Appendix G-2

Reasonable Progress Assessment for Domtar Paper Company, LLC – Plymouth, NC

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Appendix G-2a

Four-Factor Analysis for Domtar Paper Company, LLC – Plymouth, NC

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Correspondence Record

Date	From	To	Description
May 4, 2020	NCDAQ	Domtar	Request to review 2028 SO_2 emissions and PSAT modeling, evaluate sources for four-factor analysis
May 12, 2020	Domtar	NCDAQ	Revised emissions estimates
May 22, 2020	NCDAQ	Domtar	Request four-factor analysis on three units using updated emissions and revised PSAT modeling results
July 17, 2020	Domtar	NCDAQ	Four-factor analysis of requested units for SO_2 control
March 2, 2021	Domtar	NCDAQ	Supplemental Information for Regional Haze Rule Four-Factor Analysis
March 15, 2021	Domtar	NCDAQ	Email response to EPA comments on four-factor analysis
May 12, 2021	NCDAQ	Domtar	Request for revised four-factor analysis based on pre-draft comments from EPA and FLMs
May 28, 2021	Domtar	NCDAQ	Revised four-factor analysis

ROY COOPER
Governor

MICHAEL S. REGAN
Secretary

MICHAEL ABRACZINSKAS
Director

NORTH CAROLINA
Environmental Quality

May 4, 2020

Everick Spence
Mill Manager
Domtar Paper Company, LLC
PO Box 747
NC Highway 149 North
Plymouth, NC 27962

Subject: Regional Haze Reasonable Progress Assessment for Second Planning Period

Dear Mr. Spence:

The North Carolina Division of Air Quality (DAQ) is preparing the North Carolina 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 Domtar Paper Company (Domtar) in Plymouth, North Carolina have been shown to contribute ≥1% to visibility impairment at the Swanquarter National Wildlife Refuge.

I am requesting that Domtar review the projected 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 Domtar 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 May 15, 2020. The DAQ will review your submittal and notify you by May 22, 2020, if it is necessary for Domtar 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 Domtar 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 Domtar, 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: Robert Bright, NCDAQ
Betsy Huddleston, NCDAQ
Tammy Manning, NCDAQ
Randy Strait, NCDAQ
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 Swanquarter National Wildlife Refuge. 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 Swanquarter National Wildlife Refuge. 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 Swanquarter National Wildlife Refuge.

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 (Domtar's contribution to Swanquarter was 3.3%). 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% 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 Domtar Paper Company in Plymouth, North Carolina have been shown to contribute 1% to visibility impairment at the Swanquarter National Wildlife Refuge.

Step 4: Evaluate 2028 emissions.

For the 2028 modeling analysis, the DAQ projected 2028 non-EGU point source emissions from EPA's 2016 modeling platform that includes emissions that North Carolina facilities submitted to the DAQ. The DAQ projected 2028 SO_2 emissions to be about 687 tons for Domtar by applying growth and control factors to 2016-year emissions. For each SO_2 emission unit at Domtar, Table 1 shows historical emissions for 2016-2018, projected 2028 emissions, and the growth and control factors applied to 2016 emissions to estimate 2028 emissions. Table 2 provides a cross-reference between Group and Permit IDs for the SO_2 emission units in Table 1. Please review the 2028 projected emissions and notify the DAQ if these estimates are reasonable or not. If you provide revised 2028 estimates, please explain the methodology and assumptions for the revised estimates. Please respond to this request by May 15, 2020.

If you can document controls or process modifications that have been implemented since 2016 (or will be implemented before 2028) that significantly lower the DAQ's 2028 emission estimates for your facility, the DAQ will use the PSAT modeling results for your facility to determine if the revised emissions will significantly lower the contribution to visibility impairment at Swanquarter. 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 each of the hog fuel boilers (Nos. 1 and 2) at Domtar's Plymouth facility. You should submit the requested four-factor analyses by no later than July 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. Domtar – Plymouth (Facility ID 3711700069)
Actual Sulfur Dioxide Emissions for 2016 – 2018 and Projected Emissions for 2028

