RECOMMENDATIONS

As noted in this report, no additional SO_2 control measures by Cokenergy are necessary for IDEM to meet the RH Program requirements. Indeed, Cokenergy has already implemented significant SO_2 reduction measures through the FGD optimization program at significant capital cost. Furthermore, there is no indication from VISTAS photochemical modeling that Cokenergy is causing significant impact (or any impact at all) on Class I areas (Section), including the Class I area at issue here—Mammoth Cave. Finally, as it pertains to the four factors of the second RH planning period, there are no additional reasonable SO_2 control options for the lime spray dryer FGD unit located at Arcelor-IH. Cokenergy will continue to operate the FGD system following the optimization strategies already in place that will continue to enhance the SO_2 reduction from Stack 201.

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Appendix G

SABIC Four-Factor Analysis Submittal

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September 30, 2020

VIA EMAIL

Ms. Jean Boling
Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue, IGCN 1003
Indianapolis, IN 46204

RE: Regional Haze
Request for Four-Factor Analysis
SABIC INNOVATIVE PLASTICS MT. VERNON, LLC
Mt. Vernon, Indiana

Dear Ms. Boling,

Please find attached the requested Four-Factor Analysis for the SABIC Innovative Plastics Mt. Vernon, LLC (SABIC) site at Mt. Vernon, Indiana.

Should you have any questions or concerns, please contact me at (217) 521-1799 or by e-mail gregory.michael@sabic.com.

Sincerely,

Greg Michael
Environmental Manager

Attached

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REGIONAL HAZE FOUR-FACTOR ANALYSIS

SABIC Innovative Plastics / Mt. Vernon, IN

Prepared By:

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September 2020

Project 2018001.0012

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYM LIST

Ammonia	NH_3
Area of Influence	AoI
Carbon Dioxide	CO_2
Carbon Disulfide	CS_2
Carbon Monoxide	CO
Carbonyl Sulfide	COS
Chemical Engineering Plant Cost Index	CEPCI
Chlorine Gas	Cl_2
Clean Air Act	CAA
Comprehensive Air Quality Model with Extensions	CAMx
Continuous Emission Monitoring System	CEMS
Diatomic Nitrogen/Molecular Nitrogen	N_2
Electrical Generating Utilities	EGU
Flue Gas Desulfurization	FGD
Heat Recovery Steam Generator	HRSG
Hydrogen Sulfide	H_2S
Indiana Department of Environmental Management	IDEM
Kilometer	km
Lake Michigan Air Directors Consortium	LADCO
Megawatt	MW
MMBTU per hour	MMBTU/hr
Mt. Vernon, Indiana	MtV
Nitric Oxide	NO
Nitrogen	N_2
Nitrogen Dioxide	NO_2
Nitrogen Oxides	NO_X
Oxygen	O_2
Particulate Matter	PM
Particulate Matter Source Apportionment Technology	PSAT
Petrochemical Coke	petcoke
Phosgene	$COCl_2$
Prevention of Significant Deterioration	PSD
Regional Haze Planning Organization	RPO
Remaining Useful Life	RUL
Risk Management Program	RMP
Selective Catalytic Oxidizer with additional capability of reducing NOX emissions	SCONOx™

Selective Catalytic Reduction	SCR
Selective Non-Catalytic Reduction	SNCR
Southeastern Air Pollution Control Agencies	SESARM
Standard Cubic Foot	SCF
State Implementation Plan	SIP
Sodium Hydroxide	NaOH
Sulfur Dioxide	SO_2
Tons per year	tpy
Total Capital Investment	TCI
Uniform Rate of Progress	URP
U. S. Environmental Protection Agency	EPA
Visibility Improvement State and Tribal Association of the Southeast	VISTAS
Volatile Organic Compounds	VOC
Water/Water Vapor	H_2O

1. EXECUTIVE SUMMARY

This report was prepared on behalf of SABIC Innovative Plastics Mt. Vernon LLC (SABIC) for its plastics manufacturing facility located in Mt. Vernon, Indiana (MtV) as the response to the June 2020 request from Indiana Department of Environmental Management's (IDEM's) Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis letter. IDEM requested that SABIC's MtV facility prepare a four-factor analysis per Section 169a(g)(1) of the Clean Air Act (CAA) to support IDEM's development of a revised Regional Haze State Implementation Plan (SIP) for the second planning period, 2018 to 2028. The second planning period SIP is due for submission to Region 5 of the U.S. Environmental Protection Agency (EPA) by July 31, 2021.[1]

As detailed in IDEM's four-factor analysis request, the MtV facility operates two (2) sources for which IDEM requested a four-factor analysis, identified as the Co-generation unit (COGEN) and Phosgene COS Vent Oxidizer (COS Vent Oxidizer) and flare associated with Building 6 carbon monoxide generators.[2] This report provides information related to effective and reasonable control measures in light of cost and time necessary for implementation, energy and non-air quality impacts, and remaining useful life of equipment for sulfur dioxide (SO_2) emissions from both COGEN and COS Vent Oxidizer and nitrogen oxides (NO_X) emissions from only COGEN.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered, in accordance with instructions in the four-factor analysis request:

- Identification of technically feasible options
- Costs of compliance[3] (Statutory Factor 1)
- Time necessary for compliance[3] (Statutory Factor 2)
- Energy and non-air quality environmental impacts of compliance[3] (Statutory Factor 3)
- Remaining useful life of affected sources [3] (Statutory Factor 4)

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[1] 40 CFR 51.308(f)

[2] The COS Flare is a backup control device to the COS Vent Oxidizer (it is also used during safety interlock of the CO generator system to the COS Vent Oxidizer; therefore, this report focuses on a four-factor analysis to reduce SO_2 emissions from the COS Vent Oxidizer only. Adding end-of-pipe control to the COS Flare could impact the COS/VOC removal efficiency of the flare and was not assessed in this report.

[3] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations pursuant to 40 CFR 51.308(f)(2)(i). Additionally, identification of technically feasible options as well as assessments of technical feasibility, control effectiveness, and emissions reductions are required to assess the cost of implementation.

2. FACILITY AND PROCESS DESCRIPTIONS

The following offers background on SABIC's MtV facility and the applicable process operations IDEM included in their four-factor analysis request to SABIC. To align with IDEM's requested four-factor analysis, SABIC will only describe the process operations identified in the June 2020 request letter (i.e., COS Vent Oxidizer and COGEN).

2.1 Facility Description

The MtV facility was built in 1960 to produce Lexan™ Resin on 150 acres of land. Currently, the site encompasses 1,100 acres and has expanded its chemical and plastics manufacturing operations to manufacture numerous products that are sold to end-use customers. MtV manufactures many intermediate products necessary for end-use plastics products. These intermediates are used at MtV and other SABIC facilities prior to reaching the marketplace. The site's extensive product portfolio includes thermoplastic resins, coatings, specialty compounds, and plastics film/sheet.

2.2 Process Operation Descriptions

2.2.1 Phosgene Process Description

The Phosgene process area, Section I of SABIC's current Title V[4] permit 129-42984-00002, generates phosgene, which is a key intermediate to produce polycarbonate. Polycarbonate is an end-use plastic with countless purposes in many impactful industries (e.g., medical, automotive). The chemical reaction to generate phosgene ($COCl_2$) is shown by the following equation.

$$CO + Cl_2 \rightarrow COCl_2$$

The COS Vent Oxidizer, one of the two emission units requested by IDEM to conduct a four-factor analysis, controls the production of carbon monoxide (CO). The chlorine (Cl_2) gas is generated in another process area within the MtV facility. Cl_2 gas production is not discussed in this report as it is not included in IDEM's four-factor analysis request.

The major process steps to produce purified CO, an essential step in producing phosgene, are described as follows:

