Appendix T

Warrick Newco, LLC formerly Alcoa Warrick Operations, LLC - Alcoa Responses to the FLMs Comments

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Boling, Jean

From:	SHAW, THOMAS <thomas.shaw@alcoa.com>
Sent:	Friday, August 27, 2021 10:32 AM
To:	Boling, Jean
Subject:	Response to Federal Land Managers Comments with the Alcoa Warrick Operations Facility
Attachments:	2020.09.25_Alcoa Four Factor Analysis - Final Report Burns & McDonnell.pdf; Burns & McDonnell Response to FLM Comments on Alcoa Warrick Four-factor Analysis 08-13-2021.pdf; Alcoa Response to FLM comments.pdf

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Good morning Jean,
Alcoa appreciates the opportunity to respond to the Federal Land Managers comments on the four-factor analysis conducted for the Alcoa Warrick Operations facility (Warrick Newco LLC). The responses are included in the attachments to this email. Please contact me if you have additional questions or need additional information.
Best regards,
Tom

Thomas Shaw, Ph.D.
Manager Environmental
Alcoa Warrick Operations
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BURNS & McDONNELL

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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BURNS & McDONNELL

August 13, 2021

Thomas Shaw, PhD.
Environmental Manager
Alcoa Warrick Operations
thomas.shaw@alcoa.com

Re: Response to Federal Land Manager Comments on Alcoa Warrick Four-Factor Analysis

Dear Tom,

As tasked by Alcoa Warrick Operations, Burns & McDonnell is pleased to provide the responses to two of Federal Land Manager Comments on Alcoa Warrick Four-Factor Analysis prepared by Burns & McDonnell, dated September 25, 2020.

1. *The inflation adjustment used in the Alcoa analysis is too high. The EPA CCM recommends use of the CEPCI which increased by 13% since the original 2007 cost estimates. Instead, Burns & McDonnell assumed a 2.5% annual interest rate which inflated costs by 38%.*

   The capital and annual O&M cost estimates for a new FGD system on the potlines and the Anode Baking Ring Furnace that were summarized by IDEM in Table 1 has been updated per the Chemical Engineering Plant Cost Index (CEPCI) cost increase over the escalation period. The updated Table 1 rough order-of-magnitude costs for both Capital and Annual O&M costs are as follows:

   Table 1. FGD System Cost Estimate Summary

Scrubber	Capital	Annual O&M
Potline 2 through 6	$422,100,000	$4,500,000
Anode Baking Ring Furnace	$52,600,000	$600,000
Total	**$474,700,000**	**$5,100,000**

2. *The Alcoa 4FA assumed 70% control efficiency for the FGD. This seems low. What is the basis for this assumption? Note, a 95% control efficiency was assumed for the FGD in the BART analysis for the Warrick facility in the previous round of RH planning.*

   The Burns & McDonnell analysis did not use or present an FGD control efficiency as a specific efficiency was not required for FGD capital or Annual O&M cost estimating. However, EPA Guidance on retrofit SO_2 Emission Control Performance Assumptions does support an over 90% control efficiency for FGD technologies, and the "SO_2 Controls Table" from IDEM's Appendix J for the Alcoa aluminum plant has been updated to reflect a 95% control efficiency along with the revised costs Table 1 above:

SO_2 Controls

Control Cost Summary	Potlines 2-6	Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers
	Flue Gas Desulfurization	Flue Gas Desulfurization
Total Capital Cost	$422,100,000	$52,600,000
Total Annual Cost (Capital & Operating)	$4,500,000	$600,000
Current Emissions (ton/yr)	3,000	139
Control Efficiency	95%	95%
New Emission Rate (tons/yr)	150	7.0
Emission Reductions (tons/yr)	2,850	132
Cost-Effectiveness ($/ton)	$1,579*	$4,544*

*Total Annual Cost as presented does not include indirect costs such as Capital Recovery. Including Capital Recovery over 15 years at 6% interest, the corresponding Cost-Effectiveness would change to $16,800 / ton for Potlines 2-6, and $45,500 / ton for the Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers.

Note that the "SO_2 Controls Table" presents the "Annual O&M" costs prepared by Burns & McDonnell as "Total Annual Costs". Capital Recovery costs were not included in the Table 1 "FGD System Cost Estimate Summary" under the "Annual O&M" amounts, as the "Annual O&M" amounts were not intended to represent "Total Annual Cost".

Sincerely,

Ben Zhang, PhD, PE
Industrial Services Manager
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Cc. Bill Celenza, PE, Sr. Process Engineer

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(March 2021)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

__Step 1:__ Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

__Step 2:__ Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

__Step 3:__ Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

__Step 4:__ Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2016 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

__Step 5:__ Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? MW

What is the higher heating value (HHV) of the fuel? Btu/lb

What is the estimated actual annual MWh output? MWh

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Coal blend

Enter the sulfur content (%S) = 1.13 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 1.125% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 7.535 percent by weight

*The ash content of 7.535% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0.5	1.84	9.23	12,000	2.4
Sub-Bituminous	0.5	0.41	5.84	9,000	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	320 days
Number of days the boiler operates (t_{plant})	320 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	3 ~~lb/MMBtu~~ lb NOX/ton clinker
Oulet NO_x Emissions (NOx_{out}) from SNCR	1.8 ~~lb/MMBtu~~ lb NOX/ton clinke
Estimated Normalized Stoichiometric Ratio (NSR)	1.05

Plant Elevation: 843 Feet above sea level

Concentration of reagent as stored (C_{stored})	19 Percent
Density of reagent as stored (ρ_{stored})	56 lb/ft^3
Concentration of reagent injected (C_{inj})	19 percent
Number of days reagent is stored ($t_{storage}$)	14 days
Estimated equipment life	20 Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	541.7	541.7	2016 CEPCI
Annual Interest Rate (i)	5.75 Percent		
Fuel ($Cost_{fuel}$)	$/MMBtu		
Reagent ($Cost_{reag}$)	0.57 $/gallon for a 19 percent solution of ammonia		
Water ($Cost_{water}$)	$/gallon		
Electricity ($Cost_{elect}$)	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	$/ton		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .

