Appendix G-1

Reasonable Progress Assessment for Blue Ridge Paper Products, LLC – Canton, NC

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Correspondence Record

Date	From	To	Description
June 18, 2020	NCDAQ	Blue Ridge Paper Products	Request to review 2028 SO_2 emissions and PSAT modeling, evaluate sources for four-factor analysis
July 1, 2020	Blue Ridge Paper Products	NCDAQ	Revised emissions estimates
July 15, 2020	NCDAQ	Blue Ridge Paper Products	Request for four-factor analysis on three units using updated emissions and revised PSAT modeling results
September 11, 2020	Blue Ridge Paper Products	NCDAQ	Four-factor analysis of requested units for SO_2 control
March 2, 2021	Blue Ridge Paper Products	NCDAQ	Email Response to Questions on Riley Bark Boiler
March 15, 2021	Blue Ridge Paper Products	NCDAQ	Email response to EPA Comments on BRPP Four-Factor Analysis
May 12, 2021	NCDAQ	Blue Ridge Paper Products	Request for revised four-factor analysis based on pre-draft comments from EPA and FLMs
June 1, 2021	Blue Ridge Paper Products	NCDAQ	Revised four-factor analysis of requested units for SO_2 control
January 17, 2022	Blue Ridge Paper Products	NCDAQ	BRPP Responses to Additional Comments on the Regional Haze Four Factor Analysis, as requested by NCDAQ

ROY COOPER
Governor

MICHAEL S. REGAN
Secretary

MICHAEL ABRACZINSKAS
Director

NORTH CAROLINA
Environmental Quality

June 18, 2020

Wallace McDonald
Mill Manager
Evergreen Packaging
175 Main Street
Canton, NC 28716

Subject: Regional Haze Reasonable Progress Assessment for Second Planning Period

Dear Mr. McDonald:

The North Carolina Division of Air Quality (DAQ) is preparing the North Carolina's Regional Haze State Implementation Plan (SIP) for the second planning period (2018 – 2028). The DAQ has worked with the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), of which North Carolina is a member, to identify emission source sectors and facilities that significantly impact visibility impairment in Class I Federal areas within and outside of North Carolina consistent with the regional haze statutory and regulatory requirements and United States Environmental Protection Agency (EPA) guidance. Based on analyses conducted by North Carolina and VISTAS, sulfur dioxide (SO_2) emissions from Blue Ridge Paper Products (BRPP) in Canton, North Carolina have been shown to contribute ≥1.00% to visibility impairment at the Shining Rock Wilderness Area.

I am requesting that BRPP review the 2028 SO_2 emissions upon which the DAQ's contribution assessment is based, and either confirm or revise the 2028 emissions for the DAQ to review and determine if it will be necessary for BRPP to complete a four-factor analysis of its major SO_2 sources. We request that you complete this review and report your conclusions with documentation of any revised emissions to the DAQ by July 2, 2020. The DAQ will review your submittal and notify you by July 15, 2020, if it is necessary for BRPP to complete a four-factor analysis of its major SO_2 sources.

Part I of this letter provides background on the regional haze program requirements. Part II explains the process that VISTAS followed to identify facilities such as BRPP for additional analyses. Part II also includes a summary of SO_2 emissions for your facility for your review. Part III explains how to proceed with a four-factor analysis of the major SO_2 sources at BRPP, if needed.

Please submit all items requested in this letter to the DAQ Planning Section Chief, Randy Strait (randy.strait@ncdenr.gov), within the dates specified. Should you have any questions regarding this request, please feel free to contact me at (919) 707-8447 or Randy Strait at (919) 707-8721.

Sincerely,

Michael A. Abraczinskas, Director
Division of Air Quality, NCDEQ

MAA/rps

cc: Brendan Davey, NCDAQ
Tammy Manning, NCDAQ
Randy Strait, NCDAQ
Daniel Meyer, Evergreen Packaging
Central Files

Part I. Overview of the Regional Haze Program

In Section 169A of the 1977 Amendments to the Clean Air Act (CAA), Congress set forth a program for protecting visibility in Federal Class I areas which calls for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." In the 1990 Amendments to the CAA, Congress added section 169B and called on the United States Environmental Protection Agency (EPA) to issue regional haze rules. The Regional Haze Rule (RHR) that EPA promulgated on July 1, 1999 (64 FR 35713) revised the existing visibility rule to integrate provisions addressing regional haze impairment and establish a comprehensive visibility protection program for each Class I Federal area that provides for reasonable progress towards achieving natural visibility conditions by 2064.

The regional haze rules are codified at 40 Code of Federal Regulations (CFR) 51.300. Paragraph 40 CFR 51.308(f) (Regional Haze Program Requirements) requires each state to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State." The State of North Carolina submitted its regional haze plan for the first planning period (2008 – 2018) to EPA on December 17, 2007.[1] The North Carolina Division of Air Quality (DAQ) is now preparing the States regional haze plan for the second planning period (2018 – 2028).

The EPA finalized revisions to the RHR in January 2017 (82 FR 3078) to strengthen, streamline, and clarify certain aspects of the agency's regional haze program. Paragraph 40 CFR 51.308(f) of the RHR requires that states must submit a regional haze plan for the second planning period by July 31, 2021. As part of the plan revision, the State of North Carolina must establish a reasonable progress goal (expressed in deciviews) that provides for reasonable progress towards achieving natural visibility conditions by 2064 in the Shining Rock Wilderness Area. The goal "must 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 clearest days over the same period."

The State of North Carolina must also submit a long-term strategy that addresses regional haze visibility impairment for Shining Rock Wilderness Area. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goal established for the Shining Rock Wilderness Area.

In establishing reasonable progress goals, the State must consider the four factors specified in section 169A of the CAA and in paragraph 51.308(f)(2)(i) of the RHR: (1) the cost of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources.

On August 20, 2019, EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period."[2] Among other things, this document provides guidance to states on the selection of sources for analysis, characterization of factors for emission control measures, and decisions on what control measures are necessary to make reasonable progress.

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[1] North Carolina's Round 1 SIP submittals and EPA approval of those submittals is provided on the DAQ's website at: https://deq.nc.gov/about/divisions/air-quality/air-quality-planning/state-implementation-plans/regional-haze-state-sip.

[2] The guidance document is available on EPA's website at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Part II. Reasonable Progress Assessment

The DAQ has recently completed the reasonable progress assessment for its second Regional Haze SIP. The following explains the DAQ's process for conducting its reasonable progress assessment for the current planning period from 2018 through 2028.

Step l: Determine pollutants of concern.

Using 2013 through 2017 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data for Class I Federal areas in the VISTAS states, VISTAS evaluated the species contribution on the 20% most impaired visibility days and concluded that sulfate accounted for greater than 70% of the visibility impairing pollution associated with anthropogenic emission sources. The VISTAS states concluded that controlling sulfur dioxide (SO_2) emissions was the appropriate step in addressing the reasonable progress assessment for 2028.

Step 2: Determine which source sectors should be evaluated for reasonable progress.

For the 10 VISTAS states, point source SO_2 emissions in 2028 are projected to represent over 80% of the total SO_2 emissions inventory for all sectors. Therefore, the VISTAS states concluded that the focus should be on electricity generating unit (EGU) and non-EGU point sources of SO_2 emissions.

Step 3: Determine which facilities would be evaluated based on impact.

VISTAS initially utilized an Area of Influence (AoI) analysis to help identify the areas and sources most likely contributing to poor visibility in Class I Federal areas. This AoI analysis involved running a backward trajectory model to determine the origin of the air parcels affecting visibility in each Class I Federal area. This information was then spatially combined with emissions data to determine the pollutants, sectors, and individual sources that were most likely contributing to the visibility impairment at each Class I Federal area. North Carolina first used this information to determine that the pollutant and sector with the largest impact on visibility impairment was SO_2 from point sources.

North Carolina then used the results of the AoI analysis for each Class I Federal area to identify sources to select for Particulate Matter Source Apportionment Technology (PSAT) modeling. Point source facilities with an AoI contribution of ≥3% for sulfate and nitrate combined were selected for PSAT modeling (BRPP's contribution to the Shining Rock Wilderness Area was 41.29%). PSAT modeling uses "reactive tracers" to apportion particulate matter among different sources, source categories, and regions. PSAT was implemented with the Comprehensive Air Quality Model with extensions (CAMx) photochemical-grid model to determine visibility impairment due to individual facilities. Use of PSAT modeling is a superior approach to the AoI analyses for determining individual facility contributions to visibility impairment in Class I Federal areas. North Carolina identified facilities with an impact on one or more Class I Federal areas with ≥1.00% of the total visibility impairment associated with SO_2 on the 20% most impaired days for each Class I Federal area. These sources are being considered for additional reasonable progress analyses.

Based on analyses conducted by North Carolina and VISTAS, SO_2 emissions from BRPP in Canton, North Carolina have been shown to contribute 1.08% to visibility impairment at the Shining Rock Wilderness Area.

Step 4: Evaluate 2028 emissions.

For the 2028 modeling analysis, the DAQ modeled 2019 actual emissions based on the data that BRPP supplied the DAQ for the draft source-specific State Implementation Plan (SIP) for the 2010 1-hour SO_2 National Ambient Air Quality Standard (NAAQS). This information is presented in Table 1 along with historical data for 2017 and 2018 and permitted maximum allowable emissions. This table also shows current SO_2 controls for each of the SO_2 emission sources. Please review the information in Table 1 and notify the DAQ if it is reasonable to assume that the 2019 actual emissions are representative of 2028 emissions. If you provide revised 2028 estimates, please explain the methodology and assumptions for the revised estimates. Please respond to this request by July 2, 2020.

If you provide revised emissions for 2028, the DAQ will use the PSAT modeling results for your facility to determine if the revised emissions will significantly change the contribution to visibility impairment at the Shining Rock Wilderness Area. Otherwise, the DAQ is requesting that you complete a four-factor analysis as outlined in Part III of this letter.

Part III. Evaluate the Four Factors

To meet the requirements of Section 51.308(d)(1)(i)(A) of the RHR, the DAQ must consider each of the four statutory factors for emission sources at your facility that are estimated to significantly contribute to visibility impairment in a Class I Federal area. The four factors include: 1) cost of compliance, 2) time necessary for compliance, 3) the energy and non-air quality environmental impacts of compliance, and 4) the remaining useful life of the emissions unit. If after completing Part II it is determined that a four factor analysis is necessary, the DAQ requests that you conduct a four-factor analysis on the Riley Coal Boiler (ID G11039), No. 4 Power Boiler (ID G11040), and the Riley Bark Boiler (ID G11042) at BRPP's Canton facility. You should submit the requested four-factor analyses by no later than August 31, 2020.

EPA's August 20, 2019, regional haze guidance explains how the four statutory factors can be characterized. To identify control measures with the highest level of control effectiveness that are both technically feasible and cost effective using the minimal amount of effort, the DAQ requests that the analyses be conducted using a "top-down" approach for each emission unit as follows:

Step 1: Identify all control technologies;

Step 2: Eliminate technically infeasible options;

Step 3: Rank remaining control technologies by control effectiveness;

Step 4: Application of the four statutory factors (cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, remaining useful life of existing source) to control technologies identified in Step 3 and document the results; and

Step 5: Select control technology and control effectiveness

Implementation of the methodology specified in EPA's August 20, 2019, guidance using a top-down approach is provided in the following summary.

Table 1. Trends in Actual Annual SO_2 Emissions (2017 – 2019) and Comparison of 2019 Actual Annual SO_2 Emissions to Permitted Maximum Allowable Emissions for BRPP Canton Mill

		Annual SO_2 Emissions (Tons)					
Permit ID	**Source Description**	**2017**	**2018**	**2019**	**Permitted Max. Allowable Emissions**	**2019 Annual Emissions as a Percent of Max. Allowable***	**SO_2 Controls**
G08020	No. 10 Recovery Furnace – Black Liquor Solids (BLS) - normal operation	575.23	157.64	5.47	122.64	4	Furnace sodium salt fume provides SO_2 control.
G08020	No. 10 and No. 11 Recovery Furnace - Ultra-Low Sulfur Diesel (ULSD) - startup and shutdown	0.00	0.01	0.08	4.76	2	ULSD now used for startup and shutdown.
G08021	No. 11 Recovery Furnace - BLS - normal operation	461.34	133.19	27.57	122.64	22	Furnace sodium salt fume provides SO_2 control.
G08022	Black Liquor Oxidation - Regenerative Thermal Oxidizer (RTO)	1.07	1.08	0.55	10.95	5	Wet scrubber.
G08023	No. 10 Smelt Dissolving Tank	1.21	1.18	1.16	1.84	63	Wet scrubber.
G08024	No. 11 Smelt Dissolving Tank	1.25	1.19	1.17	1.84	64	Wet scrubber.
G09028	No. 4 Lime Kiln	1.31	1.11	1.41	27.51	5	Calcium in the kiln provides SO_2 control along with the wet scrubber.
G09029	No. 5 Lime Kiln	0.38	0.36	0.50	45.84	1	Calcium in the kiln provides SO_2 control along with the wet scrubber.
G11039	Riley Coal Boiler	1,388.41	833.39	115.08	268.58	43	Commenced initial operation of the new wet scrubbers on June 29, 2018. Adjusted reported 2018 emissions to account for scrubber SO_2 control. The scrubber was operational when the boiler commenced operation following the shutdown required to install it. There was no delay between completion of construction and operation.
G11040	No. 4 Power Boiler	1,561.36	1,168.63	195.21	360.12	54	Commenced initial operation of the new wet scrubbers on August 1, 2018. Adjusted reported 2018 emissions to account for scrubber SO_2 control. The scrubber was operational when the boiler commenced operation following the shutdown required to install it. There was no delay between completion of construction and operation.

		Annual SO_2 Emissions (Tons)					
Permit ID	**Source Description**	**2017**	**2018**	**2019**	**Permitted Max. Allowable Emissions**	**2019 Annual Emissions as a Percent of Max. Allowable***	**SO_2 Controls**
G11042	Riley Bark Boiler	687.09	602.20	55.07	297.84	18	Commenced monitoring of wet scrubber pH for SO_2 control on September 10, 2018. Adjusted reported 2018 emissions to account for additional scrubber SO_2 control.
G11050	No. 1 Natural Gas Package Boilers	0.01	0.37	0.40	0.58	69	Startup on May 23, 2017. Permitted to burn only natural gas.
G11051	No. 2 Natural Gas Package Boilers	0.01	0.43	0.41	0.58	71	Startup on May 23, 2017. Permitted to burn only natural gas.
G12077	Calendar natural gas and/or propane hot oil heaters	0.01	0.01	0.01	0.05	20	Permitted to burn only natural gas or propane.
16-CU-001	One 1850 horsepower (hp), diesel-fired emergency generator	5.6E-03	5.6E-03	5.6E-03	5.6E-03	See note	Permitted to burn only ULSD. Emissions conservatively estimated based on 500 hours per year of operation on 15 parts per million (ppm) sulfur diesel. Actual operating hours are less than 500.
I-G23066.f-ire, I-G23066.f-rec, I-G23066.f-gen	200 hp Fire Control Generator #1; 200 hp Fire Control Generator #2; 64 hp Lime Kiln Emergency Generator; 227 hp Lime Kiln Emergency Generator; and 100 kilowatt (kW) Recovery Furnace Emergency Generator.	2.5E-03	2.5E-03	2.5E-03	2.5E-03	See note	Permitted to burn only ULSD. Emissions conservatively estimated based on 500 hours per year of operation on 15 ppm sulfur diesel. Actual operating hours are less than 500.
G11037	Big Bill coal-fired utility boiler (tons of bituminous coal/year)	538.11	0.00	0.00	0	0	Permanently shut down July 14, 2017. Removed from Permit No. 08961T28 in April 2020.
G11038	Peter G-One Coal Fired utility boiler (tons of bituminous coal per year)	657.51	0.00	0.00	0	0	Permanently shut down Nov. 30, 2017. Removed from Permit No. 08961T28 in April 2020.
	Totals	**5,875**	**2,901**	**405**	**1,266**		
	Reduction (2018-2017) = 51%		2,973.51				
	Reduction (2019-2018) = 86%			2,496.70			
	Reduction (2019-2017) = 93%			5,470.21			

* Represents maximum allowable emissions based on the maximum allowable permitted emission limitation x 8,760 hours per year divided by 2,000 lbs/ton (except for emergency engines, which are based on 500 hours per year).