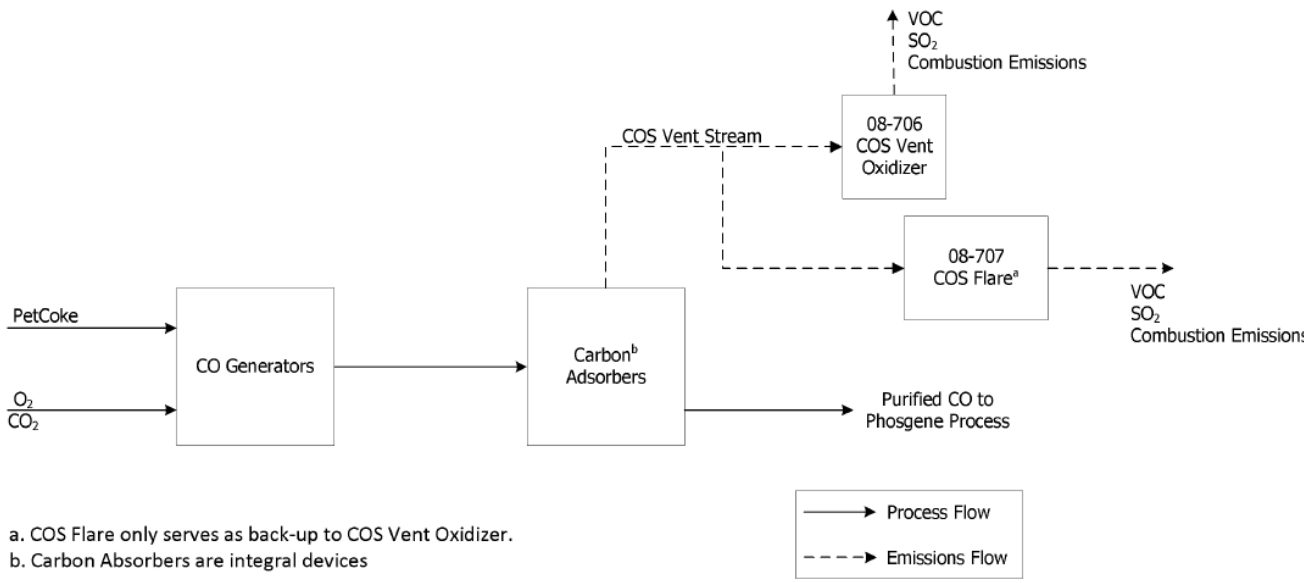
- The CO generation process involves the controlled combustion of petrochemical coke (petcoke) to form CO. The petcoke contains sulfur as an impurity. During the controlled combustion process, the sulfur is converted to reduced sulfur compounds containing organic sulfides. The organic sulfides primarily consist of carbonyl sulfide (COS), hydrogen sulfide (H_2S), and carbon disulfide (CS_2).[5]
- The generated CO and organic sulfides are passed through a carbon bed that adsorbs the organic sulfides present.
- The carbon bed adsorbers are periodically regenerated by purging the beds to desorb the sulfides.

[4] SABIC's most recently issued Title V permit (129-42984-00002 from August 17, 2020) was for a minor source modification/administrative amendment.

[5] The facility description box in Section I.2 of SABIC's Title V permit notes the COS vent stream contains organic sulfides, which primarily consist of carbonyl sulfide, hydrogen sulfide, and carbon disulfide.

- During the regeneration of the carbon adsorbers the organic sulfides are removed from the carbon and become part of the regeneration gas stream referred to as the COS vent stream.
- The COS vent stream from the carbon bed adsorbers[6] is routed to the COS Vent Oxidizer (Stack Vent ID 08-706).
- The SO_2, the pollutant addressed in this four-factor analysis, is a byproduct created during the incineration of the COS vent stream in the COS Vent Oxidizer.
- Figure 2-1 represents SABIC's existing air pollution control scenarios for controlling the organic sulfides in the COS vent stream that originated during CO generation.

Figure 2-1. Process Flow Diagram for CO Generation in Phosgene Process Area



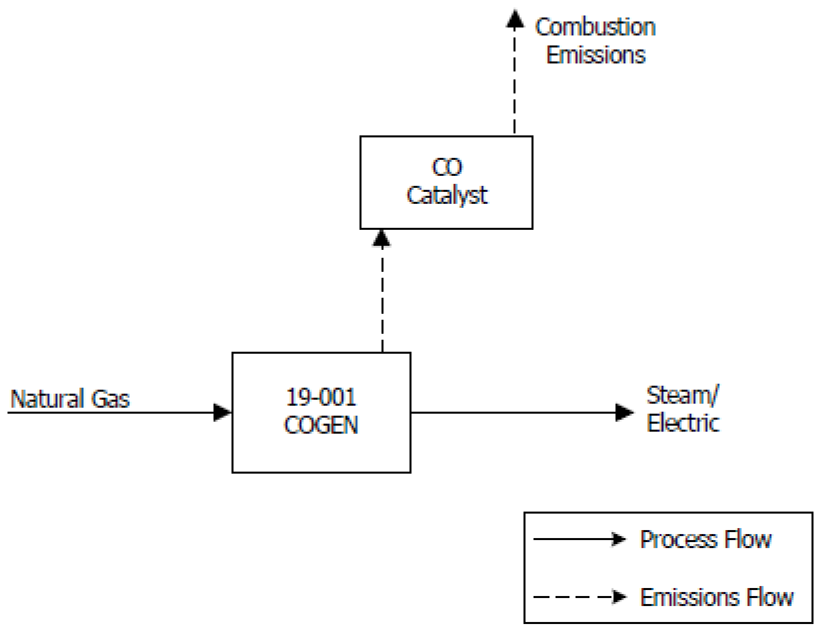
2.2.2 Co-generation Facility Process Description

The co-generation facility at MtV began construction in 2015 and was fully operational in the fourth quarter of 2016. The installation of the 1,812 MMBTU per hour (MMBTU/hr) stationary natural gas-fired combustion turbine and nominal 486 MMBTU/hr natural gas-fired duct burner with a heat recovery steam generator (HRSG) allowed SABIC to cease using coal as fuel to generate steam for process operations.

IDEM requested SABIC to conduct a four-factor analysis for both SO_2 and NO_X emissions from the COGEN unit, Stack Vent ID 19-001. Figure 2-2 represents the process flow for the COGEN unit.

[6] The carbon adsorbers are listed as integral devices in Section I.2 of SABIC's Title V permit, T129-36775-00002, V-948, V-949, V-050A, V-951A, V-9020, and V-9021.

Figure 2-2. Process Flow Diagram for COGEN



3. REGIONAL HAZE PROGRAM IN INDIANA

3.1 Regional Haze Program

Pursuant to 40 CFR 51.308(d), each state must address regional haze in each mandatory Class I Federal area located within the state, and each area outside the state if affected by interstate emissions. States must establish reasonable progress goals that provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period. The regional haze program is within the second planning period (2018-2028).

3.2 IDEM's Analysis Request to SABIC

IDEM sent SABIC a four-factor request letter, via email, on June 18, 2020 which included the list of emission units to be included in the four-factor analysis. IDEM's request of SABIC included:

Table 3-1. Emission Units and Pollutants in IDEM's Four-Factor Analysis Request to SABIC [a]

Emission Unit	Type of Four-Factor Analysis
Co-generation unit	SO_2 and NO_X
Phosgene COS vent oxidizer and flare associated with Building 6 carbon monoxide generators	SO_2

a. This table was presented by IDEM in the June 18, 2020 Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis letter sent to SABIC via email on June 18, 2020.

IDEM described their selection methodology to request four-factor analyses for facilities in Indiana during the June 3, 2020 webinar. To summarize the information presented, IDEM selected steel mills, cement kilns[7], and non-electric generating utility (EGU) sources[8] with a "Q/d" greater than 5.0 to complete or request completion of a four-factor analysis. IDEM indicated the "Q/d" approach was chosen to include a reasonable number of sources to be evaluated and for consistency with other Lake Michigan Air Directors Consortium (LADCO) states. LADCO is a regional planning organization (RPO) and includes Indiana, Illinois, Ohio, Wisconsin, and Michigan.

IDEM based inclusion of sources in this second implementation period of regional haze planning on a ratio of 2018 actual annual emissions of visibility-affecting pollutants (determined by IDEM to be NO_X and SO_2 for Indiana), known as "Q" in tons per year (tpy), and distance to Class I[9] area, known as "d" in kilometers (km). IDEM has selected the conservative ratio criteria of "Q/d > 5.0" to identify the facilities for which four-factor analyses will be completed. Based on this screening approach, IDEM calculated the "Q/d" to be 5.3[10] for SABIC which led to IDEM's request that SABIC develop a four-factor analysis.

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[7] IDEM indicated the completion of the four-factor analyses for the two cement facilities in Indiana with a "Q/d > 5.0" (Lehigh Cement Company and Lone Star Industries Inc) was undertaken internally.

[8] SABIC falls into the non-EGU category.

[9] Class I areas are designated by the CAA which gave special air quality and visibility protection to national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the CAA was amended in 1977.

[10] Actual 2018 site-wide SO_2 and NO_X emissions of 965 tpy with a distance of 182 km to Mammoth Cave NP (965 Q / 182 d = 5.292).

The "Q/d" selection criterion is the least complicated technique offered in the guidance memorandum by EPA on Regional Haze SIP for the Second Implementation Period.[11] The selection criteria offered by EPA are as follows, ranked in order of least to most complex:

- Emissions divided by distance (Q/d) – Ratios SO_2 and NO_X emissions with distance to Class I areas.
- Trajectory analyses – Examines the wind direction on individual days.
- Residence time analyses – A trajectory-based analysis technique that combine emissions, ambient particulate data, and trajectory information.
- Photochemical modeling (zero-out and/or source apportionment) – The only modeling technique suggested by EPA. Photochemical modeling quantifies source or source sector visibility impacts.

Although the "Q/d" selection technique is easy to implement, it does not include as much information as the three (3) more complex selection techniques suggested by EPA. The more sophisticated techniques account for detailed information on particulate matter (PM), and PM species impacts but are more resource intensive. EPA allowed each state to select their own four-factor analysis selection techniques and did allow states to use other reasonable techniques.

IDEM's "Q/d >5.0" selection criterion does not account for the data analyzed (i.e., photochemical modeling) and summarized by RPOs. RPO modeling results do not indicate SABIC has a sulfate or nitrate impact on Mammoth Cave greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the twenty (20) percent most impaired days. This criterion is used to include or exclude, in SABIC's case, emissions from a point source as within the Area of Influence (AoI) of a Class I area.