Unit ID	Unit Description	Annual SO_2 Emissions (Tons)				Control Factor (%)[1]	Growth Factor[2]
		2016	2017	2018	2028		
G-148	No. 2 Hog Fuel Boiler	526.28	555.74	635.15	505.23	4.0	1.00
G-143	No. 1 Hog Fuel Boiler	174.83	200.10	223.12	167.84	4.0	1.00
G-225	South smelt tank and salt cake mix tank	6.05	5.77	4.93	6.52		1.078
G-158	No. 5 Recovery Boiler	6.51	0.89	6.72	6.51		1.00
G-431	Lime Kiln No. 5 and crusher	0.78	0.77	0.66	0.84		1.078
G-258	Backup diesel and natural gas engines	0.68	0.56	1.20	0.37		0.541
G-408	Spill collection tank and white liquor surge tank	0.09	0.09	0.07	0.10		1.078
GR44	Material reuse handling of various by-product streams at the No. 3 landfill location	0.04	0.04	0.12	0.04		1.078
	Total	**715.26**	**763.96**	**871.97**	**687.45**		

[1] Control Factor: 4% reduction was applied to 2016 emissions to account for boiler tune-up required under Section 112 DDDDD Boiler Maximum Achievable Control Technology (MACT) rule effective for North Carolina sources on May 20, 2020.

[2] Growth Factors (GF) were applied to 2016 emissions to estimate 2028 emissions:

GF = 1.078: Average of the growth rates computed from projections of Paper industry employment and revenue for the southeast region (region that includes North Carolina); based on employment projections (available at 3-digit NAICS code level (322)) and revenue Projections (available at 4-digit NAICS code level (3221)).

GF = 0.541: Projected change in distillate fuel oil consumption in the Paper industry (NAICS 322) for the southeast region.

GF = 1.00: No growth assumption based on an analysis of 2010-2016 trend in wood/wood waste consumption (in million British thermal units) by Domtar (EIA plant ID 50189) as reported to EIA via Form-923.

Table 2. Domtar – Plymouth (Facility ID 3711700069)
Cross-reference between Group and Permit IDs for SO_2 Emission Units in Table 1

Unit ID	Permit ID
G-148	ES-65-25-0310
G-143	ES-64-25-0290
G-225	ES-10-08-0010, ES-14-05-0050, ES-14-05-0300
G-158	ES-10-25-0110
G-431	ES-14-60-3000, ES-14-60-3015
G-258	ES-14-60-3000a,ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580, ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580, ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580
G-408	ES-08-65-1060, ES 08-70-0900
GR44	IES-KLime

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.

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

Domtar

Domtar Paper
Company, LLC
Plymouth Mill
P.O. Box 747
Highway 149 North
Plymouth, NC 27962
Tel: (252) 793-8111

May 12, 2020

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

Certified Mail
Return Receipt Requested

Re: Review of Projected 2028 Emissions for Regional Haze Analysis
Domtar Paper Company, LLC Mill in Plymouth, NC
Permit No. 04291T47/Facility ID 07/59/00069

Dear Mr. Strait:

On May 4, 2020, Domtar Paper Company, LLC – Plymouth Mill (Domtar or Mill) received a letter from the North Carolina Division of Air Quality (DAQ) requesting that Domtar review the projected 2028 Sulfur Dioxide (SO_2) emissions upon which the DAQ's contribution assessment was based for the Regional Haze Second Planning Period. Domtar reviewed the projected 2028 SO_2 emissions presented in Table 1 of DAQ's request and is providing an update as described below and in Attachment 1.

On August 15, 2018, DAQ issued Permit No. 04291T45 authorizing the Mill Optimization Project that is intended to improve efficiency and streamline operations. The project includes installation of a Thermal Oxidizer (TOx) as a backup control device for High Volume, Low Concentration (HVLC) pulp mill gases as use of No. 1 Hog Fuel Boiler (HFB1) is phased out. The TOx started up in July of 2019 and the HFB1 will be permanently shut down prior to 2028. Table 1 has been updated to include SO_2 emissions from combusting HVLC gases in the TOx and to remove future emissions from the HFB1. SO_2 emissions as a result of firing HVLC gases in the TOx are calculated based on sampling of the HVLC header conducted in 2014, assuming 100% conversion of sulfur compounds to SO_2, and actual pulp production data during use of the TOx.