Reagent Cost	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	Used $0.57/gallon for 19% ammonia based on average BUUSA 2021 budgeted cost per ton/ammonia at 5 plants currently using SNCR. Converted to cost per gallon from cost per ton.
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	2.15	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	1.13	Weighted average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	7.54	Weighted average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	10,334	Weighted average HHV based on 2014 HHV coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, "Power Plant Operations Report." Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR 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) =	Bmw x NPHR =	160	~~MMBtu/hour~~	tons clinker/hr
Maximum Annual MWh Output =	Bmw x 8760 =	0	~~MWh~~	
Estimated Actual Annual MWh Output (Boutput) =		0	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	0.00		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/tplant) =	0.900	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7884	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	40	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	192.00	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	756.86	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.03		
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	#DIV/0!	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 843 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.3	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.

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	187	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	982	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	131.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	44,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0854

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	#DIV/0!	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.72	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	#DIV/0!	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =		$0	in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	#DIV/0!		in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =		$0	in 2016 dollars
Total Capital Investment (TCI) =	#DIV/0!		in 2016 dollars

#DIV/0!

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$0	in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	#DIV/0!	in 2016 dollars

#DIV/0!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0	in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	#DIV/0!	in 2016 dollars
Indirect Annual Costs (IDAC) =	#DIV/0!	in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	#DIV/0!	in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	#DIV/0!	in 2016 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$589,391	in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	#DIV/0!	in 2016 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2016 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$0	in 2016 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	#DIV/0!	in 2016 dollars
Direct Annual Cost =		#DIV/0!	in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	#DIV/0!	in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	#DIV/0!	in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	#DIV/0!	in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	#DIV/0!	per year in 2016 dollars
NOx Removed =	757	tons/year
Cost Effectiveness =	#DIV/0!	per ton of NOx removed in 2016 dollars

Warrick Newco LLC

Alcoa

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Warrick Newco LLC appreciates the opportunity to respond the Federal Land Managers (FLM) comments.

FLM Comments on Alcoa Warrick Operations (Aluminum) Four-Factor Analysis

1.Summary of NPS Recommendations and Requests for Alcoa Warrick Aluminum Plant

- FLM Comment: Notwithstanding the analysis issues noted below, the costs for adding a FGD system to control potline emissions appear to be very reasonable and IDEM agreed with this conclusion in the SIP yet determined that no controls were necessary. We recommend that controls should be considered based on the four-factors evaluated.

  <u>Alcoa Response:</u> The cost install controls was not correctly identified in the four-factor analysis. The original analysis only included the Annual Operating cost of $4,500,000 while omitting the Capital Cost to calculate the Cost-Effectiveness. The correct Cost-Effectiveness calculation is as follow:
  - Potlines 2 through 6 capital cost after adjusting the Chemical Engineering Plant Cost Index, as requested by the Federal Land Manager is $422,100,000 to remove 90-95% of the SO2. Utilizing the estimated 3,000 tons of SO2 (Total potline emissions for 2020 were 2106 tons) and the conservative removal estimate of 95%, the emission reduction would be 2850 tons. The Cost-Effectiveness $/ton, correcting for the cost of Capital recovery would be $16,800/ton (See attached updated August 13, 2021 Burns & McDonnell report). This Cost-Effectiveness in not reasonable.

- FLM Comment: The Alcoa four-factor analysis (4FA) is almost completely lacking in essential economic and emissions information. Please provide the necessary cost information in the SIP, including the Burns & McDonnell update of Babcock Power budgetary proposal, which was the basis of the Alcoa 4FA.

  <u>Alcoa Response:</u> The original and the updated Burns & McDonnell reports are included with this response.

- FLM Comment: The inflation adjustment used in the Alcoa analysis is too high. The EPA CCM recommends use of the CEPCI which increased by 13% since the original 2007 cost estimates. Instead, Burns & McDonnell assumed a 2.5% annual interest rate which inflated costs by 38%

  <u>Alcoa Response:</u> Alcoa directed Burns & McDonnell to provide an updated budgetary cost based upon the original budgetary cost developed by Babcock Power. The updated report is included with this response.

- FLM Comment: The Alcoa 4FA assumed 70% control efficiency for the FGD. This seems low. What is the basis for this assumption? Note, a 95% control efficiency was assumed for the FGD in the BART analysis for the Warrick facility in the previous round of RH planning.

  Alcoa Response:
  The 70% removal efficiency was not determined in either the original proposed budgetary estimate by Babcock Power or the update by Burns & McDonnell. Alcoa agrees that a new SO2 scrubber would operate in the range of 90-95% removal efficiency and the correct Cost-Effectiveness analysis reflects the removal rate.