3.3 VISTAS Modeled Class I Impacts Outside LADCO RPO

SABIC is physically located in the RPO of LADCO although the only Class I area IDEM referred to in the June 2020 request letter is Mammoth Cave, which is in Kentucky. Kentucky is located within the Visibility Improvement State and Tribal Association of the Southeast (VISTAS). VISTAS is a subcommittee of the Southeastern Air Pollution Control Agencies (SESARM) RPO. VISTAS conducted technical analyses to help states identify sources that significantly impact visibility impairment for Class I areas within and outside the VISTAS region (i.e., VA, WV, NC, SC, GA, FL, AL, TN, MI, KY, GA). VISTAS conducted an AoI analysis to identify sources to "tag" for PM Source Apportionment Technology (PSAT) modeling, which was implemented with the Comprehensive Air Quality Model with Extensions (CAMx) analysis to identify emissions sources that strongly contribute to regional haze.[12] VISTAS identified three (3) impactful sources in Indiana[13] as a result of this analysis, all EGUs, and they did not include SABIC.[14] Therefore, the VISTAS's analyses concluded that SABIC's facility in Mt. Vernon, Indiana was not a source shown to have a significant sulfate or nitrate impact on a Class I area.

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[11] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

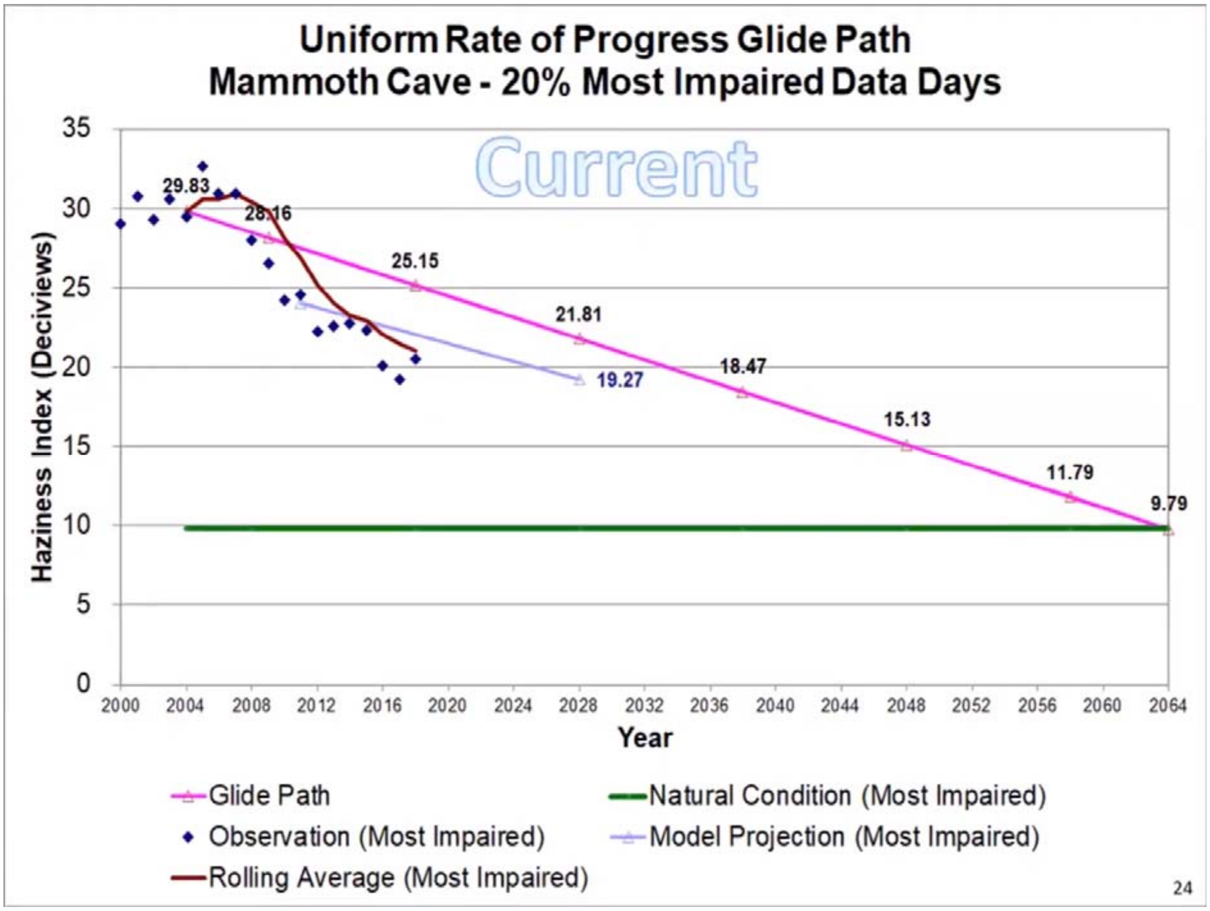
[12] Defined by VISTAS as sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00% of the total sulfate plus nitrate point source visibility impairment on the 20% most impaired days for each Class I area.

[13] VISTAS identified Indianapolis Power & Light Petersburg (18125-73624111), Gibson (18051-7363111), and Indiana Michigan Power DBA AEP Rockport (18147-9017211) as the Indiana sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00 percent of total sulfate plus nitrate point source visibility impairment on the 20 percent most impaired days for each Class I area.

[14] VISTAS Letter- Request for Regional Haze Reasonable Progress Analyses for Indiana Sources Impacting VISTAS Class I Areas, June 2020.

In addition, VISTAS updated 2028 CAMx modeling based on actual observations through 2018 and revised future projections based on reasonable progress.[15] As indicated in Figure 3-1, current visibility conditions and projected visibility conditions at Mammoth Cave are better than the target uniform rate of progress (URP) glidepath line. Therefore, emission reductions are not required to meet the 2028 uniform rate of progress goal for visibility at Mammoth Cave.

Figure 3-1. VISTAS Haziness Index Modeling Results – Mammoth Cave Class I Area



With the data presented, and detailed in this report, it can be concluded that emissions from SABIC do not impact Mammoth Cave. SABIC is fulfilling IDEM's request by submitting this four-factor analysis report, although no current data indicates the site significantly impacts Class I visibility.

[15] VISTAS presentation- Regional Haze Project Update- EPA, FLM, RPO Briefing https://youtu.be/FN83NmV0JWQ , August 2020.

4. TECHNICALLY FEASIBLE CONTROL MEASURES IDENTIFICATION

This section describes the baseline controls currently in use and the potential add-on controls for SO_2 and NO_X at the MtV facility.

4.1 Baseline Control Scenario

At present and as required by SABIC's current Title V permit, the following controls are in operation for the units in IDEM's four-factor analysis request:

- The COS Vent Oxidizer is itself a control device. It controls the carbon adsorbers that are integral control devices to the CO generators 1 to 16 as described in the permit's Section I.2 facility description box. The COS Vent Oxidizer reduces volatile organic compounds (VOC) from the COS vent stream.
- COGEN combusts only natural gas, a low-sulfur fuel. An oxidation catalyst controls both CO and VOC emissions from the stationary combustion turbine and HRSG. A low-NO_X duct burner was installed as well.

Table 4-1. SABIC Mt. Vernon – Four-Factor Analysis Emission Units, Permit Limits, and Actual Annual Emissions

Emission Unit (Stack/Vent ID)	Description	Pollutant	Permit Limits in TV 129-42984-00002	2018 Emissions (tpy)
COS Vent Oxidizer (08-706)	Phosgene COS vent oxidizer and flare associated with Building 6 CO generators	SO_2	Condition I.2.1(c and d) COS vent stream is being vented to COS Vent Oxidizer or Flare total sulfur input to CO generators shall be limited to 928.65 tons per 365-day period rolled on daily basis	570 [a]
COGEN (19-001)	1,812 MMBTU/hr stationary natural gas-fired combustion turbine including a nominal 486 MMBTU/hr natural gas-fired duct burner and HRSG	NO_X	No site-specific limits; W.2.8 and 9 establish NSPS Subpart KKKK as permit limits	119 [b]
		SO_2	No site-specific limits; W.2.10 establish NSPS Subpart KKKK as permit limits	2.3 [a]

a. Actual emissions calculated using accepted and standard methodologies for applicable emission units and reported in SABIC's 2018 annual emission summary submitted to IDEM.
b. NO_X emissions for COGEN use continuous emission monitoring system (CEMS) data.

4.1.1 Baseline SO_2

4.1.1.1 CO Generation Process SO_2 Emissions

The SO_2 emissions from the CO generation process are created during the incineration of the COS vent stream in the COS Vent Oxidizer. The COS vent stream, containing reduced sulfur compounds, predominately originates from the reduction of carbon dioxide (CO_2) over petcoke to generate purified CO.

The MtV facility operates sixteen (16) CO generators to produce a high-purity CO as an intermediate to be used for phosgene generation in the Phosgene process area. The sulfur content of the petcoke is analyzed frequently by MtV or the petcoke supplier. A mass balance of the total sulfur input to the CO generators is required in MtV's current Title V permit Condition I.2.3(c) to comply with the Prevention of Significant Deterioration (PSD) avoidance limit in Condition I.2.1. The SO_2 that exits the COS Vent Oxidizer originates as sulfur in the petcoke.