The bulk of the SO_2 emissions from No. 2 Hog Fuel Boiler (HFB2) are from combustion of pulp mill non-condensable gas (NCG) because the main fuel fired in HFB2 is biomass. In December 2019, Domtar conducted emissions testing for multiple pulp mill NCG firing scenarios in HFB2 to obtain updated emissions factors representing the current

configuration of the Mill. Domtar performed follow-up testing in March 2020 and May 2020 to gather additional data. For reporting year 2019, Domtar is updating the SO_2 emissions calculation methodology when firing NCG's in HFB2 to more accurately calculate emissions.

Domtar is providing an update to the 2028 SO_2 emissions projection using 2019 as a more representative base year (in place of 2016) to reflect the Optimization Project and the recent HFB2 SO_2 test data. The attachment includes an update to Table 1 provided by DAQ. Table 2 of the attachment includes the basis of the 2028 emissions estimates for the hog fuel boilers and thermal oxidizer. The growth factors provided by DAQ were applied to 2019 emissions in order to project 2028 emissions, excluding use of the 4% control factor for boiler tune-ups because the tune-up has already been performed.

Should the DAQ have any questions concerning Domtar's update to the 2028 SO_2 emissions projection, please contact Don Wynne by phone at (252) 793-8984 or by email at Don.Wynne@domtar.com or Claire Corta by phone at (919) 578-4195 or by email at ccorta@all4inc.com.

Sincerely,

Diane R. Hardison
EH&S Manager

Everick W. Spence
Mill Manager

cc: Don Wynne - Domtar
Claire Corta - ALL4
Betsy Huddleston – NC DAQ- WaRO

Attachment 1 – Update to 2028 Emissions Projection

Attachment 1
Update to 2028 Emissions Projection

Table 1. Domtar - Plymouth (Facility ID 3711700069)
Actual Sulfur Dioxide Emissions for 2016-2019 and Projected Emissions for 2028

Unit ID	Unit Description	Annual SO_2 Emissions (Tons)					Control Factor (%)[1]	Growth Factor[2]
		2016	2017	2018	2019[4]	2028		
G-148	No. 2 Hog Fuel Boiler	526.28	555.74	635.15	877.87	1009.57	0.0	1.00
G-143	No. 1 Hog Fuel Boiler	174.83	200.10	223.12	58.22	0.00	0.0	0.00
TOx	Thermal Oxidizer	N/A	N/A	N/A	85.81	85.96		1.00
G-225	Smelt Dissolving Tanks and salt cake mix tank	6.05	5.77	4.93	5.08	5.47		1.078
G-158	No. 5 Recovery Boiler	6.51	6.89[3]	6.72	5.91	5.91		1.00
G-431	Lime Kiln No. 5 and Crusher	0.78	0.77	0.66	0.58	0.63		1.078
G-258	Backup diesel and natural gas engines	0.68	0.56	1.20	1.22	0.66		0.541
G-408	Spill collection tank and white liquor surge tank	0.09	0.09	0.07	0.07	0.08		1.078
GR44	Material reuse handling of various by-product streams at the No. 3 landfill location	0.04	0.04	0.12	0.12	0.13		1.078
	Total Emissions:	715.26	763.07	871.97	1034.87	1108.41		

1) Control Factor: Removed 4% control factor since 2028 emissions were updated to be based on 2019 emissions.
The 4% reduction was originally applied to 2016 emissions to account for boiler tune-up required under Section 112 DDDDD Boiler Maximum Achievable Control Technology (MACT) rule effective for North Carolina sources on May 20, 2020.

2) Growth Factors (GF) were applied to 2019 emissions to estimate 2028 emissions as detailed below and in Table 2:

GF = 1.078: Average of the growth rates computed from projection of Paper industry employment and revenue for the southeast region (region that includes North Carolina); based on employment projections (available at 3-digit NAICS code level (322)) and revenue Projections (available at 4-digit NAICS code level (3221)).