Summary of 4-Factor Analysis Methodology Specified in EPA's August 20, 2019, Guidance Using a Top-Down Approach

Determining which emission control measures to consider – You should first identify all technically feasible sulfur dioxide control measures for each source selected for four-factor analysis. You should then rank them in order of highest to lowest control effectiveness. The projected 2028 actual sulfur dioxide emissions from the source should be used as the baseline emission level for estimating control effectiveness of each control measure.

Characterizing the cost of compliance (statutory factor 1) – You should estimate the cost of compliance starting with the control measure with the highest level of control effectiveness. The cost of compliance should be in terms of cost/ton of sulfur dioxide reduced. The cost used as the numerator in the cost/ton metric should be the annualized cost of implementing the control measure and should be determined using methods consistent with United States Environmental Protection Agency's (EPA) Air Pollution Cost Control Manual.[3] Should you use a method that deviates from the Cost Control Manual, you should include that methodology, including all calculations and assumptions, and you should justify why the method used is more appropriate than methods specified in the Cost Control Manual. The emission reduction used as the denominator for the cost/ton metric should be the annual tons of reduction from implementation of the control measure. If your analysis indicates that the control measure should be included as part of North Carolina's long-term strategy for the second implementation period, further analysis is not necessary. If your analysis indicates that the control measure is not cost effective, you should estimate the cost of compliance for the control measure with the next highest level of control effectiveness. This process should be repeated until you have identified a control measure that should be included in North Carolina's long-term strategy or until all control measures have been analyzed.

Characterizing the time necessary for compliance (statutory factor 2) – You should provide an estimate of the time needed to comply with the control measure(s) identified using statutory factor 1. You should specify the source-specific factors used to estimate the time to install the control measure and provide a justification as to why the estimated time is reasonable.

Characterizing energy and non-air environmental impacts (statutory factor 3) – The cost of the direct energy consumption of the control measure should be specified and included in the cost of compliance analysis. If there are any non-air environmental impacts associated with a control measure, such as impacts on nearby water bodies, those impacts should be specified.

Characterizing remaining useful life of the source (statutory factor 4) – The length of the remaining useful life of a source is the number of years prior to the shutdown date during which the new emission control would be operating. If the remaining useful life of the source is less than the useful life of the control system being analyzed, then you should use the remaining useful life of the source in determining the annualized cost in the cost of compliance analysis. Otherwise, you should use the useful life of the control measure in the cost of compliance analysis. If the remaining useful life of a source is relied upon in in a four-factor analysis of a control measure instead of the useful life of the control system, and that control system becomes part of the state's long-term strategy, the shutdown date for the source will need to be included in the Regional Haze SIP and be made federally enforceable.

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[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost manual.

evergreen packaging
Canton Office
PO Box 4000 • Canton, NC 28716

DEM 36-20
Certified Mail Return Receipt Requested
7018 3090 0001 6626 3150

July 1, 2020

Mr. Randy Strait
Planning Section Chief
NC Department of Environmental Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641
(transmitted via e-mail)

Re: Regional Haze Reasonable Progress Assessment for Second Planning Period - 2028 SO_2 Emissions Projections
Blue Ridge Paper Products LLC
Permit No. 08961T29; Facility ID: 4400159

Dear Mr. Strait:

On June 18, 2020, Blue Ridge Paper Products LLC (BRPP) received a letter from the North Carolina Division of Air Quality (DAQ) describing DAQ's progress to date in the reasonable progress assessment for the Regional Haze Rule (RHR) second planning period (2018-2028). Your letter requested that BRPP determine if 2019 actual emissions could be used to represent 2028 sulfur dioxide (SO_2) emissions in the assessment. BRPP has reviewed the SO_2 emissions presented in Table 1 of DAQ's request and is providing an update as described below and in Attachment 1.

As you know, BRPP has reduced its SO_2 emissions by thousands of tons since 2016. BRPP has shutdown or modified several major SO_2 emissions sources in order to reduce facility-wide SO_2 emissions. BRPP installed two new gas-fired package boilers and shut down its Big Bill and Peter G coal-fired boilers in 2017, resulting in a reduction in total SO_2 emissions of 2,300 tons per year (tpy). In late 2018, BRPP transitioned the Nos. 10 and 11 Recovery Furnaces from startup and shutdown on No. 6 fuel oil to startup and shutdown on ultra-low sulfur diesel, resulting in an SO_2 emissions reduction of 1,050 tpy.

In the summer of 2018, BRPP commenced operation of a new wet scrubber on its Riley Coal Boiler and a new wet scrubber on its No. 4 Power Boiler. The addition of these control devices has resulted in a reduction of SO_2 emissions by 2,050 tpy from Riley Coal Boiler and 1,175 tpy from No. 4 Power Boiler. BRPP optimized the operation of the Riley Bark Boiler's wet scrubber to improve SO_2 emissions control and reduce actual emissions by about 600 tpy. BRPP also installed an SO_2 ambient monitor and completed an SO_2 modeling exercise to establish enforceable permit limits that will be incorporated into the State Implementation Plan (SIP) and ensure these SO_2 emissions reductions are permanent. Average 2014-2016 actual SO_2 emissions were approximately 7,600 tpy but actual 2019 SO_2 emissions were only 405 tons.

DAQ may assume that 2019 actual SO_2 emissions are a reasonable projection for 2028 SO_2 emissions for the gas-fired package boilers, calender hot oil heaters, and emergency generators. However, we have provided updated projections for 2028 emissions for the other SO_2 sources. The projections for the recovery furnaces, black liquor oxidation, smelt dissolving tanks, and lime kilns are equivalent to the projected actual SO_2 emissions for the White Liquor Improvement Project. We estimated the 2028 emissions for the Riley Coal Boiler, No. 4 Power Boiler, and Riley Bark Boiler using the 2019 SO_2 stack test results and adjusting emissions for the highest recent coal usage. Attachment 1 details the updated emissions projections, although these projections should not be considered emissions limits or enforceable restrictions. The 2028 emissions projections are slightly higher than 2019 emissions for some sources but the emissions are still significantly below SO_2 emission rates in 2018 and prior years.

Should the DAQ have any questions on this submittal, please contact me by phone at (828) 646-2945 or by email at daniel.meyer@everpack.com.

Sincerely,

Daniel E Meyer

Dan Meyer
Environmental Manager

cc: Wallace McDonald, BRPP
Paul Syslo, BRPP
Andrew Mohr, BRPP
Amy Marshall, ALL4
Steven Moore, ALL4

Attachment 1 – Update to 2028 SO_2 Emissions Projections

Attachment 1
Update to 2028 Emissions Projections

Table 1. Blue Ridge Paper Products LLC - Facility ID: 4400159
Actual Sulfur Dioxide Emissions for 2017-2019 and Projected Emissions for 2028

Unit ID	Unit Description	Annual SO_2 Emissions (Tons)			
		2017	2018	2019	2028 Projected
G08020	No. 10 Recovery Furnace - Black Liquor Solids (BLS) - normal operation	575.23	157.64	5.47	6.10
G08020, G08021	No. 10 and No. 11 Recovery Furnace - ULSD (startup and shutdown)	0.00	0.01	0.08	0.08
G08021	No. 11 Recovery Furnace - BLS - normal operation	461.34	133.19	27.57	27.62
G08022	Black Liquor Oxidation - Regenerative Thermal Oxidizer (RTO)	1.07	1.08	0.55	1.10
G08023	No. 10 Smelt Dissolving Tank	1.21	1.18	1.16	1.25
G08024	No. 11 Smelt Dissolving Tank	1.25	1.19	1.17	1.28
G09028	No. 4 Lime Kiln	1.31	1.11	1.41	2.41
G09029	No. 5 Lime Kiln	0.38	0.36	0.50	0.76
G11039	Riley Coal Boiler	1388.41	833.39	114.99	183.77
G11040	No. 4 Power Boiler	1561.36	1168.63	195.21	195.21
G11042	Riley Bark Boiler	687.09	602.20	55.07	64.75
G11050	No. 1 Natural Gas Package Boiler	0.01	0.37	0.40	0.40
G11051	No. 2 Natural Gas Package Boiler	0.01	0.43	0.41	0.41
G12077	Calender natural gas and/or propane hot oil heaters	0.01	0.01	0.01	0.01
16-CU-001	One 1850 horsepower (hp), diesel-fired emergency generator	5.60E-03	5.60E-03	5.60E-03	5.60E-03
I-G23066.f-ire, I-G23066.f-rec, I-G23066.f-gen	200 hp Fire Control Generator #1; 200 hp Fire Control Generator #2; 64 hp Lime Kiln Emergency Generator; 227 hp Lime Kiln Emergency Generator; and 100 kilowatt (kW) Recovery Furnace Emergency Generator	2.50E-03	2.50E-03	2.50E-03	2.50E-03
G11037	Big Bill coal-fired boiler	538.11	0.00	0.00	0.00
G11038	Peter G coal-fired boiler	657.51	0.00	0.00	0.00
	Total Emissions:	**5,874.31**	**2,900.80**	**404.01**	**485.16**

2028 projections for Nos. 10-11 Recovery Furnaces BLS firing, BLOX RTO, Nos. 10-11 Smelt Dissolving Tanks, and Nos. 4-5 Lime Kilns are based on projected actual emissions for the 2019 White Liquor Improvement Project.

Riley Coal Boiler 2028 projection is based on 2015 coal usage, No. 4 Power Boiler 2028 projection is based on 2019 coal usage, and Riley Bark Boiler 2028 projection is based on 2013 coal usage.

ROY COOPER
Governor

MICHAEL S. REGAN
Secretary

MICHAEL ABRACZINSKAS
Director

NORTH CAROLINA
Environmental Quality

July 15, 2020

Wallace McDonald
Mill Manager
Evergreen Packaging
175 Main Street
Canton, NC 28716

SUBJECT: Regional Haze Reasonable Progress Assessment for Second Planning Period
Blue Ridge Paper Products LLC, Canton, Haywood County, North Carolina
Facility ID: 4400159

Dear Mr. McDonald:

Thank you for your letter dated July 1, 2020, responding to my June 18, 2020 letter. I appreciate the review of the North Carolina Division of Air Quality's (DAQ) projected 2028 sulfur dioxide (SO_2) emissions for the Blue Ridge Paper Products LLC (BRPP) facility in Canton, North Carolina and providing revised 2028 emissions for the SO_2 emission units at the facility. As noted in your letter, BRPP reviewed the DAQ's 2028 projections based on actual 2019 emissions and provided the following comments:

- BRPP agrees with the DAQ's 2028 emissions estimates for the gas-fired package boilers, calendar hot oil heaters, and emergency generators.
- BRPP provided revised 2028 emissions projections for the Recovery Furnaces, Black Liquor Oxidation, Smelt Dissolving Tanks, and Lime Kilns based on projected actual SO_2 emissions for the White Liquor Improvement Project. The revisions to the 2028 SO_2 emissions for these increased by 2.69 tons relative to the DAQ's estimates.
- BRPP also provided revised 2028 emissions for the Riley Coal Boiler and Riley Bark Boiler using the 2019 SO_2 stack test results and adjusting emissions for the highest recent coal usage. The revisions to the 2028 SO_2 emissions for these two boilers increased by 78.46 tons relative to the DAQ's estimates. BRPP agrees with the DAQ's 2028 emissions estimates for the No. 4 Power Boiler.

Relative to the DAQ's original 2028 emissions projections, the revised emissions provided in your letter increased SO_2 emissions by 20.1% (81.15 tons) with the majority of the 2028 emissions associated with the Riley Coal Boiler, Riley Bark Boiler, and No. 4 Power Boiler. It is our understanding that the revised 2028 emissions you provided for these processes are below the permitted maximum allowable annual emissions reported in Table 1 of the *Source-Specific State Implementation Plan for Evergreen Packaging/Blue Ridge Paper Products, LLC, Canton, Beaverdam Township, Haywood County, North Carolina for the 2010 1-Hour Sulfur Dioxide National Ambient Air Quality Standard (NAAQS)*, dated June 24, 2020.

The DAQ used the revised 2028 SO_2 emissions you provided and recalculated BRPP's contribution to visibility impairment for the 20% most impaired days at Shining Rock Wilderness Area using the Particulate Matter Source Apportionment Technology (PSAT) modeling approach referenced in my June 18, 2020 letter. The revised PSAT results indicate that BRPP's contribution of SO_2 emissions to visibility impairment would increase from 1.08% to 1.30% in 2028.

In establishing reasonable progress goals, North Carolina must consider the four factors specified in section 169A of the Clean Air Act and in paragraph 51.308(f)(2)(i) of the regional haze rule: (1) the cost of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources. To fulfill this requirement, North Carolina is requesting that facilities that have ≥1.00% sulfate contribution to visibility impairment at a Class I Federal area to complete a four-factor analysis. For this reason, I am requesting that you conduct a four-factor analysis on the SO_2 emission sources at the BRPP's Canton Mill facility as outlined in Part III of my June 18, 2020 letter.

Please submit the requested four-factor analyses to the DAQ Planning Section Chief, Randy Strait (randy.strait@ncdenr.gov) by no later than September 25, 2020. Should you have any questions regarding this request, please feel free to contact Randy Strait at (919) 707-8721 or me at (919) 707-8447.

Sincerely,

Michael A. Abraczinskas, Director
Division of Air Quality, NCDEQ

MAA/rps

cc: Brendan Davey, NCDAQ
Tammy Manning, NCDAQ
Randy Strait, NCDAQ
Daniel Meyer, Evergreen Packaging
Central Files

evergreen packaging
Canton Office
PO Box 4000 • Canton, NC 28716

DEM 55-20
Certified Mail Return Receipt Requested
7018 3090 0001 6626 3358

September 11, 2020

Mr. Randy Strait
Planning Section Chief
NC Department of Environmental Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641
(transmitted via e-mail)

Re: Regional Haze Reasonable Progress Assessment for Second Planning Period - Four-Factor Analysis
Blue Ridge Paper Products LLC
Permit No. 08961T29; Facility ID: 4400159

Dear Mr. Strait:

Enclosed please find one (1) copy of the subject four-factor analysis requested by your office.

Should the DAQ have any questions on this submittal, please contact me by phone at (828) 646-2945 or by email at daniel.meyer@everpack.com.