4.1.1.2 COGEN SO_2 Emissions

The four-factor analysis request from IDEM included SO_2 emissions from COGEN. However, COGEN is a natural gas-fired combustion turbine that has inherently low SO_2 emissions due to the small amount of sulfur present in the fuel. SABIC receives pipeline quality natural gas which pursuant to 40 CFR 72.2 must contain 0.5 grains/100 standard cubic foot (SCF) or less of sulfur.

> *40 CFR 72.2 - Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.*

The low sulfur input into COGEN results in low SO_2 emissions at the COGEN stack (i.e., post combustion).

4.1.2 Baseline NO_X[16]

The only emission unit at SABIC for which IDEM requested a four-factor analysis for NO_X is SABIC's COGEN; therefore, this section describes the NO_X emissions from the stationary natural gas-fired combustion turbine with a natural gas-fired duct burner and HRSG.

NO_X formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing natural gas is thermal NO_X, which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel to air interface.

The second mechanism, referred to as prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically bound fuel nitrogen, although some molecular nitrogen maybe present. It can be assumed that all NO_X formed from natural gas combustion is thermal NO_X.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air because

[16] Technical description adapted from AP-42 Chapter 3.1 Stationary Gas Turbines 3.1.3.1 Nitrogen Oxides, as applicable to SABIC.

turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits.

Diffusion flames are characterized by regions of near-stoichiometric fuel-air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame; therefore, decreasing thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature thereby reducing thermal NO_X. SABIC's COGEN uses lean, premixed combustion technology. The natural gas is typically premixed with more than 50 percent theoretical air, which results in lower flame temperatures suppresses thermal NO_X formation.

Ambient weather conditions impact NO_X emissions and power output from turbines more than from external combustion systems (e.g., natural gas-fired boilers). The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure. Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature in the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X generated.

SABIC's COGEN is equipped with fully integrated programmable process controls that vary the operational parameters of the unit to reduce thermal NO_X generation. MtV's current Title V permit contains conditions, W.2.8, 9 and 10, that limit COGEN's NO_X emissions to 40 CFR 60 Subpart KKKK-Standards of Performance for Stationary Combustion Turbines. SABIC demonstrates compliance with a NO_X continuous emission monitoring equipment as required by Title V condition W.2.18.

4.2 Four Factor Analysis Technical Feasibility

The four-factor analyses for the COS Vent Oxidizer and COGEN begins with an assessment of technical feasibility to determine what emission control measures to reasonably consider with respect to emission-related factors and cost. This aligns with EPA's guidance which states:[17]

> *The first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment. Identification of these measures does not create a presumption that one of them will be determined to be necessary to make reasonable progress. A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set.*

Based on this guidance, SABIC is providing background information below to support the selection of control measures that IDEM may consider as technically feasible and reasonable for the requested units at the MtV facility.

[17] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

4.2.1 Technical Feasibility Assessment of Additional SO_2 Control Measures

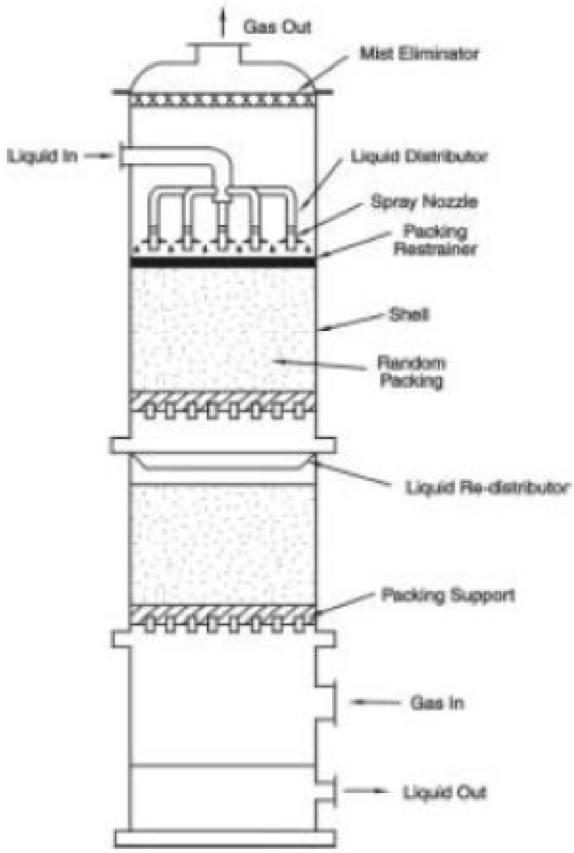
4.2.1.1 Packed-Bed Wet Scrubber[18] for COS Vent Oxidizer SO_2 Control

SABIC has evaluated a packed-bed wet scrubber as a potential technically feasible SO_2 control measure for an end-of-pipe control after the COS Vent Oxidizer.

Packed-bed scrubbers, sometimes referred to as packed-tower scrubbers, consist of a chamber containing layers of variously-shaped packing material (e.g., Raschig rings, spiral rings, or Berl saddles) that provide a large surface area for liquid to particle contact. The packing is held in place by wire mesh retainers and supported by a plate near the bottom of the scrubber. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The pollutant, SO_2 from the CO generation process, to be absorbed must be soluble in the fluid. In vertical designs (packed towers), the gas stream flows up the chamber (countercurrent to the liquid). Some packed beds are designed horizontally for gas flow across the packing (crosscurrent). Physical absorption depends on properties of the gas stream and liquid solvent (e.g., density and viscosity), as well as specific characteristics of the pollutant in the gas and the liquid stream (e.g., diffusivity, equilibrium solubility). These properties are temperature dependent, and lower temperatures generally favor absorption of gases by the solvent. Absorption is also enhanced by greater contacting surface, higher liquid-gas ratios, and higher concentrations in the gas stream. Chemical absorption may be limited by the rate of reaction, although the rate-limiting step is typically the physical absorption rate, not the chemical reaction rate.

[18] Technical description adapted from EPA Air Pollution Control Technology Fact Sheet-Packed-Bed/Packed-Tower Wet Scrubber, as applicable to SABIC.

Figure 4-1. Packed-Bed Wet Scrubber Schematic



For a packed-bed wet scrubber to control SO_2 emissions from SABIC's COS Vent Oxidizer, pollutant removal may be enhanced by manipulating the chemistry of the absorbing solution so that it reacts with the pollutant. A caustic solution of sodium hydroxide (NaOH) is the most common scrubbing liquid used for acid-gas control such as the COS vent stream at MtV. When the acid gases are absorbed into the scrubbing solution, they react with alkaline compounds to produce neutral salts. The rate of absorption of the SO_2 is dependent upon the solubility of the pollutant in the NaOH scrubbing liquid.

Advantages of a scrubber for SO_2 control as end-of-pipe technology after the COS Vent Oxidizer include:

- Relatively low pressure drop across the scrubber,
- Equipment construction is typically fiberglass-reinforced plastic that operates well in highly corrosive atmospheres,
- Reasonably high mass-transfer efficiencies are achievable,
- Packing inside scrubbers can be changed out to improve mass transfer without purchasing a new scrubber body/shell, and
- Comparatively low capital costs and space requirements.

Of the usual drawbacks to a scrubber for this application, only the blowdown/scrubber waste disposal issues are likely to be of issue to SABIC. Typical disadvantages to scrubbers can be plugging of scrubber media from particulate matter and scrubber construction being sensitive to temperature, both of which are not anticipated for MtV. With proper scrubber pH and temperature control, the potential plugging of the media from precipitation of salts can be avoided.

Wet scrubbing by a packed bed/tower scrubber is considered a technically feasible SO_2 control of the COS vent stream from the COS Vent Oxidizer.

4.2.1.2 Other Gas Absorber (Scrubber) Technologies for COS Vent Oxidizer SO_2 Control

Gas absorbers are generally referred to as scrubbers due to the mechanisms by which gas absorption take place. The term scrubber is often used very broadly to refer to a wide range of different control devices, such as those used to control particulate matter emissions. The term scrubber, in this report, is used to refer to control devices that use gas absorption to remove gases from waste gas streams. There are several SO_2 gas absorption technologies that are intended to control large volume (gas flow rate) and high SO_2 concentration (ppm) emission streams. Typically, these sources combust coal at large EGUs, steel mills, cement kilns, or large industrial boilers which generate a large volume of exhaust with a high SO_2 concentration due to the large amounts of coal combusted in the units.

The two broad categories of scrubber technologies used on large volume/high SO_2 concentration are wet flue gas desulfurization (FGD) and dry FGD. To further qualify the need for a high gas exhaust flow and concentration, EPA's Air Pollution Control Cost Manual (Cost Manual) for SO_2 and Acid Gas Controls requires data inputs such as, fuel higher heating value and boiler output megawatt (MW) rating. Neither of these data inputs are applicable to MtV's COS Vent Oxidizer exhaust stream.

In addition, the EPA air pollution control technology fact sheet for FGD- Wet, Spray Dry, and Dry Scrubbers has the following as the typical industrial applications for this technology.