GF = 0.541: Projected change in distillate fuel oil consumption in the Paper industry (NAICS 322) for the southeast region.

GF = 1.00: No growth assumption based on an analysis of 2010-2016 trend in wood/wood waste consumption (in million British thermal units) by Domtar (EIA plant ID 50189) as reported to EIA via Form-923.

3) Corrected a typo for 2017 emissions from the No. 5 Recovery Boiler Group G-158 from 0.89 to 6.89.

4) Draft 2019 Emissions to be submitted to NC DAQ with the reporting year 2019 air emissions inventory due June 30, 2020

Table 2: Domtar - Plymouth (Facility ID 3710700069)
2028 Sulfur Dioxide Emissions from No. 1 and 2 Hog Fuel Boilers and HVLC Thermal Oxidizer

Unit ID	Unit Description	Reference	Firing Scenario	Throughput	Throughput Units	Emission Factor	Emission Factor Units	2028 SO_2 Emissions (tons/yr)
G-148	No. 2 Hog Fuel Boiler	1	LVHC/SOG + Fuel	58,384	ODTUBP/yr	7.48	lb/ODTUBP	218.36
G-148	No. 2 Hog Fuel Boiler	2	LVHC/SOG + Fuel (WLS Offline)	6,737	ODTUBP/yr	8.91	lb/ODTUBP	30.01
G-148	No. 2 Hog Fuel Boiler	3	HVLC + Fuel	415,766	ODTUBP/yr	3.66	lb/ODTUBP	760.85
G-148	No. 2 Hog Fuel Boiler	4	Hog Fuel and Natural Gas (No NCG)	431,519	MMBtu/yr	1.63E-03	lb/MMBtu	0.35
G-143	No. 1 Hog Fuel Boiler	7	Shut Down	0	ODTUBP/yr	3.66	lb/ODTUBP	0.00
TOx	Thermal Oxidizer	5	Natural Gas (No NCG)	15	MMSCF/yr	0.6	lb/MMSCF	4.35E-03
TOX	Thermal Oxidizer	6	HVLC and Natural Gas	34,723	ODTUBP/yr	4.95	lb/ODTUBP	85.96

1) Emissions factor from March 2020 stack test when firing hog fuel, natural gas, and LVHC/SOG.

2) Emissions factor from May 2020 stack test when firing hog fuel, natural gas, and LVHC/SOG with white liquor scrubber offline.

3) Emissions factor from December 2019 stack test on No. 2 HFB when firing hog fuel, natural gas, and HVLC.

4) Emissions factor from December 2019 stack test on No. 2 HFB when firing hog fuel and natural gas.

5) Emissions factor from AP-42, Table 1.4-2.

6) 2014 Max HVLC Header Data. Assuming 100% Sulfur to SO2. HVLC includes lignin plant operation.

7) 2028 Throughput is assumed to be equal to 2019 throughput and fuel use multiplied by the growth factors, except HVLC firing has been reallocated to represent the projection for current firing configuration. HVLC gases are presently fired in the No. 2 Hog Fuel Boiler and in the Thermal Oxidizer as back up. Beginning in 2019, HVLC gases can no longer be burned in No. 1 Hog Fuel Boiler and this boiler will be shut down by 2028.

ROY COOPER
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NORTH CAROLINA
Environmental Quality

May 22, 2020

Everick Spence
Mill Manager
Domtar Paper Company, LLC
PO Box 747
NC Highway 149 North
Plymouth, NC 27962

Subject: Regional Haze Reasonable Progress Assessment for Second Planning Period

Dear Mr. Spence:

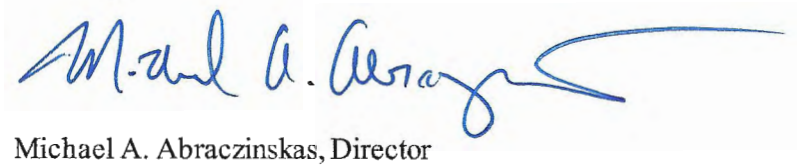
Thank you for your letter dated May 12, 2020, responding to my May 4, 2020 letter. I appreciate you reviewing the North Carolina Division of Air Quality's (DAQ) projected 2028 sulfur dioxide (SO_2) emissions for the Domtar Paper Company (Domtar) in Plymouth, North Carolina and providing revised 2028 emissions for the nine SO_2 emission units at the facility. As noted in your letter, Domtar developed SO_2 emissions for 2019 based on the Mill's Optimization Project that is intended to improve efficiency and streamline operations as authorized under Permit No. 04291T45 issued by the DAQ on August 15, 2018. Domtar then projected 2019 emissions to 2028 using the growth factors applied by DAQ in developing the initial 2028 SO_2 emission estimates that you reviewed. Relative to the DAQ's original 2028 emissions projections, the revised emissions provided in your letter increased SO_2 emissions by 61.2% (420.96 tons) with the majority of the emissions associated with the No. 2 Hog Fuel Boiler and Thermal Oxidizer.

The DAQ used the revised 2028 SO_2 emissions you provided and recalculated Domtar's contribution to visibility impairment for the 20% most impaired days at Swanquarter National Wildlife Refuge using the PSAT modeling approach referenced in my May 4, 2020 letter. The revised PSAT results indicate that Domtar's contribution would increase from 1.00% to 1.61% in 2028.

In establishing reasonable progress goals, the 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 Domtar's Plymouth facility as outlined in Part III of my May 4, 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 July 31, 2020. 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: Robert Bright, NCDAQ
Betsy Huddleston, NCDAQ
Tammy Manning, NCDAQ
Randy Strait, NCDAQ
Central Files

Domtar Paper
Company, LLC
Plymouth Mill
P.O. Box 747
Highway 149 North
Plymouth, NC 27962
Tel: (252) 793-8111

July 17, 2020

Certified Mail
Return Receipt Requested
7017 0530 0000 8572 3943

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

Re: Regional Haze Rule Four-Factor Analysis
Domtar Paper Company, LLC Mill in Plymouth, NC
Permit No. 04291T47/Facility ID 07/59/00069

Dear Mr. Strait:

On May 4, 2020, Domtar Paper Company, LLC – Plymouth Mill (Domtar or Mill) received a letter from the North Carolina Division of Air Quality (DAQ) requesting that Domtar review the projected 2028 Sulfur Dioxide (SO_2) emissions upon which the DAQ's contribution assessment was based for the Regional Haze Second Planning Period. Domtar reviewed the projected 2028 SO_2 emissions and provided DAQ with an updated 2028 emissions projection on May 12, 2020 using 2019 as a more representative base year (in place of 2016) to reflect the Optimization Project and the recent No. 2 Hog Fuel Boiler SO_2 test data.

On May 22, 2020, Domtar received a letter from the DAQ requesting that the Mill conduct a four-factor analysis for the SO_2 emission sources outlined in Part III of the May 4, 2020 letter (Nos. 1 and 2 Hog Fuel Boilers). Please find enclosed the requested Regional Haze Rule Four-Factor Analysis. Based on the enclosed analysis, no additional SO_2 emissions controls were determined to be cost effective for the Mill's hog fuel boilers.

Should the DAQ have any questions on Domtar's Four-Factor Analysis, please contact Don Wynne by phone at (252) 793-8984 or by email at Don.Wynne@domtar.com or Claire Corta by phone at (919) 578-4195 or by email at ccorta@all4inc.com.

Sincerely,

Diane R. Hardison
EH&S Manager

Everick W. Spence
Mill Manager

cc: Don Wynne - Domtar
Claire Corta – ALL4
Betsy Huddleston – NC DAQ- WaRO

Enclosure

Regional Haze Rule Four-Factor Analysis for the Domtar Paper Company Plymouth Mill

July 2020

Submitted by:

Domtar Paper Company – Plymouth Mill
P.O. Box 747
Highway 149 North
Plymouth, NC 27962

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 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 Domtar Paper Company's (Domtar's) FFA for SO_2 emissions from the following units at the Plymouth, NC Mill, as requested in Part III of DAQ's May 4, 2020 letter:

- No. 1 Hog Fuel Boiler
- No. 2 Hog Fuel 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 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.