Sincerely,

Daniel E Meyer

Dan Meyer
Environmental Manager

cc: Wallace McDonald, BRPP
Paul Syslo, BRPP
Andrew Mohr, BRPP
Amy Marshall, ALL4
Steven Moore, ALL4

Enclosure –
Regional Haze Reasonable Progress Assessment for Second Planning Period - Four-Factor Analysis

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Regional Haze Rule Four-Factor Analysis for the Blue Ridge Paper Products LLC Canton Mill

August 2020

Submitted by:

Blue Ridge Paper Products LLC
PO Box 4000
Canton, NC 28716

Submitted to:

NC Department of Environmental Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

ALL4 Contact Information: info@all4inc.com | 610.933.5246 | www.all4inc.com

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1. INTRODUCTION

The North Carolina Department of Environmental Quality (DEQ) Division of Air Quality (DAQ) is in the process of developing a State Implementation Plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DAQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of visibility impairing pollutants, such as sulfur dioxide (SO_2), for the 2021-2028 planning period. DAQ has requested that several facilities within the State submit a Four-Factor Analysis (FFA) to examine the feasibility of additional SO_2 emissions controls. This report provides the Blue Ridge Paper Products (BRPP) Canton Mill's FFA for the following emissions sources (Title V emission source ID's in parenthesis), as requested in Part III of DAQ's June 18, 2020 letter:

- Riley Coal Boiler (G11039)
- No. 4 Power Boiler (G11040)
- Riley Bark Boiler (G11042)

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available Retrofit Technology (BART). Specifically, the BART provisions required states to conduct an evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the New Source Performance Standards (NSPS) at 40 CFR Part 60. The purpose of the program was to identify older emission units that contributed to haze at Class I areas that could be retrofitted with emissions control technology to reduce emissions and improve visibility in these areas. The BART requirement applied to emission units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;

2. The units are located at facilities in one of 26 NSPS categories; and
3. The units have a total potential-to-emit (PTE) of at least 250 tpy of NO_X, SO_2, and PM_{10} from all BART-era emission units at the same facility.

National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR Part 63, which require the use of Maximum Achievable Control Technology (MACT) that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART." The Canton Mill's major sources of SO_2 are all subject to MACT requirements.

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Section Implementation Period, "there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area."[1] The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas or ultra-low sulfur diesel, and sources that are already well-controlled for SO_2. In addition, as the goal of the state's analysis is to identify measures that would contribute to reasonable progress, it is not reasonable to evaluate sources with very low emissions.

This report focuses on the three significant sources of SO_2 emissions at the Canton Mill that DAQ requested BRPP evaluate. We note that all the Canton Mill's SO_2 emissions sources are subject to federally-enforceable permit limits designed such that the mill demonstrates compliance with the 1-hour SO_2 national ambient air quality standard (NAAQS) via air dispersion modeling. Prior

[1] EPA-457/B-19-003, August 2019, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period."

to incorporation of those emissions limits into the permit in September 2019, the Mill spent a significant amount of capital to make changes that decreased actual SO_2 emissions by over 5,000 tons per year. An ambient monitor has been sited adjacent to the mill since November of 2016. After completion of the capital upgrades, the monitor has confirmed that mill impacts are consistently well below the stringent 1-hour SO_2 NAAQS, and we are confident in calling mill SO_2 emissions well-controlled.

Section 2 of this report provides a detailed FFA for SO_2 emissions from the Mill's three solid fuel-fired boilers. Appendix A presents the control cost calculations and Appendix B presents supporting information.

1.1 FOUR-FACTOR ANALYSIS

Pursuant to 40 CFR 51.308(f)(2)(i), DAQ has requested that the Mill address the following four factors to determine if additional emissions control measures are necessary to make reasonable progress toward natural visibility conditions at nearby Class I areas:

- The cost of compliance
- Energy and non-air quality impacts of compliance
- The time necessary for compliance
- Remaining useful life of existing affected sources

BRPP has addressed these factors for additional control options that could be applied to the Canton Mill's solid fuel-fired boilers using available site-specific data, capital costs of controls from U.S. EPA publications or previous analyses (either company-specific or for similar sources), and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual and U.S. EPA fact sheets. The Mill has not performed additional site-specific engineering analyses for this study, but has used readily available information to determine if additional emissions controls may be feasible and cost effective. The emissions reduction expected for each control technology evaluated was based on a typical expected control efficiency and projected actual emissions during the second planning period.

Evaluating cost effectiveness based on actual emissions provides a better representation of the true cost of each technology to the Mill than an evaluation based on allowable emissions.

An interest rate of 4.75% and the typical values for equipment life shown in the OAQPS Cost Manual examples were used to calculate the capital recovery factor. A 4.75% interest rate represents the prime rate just prior to the COVID-19 pandemic and is representative because the prime rate has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018. Labor and fuel costs are based on mill-specific values.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 provides basic information regarding the sources that were evaluated in detail. The sources evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants (HAPs) and are already well controlled. The Mill's boilers are subject to NESHAP at 40 CFR 63, Subpart DDDDD, that require the use of MACT. While the MACT standards are intended to minimize HAP emissions, they also directly reduce criteria pollutant emissions and promote good combustion practices. The No. 4 Power Boiler is also subject to an NSPS SO_2 limit at 40 CFR 60, Subpart D. All three boilers are equipped with wet scrubbers designed and operated to achieve an SO_2 control efficiency of 90 percent.

Table 1-1
Summary of Emissions Sources Evaluated

Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	SO_2 Removal Efficiency	Projected 2028 Actual SO_2 Emissions (tons/year)	Major Regulatory Programs
Riley Coal Boiler (G11039)	1946	Coal Natural gas/kerosene ignitors	Electrostatic precipitator (ESP) Wet scrubber	90%	184	MACT DDDDD
No. 4 Power Boiler (G11040)	1986	Coal Natural gas startup burners	ESP Wet scrubber	90%	195	MACT DDDDD NSPS D

Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	SO_2 Removal Efficiency	Projected 2028 Actual SO_2 Emissions (tons/year)	Major Regulatory Programs
Riley Bark Boiler (G11042)	1952	Biomass and coal Kerosene used during startup	Wet scrubber	90%	65	MACT DDDDD

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

In the past few years, the Mill has made significant SO_2 emissions reductions. As shown in Table 1-1, the Mill is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including the use of clean fuels for startup and a limitation on fuel oil use to periods of natural gas curtailment for boilers in the gas 1 subcategory. Emission standards for HCl also serve to limit emissions of SO_2.

In order to comply with both Boiler MACT and the SO_2 NAAQS, the mill recently invested more than 45 million dollars in capital. In 2017, two new natural gas-fired boilers were installed and two older coal-fired boilers were shutdown. In 2018, the mill replaced No. 6 fuel oil with ultra-low sulfur diesel (ULSD) as the startup fuel on both recovery furnaces, rebuilt the ESPs and installed new wet scrubbers on the Riley Coal and No. 4 Power Boilers, and adjusted operation of the Riley Bark Boiler wet scrubber to reduce SO_2 emissions.

The projected mill-wide SO_2 emissions during the second planning period are approximately 485 tons per year compared to the 2017 actual emissions of 5,875 tons, representing a 90% reduction in SO_2 emissions. DAQ has indicated that air quality modeling shows the Mill impacts visibility at the Shining Rock Wilderness Area by slightly more than 1 percent. The haziness index at Shining Rock on the 20% most impaired days in 2017 was approximately 15 deciviews, compared to the uniform rate of progress (glide path) goal of approximately 24 deciviews in 2018 and approximately 21 deciviews in 2028. The recent SO_2 emissions reductions from the Mill should contribute to further improvement in the haziness index at Shining Rock during the second RHR planning period.

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the FFA.
- **Section 2 – Four-Factor Analysis for Boilers:** provides the FFA for the solid-fuel boilers.
- **Section 3 – Summary of Findings:** presents a summary of the FFA.
- **Appendix A – Control Cost Analyses**
- **Appendix B – Supporting Information**

2. FOUR-FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of the FFA for SO_2 emissions from the three solid fuel-fired industrial boilers at the Mill. To evaluate the cost of compliance portion of the FFA, the following steps were performed:

- identify available control technologies,
- eliminate technically infeasible options, and
- evaluate cost effectiveness of remaining controls.

The time necessary for compliance, energy and non-air environmental impacts, and remaining useful life were also evaluated.

2.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for industrial boilers was determined based on a review of the RBLC database[2] and knowledge of typical controls used on boilers in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 2-1 summarizes the potentially feasible SO_2 control technologies for industrial boilers.

[2] RACT/BACT/LAER Clearinghouse (RBLC). https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information

Table 2-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet scrubber Dry sorbent injection (DSI)

Technically feasible control technologies for industrial boilers were evaluated, taking into account current air pollution controls, fuels fired, and RBLC database information. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. U.S. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[3]

2.1.1 Available SO_2 Control Technologies

The potentially feasible control technologies for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Generation of SO_2 in a boiler is proportional to the amount of sulfur in the fuel being fired. Natural gas, No. 2 fuel oil (including kerosene and ULSD), and biomass are considered low-sulfur fuels.

Wet Scrubbers

In a wet scrubber, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that

[3] https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf

has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to dry PM air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device (e.g., fabric filter) to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same or similar type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same or similar type of emissions unit, it is presumed to be technically feasible. However, an available technology cannot be eliminated as infeasible simply because it has not been used on the same type of unit that is under review. If the technology has not been operated successfully on the type of unit under review, its lack of “availability” and “applicability” to the particular unit type under review must be documented in order for the technology to be eliminated as technically infeasible.

The No. 4 Power Boiler is equipped with natural gas startup burners and burns pulverized coal during normal operation. The Riley Coal Boiler is equipped with natural gas/kerosene ignitors and burns pulverized coal during normal operation. These two boilers are each equipped with an ESP and a wet scrubber. The wet scrubbers were installed to reduce emissions of hydrogen chloride for compliance with Industrial Boiler NESHAP requirements and to reduce emissions of SO_2 and achieve compliance with the 1-hour SO_2 NAAQS. The wet scrubbers were designed and are operated to achieve 90 percent control of SO_2 emissions, which is equivalent to what would be required under new source performance standards at 40 CFR 60, Subpart Db.

The Riley Bark Boiler is a hybrid suspension/grate design and burns a mixture of biomass and coal during normal operation. It is equipped with a wet scrubber that achieves about 90 percent control of SO_2 emissions.

Replacing coal with a lower-sulfur fuel would be a technically feasible way to reduce SO_2 emissions from the three boilers. The design of each boiler precludes replacing coal firing with biomass. The mill currently burns the available natural gas supply in its package boilers, lime kilns, and calender nip heaters and uses natural gas as a startup fuel for No. 4 Power Boiler. There is currently no additional supply of gas available to the mill to replace coal with natural gas in any of the three boilers. Significant infrastructure upgrades would be required to the local and regional gas supply in order to replace coal with natural gas in any of the three boilers. Replacing coal with natural gas is not feasible at this time. Replacing coal with ULSD was evaluated.

DSI in the form of trona injection prior to the ESP was evaluated for Riley Coal and No. 4 Power Boilers. DSI was not evaluated for the Riley Bark Boiler because there is no dry control device for particulate matter on this boiler.

The wet scrubbers serving all three boilers are designed to achieve 90% removal of SO_2. It is not feasible to add additional caustic to further increase the removal efficiency of the wet scrubbers.

2.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls were considered technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed company project costs, or EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated using the annualized capital and operating costs and the amount of pollutant expected to be removed based on the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. Each boiler's 2028 projected SO_2 emissions and a typical expected control efficiency were used as the basis for emissions reductions and cost effectiveness calculations.

Technically feasible control technologies were evaluated for cost effectiveness by source as summarized in Table 2-2.

Table 2-2
Control Technologies Evaluated for Boilers

Emissions Unit	Fuels Fired	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Riley Coal Boiler (G11039)	Coal Natural gas/kerosene ignitors	Electrostatic precipitator (ESP) Wet scrubber	Replace coal with ULSD DSI
No. 4 Power Boiler (G11040)	Coal Natural gas startup burners	ESP Wet scrubber	Replace coal with ULSD DSI

Emissions Unit	Fuels Fired	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Riley Bark Boiler (G11042)	Biomass and coal Kerosene used during startup	Wet scrubber	Replace coal with ULSD

Cost estimates for each feasible pollution control technique are presented in Appendix A. These are screening level cost estimates and are not based on detailed engineering studies of mill boilers.

Although DAQ has not indicated what additional controls they would consider cost effective, similar analyses performed by U.S. EPA and others were reviewed to get a general idea of the level above which additional controls on industrial boilers are not cost effective. As part of the 2016 CSAPR update rule[4], U.S. EPA performed an analysis to characterize whether there were non-electric generating unit (EGU) source groups with a substantial amount of available cost-effective NO_X reductions achievable by the 2017 ozone season. They evaluated control costs for non-EGU point sources with NO_X emissions greater than 25 tpy in 2017.[5] U.S. EPA did not further examine control options above $3,400 per ton. This is consistent with the range U.S. EPA analyzed for EGUs in the proposed and final CSAPR rules and is also consistent with what the U.S. EPA has identified in previous transport rules as cost-effective, including the NO_X SIP call. Notably, $3,400 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NO_X SIP call, adjusted to the 2011 dollars used throughout the CSAPR update proposal. Adjustments of costs were made using the Chemical Engineering Plant Cost Index (CEPCI) annual values for 1990 and 2011.) Note that industrial boilers were among the source categories that the very conservative U.S. EPA cost analysis determined were above $3,400/ton. In addition, the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high.[6] The costs presented in this report

[4] 81 Fed. Reg. 74504
[5] Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500, Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance, U.S. EPA, November 2015.
[6] https://www.wrapair.org//forums/mtf/documents/group_reports/TechSupp/SO2Tech.htm

were developed using conservative assumptions and almost all are significantly above these thresholds.

2.3.1 Site-Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints and availability of low sulfur fuels. A detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

2.3.2 SO_2 Economic Impacts

Replacing coal with ULSD was evaluated for the three boilers. The capital cost of installing ULSD burners was not evaluated, but the operating cost (calculated based on the current difference in price between coal and ULSD and the projected amount of coal that will be fired in 2028) demonstrates this approach is not cost effective.

Table 2-3
ULSD Cost Summary

Emissions Unit Description	Capital Cost ($)	Operating Cost ($/yr)	SO_2 Removed (tons/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Riley Coal Boiler (G11039)	Not determined	$22,920,384	181.82	$126,060
No. 4 Power Boiler (G11040)	Not determined	$32,154,379	192.42	$167,107
Riley Bark Boiler (G11042)	Not determined	$10,205,397	55.00	$185,565

The capital cost for a DSI system to inject milled trona prior to the ESP on the Riley Coal Boiler and No. 4 Power Boiler were estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[7] Mill-specific labor and chemical costs were used to estimate the annual cost of operating the DSI system. The Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing particulate matter emissions. Table 2-4 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology for the Riley Coal and No. 4 Power Boilers, based on operating data and projected 2028 actual emissions.

Table 2-4
DSI System Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Removed (tons/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Riley Coal Boiler (G11039)	$5,413,330	$1,566,198	91.9	$17,045
No. 4 Power Boiler (G11040)	$5,404,505	$1,767,179	97.6	$18,105

Installing DSI is not considered cost effective because the estimated capital cost is more than $5 million per boiler and the minimum cost effectiveness value is over $17,000/ton of pollutant removed.

2.3.3 Energy and Non-Air Related Impacts

Adding DSI systems would increase energy use. The additional particulate from the trona collected in the particulate control devices would be disposed of in the mill landfill. This would reduce the remaining useful life of the mill landfill and increase truck traffic through the streets of Canton.