> *Stationary coal- and oil-fired combustion units such as utility and industrial boilers, as well as other industrial combustion units such as municipal and medical waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and sulfuric acid manufacturing facilities.* [19]

The COS Vent Oxidizer exhaust stream does not have a large enough volumetric gas flow rate or sufficiently high SO_2 concentration to make the scrubber technologies in this section technically feasible.

4.2.1.3 SO_2 Reduction for COGEN

COGEN is fueled by low sulfur, pipeline quality, natural gas. While it may be theoretically feasible to install a wet or dry scrubber system on a natural gas-fired turbine such as COGEN, due to the inherently low SO_2 emission concentration associated with the combustion of natural gas, these systems are not cost effective and in Trinity's experience, regulatory agencies do not require such controls or even the evaluation of such controls. Consequently, no further discussion of additional SO_2 controls for COGEN is necessary.

4.2.2 Technical Feasibility Assessment of NO_X Control Measures

SABIC has evaluated the following additional emissions control measures for NO_X reduction for COGEN:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Oxidizer with additional capability of reducing NO_X emissions (SCONOx™)

The technical feasibility of these options is discussed in this section.

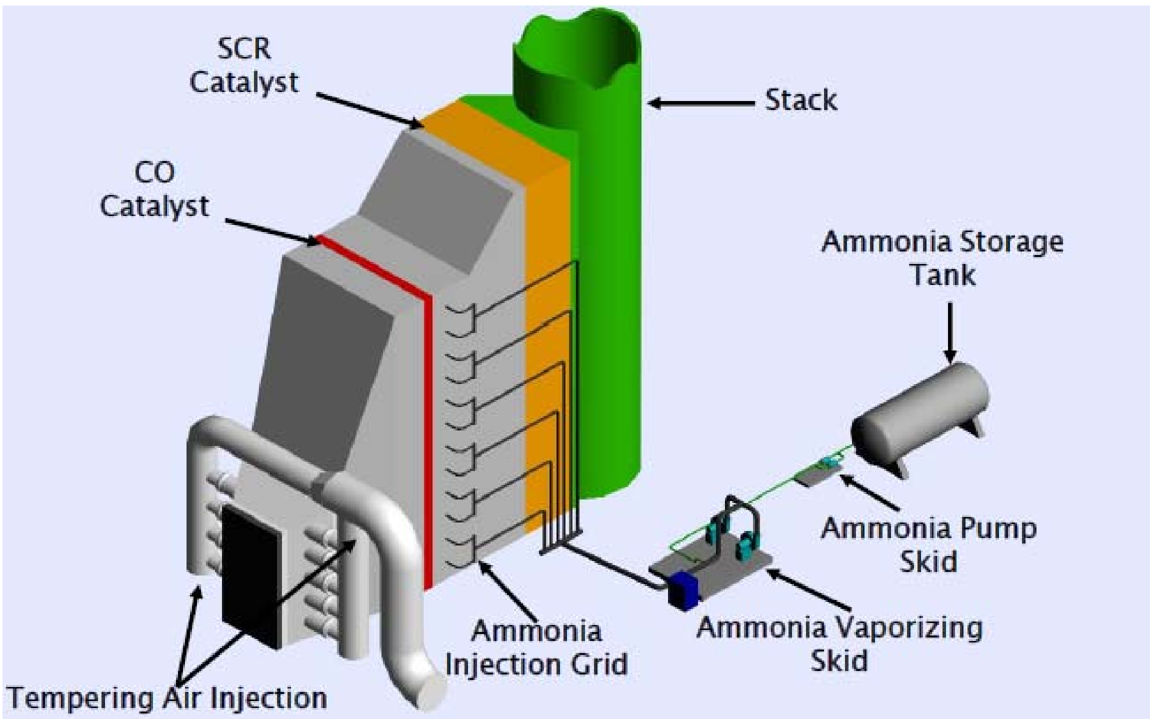
[19] Technical description adapted from EPA Air Pollution Control Technology Fact Sheet - FGD-Wet, Spray Dray, and Dry Scrubbers, as applicable to SABIC.

4.2.2.1 SCR[20]

SCR is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen (N_2) and water (H_2O). The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Figure 4-2. SCR Basic Schematic Diagram



When operated within the optimum temperature range of 480 °F to 800 °F, the reaction can result in NO_X removal efficiencies between 70 and 90 percent. The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700 °F and 750 °F. As the temperature increases to greater than the optimum temperature, the NO_X removal efficiency begins to decrease.

SCR is a technically feasible NO_X control technology for SABIC's COGEN.

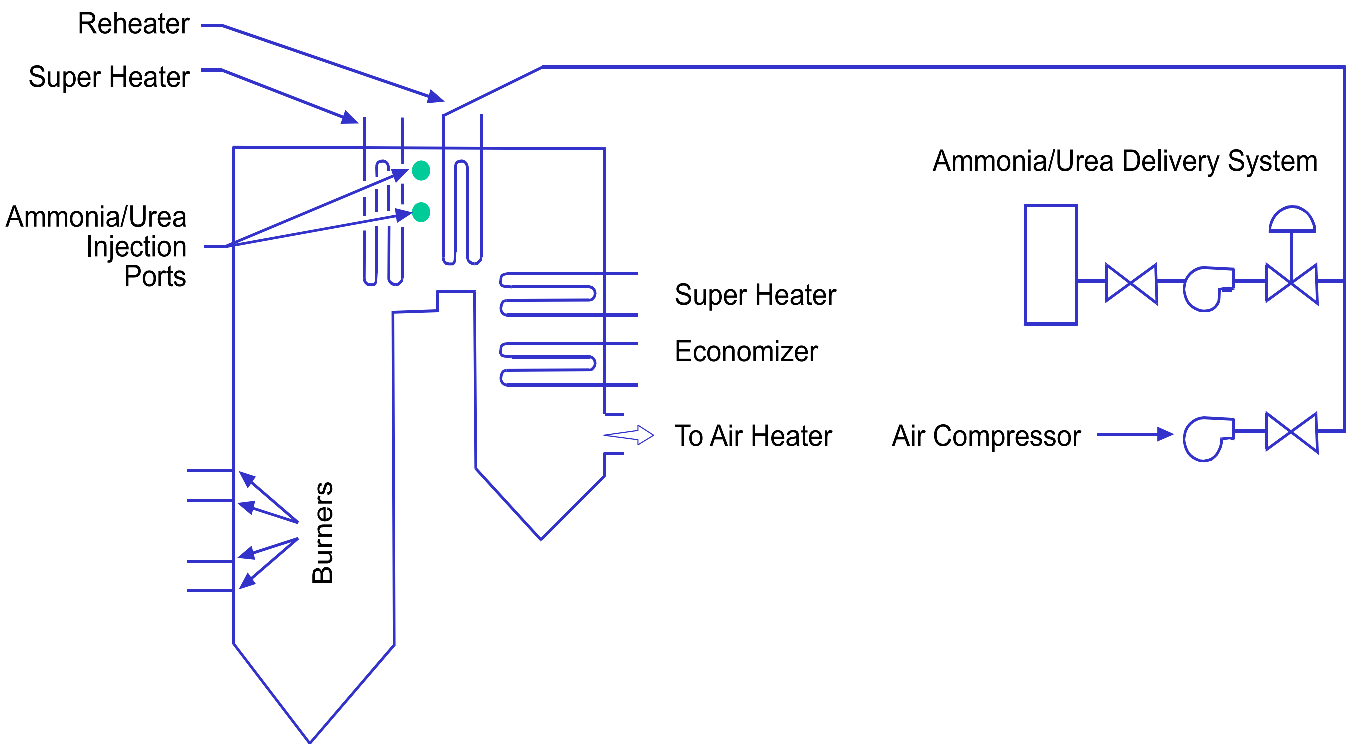
[20] Technical description adapted from EPA Air Pollution Cost Manual, Section 4.2, Chapter 2 Selective Catalytic Reduction, NO_X Controls, as applicable to SABIC.

4.2.2.2 SNCR[21]

The SNCR process reduces NO_x emissions using NH_3 or urea injection similar to SCR but operates only at higher temperatures. The overall chemical reactions can be expressed as follows:

$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

Figure 4-3. SNCR Basic Schematic Diagram



NO_x reduction levels range from 30 to 50% for SNCR. The optimal temperature range is between 1600 °F and 2,200 °F at which NO_x is reduced to N_2 and water vapor. Since SNCR does not require a catalyst, it is more attractive than SCR from an economic standpoint, however, it is not compatible with gas turbine exhaust temperatures that do not exceed 1,100 °F. Because the exhaust temperature at the exit of the existing turbines, approximately 1,000 °F at the duct burner in SABIC's COGEN, is less than the optimum temperature range, approximately 1,625 °F for the application of this technology, it is not technically feasible to apply, and it is eliminated from further evaluation in this analysis.