MACT standards 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." Sources demonstrating compliance with MACT and BART are already well controlled. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

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, and sources that are already well-controlled. This report focuses on two of the most significant sources of SO_2 emissions at the Domtar Plymouth pulp and paper mill, as per DAQ's request, and does not evaluate other well-controlled sources. Appendix A presents the control cost calculations and Appendix B presents supporting information.

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

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 SO_2 emissions control measures are necessary to make reasonable progress toward natural visibility conditions at 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

Domtar has addressed these factors for additional control options that could be applied to the hog fuel boilers at the mill 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 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 2028 actual emissions. 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. In addition, actual emissions are more representative of the 2021-2028 planning period than potential 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, chemical, and utility costs are based on mill-specific values for 2020.

1.2 SUMMARY OF SOURCES EVALUATED

Table 1-1 provides basic information regarding the sources that were evaluated in detail. The boilers 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. Industrial boilers are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), which require the use of Maximum Achievable Control Technology (MACT). While the MACT standards are intended to minimize HAP emissions, they also directly reduce acid gas emissions and promote good combustion practices. NSPS Subpart D contains emission limits for SO_2. The fuels fired by the hog fuel boilers are low-sulfur fuels (natural gas, No. 2 fuel oil, and biomass). The majority of the historical SO_2 emissions from these boilers result from combustion of pulp mill gases that contain sulfur compounds. These gases are combusted to meet the HAP emissions control requirements of 40 CFR 63, Subpart S. The alkaline nature of the bark fly ash provides some SO_2 capture.

Table 1-1
Summary of Emissions Sources Evaluated

Emissions Unit Description	Size, MMBtu/hr	Year Installed	Permitted Fuels	Control Technology	Major Regulatory Programs	2019 Actual SO_2 Emissions (tons)	Projected 2028 Actual SO_2 Emissions (tons)
No. 1 Hog Fuel Boiler[1]	1,021 (any combination of fuels) 835 (hog fuel with any other fuels)	1977	Lignin, natural gas, biomass, No. 2 fuel oil, used oil, sludge	PM: Electroscrubbers SO_2: Low-sulfur fuels and inherent bark scrubbing	NSPS Subpart D MACT Subpart DDDDD	58.22	0
No. 2 Hog Fuel Boiler[2]	889	1982	Lignin, natural gas, biomass, No. 2 fuel oil, used oil, sludge	PM: Electrostatic precipitator (ESP) SO_2: Low-sulfur fuels and inherent bark scrubbing	NSPS Subpart D MACT Subpart DDDDD	877.87	1,009.57

[1] The No. 1 Hog Fuel boiler is permitted to combust high-volume, low-concentration (HVLC) pulp mill gases but is no longer able to combust HVLC. This boiler will be permanently shutdown during the 2021-2028 planning period.
[2] The No. 2 Hog Fuel boiler can also combust HVLC and low-volume, high-concentration (LVHC) pulp mill gases and stripper off-gases (SOG).

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the mill has made emissions reductions for a variety of reasons. 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. In addition, the Plymouth Mill improved the PM control device on No. 2 Hog Fuel Boiler and is reducing utilization of No. 1 Hog Fuel Boiler and its associated emissions by transitioning to firing primarily natural gas, with No. 2 fuel oil as backup, and discontinuing combustion of HVLC in this boiler.

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 boilers evaluated.
- **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 two industrial boilers at the mill. To evaluate the cost of compliance portion of the FFA, Domtar performed the following steps:

- 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 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. Fuel switching from biomass to 100% natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. 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. 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] It is not reasonable as part of this analysis to convert an existing biomass boiler at a forest products mill to a natural gas-fired boiler because biomass boilers at forest products mills fire the biomass residuals from the mill processes as a readily available and relatively inexpensive source of fuel. In addition, the alkaline nature of bark fly ash serves to provide some SO_2 emissions capture.