[7] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

2.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls after the effective date of the final standard. Although our FFA shows there are no additional controls that would be feasible, if controls are ultimately required to meet RHR requirements, the Mill would need at least three years to implement them after final EPA approval of the RHR SIP. The Mill would need time to obtain corporate approvals for capital funding. The Mill would have to undergo substantial re-engineering (*e.g.*, due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The Mill would also need to execute air permit modifications, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate mill systems, the availability of contractors, and the like. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

If multiple units required retrofit controls, construction would need to be staggered so only one unit was out of service at a time to allow some level of continued operation during a retrofit. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

2.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The boilers included in this FFA are assumed to have a remaining useful life of 25 years or more.

2.6 CONCLUSION

Based on the FFA presented above, no additional controls were determined to be cost effective for the Mill's industrial boilers.

3. SUMMARY OF FINDINGS

The emission sources at the BRPP Canton Mill are already well-controlled, with 2019 SO2 monitor readings under 50%, and YTD 2020 SO2 monitor readings under 25%, of the stringent 1-hr NAAQS limits. However, in response to a request from DAQ, BRPP evaluated whether additional emissions controls for SO_2 are feasible for significant emissions units.

As part of the FFA, the following information was reviewed: site-specific emissions and controls information, industry- and site-specific cost data, publicly-available cost data, previous similar control evaluations, the U.S. EPA RBLC database, and U.S. EPA's OAQPS Control Cost Manual. The best information available in the time allotted to perform the analyses was used.

Our review of the best available information indicates that additional emissions controls for SO_2 are either not feasible or not cost effective. Any determination that additional controls are feasible would need to be justified based on a more detailed evaluation that fully considers site-specific factors. In addition, it is important to note the following points:

- All of the Canton Mill's SO_2 sources are subject to federally-enforceable emissions limits and monitoring requirements that serve to demonstrate compliance with the 1-hour SO_2 NAAQS.
- The Mill has reduced SO_2 emissions over 5,000 tpy since 2017.
- The three solid fuel-fired boilers included in the FFA are all equipped with wet scrubbers that were designed to reduce SO_2 emissions by at least 90 percent.
- The boilers at the Canton Mill are subject to Boiler MACT emission limits and work practices that became effective in May 2019. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the requirement to startup on clean fuel limits emissions of HAPs and criteria pollutants, including SO_2.
- U.S. EPA will continue the required process to evaluate acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology review for NESHAP Subpart DDDDD sources.

- U.S. EPA determined in its CSAPR rulemaking that controls on non-EGU combustion units are not cost effective.

APPENDIX A -
CONTROL COST ESTIMATES

Table A-1
ULSD Direct Cost Summary

Emissions Unit			Riley Coal Boiler	No. 4 Power Boiler	Riley Bark Boiler*
Fuels Fired	Coal	Cost ($/ton)	$90	$95	$107
		HHV (Btu/lb)	13,500	13,500	13,500
	ULSD	Cost ($/gallon)	$1.72	$1.72	$1.72
		HHV (Btu/gallon)	140,000	140,000	140,000
2028 Projected Coal Firing					
Coal Firing (tons)			94,900	135,947	45,454
Coal Firing (MMbtu)			2,562,300	3,670,569	1,227,258
2028 SO_2 Projected Emissions (tpy)			183.77	195.21	55.93
Coal Firing Cost ($)			$8,541,000	$12,914,965	$4,863,578
2028 Equivalent ULSD Firing					
Equivalent ULSD Firing (gallons)			18,302,143	26,218,350	8,766,129
ULSD SO_2 Emissions Factor (lb/gallon)			2.13E-04	2.13E-04	2.13E-04
2028 SO_2 Projected Emissions (tpy)			1.95	2.79	0.93
ULSD Firing Cost ($)			$31,461,384	$45,069,344	$15,068,975
Economic Impacts					
SO_2 Reduction (tpy)			181.82	192.42	55.00
SO_2 Reduction (%)			99%	99%	98%
Annual SO_2 Reduction Cost ($)			$22,920,384	$32,154,379	$10,205,397
Annual SO_2 Reduction Cost ($/ton)			$126,060	$167,107	$185,565

* SO_2 emissions from coal combustion only.

Table A-2
BRPP Canton - Riley Coal Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	35	399 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.14	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	3.99E+08	399 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.42	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.06	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0	not calculated, confidential business information
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	183.8
Controlled SO_2 Emissions:	91.9

Capital Costs				
Direct Costs				
BM (Base Module)	-	$	$ 4,296,294	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	$	$ 429,629	10% BM
Labor adjustment	A2	$	$ 214,815	5% BM
Contractor profit and fees	A3	$	$ 214,815	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 5,155,553	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 257,778	5% CECC
Total project cost w/out AFUDC	TPC	$	$ 5,413,330	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 5,413,330**	CECC+B1+B2

Table A-2
BRPP Canton - Riley Coal Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	42,963	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**154,883**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	140,521.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	629,041.0	(N+P)*S
Additional auxiliary power required	VOMP	$	$	-	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**769,562.2**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	108,267	
Property Tax	1%	of TCI	$	54,133	
Insurance	1%	of TCI	$	54,133	
Capital Recovery	7.86%	x TCI	$	425,220	
Total Indirect Annual Costs			**$**	**641,753**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**1,566,198**	
Total Annual Costs/SO_2 Emissions			**$**	**17,045**	

[(a)]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

Table A-3
BRPP Canton - No. 4 Power Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	47	535 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.11	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	5.35E+08	535 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.90	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.04	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0	not calculated, confidential business information
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	195.2
Controlled SO_2 Emissions:	97.6

Capital Costs					
Direct Costs					
BM (Base Module)	-	$	$	4,289,290	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	428,929	10% BM
Labor adjustment	A2	$	$	214,464	5% BM
Contractor profit and fees	A3	$	$	214,464	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	5,147,148	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	257,357	5% CECC
Total project cost w/out AFUDC	TPC	$	$	5,404,505	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**5,404,505**	CECC+B1+B2

Table A-3
BRPP Canton - No. 4 Power Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	42,893	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**154,812**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	139,716.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	831,944.1	(N+P)*S
Additional auxiliary power required	VOMP	$	$	-	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**971,660.3**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	108,090	
Property Tax	1%	of TCI	$	54,045	
Insurance	1%	of TCI	$	54,045	
Capital Recovery	7.86%	x TCI	$	424,526	
Total Indirect Annual Costs			**$**	**640,707**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**1,767,179**	
Total Annual Costs/SO_2 Emissions			**$**	**18,105**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

APPENDIX B - SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

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DSI Cost Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs, such as project contingency, that a facility would incur to install a retrofit control.

Technology Description

Dry sorbent injection (DSI) is a viable technology for moderate SO_2/HCl reduction on coal-fired boilers. Demonstrations and utility testing have shown SO_2/HCl removals greater than 80% for systems using sodium-based sorbents. The most commonly used sodium-based sorbent is Trona. However, if the goal is only HCl removal, the amount of sorbent injection will be significantly lower. In this case, Trona may still be the most commonly used reagent, but hydrated lime also has been employed in some situations. Because of Trona's high reactivity with SO_2, when this sorbent is used, significant SO_2 removal must occur before high levels of HCl removal can be achieved. Studies show, however, that hydrated lime is quite effective for HCl removal because the need for simultaneous SO_2 removal is much reduced. In either case, actual testing must be carried out before the permanent DSI system for SO_2 or HCl removal is designed.

The level of removal for Trona can vary from 0 to 90% depending on the Normalized Stoichiometric Ratio (NSR) and particulate capture device. NSR is defined as follows:

$$\left.\frac{\text{(moles of Na injected)}}{\text{(moles of SO}_2\text{ in flue gas)}}\right/\text{(theoretical moles of Na required)}$$

DSI Cost Methodology

The required injection rate for alkali sorbents can vary depending on the required removal efficiency, NSR, and particulate capture device. The costs for an SO_2 mitigation system are primarily dependent on sorbent feed rate. This rate is a function of NSR and the required SO_2 removal (the latter is set by the utility and is not a function of unit size). Therefore, the required SO_2 removal is determined by the user-specified SO_2 emission limit, and the cost estimation is based on sorbent feed rate and not unit size. Because HCl concentrations are low compared with SO_2 concentrations, any unused reagent for SO_2 removal is assumed to be used for HCl removal, resulting in a very small change in the NSR used for SO_2 removal when HCl removal is the main goal.

The sorbent solids can be collected in either an ESP or a baghouse. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs because the presence of filter cake on the bags allows for a longer reaction time between the sorbent solids and the flue gas. Thus, for a given Trona removal efficiency, the NSR is reduced when a baghouse is used for particulate capture.

The dry-sorbent capture ability is also a function of particle surface area. To increase the particle surface area, the sorbent must be injected into a relatively hot flue gas. Heating the solids produces micropores on the particle surface, which greatly improve the sulfur capture ability. For Trona, the sorbent should be injected into flue gas at temperatures above 275°F to maximize the micropore structure. However, if the flue gas is too hot (greater than 800°F), the solids may sinter, reducing their surface area and thus lowering the SO_2 removal efficiency of the sorbent.

Another way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Typically, Trona is delivered unmilled. The ore is ground such that the unmilled product has an average particle size of approximately 30 μm. Commercial testing has shown that the reactivity of the Trona can be increased when the sorbent is ground to produce particles smaller than 30 μm. In the cost estimation methodology, the Trona is assumed to be delivered in the unmilled state only. To mill the Trona, in-line mills are continuously used during the Trona injection process. Therefore, the delivered cost of Trona will not change; only the reactivity of the sorbent and amount used change when Trona is milled.

Ultimately, the NSR required for a given removal is a function of Trona particle size and particulate capture equipment. In the cost program, the user can choose either as-delivered Trona (approximately 30 μm average size) or in-line milled Trona (approximately 15 μm average size) for injection. The average Trona particle size and the type of particulate removal equipment both contribute to the predicted Trona feed rate.

DSI Cost Methodology

Establishment of the Cost Basis

For wet or dry FGD systems, sulfur removal is generally specified at the maximum achievable level. With those systems, costs are primarily a function of plant size and target sulfur removal rate. However, DSI systems are quite different. The major cost for the DSI system is the sorbent itself. The sorbent feed rate is a function of sulfur generation rate, particulate collection device, and removal efficiency. To account for all of the variables, the capital cost was established based on a sorbent feed rate, which is calculated from user input variables. Cost data for several DSI systems were reviewed and a relationship was developed for the capital costs of the system on a sorbent feed-rate basis.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The sulfur feed rate and NSR are the major variables for the cost estimate. The NSR is a function of the following:

- Removal efficiency,
- Sorbent particle size, and
- Particulate capture device.

A retrofit factor that equates to difficulty in construction of the system must be defined. The gross unit size and gross heat rate will factor into the amount of sulfur generated.

Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO_2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO_2. A baghouse used with sodium-based sorbents generally achieves a higher SO_2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO_2/MMBtu.

Units with a baghouse and limited NO_X control that target a high SO_2 removal efficiency with sodium sorbents may experience a brown plume resulting from the conversion of NO to NO_2. The formation of NO_2 would then have to be addressed by adding an adsorbent, such as activated carbon, into the flue gas. However, many coal-fired units control NO_X to a sufficiently low level that a brown plume should not be an issue with sodium-based DSI. Therefore, this algorithm does not incorporate any additional costs to control NO_2.

DSI Cost Methodology

The equations provided in the cost methodology spreadsheet allow the user to input the required removal efficiency, within the limits of the technology. To simplify the correlation between efficiency and technology, SO_2 removal should be set at 50% with an ESP and 70% with a baghouse. The simplified sorbent NSR would then be calculated as follows:

For an ESP at the target 50% removal —
Unmilled Trona NSR = 2.00
Milled Trona NSR = 1.40

For a baghouse at the target 70% removal —
Unmilled Trona NSR = 1.90
Milled Trona NSR = 1.50

The algorithm identifies the maximum expected HCl removal based on SO_2 removal. The HCl removal should be limited to achieve 0.002 lb HCl/MBtu to meet the Mercury Air Toxics (MATS) regulation. The hydrated lime algorithm should be used only for the HCl removal requirement. For hydrated lime injection systems, the SO_2 removal should be limited to 20% to achieve maximum HCl removal.

The correlation could be further simplified by assuming that only milled Trona is used. The current trend in the industry is to use in-line milling of the Trona to improve its utilization. For a minor increase in capital, milling can greatly reduce the variable operating expenses, thus it is recommended that only milled Trona be considered in the simplified algorithm.

Outputs

Total Project Costs (TPC)

First, the base installed cost for the complete DSI system is calculated (BM). The base installed cost includes the following:

- All equipment,
- Installation.
- Buildings,
- Foundations,
- Electrical, and
- Average retrofit difficulty.

The base module cost is adjusted by the selection of in-line milling equipment. The base installed cost is then increased by the following:

DSI Cost Methodology

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 5% of the BM cost; and
- Contractor profit and fees at 5% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include the following:

- Owner's home office costs (owner's engineering, management, and procurement) are added at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) is added at 0% of the CECC and owner's costs because these projects are expected to be completed in less than a year.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the DSI installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 2 additional operators are required for a DSI system. The FOMO is based on the number of additional operations staff required.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

DSI Cost Methodology

Variable O&M (VOM)

Variable O&M is a function of the following:

- Reagent use and unit costs,
- Waste production and unit disposal costs, and
- Additional power required and unit power cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per megawatt-hour (MWh) basis.
- The additional power required includes increased fan power to account for the added DSI system and, as applicable, air blowers and transport-air drying equipment for the SO_2 mitigation system.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The reagent usage is a function of NSR and the required SO_2 removal. The estimated NSR is a function of the removal efficiency required. The basis for total reagent rate purity is 95% for hydrated lime and 98% for Trona.
- The waste-generation rate, which is based on the reaction of Trona or hydrated lime with SO_2, is a function of the sorbent feed rate. The waste-generation rate is also adjusted for excess sorbent fed. The reaction products in the waste for hydrated lime and Trona mainly contain $CaSO_4$ and Na_2SO_4 and unreacted dry sorbent such as $Ca(OH)_2$ and Na_2CO_3, respectively.
- The user can remove fly ash disposal volume from the waste disposal cost to reflect the situation where the unit has separate particulate capture devices for fly ash and dry sorbent.
- If Trona is the selected sorbent, the fly ash captured with this sodium sorbent in the same particulate control device must be landfilled. Typical ash content for each fuel is used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for a total waste stream in the O&M analysis.

DSI Cost Methodology

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are as follows:

- Reagent cost in $/ton.
- Waste disposal costs in $/ton that should vary with the type of waste being disposed.
- Auxiliary power cost in $/kWh; no noticeable escalation has been observed for auxiliary power cost since 2012.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR =	Variable O&M costs for reagent
VOMW =	Variable O&M costs for waste disposal
VOMP =	Variable O&M costs for additional auxiliary power

The total VOM is the sum of VOMR, VOMW, and VOMP. The additional auxiliary power requirement is also reported as a percentage of the total gross power of the unit. Table 1 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of an ESP. Table 2 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of a baghouse. Table 3 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona injection ahead of an ESP. Table 4 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona ahead of a baghouse. Table 5 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime injection ahead of an ESP. Table 6 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime ahead of a baghouse.