4.2.2.3 SCONOx™ [22]

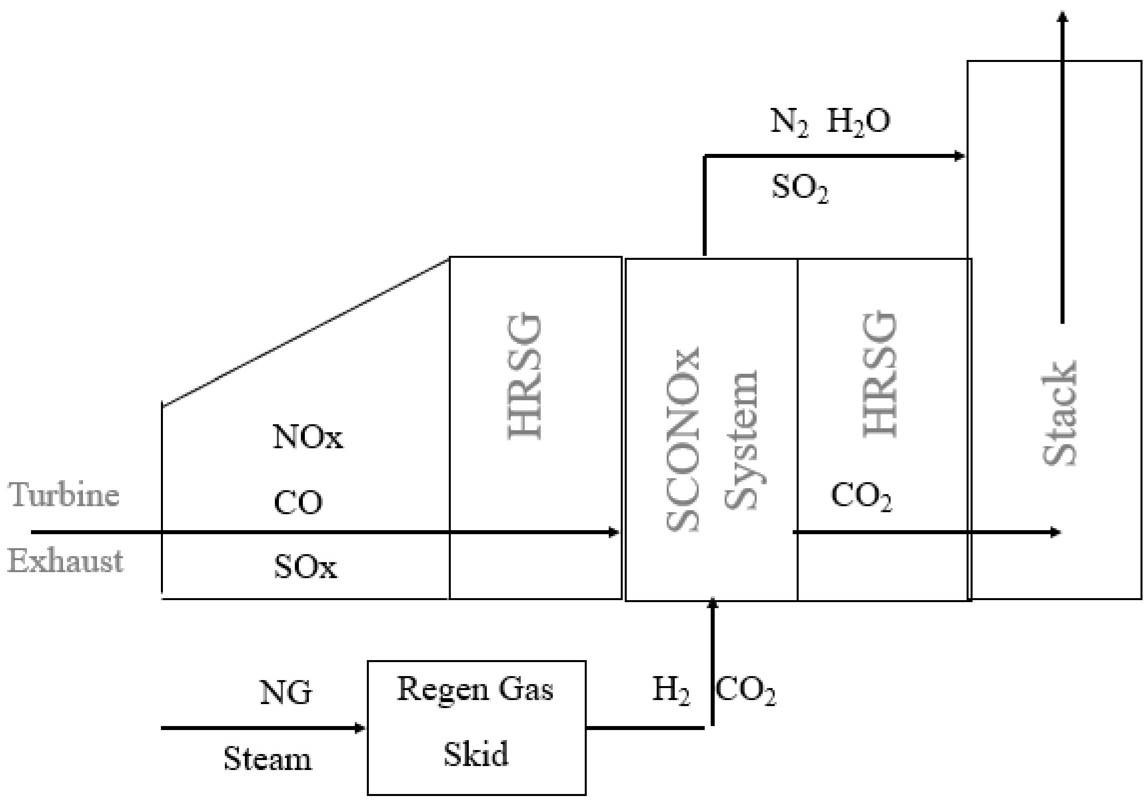
A relatively new post-combustion technology from EmeraChem is $SCONO_x$™, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. $SCONO_x$™ has been primarily installed on co-generation or combined cycle systems where the exhaust gas temperature is

[21] Technical description adapted from EPA Air Pollution Cost Manual, Section 4.2, Chapter 1 Selective Non-Catalytic Reduction, NO_x Controls, as applicable to SABIC.

[22] Technical description adapted from National Energy Technology Laboratory https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/nitrogen-oxides, as applicable to SABIC.

reduced by recovering energy to produce steam. The $SCONO_x$™ system catalyst is installed in the exhaust system at a point where the temperature is between 280 °F and 650 °F. Because the exhaust temperature at the exit of the existing turbines, approximately 1,000 °F, is greater than the optimum temperature range for the application of this technology, it is not technically feasible to apply $SCONO_x$™, and it is eliminated from further evaluation in this four-factor analysis.

Figure 4-4. $SCONO_x$™ General Schematic Diagram



5. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS

The technically feasible SO_2 control option of a packed-bed/tower scrubber to control emissions from the COS Vent Oxidizer, referred to as COS Vent Scrubber, is analyzed herein using the four statutory factors from Section 169A(g)(1) of the CAA.

5.1 Cost of Compliance (Statutory Factor 1)

5.1.1 Control Effectiveness

Table 5-1 summarizes the estimated control efficiency for a packed-bed wet scrubber, the only technically feasible add-on SO_2 emissions reduction options for COS Vent Oxidizer.

Table 5-1. Control Effectiveness of SO_2 Emissions Control Options

Source	SO_2 Control Option	Estimated Control Efficiency (%)
08-706 COS Vent Oxidizer	COS Vent Scrubber	95[a]

a. Engineering determination based on inlet loading SO_2 concentration and engineering knowledge of similar process applications.

5.1.2 Controlled Emissions

Table 5-2 summarizes the baseline and controlled emission rates and emission reduction potentials for the technically feasible SO_2 reduction option for the COS Vent Oxidizer.

Table 5-2. Baseline and Controlled Emission Rates of SO_2 Emissions Reduction Option

Source	Baseline Emission Rate [a] (tpy)	SO_2 Control Option	Controlled Emission Rate [a] (tpy)	Emissions Reduction (tpy)
COS Vent Oxidizer	570	COS Vent Scrubber	28	542

a. Based on 2018 actual emissions as submitted in SABIC's 2018 annual emissions inventory.

5.1.3 Cost

The following presents cost of compliance based on minimum estimated control efficiency of the add-on control option. An overall summary of estimated cost is presented in Table 5-3 with a detailed breakdown presented in Appendix A.

Table 5-3. Estimated Costs of SO_2 Emissions Reduction in 2019$

Source	SO_2 Control Option	Total Capital Investment ($)	Annual Cost ($/yr)	Cost Effectiveness ($/ton)
COS Vent Oxidizer	COS Vent Scrubber	$51,109,757	$6,213,119	$12,449

- As appropriate, SABIC used site-specific data and engineering judgement to refine the estimated costs summarized in Table 5-3. Appendix A contains additional details, references, and data sources for this SO_2 cost analysis.
- The Total Capital Investment (TCI) which includes a retrofit factor, uses cost data from a similar wet packed tower scrubber installation at MtV in 2010.
    - MtV's engineering and project management department records detailed the 2010 project included the absorber body/shell, packing, auxiliary equipment, instrumentation, sales taxes, and freight as well as direct installation costs (foundations, erection, piping, etc.) and indirect installation costs (engineering, start-up, etc.). [23]
    - The 2010 project did not include a quench chamber. This additional piece of equipment is assumed to be necessary between COS Vent Oxidizer outlet and the COS Vent Scrubber inlet. A quench chamber is deemed necessary to reduce the temperature of the COS Vent Oxidizer outlet to prevent damage (e.g., melting of scrubber packing) in the COS Vent Scrubber.
- The gas inlet flow rate from the 2010 scrubber project was ratioed with the anticipated COS Vent Scrubber gas inlet flow rate. SABIC used performance test data from the COS Vent Oxidizer (gas outlet flow rate from COS Vent Oxidizer is assumed to equal the inlet to a COS Vent Scrubber) to estimate the inlet gas flow rate for a COS Vent Scrubber.
- The Chemical Engineering Plant Cost Index (CEPCI)[24] was used to ratio the 2010 project cost to 2019 dollars.
- The factors provided in the EPA Air Pollution Control Cost Manual Section 5 Chapter 1 – Wet Scrubbers for Acid Gas for SO_2 were used to estimate the annual costs necessary to operate a packed tower scrubber.

A cost of over $12,000 per ton of SO_2 removed is too high to be economically feasible. SABIC did include discussion on the remaining three (3) statutory factors despite the installation of the COS Vent Scrubber being economically infeasible.

5.2 Time Necessary for Implementation (Statutory Factor 2)

The technically feasible SO_2 reduction option of a packed-bed wet scrubber, COS Vent Scrubber, for the CO generation process in the Phosgene process area would require substantial capital cost and detailed engineering design that is not included in this report. In addition, SABIC estimates that in order to secure additional funding (i.e., capital expenditure dollars) and engineering analysis/study for a wet scrubber

[23] EPA Air Pollution Control Cost Manual Section 5 SO_2 and Acid Gas Control, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, Table 1.7: Capital Cost Factors for Wet Packed Tower Absorbers, Public notice version issued July 2020.

[24] From https://www.chemengonline.com/pci-home accessed on February 10, 2020:

Year:	2010	2019
CEPCI:	550.8	607.5

system, would take 2 to 3 years if additional SO_2 control is required for regional haze visibility reasonable progress. If IDEM does not concur with SABIC's analysis that no control device is necessary after the COS Vent Oxidizer, SABIC requests additional time to provide further documentation and information to demonstrate that controls for this process operation are unnecessary.

Prior to implementation of any process design changes, including air pollution control projects, SABIC undergoes an independent and comprehensive engineering analysis. A typical schedule for such an engineering study is over a year.

A key metric within such an engineering study would be the impact the COS Vent Scrubber could have on the existing control device, COS Vent Oxidizer, or the process being controlled, CO generators and carbon adsorbers. The cost estimated for this four-factor analysis in Table 5-3 did not consider such impacts. It is possible that additional auxiliary equipment (e.g., blowers and ducting) could be necessary which would incur additional costs beyond those presented.

SABIC does not intend to investigate any add-on control device technologies to the COS Vent Oxidizer beyond what is discussed in this four-factor analysis.

5.3 Energy & Non-Air Quality Environmental Impacts (Statutory Factor 3)

The cost of energy required to operate the SO_2 control options is presented in the detailed cost analysis presented in Appendix A.