2.1.1 Available SO_2 Control Technologies

Natural gas, No. 2 fuel oil, and biomass are considered low-sulfur fuels and are fired by the boilers included in this report. Natural gas and biomass combustion result in negligible SO_2 emissions. However, as mentioned above, the majority of the historical emissions from the hog fuel boilers (and the future actual SO_2 emissions from No. 2 Hog Fuel Boiler) are from combustion of HVLC, LVHC, and SOG that contain sulfur compounds that oxidize to SO_2. LVHC gases are treated by a white liquor scrubber for reduction of sulfur compounds prior to combustion in the No. 2 Hog

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

Fuel boiler, resulting in lower SO_2 emissions. The potentially feasible add-on control technologies for reducing emissions of SO_2 from industrial boilers are discussed in detail in this section.

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 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 and the amount of gas to liquid contact and residence time. 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 and prior to 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 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, hydrochloric acid 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. 1 Hog Fuel Boiler currently burns only natural gas and hog fuel, with low-sulfur No. 2 fuel oil as backup and is reducing hog fuel use. HVLC gases are no longer combusted and SO_2 emissions from No. 1 Hog Fuel Boiler are now very low. Additionally, the Mill plans to shut down No. 1 Hog Fuel Boiler during the 2021-2028 planning period. Therefore, there are no additional SO_2 controls beyond the current practice of combustion of low-sulfur fuels that are necessary to evaluate for this boiler.

Installing a wet scrubber following the No. 2 Hog Fuel Boiler ESP is considered technically feasible and was evaluated. Installing DSI in the form of trona injection prior to the No. 2 Hog Fuel Boiler ESP is also considered technically feasible and was evaluated.

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, source-specific vendor cost estimates, 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. Projected actual emissions and a typical expected control efficiency were used as the basis for emissions reductions.

Capital, operating, and total annual 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 site-specific engineering studies.

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. For example, 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

[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.

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 are 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. 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 – Wet Scrubber

The wet scrubber capital cost is based on a cost estimate provided by LDX Solutions on June 15, 2020 and the fan upgrade cost is from H. Clay Moore & Associates Inc. The cost estimate was based on design conditions obtained from 2020 air emissions testing on No. 2 Hog Fuel Boiler and discussions with the Mill. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1, operating data provided by LDX Solutions, and site-specific labor, chemical, and utility costs.

U.S. EPA indicates that a retrofit factor is appropriate when estimating the cost to install a control system on an existing facility, in order to address the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the cost of correcting design errors. A retrofit factor can be used to reflect additional difficulty associated with installing auxiliary equipment, special care in placing equipment, additional insulation and painting of piping and ductwork, additional site preparation, extra engineering or

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

supervision during installation, and unanticipated delays that cause lost production costs. The manual states that at the study cost level, a retrofit factor of as much as 50 % is justified, and even at the detailed cost level, a retrofit factor is often added. A retrofit factor of 1.3 was applied to the total capital cost as the vendor cost estimate was conducted remotely, an engineering study has not been performed, and production will be lost due to an extended Mill outage that is required for scrubber installation.

Table 2-2
Wet Scrubber Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
No. 2 Hog Fuel Boiler	$13,341,296	$4,106,120	$4,281

Installing a wet scrubber is not considered cost effective because the estimated capital cost is more than $13 million and the cost effectiveness value is over $4,000/ton of SO_2 removed.

2.3.3 SO_2 Economic Impacts – DSI

The capital cost for a system to inject milled trona prior to the ESP on the No. 2 Hog Fuel Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[7] Site-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing PM emissions. Table 2-3 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology for the No. 2 Hog Fuel Boiler, based on operating data and the projected 2028 actual SO_2 emissions.

[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.

Table 2-3
Trona Injection System Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
No. 2 Hog Fuel Boiler	$13,813,979	$11,647,397	$23,074

Installing trona injection is not considered cost effective because the estimated capital cost is more than $13 million and the cost effectiveness value is over $20,000/ton of SO_2 removed.

2.3.4 Energy and Non-Air Related Impacts

This section describes the energy and non-air environmental impacts associated with each add-on control option evaluated.

Additional electricity and water would be needed to run a wet scrubber and additional fan power would be required overcome the additional pressure drop through the wet scrubber. Other environmental and energy impacts associated with operating a wet scrubber include generation and disposal of wastewater. Additional electricity would be needed to operate a DSI system and it would create additional solid waste.