DSI Cost Methodology

Table 1. Example of a Complete Cost Estimate for a Milled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	16.33	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	13.12	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$ 18,348,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		37	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 1,835,000	Engineering and Construction Management costs
A2 = 5% of BM		$ 917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$ 917,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 22,017,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 1,101,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 23,118,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 23,118,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$ 0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$ 0.37	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$ 0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$ 0.89**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A		$ 5.55	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$ 3.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$ 0.39	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$ 9.33**	

DSI Cost Methodology

Table 2. Example of a Complete Cost Estimate for a Milled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		0.85	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	9.67	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.20	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,812,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		32	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,581,000	Engineering and Construction Management costs
A2 = 5% of BM	$	791,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	791,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**18,975,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	949,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**19,924,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**19,924,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.32	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.29	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.89	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.41**	

Table 3. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<— User Input
Retrofit Factor	B		1	<— User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<— User Input
SO2 Rate	D	(lb/MMBtu)	2	<— User Input
Type of Coal	E		Bituminous	<— User Input
Particulate Capture	F		ESP	<— User Input
Sorbent	G		Unmilled Trona	<— User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.98	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	22.54	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	17.71	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	Q	(%)	0.81	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<— User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<— User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<— User Input
Operating Labor Rate	U	($/hr)	60	<— User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$ 18,168,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		36	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 1,817,000	Engineering and Construction Management costs
A2 = 5% of BM		$ 908,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$ 908,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 21,801,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 1,090,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 22,891,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 22,891,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$ 0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$ 0.36	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$ 0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$ 0.88**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A		$ 10.14	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$ 3.84	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$ 0.49	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$ 14.47**	

Table 4. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Unmilled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.12	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	12.79	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	10.50	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.46**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$ 15,468,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		31	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 1,547,000	Engineering and Construction Management costs
A2 = 5% of BM		$ 773,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$ 773,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 18,561,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**37**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 928,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 19,489,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**39**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 19,489,000**	Total project cost
TPC ($/kW) =		**39**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$ 0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$ 0.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$ 0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$ 0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A		$ 5.76	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$ 3.12	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$ 0.28	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$ 9.16**	

DSI Cost Methodology

Table 5. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	30	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.90	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	10.85	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	95	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	12.18	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Calculation		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	14,762,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		30	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,476,000	Engineering and Construction Management costs
A2 = 5% of BM	$	738,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	738,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**17,714,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**35**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	886,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**18,600,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**37**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**18,600,000**	Total project cost
TPC ($/kW) =		**37**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.30	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.81**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.26	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.29	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.78**	

DSI Cost Methodology

Table 6. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.09	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	6.19	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	99	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.41	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.22**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	12,588,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		25	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,259,000	Engineering and Construction Management costs
A2 = 5% of BM	$	629,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	629,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**15,105,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**30**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	755,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**15,860,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**32**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**15,860,000**	Total project cost
TPC ($/kW) =		**32**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.25	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.77**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	1.86	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.91	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.13	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**4.91**	

From: Amy Marshall
To: Strait, Randy P; Meyer, Daniel
Cc: Steven Moore; Mohr, Andrew; Syslo, Paul
Subject: RE: [External] RHR Four-Factor Analysis for Blue Ridge Paper Products LLC Canton Mill
Date: Tuesday, March 02, 2021 9:44:33 AM
Attachments: image001.png
image002.png

Hi Randy – Here are the answers to the questions you asked me a few weeks ago about Riley Bark Boiler. Please let us know if you need additional clarification.

Q1: Can you take coal out of the Riley Bark Boiler and burn just biomass?

A1: The Riley Bark Boiler is not designed to burn 100% biomass at full steam load and it is not currently feasible to burn more biomass than is currently burned. The boiler combustion air system does not provide sufficient overfire air to support 100% biomass firing while maintaining compliance with current emissions standards for particulate matter, carbon monoxide and opacity. The biomass storage, delivery and feed systems are not sized to support firing 100% biomass. The mill is landlocked and has no additional space available to expand biomass storage capacity to support the amount of biomass storage that would be necessary for firing 100% biomass. Co-firing coal also promotes stable boiler operation and more uniform and efficient combustion because the biomass characteristics (moisture content, size and shape, etc.) can exhibit short-term variability, impacting boiler efficiency.

Q2: What is the typical split between coal and biomass in the Riley Bark Boiler?

A2: The split is typically 33% coal and 67% biomass on an annual mass basis. The split is typically 60% coal and 40% biomass on an annual heat input basis.

Q3: Why do you burn one fuel over another in the Riley Bark Boiler?

A3: Both biomass and coal are purchased by the Canton Mill. The available biomass is currently less expensive than coal per unit of heat input (Btu), but a significant increase in the amount of biomass burned would result in sourcing from a larger geographical area, which would likely increase biomass fuel cost (and as mentioned above, would require modifications related to biomass fuel storage, fuel delivery, and boiler combustion air). The boiler can burn 100% coal for short periods of time (e.g., for stack testing at worst case conditions or during biomass fuel feed interruptions). However, at 100% coal firing a large amount of caustic is required in the wet scrubber to meet the SO_2 SIP emissions limit. The boiler also must burn at least 10% biomass on an annual heat input basis to maintain its classification as a biomass hybrid suspension grate boiler under Boiler MACT. The fuel mix balances operational cost and compliance with environmental requirements.

Thanks!

Amy Marshall / Technical Director

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From: Amy Marshall <amarshall@ALL4INC.COM>
Sent: Tuesday, March 02, 2021 9:44 AM
To: Strait, Randy P <randy.strait@ncdenr.gov>; Meyer, Daniel <Daniel.Meyer@everpack.com>
Cc: Steven Moore <smoore@all4inc.com>; Mohr, Andrew <Andrew.Mohr@everpack.com>; Syslo, Paul <Paul.Syslo@everpack.com>
Subject: RE: [External] RHR Four-Factor Analysis for Blue Ridge Paper Products LLC Canton Mill

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Thanks!

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From: Strait, Randy P <randy.strait@ncdenr.gov>
Sent: Monday, February 22, 2021 3:45 PM
To: Meyer, Daniel <Daniel.Meyer@everpack.com>
Cc: Amy Marshall <amarshall@ALL4INC.COM>; Steven Moore <smoore@all4inc.com>; Mohr, Andrew <Andrew.Mohr@everpack.com>; Syslo, Paul <Paul.Syslo@everpack.com>; Abraczinskas, Michael <michael.abraczinskas@ncdenr.gov>; Pjetraj, Michael <michael.pjetraj@ncdenr.gov>; Manning, Tammy <tammy.manning@ncdenr.gov>; Bartlett, Joshua W <joshua.bartlett@ncdenr.gov>
Subject: RE: [External] RHR Four-Factor Analysis for Blue Ridge Paper Products LLC Canton Mill

Hello Dan,

I want to make you aware that the NC Division of Air Quality (DAQ) has received a request from a member of the public to review the draft reasonable progress analysis/four-factor analysis (RPA/4FA) for Blue Ridge Paper Products. Because the draft RPA/4FA is public information, the DAQ has posted this information on the DAQ’s website as we need to make it available to all the public in order to fulfill the request from the stakeholder. This information is now posted on our website at:
https://deq.nc.gov/about/divisions/air-quality/air-quality-planning/state-implementation-plans/regional-haze-state-sip

We noted on our website that the information is draft and subject to change based on the DAQ’s, EPA’s, and Federal Land Manager’s (FLM) review.

Our current schedule is to start the 60-day mandatory FLM review process by mid-March and post the draft SIP for public comment by mid- to late-May.

We look forward to receiving the additional information we requested through Amy a couple of weeks ago.

Please let me know if you have any questions.

Thank you,
Randy

Randy Strait
Chief, Planning Section
Division of Air Quality

North Carolina Department of Environmental Quality

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From: Amy Marshall <amarshall@ALL4INC.COM>
Sent: Monday, March 15, 2021 8:06 AM
To: Strait, Randy P <randy.strait@ncdenr.gov>; Claire Corta <ccorta@ALL4INC.COM>
Subject: [External] RE: EPA Comments on 4FA for Domtar and BRPP

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Hi Randy –

1. As we discussed, there is a section in the report that provides the estimated remaining useful life of the boilers evaluated, but the cost estimate for each control device uses the estimated equipment life for each type of control device, based on examples in the cost manual or other similar reports. Section 1, Chapter 2 (Cost Estimation: Concepts and Methodology) of the Control Cost Manual specifies that the "lifetime not only varies according to the type of the control system, but with the severity of the environment in which it is installed," which indicates that one particular value should not be used in every single case.
2. As stated in the Four-Factor Analysis, if DAQ determines that additional controls are reasonable, it will likely take 3 years to complete installation. It is not likely that the current low prime rate of 3.25% will be in place at that time, as the economy is recovering from the COVID downturn. The prime rate when many states started requesting four factor analyses was 4.75% in October 2019, down from a 5-year high of 5.5% from 12/20/18 to 7/31/19. According to https://www.jpmorganchase.com/about/our-business/historical-prime-rate the prime rate can change multiple times per year and the current 3.25% prime rate is the historical low. Use of a low interest rate and an overly high estimate of equipment life artificially depresses the capital recovery factor in the cost estimates, resulting in a low annualized capital cost. Any capital investment in controls deemed reasonable under the RH SIP would be taking investment dollars away from mill projects that would have a return on investment. The cost estimates are not site-specific assessments based on engineering studies – they are estimates based on similar published analyses. Therefore, it is reasonable to use conservative values within the estimate itself, as we have done, in order to factor in contingency.

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From: Strait, Randy P <randy.strait@ncdenr.gov>
Sent: Friday, March 12, 2021 11:30 AM
To: Amy Marshall <amarshall@ALL4INC.COM>; Claire Corta <ccorta@ALL4INC.COM>
Subject: EPA Comments on 4FA for Domtar and BRPP

Amy and Claire, here are EPA comments on the 4FA for Domtar and BRPP. I sent EPA a response to #1 noting that costs were calculated using the control equipment life rather than the remaining useful life of the emission source (and pointed them to the tables in the 4FA documenting the equipment life). Please review #2 and let me know your thoughts.

1. Remaining Useful Life (RUL): EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019 (2019 Guidance) recommends that states can consider this factor by considering the useful life of the control system rather than the source, unless the source (or in this case, the emission unit(s)) is under an enforceable requirement to cease operation (see p.33). (Another avenue for using the unit's RUL is if the control device is a switch to a lower sulfur fuel.) We recommend to follow the 2019 Guidance for RUL and update the RUL values based on the controls being evaluated. For reference, this comment applies to both Domtar and BRPP: (BRPP): Section 2.5 states that: "The boilers included in this FFA are assumed to have a remaining useful life of 25 years or more." (Domtar): "The No. 2 Hog Fuel Boiler has a remaining useful life of twenty years or more."

2. Interest Rates used in the Domtar and BRPP 4FAs:
Excerpt: An interest rate of 4.75% and the typical values for equipment life shown in the OAQPS Cost Manual examples were used to calculate the capital recovery factor. A 4.75% interest rate represents the prime rate just prior to the COVID-19 pandemic and is representative because the prime rate has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018.
EPA's Air Pollution Control Cost Manual (CCM) recommends to use the current bank prime interest rate (see link in footnote (1)) or use a firm-specific rate that is justified by the source that is being examined (see CCM section 2.5.2, pp. 15-17, at link listed in footnote (2)). The 4FA excerpt regarding interest rates above does not fall into either category that would be acceptable under the CCM and thus, we recommend that the State use one of these two ways to identify the interest rates to be used.

Regarding the firm-specific interest rate justification, the responsibility for its justification is on the source if its position is that the bank prime interest rate is not appropriate for capital investments included in their 4FA. Relevant information from its normal process of deciding on a capital investment will be helpful as part of a justification for a firm-specific interest rate, whether that information pertains to the use of debt (borrowing) or the firm's equity, or a combination of both.

Footnotes:
(1) To identify the current bank prime interest rate, go to: https://www.federalreserve.gov/releases/h15/ (go to "bank prime loan" rate in the table).
(2) The most current version of Section 2.5.2 of the CCM is located at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

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From: Strait, Randy P
Sent: Wednesday, May 12, 2021 11:00 AM
To: Amy Marshall; Meyer, Daniel
Cc: Steven Moore; Mohr, Andrew; Syslo, Paul; Manning, Tammy; Bartlett, Joshua W; Curry, Dan; Pjetraj, Michael; Abraczinskas, Michael
Subject: RE: [External] RHR Four-Factor Analysis for Blue Ridge Paper Products LLC
Canton Mill

Amy and Dan,

This is to request that BRPP revise the four-factor analysis and submit it to the NCDAQ for inclusion in
the pre-hearing draft SIP. If you would like to arrange a Teams meeting to discuss please let me know. I
will be on vacation next week so if you have time this week I will be available after 1:00 pm today, after
12:00 pm Thursday, and all day Friday.

Schedule: NCDAQ would like to receive the revised four-factor analysis by May 28. However, we will
need to confirm if the federal land managers will have comments on the four-factor analysis and if so
when we will receive the comments. If we receive FLM comments late we will give you time to address
them.

Revisions to the Four-Factor Analysis: Please revise the analysis to address the following comments.

A. EPA’s 3-22-2021 comments on draft four-factor analysis (see email dated March 24, 2021)
1. Interest Rate: Revise using the current prime rate of 3.25%
2. Equipment Life for milled Trona dry sorbent injection (DSI) system: Revise from 20 to 30 years. If
you disagree with this change, please provide a detailed explanation to justify 20 years for the
equipment life.
3. Auxiliary Power Costs: Please address EPA’s comments.
4. Property Taxes for DSI: Please remove.

B. NCDAQ Comments:
1. Riley Bark Boiler: Please incorporate the responses from your March 02, 2021 email (see below)
regarding increasing the use of biomass (i.e., why it is technically not feasible).

C. EPA Comments on Draft SIP submitted to NCDAQ
EPA requested that we explain why the wet scrubber and dry sorbent injection are technically

infeasible. NCDAQ revised the following table (included in the draft SIP) to address these
comments. Please review and revise the information in the table if you are able to improve on the
response.

BRPP’s Boiler Control Technologies Identified and Evaluated for Technical Feasibility
Control Technology
Feasible
Explanation
Convert to natural gas
No
Insufficient local/regional supply to fuel any of the three boilers.
Convert to biomass
No
For the Riley Coal and No. 4 Power Boilers, the boiler designs preclude replacing coal with biomass.
Wet scrubber
No
Wet scrubbers with 90% control efficiency already installed on all three boilers. It was considered technically
infeasible to add additional caustic to exceed the design limitations of the scrubbers.
Convert coal to ultra-low
sulfur diesel (ULSD)
Yes
Completed four-factor analysis for all three boilers.
Dry sorbent injection
(DSI)
Yes (for
2 units)
Completed four-factor analysis for Riley Coal and No. 4 Power Boilers. Considered infeasible for Riley Bark Boiler
because this unit does not have any dry control device for PM. A PM control device is necessary to remove the
injected sorbent material from the flue. Use of DSI without PM control would drastically increase PM emissions.
Convert Riley Bark Boiler
to 100% biomass
No
The design of the over-fire air system as well as the size and limited potential for expansion of the biomass storage,
delivery and feed systems prevent the firing of 100% biomass. Co-firing coal also promotes stable boiler operation
and more uniform and efficient combustion because the biomass characteristics (moisture content, size and shape,
etc.) can exhibit short-term variability, impacting boiler efficiency.[1]
[1] Biomass conversion of Riley Bark Boiler is discussed in March 2, 2021 email provided as an addendum

to the Blue Ridge four-factor analysis in Appendix G-1d.

Thank you,
Randy

Randy Strait
Chief, Planning Section
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From: Amy Marshall <amarshall@all4inc.com>
Sent: Tuesday, June 01, 2021 8:37 AM
To: Strait, Randy P; Meyer, Daniel
Cc: Steven Moore; Mohr, Andrew; Syslo, Paul; Manning, Tammy; Bartlett, Joshua W; Curry, Dan;
Pjetraj, Michael; Abraczinskas, Michael
Subject: RE: [External] RHR Four-Factor Analysis for Blue Ridge Paper Products LLC Canton Mill
Attachments: BRPP 4-Factor Analysis (052821).pdf

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attachment to Report Spam.