To operate control devices requiring greater power demand could decrease overall plant energy efficiency. At a minimum, the COS Vent Scrubber would require increased electrical usage by MtV which could create an increase in indirect (secondary) emissions from nearby power stations. Also, the Phosgene process area could need a new Motor Control Center for the various motors required to implement the wet scrubber control options.

Adverse environmental impacts are incurred for wet scrubbing in treating and disposing of large volumes of water from wet scrubber blowdown. SABIC's existing onsite wastewater treatment operations need to be consulted and involved in any alterations to MtV's wastewater facilities. The cost of wastewater treatment modifications is not analyzed in this report.

5.4 Remaining Useful Life (Statutory Factor 4)

The remaining useful life (RUL) of the CO generators in the Phosgene process area does not impact the annualized cost of an add-on control technology because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 30 years. Similarly, the remaining useful life of the CO Generators does not impact the annualized cost for the control options that are evaluated.

5.5 SO_2 Emission Control Determination for Reasonable Progress

In consideration of all four factors required, SABIC has not identified any technically and economically feasible SO_2 control options for the COS Vent Oxidizer or COGEN at the MtV facility. Furthermore, there is no indication from VISTAS modeling that SABIC is causing significant impact on Class I areas as detailed in Section 3.3.

If IDEM does not agree with SABIC's conclusion that no additional SO_2 controls are necessary as part of this regional haze second implementation period, MtV requests additional time be given to undergo additional assessments (e.g., engineering studies, in-depth air dispersion modeling).

6. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS

The technically feasible NO_X control option of a SCR is analyzed herein using the four statutory factors in Section 169A(g)(1) of the CAA.

6.1 Cost of Compliance (Statutory Factor 1)

6.1.1 Control Effectiveness

Table 6-1 summarizes the estimated control efficiency for a SCR to control NO_X emissions for COGEN, the only technically feasible add-on NO_X emissions reduction option.

Table 6-1. Control Effectiveness of SO_2 Emissions Control Options

Source	SO_2 Control Option	Estimated Control Efficiency (%)
19-001 COGEN	SCR	85[a]

a. Engineering determination based on internal design documents developed during COGEN installation.

6.1.2 Controlled Emissions

Table 6-2 summarizes the baseline and controlled emission rates and emission reduction potentials for the technically feasible SO_2 reduction options for COGEN.

Table 6-2. Baseline and Controlled Emission Rates of NO_X Emissions Reduction

Source	Baseline Emission Rate [a] (tpy)	NO_X Control Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
COGEN	119	SCR	17.8	101

a. Based on 2018 actual emissions as submitted in SABIC's 2018 annual emissions inventory.

6.1.3 Cost

The EPA Cost Manual for SCR[25] was used along with site-specific data inputs to estimate the cost of installing a SCR to control NO_X emissions from COGEN.

An overall summary of estimated cost is presented in Table 6-3 with a detailed breakdown presented in Appendix B.

[25] EPA Air Pollution Control Cost Manual Section 4 NO_X Controls Chapter 2-Selective Catalytic Reduction, June 2019.

Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction

Source	NO_X Control Option	Total Capital Investment ($)	Annual Cost ($/yr)	Cost Effectiveness ($/ton)
COGEN	SCR	$21,805,180	$2,602,806	$25,691

SCR as a control technology to remove NO_X from COGEN emissions is achievable at an efficiency of 85 percent (%). The low concentration of NO_X in the COGEN exhaust leads to the high cost dollar per ton removal. The cost effectiveness per ton of NO_X removed is over $25,000 per ton, which is exorbitantly high. Installing a SCR to control NO_X emissions is not economically feasible for MtV.

6.2 Time Necessary for Implementation (Statutory Factor 2)

Installation of a SCR to reduce NO_X emissions from COGEN would require substantial capital and operating cost investments. A detailed design engineering project would need to be conducted, which in not included in the costs summarized in Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction

SABIC estimates a total project length to install a SCR of 2 to 3 years including tasks such as, securing additional funding (i.e., capital expenditure dollars), completing a comprehensive engineering analysis and design studies.

SABIC does not intend to investigate any add-on control device technologies to COGEN beyond what is discussed in this four-factor analysis.

If IDEM does not concur with SABIC's analysis that no control device is necessary to reduce NO_X from COGEN, SABIC requests additional time to provide further documentation and information to confirm the unnecessariness of controls for this process operation.

6.3 Energy and Non-Air Environmental Impacts (Statutory Factor 3)

Potential energy and non-air environmental impacts of SCR include:

- Electric demand did not exist prior to installation.
- Creation of a new solid waste stream (spent catalyst).
- Storage of large amounts of liquid ammonia that may be regulated by EPA's risk management program (RMP) as accidental release of ammonia can cause serious injury.

Additionally, SCR operation can result in emissions of unreacted ammonia to the atmosphere (i.e., ammonia slip) during any periods of time when temperatures are too low for effective operation or if too much ammonia is injected. Ammonia emissions will react to directly form ammonium sulfate and ammonium nitrate. The amount of the potential visibility impact attributable to the use of ammonia in a SCR has not been quantified, but it would presumably negate some of the calculated visibility improvement that would otherwise be associated with the NO_X emission reductions.

As described in Section VISTAS Modeled Class I Impacts Outside LADCO RPO3.3, VISTAS CAMx modeling does not indicate any NO_X emissions, including those from COGEN, impact the visibility at Mammoth Cave.

6.4 Remaining Useful Life (Statutory Factor 4)

There are no enforceable limitations on the RUL for COGEN or any other units at MtV. However, the entire Co-generation facility was constructed in 2015 to 2016 and began full operation in fourth quarter 2016. For the purposes of this analysis, a 20-year RUL was used in the cost calculations summarized in Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction and detailed in Appendix B.

6.5 NO_X Emission Control Determination for Reasonable Progress

The only technically feasible NO_X emissions reduction option, SCR, is not economically feasible based on this evaluation. Therefore, no additional NO_X controls are required for SABIC's COGEN unit during the regional haze second planning period. Furthermore, there is no indication from VISTAS modeling that NO_X emissions from SABIC are causing significant impact on Class I areas (Section 3.3).

7. RECOMMENDATIONS

In consideration of all four factors of the Regional Haze Program, SABIC has identified no reasonable NO_X or SO_2 control options for COGEN or COS Vent Oxidizer located at the MtV facility. Furthermore, there is no indication from photochemical modeling conducted by VISTAS that SABIC is causing a visibility impact on areas.

APPENDIX A. SO_2 COST ANALYSIS

Appendix A- SO_2 Control Effectiveness for Wet Packed Tower Gas Absorber (COS Vent Scrubber)

Capital Cost Summary

1	Preliminary Total Capital Investment (Prelim TCI)	PEC + DC + IC	$38,988,800	Table 1.7
2a	Estimated Direct and Indirect Costs (DC + IC)	Prelim. TCI / 2.17	$17,967,189	Equation 1.100
2b	Retrofit Cost	0.30 * (DC + IC)	$5,390,157	Section 1.2.4.3
1	Quench Chamber Cost		$1,960,556	
	Total Capital Investment (TCI) with Retrofit Cost Consideration and Quench Chamber		$46,339,513	
5	TCI as 2019 $		$51,109,757	

Annual Costs

Ref.	*Operation and Maintenance Costs*			*Table Ref.*
2a, 6	Operating Labor	0.5 hr/shift * 3 shifts/day * $/hr	$21,920	Table 1.8
2a, 6	Supervisor Labor	15% of operator labor	$3,288	Table 1.8
2a, 6	Maintenance Labor	0.5 hr/shift * 3 shifts/day * $/hr	$29,044	Table 1.8
2a	Maintenance Materials	100% of maintenance labor	$29,044	Table 1.8
Ref.	*Cost of Solvent/Reagent (Sodium Hydroxide NaOH)*			
3	Total Annual NaOH Usage	tons/yr	975	
7	Unit cost	$/ton	$385.49	
2a	Total	ton/yr * $/ton	$375,960	
Ref.	*Cost of Wastewater Treatment*			
3	Discharge Blowdown	m^3/yr	31,122	
3	Unit cost	$/$m^3$	$2.00	
2a	Total	m^3/yr * $/$m^3$	$62,244	
Ref.	*Auxiliary Power Costs*			
3	Power Required	kW	24	
3	Hours Operated	t_{op}	6,340	
8	Unit cost	$/kW-hr	$0.072	
2a	Total	kW * $/kWh * t_{op}	$11,079	
	Direct Annual Cost (DAC)		**$532,580**	

Ref.	*Indirect Annual Cost*			*Table / Equation Ref.*
2a	Overhead	0.60 * Total Labor/Material $	$49,978	Table 1.8
2a	Administration Charges (AC)	0.02 * TCI	$1,022,195	Table 1.8
2a	Property Tax	0.01 * TCI	$511,098	Table 1.8
2a	Insurance	0.01 * TCI	$511,098	Table 1.8
2a, 4	Economic Life of Control Device	years	30	Table 1.8
2a, 4	Annual Interest Rate	%	7%	Table 1.8
2b	Capital Recovery Factor	CRF	0.0806	Equation 1.30
2a	Capital Recovery (CR)	CRF * TCI	$4,118,751	Table 1.8
	Indirect Annual Cost (IDAC)		**$6,213,119**	Table 1.8