Hi Randy – here is the revised Four Factor Analysis. Please let us know if you have further questions or
receive further comments. Thanks!

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Regional Haze Rule Four-Factor Analysis for the Blue Ridge Paper Products LLC Canton Mill

Revised May 2021

Submitted by:

Blue Ridge Paper Products LLC
PO Box 4000
Canton, NC 28716

Submitted to:

NC Department of Environmental Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

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LIST OF APPENDICES

1. INTRODUCTION

The North Carolina Department of Environmental Quality (DEQ) Division of Air Quality (DAQ) is in the process of developing a State Implementation Plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DAQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of visibility impairing pollutants, such as sulfur dioxide (SO_2), for the 2021-2028 planning period. DAQ has requested that several facilities within the State submit a Four-Factor Analysis (FFA) to examine the feasibility of additional SO_2 emissions controls. This report provides the Blue Ridge Paper Products (BRPP) Canton Mill's FFA for the following emissions sources, as requested in Part III of DAQ's June 18, 2020 letter:

- Riley Coal Boiler
- No. 4 Power Boiler
- Riley Bark Boiler

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available Retrofit Technology (BART). Specifically, the BART provisions required states to conduct an evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the New Source Performance Standards (NSPS) at 40 CFR Part 60. The purpose of the program was to identify older emission units that contributed to haze at Class I areas that could be retrofitted with emissions control technology to reduce emissions and improve visibility in these areas. The BART requirement applied to emissions units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;
2. The units are located at facilities in one of 26 NSPS categories; and

3. The units have a total potential-to-emit (PTE) of at least 250 tpy of NO_X, SO_2, and PM_{10} from all BART-era emissions units at the same facility.

National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR Part 63, which require the use of Maximum Achievable Control Technology (MACT) that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART." The Canton Mill's major sources of SO_2 are all subject to MACT requirements.

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, "there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area."[1] The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas or ultra-low sulfur diesel, and sources that are already well-controlled for SO_2. In addition, as the goal of the state's analysis is to identify measures that would contribute to reasonable progress, it is not reasonable to evaluate sources with very low emissions.

This report focuses on the three significant sources of SO_2 emissions at the Canton Mill that DAQ requested BRPP evaluate. We note that all the Canton Mill's SO_2 emissions sources are subject to federally-enforceable permit limits designed such that the mill demonstrates compliance with the 1-hour SO_2 national ambient air quality standard (NAAQS) via air dispersion modeling. Prior to incorporation of those emissions limits into the permit in September 2019, the Mill spent a

[1] EPA-457/B-19-003, August 2019, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period."

significant amount of capital to make changes that decreased actual SO_2 emissions by over 5,000 tons per year. An ambient monitor is also sited adjacent to the mill and confirms that mill impacts are well below the stringent 1-hour SO_2 NAAQS. Therefore, mill SO_2 emissions are already well controlled.

Section 2 of this report provides a detailed FFA for SO_2 emissions from the Mill's three solid fuel-fired boilers. Appendix A presents the control cost calculations and Appendix B presents supporting information.

1.1 FOUR-FACTOR ANALYSIS

Pursuant to 40 CFR 51.308(f)(2)(i), DAQ has requested that the Mill address the following four factors to determine if additional emissions control measures are necessary to make reasonable progress toward natural visibility conditions at nearby Class I areas:

- The cost of compliance
- Energy and non-air quality impacts of compliance
- The time necessary for compliance
- Remaining useful life of existing affected sources

BRPP has addressed these factors for additional control options that could be applied to the Canton Mill's solid fuel-fired boilers using available site-specific data, capital costs of controls from U.S. EPA publications or previous analyses (either company-specific or for similar sources), and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual and U.S. EPA fact sheets. The Mill has not performed additional site-specific engineering analyses for this study, but has used readily available information to determine if additional emissions controls may be feasible and cost effective. The emissions reduction expected for each control technology evaluated was based on a typical expected control efficiency and projected actual emissions during the second planning period. Evaluating cost effectiveness based on actual emissions provides a better representation of the true cost of each technology to the Mill than an evaluation based on allowable emissions.

The current prime rate of 3.25% and the typical values for equipment life shown in the OAQPS Cost Manual examples were used to calculate the capital recovery factor. Labor and fuel costs are based on mill-specific values.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 provides basic information regarding the sources that were evaluated in detail. The sources evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants (HAPs) and are already well controlled. The Mill's boilers are subject to NESHAP at 40 CFR 63, Subpart DDDDD, that require the use of MACT. While the MACT standards are intended to minimize HAP emissions, they also directly reduce criteria pollutant emissions and promote good combustion practices. The No. 4 Power Boiler is also subject to an NSPS SO_2 limit at 40 CFR 60, Subpart D. All three boilers are equipped with wet scrubbers designed and operated to achieve an SO_2 control efficiency of 90 percent.

Table 1-1
Summary of Emissions Sources Evaluated

Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	SO_2 Removal Efficiency	Projected 2028 Actual SO_2 Emissions (tons/year)	Major Regulatory Programs
Riley Coal Boiler (G11039)	1946	Coal Natural gas/kerosene ignitors	Electrostatic precipitator (ESP) Wet scrubber	90%	184	MACT DDDDD
No. 4 Power Boiler (G11040)	1986	Coal Natural gas startup burners	ESP Wet scrubber	90%	195	MACT DDDDD NSPS D
Riley Bark Boiler (G11042)	1952	Biomass and coal Kerosene used during startup	Wet scrubber	90%	65	MACT DDDDD

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

In the past few years, the Mill has made significant SO_2 emissions reductions. As shown in Table 1-1, the Mill is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including the use of clean fuels for startup and a limitation on fuel oil use to periods of natural gas curtailment for boilers in the gas 1 subcategory. Emission standards for HCl also serve to limit emissions of SO_2.

In order to comply with both Boiler MACT and the SO_2 NAAQS, the mill recently invested more than 45 million dollars in capital. In 2017, two new natural gas-fired boilers were installed and two older coal-fired boilers were shutdown. In 2018, the mill replaced No. 6 fuel oil with ultra-low sulfur diesel (ULSD) as the startup fuel on both recovery furnaces, rebuilt the ESPs and installed new wet scrubbers on the Riley Coal and No. 4 Power Boilers, and adjusted operation of the Riley Bark Boiler wet scrubber to reduce SO_2 emissions.

The projected mill-wide SO_2 emissions during the second planning period are approximately 485 tons per year compared to the 2017 actual emissions of 5,875 tons, representing a 90% reduction in SO_2 emissions. DAQ has indicated that air quality modeling shows the Mill impacts visibility at the Shining Rock Wilderness Area by slightly more than 1 percent. The haziness index at Shining Rock on the 20% most impaired days in 2017 was approximately 15 deciviews, compared to the uniform rate of progress (glide path) goal of approximately 24 deciviews in 2018 and approximately 21 deciviews in 2028. The recent SO_2 emissions reductions from the Mill should contribute to further improvement in the haziness index at Shining Rock during the second RHR planning period.

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the FFA.
- **Section 2 – Four-Factor Analysis for Boilers:** provides the FFA for the solid-fuel boilers.
- **Section 3 – Summary of Findings:** presents a summary of the FFA.
- **Appendix A – Control Cost Analyses**
- **Appendix B – Supporting Information**

2. FOUR-FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of the FFA for SO_2 emissions from the three solid fuel-fired industrial boilers at the Mill. To evaluate the cost of compliance portion of the FFA, the following steps were performed:

- identify available control technologies,
- eliminate technically infeasible options, and
- evaluate cost effectiveness of remaining controls.

The time necessary for compliance, energy and non-air environmental impacts, and remaining useful life were also evaluated.

2.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for industrial boilers was determined based on a review of the RBLC database[2] and knowledge of typical controls used on boilers in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 2-1 summarizes the potentially feasible SO_2 control technologies for industrial boilers.

[2] RACT/BACT/LAER Clearinghouse (RBLC). https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information

Table 2-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet scrubber Dry sorbent injection (DSI)

Technically feasible control technologies for industrial boilers were evaluated, taking into account current air pollution controls, fuels fired, and RBLC database information. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. U.S. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[3]

2.1.1 Available SO_2 Control Technologies

The potentially feasible control technologies for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Generation of SO_2 in a boiler is proportional to the amount of sulfur in the fuel being fired. Natural gas, No. 2 fuel oil (including kerosene and ULSD), and biomass are considered low-sulfur fuels.

Wet Scrubbers

In a wet scrubber, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that

[3] https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf

has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to dry particulate matter (PM) air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device (e.g., fabric filter) to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same or similar type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same or similar type of emissions unit, it is presumed to be technically feasible. However, an available technology cannot be eliminated as infeasible simply because it has not been used on the same type of unit that is under review. If the technology has not been operated successfully on the type of unit under review, its lack of "availability" and "applicability" to the particular unit type under review must be documented in order for the technology to be eliminated as technically infeasible.

The No. 4 Power Boiler is equipped with natural gas startup burners and burns pulverized coal during normal operation. The Riley Coal Boiler is equipped with natural gas/kerosene ignitors and burns pulverized coal during normal operation. These two boilers are each equipped with an ESP and a wet scrubber. The wet scrubbers were installed to reduce emissions of hydrogen chloride for compliance with Industrial Boiler NESHAP requirements and to reduce emissions of SO_2 and achieve compliance with the 1-hour SO_2 NAAQS. The wet scrubbers were designed and are operated to achieve 90 percent control of SO_2 emissions, which is equivalent to what would be required under new source performance standards at 40 CFR 60, Subpart Db. Operation of the scrubbers outside of their design limitations is not feasible.

The Riley Bark Boiler is a hybrid suspension/grate design and burns a mixture of biomass and coal during normal operation. It is equipped with a wet venturi scrubber that achieves about 90 percent control of SO_2 emissions. Operation of the wet scrubber at a higher pH to achieve a higher control efficiency is not feasible because it would result in excessive scaling and plugging of the scrubber due to precipitation of calcium in the bark and require more frequent cleaning of the scrubber, negatively impacting emissions and boiler operation.

Replacing coal with a lower-sulfur fuel would be a technically feasible way to reduce SO_2 emissions from the three boilers. The design of each boiler precludes replacing coal firing with biomass. Riley Coal and No. 4 Boilers were designed to burn coal. Although the Riley Bark Boiler burns a mixture of coal and biomass (about 60% coal and 40% biomass on an annual basis), it is not feasible to increase the amount of biomass burned in the boiler for various reasons, as described below.

The Riley Bark Boiler is not designed to burn 100% biomass at full steam load. The boiler combustion air system does not provide sufficient overfire air to support 100% biomass firing while maintaining compliance with current permit limits for particulate matter, carbon monoxide and opacity. The biomass storage, delivery and feed systems are not sized to support firing 100% biomass. The mill is landlocked and has no additional space available to expand biomass storage capacity to support the amount of biomass storage that would be necessary for firing 100% biomass. In addition, a significant increase in the amount of biomass burned would result in sourcing fuel from a larger geographical area, which could increase cost. Co-firing coal also promotes stable boiler operation and more uniform and efficient combustion because the biomass characteristics (moisture content, size and shape, etc.) can exhibit short-term variability, impacting boiler efficiency. Co-firing some biomass with coal reduces the amount of caustic needed in the scrubber to meet applicable requirements. The current fuel mix is based on boiler design, storage capability, cost, and environmental requirements.

The mill currently burns the available natural gas supply in its package boilers, lime kilns, and calender nip heaters and uses natural gas as a startup fuel for No. 4 Power Boiler. There is currently no additional supply of gas available to the mill to replace coal with natural gas in any of the three boilers. Significant infrastructure upgrades would be required to the local and regional gas supply in order to replace coal with natural gas in any of the three boilers. Replacing coal with natural gas is not feasible at this time. Replacing coal with ULSD was evaluated.

DSI in the form of trona injection prior to the ESP was evaluated for Riley Coal and No. 4 Power Boilers. DSI was not evaluated for the Riley Bark Boiler because there is no dry control device for particulate matter on this boiler. Adding DSI would overload the wet scrubber and increase PM emissions.

The wet scrubbers serving all three boilers are designed to achieve 90% removal of SO_2. It is not feasible to add additional caustic to further increase the removal efficiency of the existing wet scrubbers.

2.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls were considered technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed company project costs, or EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated using the annualized capital and operating costs and the amount of pollutant expected to be removed based on the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. Each boiler's 2028 projected SO_2 emissions and a typical expected control efficiency were used as the basis for emissions reductions and cost effectiveness calculations.

Technically feasible control technologies were evaluated for cost effectiveness by source as summarized in Table 2-2.

Table 2-2
Control Technologies Evaluated for Boilers

Emissions Unit	Fuels Fired	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Riley Coal Boiler (G11039)	Coal Natural gas/kerosene ignitors	Electrostatic precipitator (ESP) Wet scrubber	Replace coal with ULSD DSI
No. 4 Power Boiler (G11040)	Coal Natural gas startup burners	ESP Wet scrubber	Replace coal with ULSD DSI
Riley Bark Boiler (G11042)	Biomass and coal Kerosene used during startup	Wet scrubber	Replace coal with ULSD

Cost estimates for each feasible pollution control technique are presented in Appendix A. These are screening level cost estimates and are not based on detailed engineering studies of mill boilers.

Although DAQ has not indicated what additional controls they would consider cost effective, similar analyses performed by U.S. EPA and others were reviewed to get a general idea of the level above which additional controls on industrial boilers are not cost effective. As part of the 2016 CSAPR update rule[4], U.S. EPA performed an analysis to characterize whether there were non-electric generating unit (EGU) source groups with a substantial amount of available cost-effective NO_X reductions achievable by the 2017 ozone season. They evaluated control costs for non-EGU point sources with NO_X emissions greater than 25 tpy in 2017.[5] U.S. EPA did not further examine control options above $3,400 per ton. This is consistent with the range U.S. EPA analyzed for EGUs in the proposed and final CSAPR rules and is also consistent with what the U.S. EPA has identified in previous transport rules as cost-effective, including the NO_X SIP call. Notably, $3,400 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NO_X SIP call, adjusted to the 2011 dollars used throughout the CSAPR update proposal. Adjustments of costs were made using the Chemical Engineering Plant Cost Index (CEPCI) annual values for 1990 and 2011.) Note that industrial boilers were among the source categories that the very conservative U.S. EPA cost analysis determined were above $3,400/ton. In addition, the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high.[6] The costs presented in this report were developed using conservative assumptions and almost all are significantly above these thresholds.

2.3.1 Site-Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints and availability of low-sulfur fuels. A

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[4] 81 Fed. Reg. 74504

[5] Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500, Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance, U.S. EPA, November 2015.

[6] https://www.wrapair.org//forums/mtf/documents/group_reports/TechSupp/SO2Tech.htm

detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

2.3.2 SO_2 Economic Impacts

Replacing coal with ULSD was evaluated for the three boilers. The capital cost of installing ULSD burners was not evaluated, but the operating cost (calculated based on the current difference in price between coal and ULSD and the projected amount of coal that will be fired in 2028) demonstrates this approach is not cost effective.

Table 2-3
ULSD Cost Summary

Emissions Unit Description	Capital Cost ($)	Operating Cost ($/yr)	SO_2 Removed (tons/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Riley Coal Boiler (G11039)	Not determined	$22,920,384	181.82	$126,060
No. 4 Power Boiler (G11040)	Not determined	$32,154,379	192.42	$167,107
Riley Bark Boiler (G11042)	Not determined	$10,205,397	55.00	$185,565

The capital cost for a DSI system to inject milled trona prior to the ESP on the Riley Coal Boiler and No. 4 Power Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[7] Mill-specific labor and chemical costs were used to estimate the annual cost of operating the DSI system. A 30-year equipment life was used at EPA's suggestion. The Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing particulate matter emissions. Table 2-4 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology

[7] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

for the Riley Coal and No. 4 Power Boilers, based on operating data and projected 2028 actual emissions.

Table 2-4
DSI System Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Removed (tons/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Riley Coal Boiler (G11039)	$5,413,330	$1,372,032	91.9	$14,932
No. 4 Power Boiler (G11040)	$5,404,505	$1,573,329	97.6	$16,119

Installing DSI is not considered cost effective because the estimated capital cost is more than $5 million per boiler and the minimum cost effectiveness value is over $14,000/ton of pollutant removed.

2.3.3 Energy and Non-Air Related Impacts

Adding DSI systems would increase energy use. The additional particulate from the trona collected in the particulate control devices would be disposed of in the mill landfill. This would reduce the remaining useful life of the mill landfill and increase truck traffic through the streets of Canton.

2.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls after the effective date of the final standard. Although our FFA shows there are no additional controls that would be reasonable, if controls are ultimately required to meet RHR requirements, the Mill would need at least three years to implement them after final EPA approval of the RHR SIP. The Mill would need time to obtain corporate approvals for capital funding. The Mill would have to undergo substantial re-engineering (*e.g.*, due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The Mill would also need to execute air permit modifications, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate mill systems, the availability of contractors, and the like. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

If multiple units required retrofit controls, construction would need to be staggered so only one unit was out of service at a time to allow some level of continued operation during a retrofit. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

2.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The boilers included in this FFA are assumed to have a remaining useful life of 25 years or more.

2.6 CONCLUSION

Based on the FFA presented above, no additional controls were determined to be reasonable or cost effective for the Mill's industrial boilers.

3. SUMMARY OF FINDINGS

The emission sources at the BRPP Canton Mill are already well-controlled and are subject to various stringent emission limits. However, in response to a request from DAQ, BRPP evaluated whether additional emissions controls for SO_2 are feasible for significant emissions units.

As part of the FFA, the following information was reviewed: site-specific emissions and controls information, industry- and site-specific cost data, publicly-available cost data, previous similar control evaluations, the U.S. EPA RBLC database, and U.S. EPA's OAQPS Control Cost Manual. The best information available in the time allotted to perform the analyses was used.

Our review of the best available information indicates that additional emissions controls for SO_2 are either not feasible or not cost effective. Any determination that additional controls are reasonable would need to be justified based on a more detailed evaluation that fully considers site-specific factors. In addition, it is important to note the following points:

- All the Canton Mill's SO_2 sources are subject to federally-enforceable emissions limits and monitoring requirements that serve to demonstrate compliance with the 1-hour SO_2 NAAQS.
- The Mill has reduced SO_2 emissions over 5,000 tpy since 2017.
- The three solid fuel-fired boilers included in the FFA are all equipped with wet scrubbers that were designed to reduce SO_2 emissions by at least 90 percent.
- The boilers at the Canton Mill are subject to Boiler MACT emission limits and work practices that became effective in May 2019. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the requirement to startup on clean fuel limits emissions of HAPs and criteria pollutants, including SO_2.
- U.S. EPA will continue the required process to evaluate acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology review for NESHAP Subpart DDDDD sources.

- U.S. EPA determined in its CSAPR rulemaking that controls on non-EGU combustion units are not cost effective.

APPENDIX A -
CONTROL COST ESTIMATES

Table A-1
ULSD Direct Cost Summary

Emissions Unit			Riley Coal Boiler	No. 4 Power Boiler	Riley Bark Boiler*
Fuels Fired	Coal	Cost ($/ton)	$90	$95	$107
		HHV (Btu/lb)	13,500	13,500	13,500
	ULSD	Cost ($/gallon)	$1.72	$1.72	$1.72
		HHV (Btu/gallon)	140,000	140,000	140,000
2028 Projected Coal Firing					
Coal Firing (tons)			94,900	135,947	45,454
Coal Firing (MMbtu)			2,562,300	3,670,569	1,227,258
2028 SO_2 Projected Emissions (tpy)			183.77	195.21	55.93
Coal Firing Cost ($)			$8,541,000	$12,914,965	$4,863,578
2028 Equivalent ULSD Firing					
Equivalent ULSD Firing (gallons)			18,302,143	26,218,350	8,766,129
ULSD SO_2 Emissions Factor (lb/gallon)			2.13E-04	2.13E-04	2.13E-04
2028 SO_2 Projected Emissions (tpy)			1.95	2.79	0.93
ULSD Firing Cost ($)			$31,461,384	$45,069,344	$15,068,975
Economic Impacts					
SO_2 Reduction (tpy)			181.82	192.42	55.00
SO_2 Reduction (%)			99%	99%	98%
Annual SO_2 Reduction Cost ($)			$22,920,384	$32,154,379	$10,205,397
Annual SO_2 Reduction Cost ($/ton)			$126,060	$167,107	$185,565

* SO_2 emissions from coal combustion only.

Table A-2
BRPP Canton - Riley Coal Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	35	399 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.14	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	3.99E+08	399 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.42	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.06	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.0663	Dec 2020 NC industrial electricity cost per EIA
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	183.8
Controlled SO_2 Emissions:	91.9

Capital Costs				
Direct Costs				
BM (Base Module)	-	$	$ 4,296,294	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	$	$ 429,629	10% BM
Labor adjustment	A2	$	$ 214,815	5% BM
Contractor profit and fees	A3	$	$ 214,815	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 5,155,553	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 257,778	5% CECC
Total project cost w/out AFUDC	TPC	$	$ 5,413,330	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 5,413,330**	CECC+B1+B2

Table A-2
BRPP Canton - Riley Coal Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs						
Fixed O&M Cost						
Additional operating labor costs	FOMO	$		$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$		$	42,963	BM*0.01/B
Additional administrative labor costs	FOMA	$		$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**		**$**	**154,883**	FOMO+FOMM+FOMA
Variable O&M Cost						
Cost for Sorbent	VOMR	$		$	140,521.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$		$	629,041.0	(N+P)*S
Additional auxiliary power required	VOMP	$		$	3.42	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**		**$**	**769,565.6**	VOMR+VOMW+VOMP
Indirect Annual Costs						
General and Administrative	2%		of TCI	$	108,267	
Property Tax	0%		of TCI	$	-	(1% - removed at the request of EPA)
Insurance	1%		of TCI	$	54,133	
Capital Recovery	5.27%		x TCI	$	285,184	
Total Indirect Annual Costs				**$**	**447,583**	
Life of the Control:	30		years		3.25%	interest (30 year life is per EPA suggestion, 3.25% is COVID prime rate)
Total Annual Costs				**$**	**1,372,032**	
Total Annual Costs/SO_2 Emissions				**$**	**14,932**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

Table A-3
BRPP Canton - No. 4 Power Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	47	535 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.11	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	5.35E+08	535 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.90	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.04	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.0663	Dec 2020 NC industrial electricity cost per EIA
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	195.2
Controlled SO_2 Emissions:	97.6

Capital Costs				
Direct Costs				
BM (Base Module)	-	$	$ 4,289,290	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	$	$ 428,929	10% BM
Labor adjustment	A2	$	$ 214,464	5% BM
Contractor profit and fees	A3	$	$ 214,464	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 5,147,148	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 257,357	5% CECC
Total project cost w/out AFUDC	TPC	$	$ 5,404,505	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 5,404,505**	CECC+B1+B2

Table A-3
BRPP Canton - No. 4 Power Boiler
Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	42,893	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**154,812**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	139,716.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	831,944.1	(N+P)*S
Additional auxiliary power required	VOMP	$	$	2.69	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**971,663.0**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	108,090	
Property Tax	0%	of TCI	$	-	(1% - removed at the request of EPA)
Insurance	1%	of TCI	$	54,045	
Capital Recovery	5.27%	x TCI	$	284,719	
Total Indirect Annual Costs			**$**	**446,854**	
Life of the Control:	30	years		3.25%	interest (30 year life is per EPA suggestion, 3.25% is COVID prime rate)
Total Annual Costs			**$**	**1,573,329**	
Total Annual Costs/SO_2 Emissions			**$**	**16,119**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

APPENDIX B -
SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

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DSI Cost Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs, such as project contingency, that a facility would incur to install a retrofit control.

Technology Description

Dry sorbent injection (DSI) is a viable technology for moderate SO_2/HCl reduction on coal-fired boilers. Demonstrations and utility testing have shown SO_2/HCl removals greater than 80% for systems using sodium-based sorbents. The most commonly used sodium-based sorbent is Trona. However, if the goal is only HCl removal, the amount of sorbent injection will be significantly lower. In this case, Trona may still be the most commonly used reagent, but hydrated lime also has been employed in some situations. Because of Trona's high reactivity with SO_2, when this sorbent is used, significant SO_2 removal must occur before high levels of HCl removal can be achieved. Studies show, however, that hydrated lime is quite effective for HCl removal because the need for simultaneous SO_2 removal is much reduced. In either case, actual testing must be carried out before the permanent DSI system for SO_2 or HCl removal is designed.

The level of removal for Trona can vary from 0 to 90% depending on the Normalized Stoichiometric Ratio (NSR) and particulate capture device. NSR is defined as follows:

$$\frac{\dfrac{\text{(moles of Na injected)}}{\text{(moles of } SO_2 \text{ in flue gas)}}}{\text{(theoretical moles of Na required)}}$$

DSI Cost Methodology

The required injection rate for alkali sorbents can vary depending on the required removal efficiency, NSR, and particulate capture device. The costs for an SO_2 mitigation system are primarily dependent on sorbent feed rate. This rate is a function of NSR and the required SO_2 removal (the latter is set by the utility and is not a function of unit size). Therefore, the required SO_2 removal is determined by the user-specified SO_2 emission limit, and the cost estimation is based on sorbent feed rate and not unit size. Because HCl concentrations are low compared with SO_2 concentrations, any unused reagent for SO_2 removal is assumed to be used for HCl removal, resulting in a very small change in the NSR used for SO_2 removal when HCl removal is the main goal.

The sorbent solids can be collected in either an ESP or a baghouse. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs because the presence of filter cake on the bags allows for a longer reaction time between the sorbent solids and the flue gas. Thus, for a given Trona removal efficiency, the NSR is reduced when a baghouse is used for particulate capture.

The dry-sorbent capture ability is also a function of particle surface area. To increase the particle surface area, the sorbent must be injected into a relatively hot flue gas. Heating the solids produces micropores on the particle surface, which greatly improve the sulfur capture ability. For Trona, the sorbent should be injected into flue gas at temperatures above 275°F to maximize the micropore structure. However, if the flue gas is too hot (greater than 800°F), the solids may sinter, reducing their surface area and thus lowering the SO_2 removal efficiency of the sorbent.

Another way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Typically, Trona is delivered unmilled. The ore is ground such that the unmilled product has an average particle size of approximately 30 μm. Commercial testing has shown that the reactivity of the Trona can be increased when the sorbent is ground to produce particles smaller than 30 μm. In the cost estimation methodology, the Trona is assumed to be delivered in the unmilled state only. To mill the Trona, in-line mills are continuously used during the Trona injection process. Therefore, the delivered cost of Trona will not change; only the reactivity of the sorbent and amount used change when Trona is milled.

Ultimately, the NSR required for a given removal is a function of Trona particle size and particulate capture equipment. In the cost program, the user can choose either as-delivered Trona (approximately 30 μm average size) or in-line milled Trona (approximately 15 μm average size) for injection. The average Trona particle size and the type of particulate removal equipment both contribute to the predicted Trona feed rate.

DSI Cost Methodology

Establishment of the Cost Basis

For wet or dry FGD systems, sulfur removal is generally specified at the maximum achievable level. With those systems, costs are primarily a function of plant size and target sulfur removal rate. However, DSI systems are quite different. The major cost for the DSI system is the sorbent itself. The sorbent feed rate is a function of sulfur generation rate, particulate collection device, and removal efficiency. To account for all of the variables, the capital cost was established based on a sorbent feed rate, which is calculated from user input variables. Cost data for several DSI systems were reviewed and a relationship was developed for the capital costs of the system on a sorbent feed-rate basis.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The sulfur feed rate and NSR are the major variables for the cost estimate. The NSR is a function of the following:

- Removal efficiency,
- Sorbent particle size, and
- Particulate capture device.

A retrofit factor that equates to difficulty in construction of the system must be defined. The gross unit size and gross heat rate will factor into the amount of sulfur generated.

Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO_2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO_2. A baghouse used with sodium-based sorbents generally achieves a higher SO_2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO_2/MMBtu.

Units with a baghouse and limited NO_X control that target a high SO_2 removal efficiency with sodium sorbents may experience a brown plume resulting from the conversion of NO to NO_2. The formation of NO_2 would then have to be addressed by adding an adsorbent, such as activated carbon, into the flue gas. However, many coal-fired units control NO_X to a sufficiently low level that a brown plume should not be an issue with sodium-based DSI. Therefore, this algorithm does not incorporate any additional costs to control NO_2.

DSI Cost Methodology

The equations provided in the cost methodology spreadsheet allow the user to input the required removal efficiency, within the limits of the technology. To simplify the correlation between efficiency and technology, SO_2 removal should be set at 50% with an ESP and 70% with a baghouse. The simplified sorbent NSR would then be calculated as follows:

For an ESP at the target 50% removal —
Unmilled Trona NSR = 2.00
Milled Trona NSR = 1.40

For a baghouse at the target 70% removal —
Unmilled Trona NSR = 1.90
Milled Trona NSR = 1.50

The algorithm identifies the maximum expected HCl removal based on SO_2 removal. The HCl removal should be limited to achieve 0.002 lb HCl/MBtu to meet the Mercury Air Toxics (MATS) regulation. The hydrated lime algorithm should be used only for the HCl removal requirement. For hydrated lime injection systems, the SO_2 removal should be limited to 20% to achieve maximum HCl removal.

The correlation could be further simplified by assuming that only milled Trona is used. The current trend in the industry is to use in-line milling of the Trona to improve its utilization. For a minor increase in capital, milling can greatly reduce the variable operating expenses, thus it is recommended that only milled Trona be considered in the simplified algorithm.

Outputs

Total Project Costs (TPC)

First, the base installed cost for the complete DSI system is calculated (BM). The base installed cost includes the following:

- All equipment,
- Installation.
- Buildings,
- Foundations,
- Electrical, and
- Average retrofit difficulty.