Appendix A- SO_2 Control Effectiveness for Wet Packed Tower Gas Absorber (COS Vent Scrubber)

Cost Effectiveness Summary

Ref.	*Parameter*			*Table / Equation Ref.*
3	Baseline SO_2 Emissions	tons/yr	570	
3	Control Efficiency		95.0%	
3	Total SO_2 Removed	Baseline SO_2 * (1-Control Efficiency)	542	
2b	Total Annual Cost (2019 $)	TAC = IDAC + DAC	$6,745,699	Equation 1.31
2b	**Cost Effectiveness**	**$/ton removed**	**$12,449**	Equation 1.32

References:

1 TCI is derived using the cost for a similar wet packed tower gas absorber (i.e., scrubber) completed at MtV in 2010. MtV has assumed the 2010 project include the scrubber body, packing, auxiliary equipment, instrumentation, sales taxes, and freight as well as direct installation costs (foundations, erection, piping, etc.) and indirect installation costs (engineering, start-up, etc.).
Additionally, MtV provided an estimate for the TCI for a quench tower, which would be required prior to the scrubber to ensure proper operating conditions.
The gas inlet flow rate from the 2010 project was ratioed with the anticipated COS Vent Oxidizer Scrubber gas inlet flow rate. SABIC used stack test data from the COS Vent Oxidizer (gas outlet flow rate from COS Vent Oxidizer is assumed to equal the inlet to a COS Vent Oxidizer Scrubber) to estimate the inlet gas flow rate for a COS Vent Oxidizer Scrubber.

2 U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual* , Draft July 2020, Section 5, Chapter 1

2a Wet Packed Tower Gas Absorbers sub-section 1.3 of Section 5, Chapter 1
Table 1.7: Capital Cost Factors for Wet Packed Tower Absorbers
Table 1.8: Suggested Annual Cost Factors for Wet Packed Tower Absorbers
Section 1.3.3: Estimating Total Capital Investment: Equation 1.100

2b Wet Flue Gas Desulfurization sub-section of 1.2 of Section 5, Chapter 1
Section 1.2.4.3: Estimating Total Capital Investment
Section 1.2.4.4: Estimating Total Annual Cost for a Wet FGD System: Equations 1.30, 1.31, and 1.32

3 Data specific to SABIC's facility in Mt. Vernon, Indiana, such as estimations from engineering department and historic annual emission summary data.

4 Based on SABIC-specific estimated equipment lifetime and estimated bank interest rate.

5 Used Chemical Engineering Plant Cost Index, https://www.chemengonline.com/pci-home, accessed on February 10, 2020.

6 Hourly labor rates: Operating Labor $40/hr and Maintenance Labor $53/hr. These rates are representative of SABIC's current pay rates.

7 Reagent, sodium hydroxide NaOH, cost is an estimate from Echemi.com.

8 Electrical cost is an estimate from https://www.electricitylocal.com/states/indiana/mount-vernon/ .

APPENDIX B. NO_X COST ANALYSIS

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN
SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,812	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	15,485,970,732	scf/Year
Actual Annual fuel consumption (Mactual) =		12,643,340,488	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.816	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7,152	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.33	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	101.3	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.06	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	818,037	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	110	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	Not applicable; factor applies only to coal-fired boilers.	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.06	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.9	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,437.61	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	852	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	980	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	31.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	38	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,800	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ =	0.0837
	Where n = Equipment Life and i= Interest Rate	

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ =	931.72	kW
	where A = (0.1 x QB) for industrial boilers.		

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN
Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$21,805,180	in 2019 dollars

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$773,776	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,829,030	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,602,806	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$109,026	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$10,628	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$476,453	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$177,669	in 2019 dollars
Direct Annual Cost =		$773,776	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,936	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,825,094	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,829,030	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,602,806	per year in 2019 dollars
NOx Removed =	101	tons/year
Cost Effectiveness =	$25,691	per ton of NOx removed in 2019 dollars

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Appendix H

Alcoa Four-Factor Analysis Submittal

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September 25, 2020

Thomas Shaw, PhD
Senior Environmental Scientist
Alcoa Warrick Operations
4400 W. State Route 66
Newburgh, IN 47629

Re: Final Draft Report
Four-Factor Analysis requested by IDEM
Alcoa Warrick Operations

Dear Dr. Shaw:

In a letter dated June 24, 2020, Indiana Department of Environmental Management (IDEM) requested Alcoa complete a Four-Factor Analysis for sulfur dioxide (SO_2) emissions to assist IDEM in revising its State Implementation Plan (SIP) for the Regional Haze Rule. Information regarding SO_2 emissions control on Potlines 2 through 6 and the Anode Baking Ring Furnace was requested. IDEM has advised the four statutory factors to be evaluated for the potlines and ring furnace include the following:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance
4. The remaining life of any existing source subject to such requirements

Alcoa Warrick Operations (Alcoa) retained Burns & McDonnell to assist in responding to the request for information from IDEM. The letter report summarizes the results of the Four-Factor Analysis.

Factor 1: Cost of Compliance

In July 2007, Babcock Power Environmental (Babcock Power) provided Alcoa a budgetary proposal for a Flue Gas Desulfurization (FGD) system for the control of SO_2 emissions from Potlines 2 through 6. To estimate the capital cost of installing an FGD system to control SO_2 emissions from the potlines, Burns & McDonnell updated the budgetary cost in this proposal by escalating to reflect inflation from 2007 to 2020. An annual inflation rate of 2.5% was assumed over this time period based on information from the Chemical Engineering Plant Cost Index (CEPCI).

Burns & McDonnell developed a rough order-of-magnitude cost estimate for installing SO_2 controls on the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers based on the escalated Babcock Power budgetary proposal. The budgetary cost estimate for the FGD for the potlines was scaled to represent an FGD system for the Anode Baking Ring Furnace based on the flue gas parameters provided by Alcoa.

Babcock Power's budgetary proposal included equipment costs only. Burns & McDonnell added rough order-of-magnitude construction costs based on an industry-standard multiplier of direct equipment costs.

Operating and Maintenance (O&M) costs for an FGD system include reagent (lime) usage, waste disposal, power usage, water usage, operating labor, and maintenance labor and materials. Based on

Burns & McDonnell's past project experience, FGD system O&M costs can range from $3,800,000/year to $14,500,000/year, based on the flue gas and SO_2 loading to the FGD system.

Burns & McDonnell developed rough order-of-magnitude O&M cost estimates for FGD systems on the potlines and Anode Baking Ring Furnace based on information provided in Babcock Power's budgetary proposal for reagent, water and power usage and waste generated.

The capital and annual O&M cost estimates for a new FGD system on the potlines and the Anode Baking Ring Furnace are summarized in Table 1. Note all costs are in 2020 dollars and represent rough order-of-magnitude costs.

Table 1. FGD System Cost Estimate Summary

Scrubber	Capital	Annual O&M
Potline 2 through 6	$512,800,000	$5,300,000
Anode Baking Ring Furnace	$63,900,000	$700,000
Total	$576,700,000	$6,000,000

Factor 2: Time Needed to Achieve Compliance

A new FGD system typically requires 30 to 36 months for front end planning, design, procurement, installation and commissioning. Alcoa's capital planning process would add 12 to 18 months to this timeframe. Additional time may be needed for technology selection and environmental permitting. Note that space constraints and access limitations at the Alcoa site could result in an extended design and installation period.

Factor 3: Energy and Environmental Impacts of Compliance

FGD technologies are energy intensive. Depending on the FGD technology selected, large pumps may be needed to recycle the reagent slurry through the FGD module. The retrofit of an FGD system on an existing emission source also may require an additional fan or fans to overcome the pressure drop of the FGD module(s). These pumps and/or fans can significantly increase the energy consumption of the Alcoa facility. Auxiliary electric power is also required to operate reagent preparation systems, reagent injection equipment, and waste byproduct handling systems.

FGD systems also create solid byproducts and may have a wastewater stream, depending on the FGD technology selected. Both the disposal of the solid byproduct and the discharge of the wastewater stream may have additional impact on the environment. The synthetic gypsum market has excess inventory and undesirable pricing; therefore, the solid FGD byproduct will need to be disposed of in a landfill.

The delivery of FGD system reagent and disposal of the associated solid byproduct will increase vehicle traffic and the associated particulate matter emissions on site. The storage and handling of the reagent and byproduct also will increase particulate matter emissions from the facility. Some FGD technologies are based on chemical reactions that create carbon dioxide (CO_2), a greenhouse gas and regulated pollutant.

Factor 4: Remaining Life of the Existing Sources

The Alcoa potlines have been in operation since 1960, and Alcoa continues to maintain them for continuous, reliable operation. The Anode Baking Ring Furnace was constructed in 1981 and rebuilt in 2008. The remaining life of each of the production units is based on economic factors and product demand, and therefore cannot be predicted at this time.

Please feel free to contact Karen Burchardt at 816-509-3400 should you have any questions or require additional information regarding this report.

Respectfully submitted,

Karen E. Burchardt

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