The base module cost is adjusted by the selection of in-line milling equipment. The base installed cost is then increased by the following:

DSI Cost Methodology

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 5% of the BM cost; and
- Contractor profit and fees at 5% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include the following:

- Owner's home office costs (owner's engineering, management, and procurement) are added at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) is added at 0% of the CECC and owner's costs because these projects are expected to be completed in less than a year.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the DSI installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 2 additional operators are required for a DSI system. The FOMO is based on the number of additional operations staff required.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of the following:

- Reagent use and unit costs,
- Waste production and unit disposal costs, and
- Additional power required and unit power cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per megawatt-hour (MWh) basis.
- The additional power required includes increased fan power to account for the added DSI system and, as applicable, air blowers and transport-air drying equipment for the SO_2 mitigation system.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The reagent usage is a function of NSR and the required SO_2 removal. The estimated NSR is a function of the removal efficiency required. The basis for total reagent rate purity is 95% for hydrated lime and 98% for Trona.
- The waste-generation rate, which is based on the reaction of Trona or hydrated lime with SO_2, is a function of the sorbent feed rate. The waste-generation rate is also adjusted for excess sorbent fed. The reaction products in the waste for hydrated lime and Trona mainly contain $CaSO_4$ and Na_2SO_4 and unreacted dry sorbent such as $Ca(OH)_2$ and Na_2CO_3, respectively.
- The user can remove fly ash disposal volume from the waste disposal cost to reflect the situation where the unit has separate particulate capture devices for fly ash and dry sorbent.
- If Trona is the selected sorbent, the fly ash captured with this sodium sorbent in the same particulate control device must be landfilled. Typical ash content for each fuel is used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for a total waste stream in the O&M analysis.

DSI Cost Methodology

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are as follows:

- Reagent cost in $/ton.
- Waste disposal costs in $/ton that should vary with the type of waste being disposed.
- Auxiliary power cost in $/kWh; no noticeable escalation has been observed for auxiliary power cost since 2012.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

The total VOM is the sum of VOMR, VOMW, and VOMP. The additional auxiliary power requirement is also reported as a percentage of the total gross power of the unit. Table 1 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of an ESP. Table 2 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of a baghouse. Table 3 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona injection ahead of an ESP. Table 4 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona ahead of a baghouse. Table 5 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime injection ahead of an ESP. Table 6 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime ahead of a baghouse.

DSI Cost Methodology

Table 1. Example of a Complete Cost Estimate for a Milled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	16.33	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	13.12	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation	Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284)) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284))	$	18,348,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		37	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,835,000	Engineering and Construction Management costs
A2 = 5% of BM	$	917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	917,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**22,017,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	1,101,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**23,118,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**23,118,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.37	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.89**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	5.55	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.39	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**9.33**	

DSI Cost Methodology

Table 2. Example of a Complete Cost Estimate for a Milled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		0.85	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	9.67	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.20	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

	Example		Comments
Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,812,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM ($/KW) =		32	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,581,000	Engineering and Construction Management costs
A2 = 5% of BM	$	791,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	791,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**18,975,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	949,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**19,924,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**19,924,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.32	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.29	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.89	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.41**	

DSI Cost Methodology

Table 3. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<— User Input
Retrofit Factor	B		1	<— User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<— User Input
SO2 Rate	D	(lb/MMBtu)	2	<— User Input
Type of Coal	E		Bituminous	<— User Input
Particulate Capture	F		ESP	<— User Input
Sorbent	G		Unmilled Trona	<— User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.98	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	22.54	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	17.71	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	Q	(%)	0.81	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<— User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<— User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<— User Input
Operating Labor Rate	U	($/hr)	60	<— User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$ 18,168,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		36	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 1,817,000	Engineering and Construction Management costs
A2 = 5% of BM		$ 908,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$ 908,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 21,801,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 1,090,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 22,891,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 22,891,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$ 0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$ 0.36	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$ 0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$ 0.88**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A		$ 10.14	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$ 3.84	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$ 0.49	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$ 14.47**	

DSI Cost Methodology

Table 4. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Unmilled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.12	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	12.79	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	10.50	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.46**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,468,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		31	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,547,000	Engineering and Construction Management costs
A2 = 5% of BM	$	773,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	773,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**18,561,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**37**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	928,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**19,489,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**39**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**19,489,000**	Total project cost
TPC ($/kW) =		**39**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	5.76	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.12	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.28	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**9.16**	

DSI Cost Methodology

Table 5. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	30	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.90	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	10.85	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	95	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	12.18	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	14,762,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		30	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,476,000	Engineering and Construction Management costs
A2 = 5% of BM	$	738,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	738,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**17,714,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**35**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	886,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**18,600,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**37**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**18,600,000**	Total project cost
TPC ($/kW) =		**37**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.30	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.81**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.26	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.29	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.78**	

DSI Cost Methodology

Table 6. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.09	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	6.19	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	99	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.41	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.22**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	12,588,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		25	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,259,000	Engineering and Construction Management costs
A2 = 5% of BM	$	629,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	629,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**15,105,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**30**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	755,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**15,860,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**32**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**15,860,000**	Total project cost
TPC ($/kW) =		**32**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.25	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.77**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	1.86	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.91	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.13	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**4.91**	

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DEM 04-22
Transmitted via Email

January 17, 2022

Mr. Randy Strait
Planning Section Chief
NC Department of Environmental Quality
Division of Air Quality (DAQ)
1641 Mail Service Center
Raleigh, NC 27699-1641

Subject: **Blue Ridge Paper Products LLC Responses to Additional Comments on the Regional Haze Four Factor Analysis**

Dear Mr. Strait:

Blue Ridge Paper Products LLC (BRPP) in Canton, North Carolina submitted a four-factor analysis (FFA) of the feasibility of additional sulfur dioxide (SO_2) controls on its solid fuel-fired boilers in support of DAQ's preparation of the 2021 draft Regional Haze State Implementation Plan (SIP). We understand from our December 13, 2021 conversation with you that DAQ received comments on the draft SIP related to our FFA and would like our input on some of the questions. Our responses to the comments you provided are below.

Comment: In Table A-2 of its report, BRPP indicates that the inlet to a DSI system for the Riley Boiler would be 0.14 lbs/MMBtu. This value is very low and obviously does not reflect uncontrolled coal-fired SO_2. Presumably, since the boiler is equipped with an ESP and some type of scrubber, this value reflects the installation of a DSI system downstream of the existing wet scrubber. BRPP should verify this is the only installation strategy. BRPP states that this figure is based on "Projected 2028 emissions divided by projected 2028 fuel use." This is a very inaccurate method to arrive at such an important input to the DSI cost analysis, especially considering the required performance testing and monitoring required by its permit. BRPP should provide data to support this figure.

Response: The Riley Coal Boiler and No. 4 Power Boiler are already equipped with wet scrubbers that achieve 90 percent SO_2 control. BRPP has submitted test reports to DAQ that support the actual emissions levels used in the analysis and the wet scrubbers are continuously monitored according to the requirements of the Title V permit. The FFA evaluated an incremental level of control that would be achieved by a DSI system and only costed the additional amount of sorbent that would be necessary to achieve that incremental level of control. We used projected actual 2028 emissions, not potential emissions, as instructed by DAQ.

Comment: On page 2-8 of its report, BRPP justified its 50% DSI SO_2 control stating, "The Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing particulate matter emissions." However, that figure does not reflect the maximum control efficiency of DSI using an ESP. The same report that BRPP cites indicates that the maximum removal efficiency for milled Trona with an ESP is 80%. A similar comment also pertains to BRPP's DSI cost-analysis for the No. 4 Power Boiler.

Response: We disagree. The report does not characterize the 80% removal as being achieved by an ESP. Based on the following excerpt from the Sargent and Lundy report, the 80% removal likely refers to a baghouse: "Trona, when captured in an ESP, typically removes 40 to 50% of SO_2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO_2. A baghouse used with sodium-based sorbents generally achieves a higher SO_2 removal efficiency (70 to 90%) than that of an ESP."

Comment: In its DSI cost analysis for the Riley Boiler, BRPP should explain its calculation of a 35 MW boiler equivalent, which assumes a 399 MMBtu/hr value with only a 30% efficiency. This efficiency appears low and BRPP should provide documentation for it, as it is a key input into the DSI cost-effectiveness calculation. A similar comment also pertains to BRPP's DSI cost-analysis for the No. 4 Power Boiler.

Response: The cost equations in the Sargent and Lundy report to EPA and the recently revised EPA Control Cost Manual are all based on electric utility boiler installations. BRPP operates a combined heat and power system, not an electric utility grade system. The mill's boilers are described in terms of heat input, not power output (the Riley Coal Boiler is rated at 399 MMBtu/hr and the No. 4 Power Boiler is rated at 535 MMBtu/hr). The Mill's steam turbines utilize low-pressure steam from Mill boilers and recovery furnaces to produce the power utilized at the Mill, so in reality, the heat input to megawatt output conversion is actually much lower than 30 percent (for example, according to the energy assessment performed as required by the Boiler MACT, No. 8 turbine generator can accept 320,000 pounds per hour of 408 psi steam and produce 7.5 MW of power). Therefore, to attempt to produce the input required by the costing models, we used a typical value of 30 percent. The reference book "Introduction to Environmental Science and Engineering," 2nd Edition, states the following in Section 1.4, Energy Fundamentals: "New fossil-fuel-fired power plants have efficiencies around 40 percent. ... The average efficiency of all thermal plants actually in use in the United States, including new and old (less efficient) plants, fossil and nuclear, is close to 33 percent." Our estimate of 30 percent efficiency is valid for use in the DSI equations since the object is to input the boiler size in terms of power output that might be achieved by a utility boiler of equivalent size and age.

Comment: In its DSI cost analysis for the Riley Boiler, BRPP assumes an owners cost of $257,778. This is a disallowed cost under the Control Cost Manual methodology, which states "owner's costs and AFUDC costs are capital cost items that are not included in the EPA Control Cost Manual methodology, and thus are not included in the total capital investment (TCI) estimates in this section." A similar comment also pertains to BRPP's DSI cost-analysis for the No. 4 Power Boiler.

Based on 2%, and 1% of TCI, BRPP assumes general and administrative and insurance costs of $108,267 and $54,133 in its DSI cost analysis for the Riley Boiler. These costs may be appropriate when calculating cost-effectiveness using primary design equations, as is done in some chapters of the Control Cost Manual. However, these costs are not part of the standard IPM methodologies (Sargent & Lundy under contract to EPA) and are not appropriate when using those algorithms. All of these algorithms are based on statistical calculations of public and proprietary cost figures and inherently assume these costs. A similar comment also pertains to BRPP's DSI cost-analysis for the No. 4 Power Boiler.

Response: The new Control Cost Manual spreadsheets for DSI were not available at the time we prepared our FFA. Therefore, we used costing methodology prepared for EPA by its contractor, Sargent and Lundy, based on power plant costing models, and attempted to adjust them to estimated annual costs similar to the Control Cost Manual. If we remove the cost items at issue, DSI is still not cost effective.

Comment: The DSI cost figures calculated by BRPP are based on IPM algorithms produced by Sargent and Lundy under contract to EPA. The newest version, used by BRPP, produces costs in 2016 dollars.42 On page 291 of its SIP, NC DEQ states, "[t]he calculations were done using 2020 dollars." However, that would require using the Chemical Engineering Plant Cost Index (CEPCI) to make that adjustment and it does not appear that NC DEQ has done that. Doing so would result in a multiplier to the annualized cost of 596.2/541.7.

Response: The EPA cost spreadsheets assume a cost year of 2016. Adjusting the cost to year 2020 serves to increase the estimated cost. We have attached revised cost spreadsheets (Tables A-2 and A-3) to show that DSI is not cost effective. (We also note that a brief look at the new EPA cost manual spreadsheets also produces values that are not cost effective.)

BRPP invested significant capital over the past five years in order to reduce both actual and allowable sulfur dioxide (SO_2) emissions from the Canton Mill by over 5,000 tons per year. BRPP supports the determination that our existing controls demonstrate reasonable progress and that no additional controls are reasonable or feasible for the second planning period. DAQ correctly determined that BRPP's obligations in the existing source-specific SO_2 SIP are sufficient and it is not necessary to include further requirements for BRPP in the Regional Haze SIP.

If you require additional information, please contact Mr. Dan Meyer at (828) 492-6290 or Mr. Andrew Mohr at (828) 492-6814.

Sincerely,

John McCarthy
General Manager, Canton and Waynesville Operations
Blue Ridge Paper Products LLC

Attachments

cc: Dan Meyer, Canton Mill
Andrew Mohr, Canton Mill

Table A-3 - Revised

BRPP Canton - No. 4 Power Boiler

Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	47	535 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.11	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	5.35E+08	535 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.90	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.04	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.0663	Dec 2020 NC industrial electricity cost per EIA
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	195.2
Controlled SO_2 Emissions:	97.6

Capital Costs					
Direct Costs					
BM (Base Module)	-	$	$	4,289,290	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	428,929	10% BM
Labor adjustment	A2	$	$	214,464	5% BM
Contractor profit and fees	A3	$	$	214,464	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	5,147,148	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	257,357	5% CECC
Total project cost w/out AFUDC	TPC	$	$	5,404,505	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$			0% of (CECC+B1) [deleted per comment]
Total Capital Investment	**TCI**	**$**	**$**	**5,948,248**	[CECC+B1+B2] * 596.2 / 541.7 (To convert to 2020 dollars)

Table A-3 - Revised

BRPP Canton - No. 4 Power Boiler

Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	42,893	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**154,812**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	139,716.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	831,944.1	(N+P)*S
Additional auxiliary power required	VOMP	$	$	2.69	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**971,663.0**	VOMR+VOMW+VOMP
Indirect Annual Costs					
					Deleted per comments
					Deleted per comments
					Deleted per comments
Capital Recovery	5.27%	x TCI	$	313,364	
Total Indirect Annual Costs			**$**	**313,364**	
Life of the Control:	30	years		3.25%	interest (30 year life is per EPA suggestion, 3.25% is COVID prime rate)
Total Annual Costs			**$**	**1,439,839**	
Total Annual Costs/SO_2 Emissions			**$**	**14,752**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

Table A-2 - Revised

BRPP Canton - Riley Coal Boiler

Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	35	399 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	11,380	
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.14	Projected 2028 emissions divided by projected 2028 fuel use
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% target reduction.
Heat Input	J	Btu/hr	3.99E+08	399 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.10	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.08	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	1.42	Ash in Bituminous Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.06	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.0663	Dec 2020 NC industrial electricity cost per EIA
Operating Labor Rate	U	$/hr	26	Labor cost including all benefits
Operating Hours		hr/yr	8,400	Assumed Operating Time.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	183.8
Controlled SO_2 Emissions:	91.9

Capital Costs					
Direct Costs					
BM (Base Module)	-	$	$	4,296,294	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	429,629	10% BM
Labor adjustment	A2	$	$	214,815	5% BM
Contractor profit and fees	A3	$	$	214,815	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	5,155,553	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	257,778	5% CECC
Total project cost w/out AFUDC	TPC	$	$	5,413,330	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$			0% of (CECC+B1) [deleted per comment]
Total Capital Investment	**TCI**	**$**	**$**	**5,957,961**	[CECC+B1+B2] * 596.2 / 541.7 (To convert to 2020 dollars)

Table A-2 - Revised

BRPP Canton - Riley Coal Boiler

Capital and Annual Costs Associated with Milled Trona DSI System Prior to the ESP

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	108,160	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	42,963	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	3,760	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**154,883**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	140,521.2	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	629,041.0	(N+P)*S
Additional auxiliary power required	VOMP	$	$	3.42	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**769,565.6**	VOMR+VOMW+VOMP
Indirect Annual Costs					
					Deleted per comments
					Deleted per comments
					Deleted per comments
Capital Recovery	5.27%	x TCI	$	313,876	
Total Indirect Annual Costs			**$**	**313,876**	
Life of the Control:	30	years		3.25%	interest (30 year life is per EPA suggestion, 3.25% is COVID prime rate)
Total Annual Costs			**$**	**1,238,324**	
Total Annual Costs/SO_2 Emissions			**$**	**13,477**	

[a]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.