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 and 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.

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 SOURCES

The No. 1 Hog Fuel boiler will be permanently retired during the 2021-2028 planning period. The No. 2 Hog Fuel Boiler has a remaining useful life of twenty years or more.

2.6 CONCLUSION

Based on the FFA presented above, no additional SO_2 emissions controls were determined to be cost effective for the Mill's hog fuel boilers.

3. SUMMARY OF FINDINGS

The emission sources at the Domtar Plymouth Mill evaluated in this report are already subject to various stringent emission limits. However, in response to a request from DAQ, Domtar evaluated whether additional emissions controls for SO_2 are feasible for the hog fuel boilers.

As part of the FFA, the following information was reviewed: site-specific emissions and control 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 not feasible. 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:

- The boilers included in the FFA are subject to Boiler MACT emission limits and work practices that became effective in 2020. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the boilers only start up on clean fuel.
- 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 additional controls on non-EGU combustion units are not cost effective.

APPENDIX A -
CONTROL COST ESTIMATES

Table A-1

Domtar Plymouth - No. 2 Hog Fuel Boiler

Capital and Annual Costs Associated with Wet Scrubbing

CAPITAL COSTS[a]				ANNUALIZED COSTS				
COST ITEM	COST FACTOR		COST ($)	COST ITEM	COST FACTOR		RATE	COST ($)
Direct Costs				***Direct Annual Costs***				
Purchased Equipment Costs				***Operating Labor***				
(a) ***A*** Equipment Costs - wet scrubber			***$3,187,000***	(b) Operator[c]	0.5	hours/shift	$65.00 per hour[d]	$35,588
(a) Instrumentation			$0	(b) Supervisor	15%	of operator labor		$5,338
(b) Sales Tax	0.03	A	$95,610	***Maintenance***				
(b) Freight	0.05	A	$159,350	(b) Maintenance labor[c]	0.5	hours/shift	$65.00 per hour[d]	$35,588
B Total Purchased Equipment Cost			***$3,441,960***	(b) Maintenance materials	100%	of maintenance labor		$35,588
				Utilities[e]				
Direct Installation Costs				Electricity	845	kW	$0.052 per kWh[d]	$383,212
(b) Foundations and Supports	0.12	B	$413,035	Chemicals	1,209	lb/hr NaOH	$0.16 per lb NaOH[d]	$1,694,892
(b) Handling and erection	0.40	B	$1,376,784	Fresh water usage	217	gpm	$0.28 per 1000 gallon[d]	$32,062
(b) Electrical	0.01	B	$34,420	Wastewater disposal	66.5	gpm	$0.55 per 1000 gallon[d]	$19,238
(b) Piping	0.30	B	$1,032,588	***Total Direct Annual Costs***				***$2,241,505***
(b) Insulation for ductwork	0.01	B	$34,420					
(b) Painting	0.01	B	$34,420					
Direct Installation Cost			***$2,925,666***	***Indirect Annual Costs***				
(a) ***Installed Cost for New Fan***			***$3,000,000***	(b) Overhead	60%	Labor and Material Costs		$67,260
Total Direct Costs			***$9,367,626***	(b) General and administrative	2%	of TCI		$266,826
				(b) Property taxes	1%	of TCI		$133,413
Indirect Costs				(b) Insurance	1%	of TCI		$133,413
(a) Engineering			$0	(b) Capital recovery	0.095	x TCI		$1,263,703
(b) Construction Management	0.10	B	$344,196	Life of the control:	15	years at	4.75% interest	
(b) Contractor fees	0.10	B	$344,196					
(b) Start-up	0.01	B	$34,420	***Total Indirect Annual Costs***				***$1,864,615***
(b) Performance test	0.01	B	$34,420					
(b) Re-certification of monitors in new locations	0.01	B	$34,420					
(b) Contingencies	0.03	B	$103,259	***Total Annual Costs***				***$4,106,120***
Total Indirect Costs			***$894,910***					
(h) ***Retrofit Factor***	0.3		$3,078,761	***Cost Effectiveness ($/ton)***				
				SO_2 Control Efficiency[f]:	95%			
Total Capital Investment (TCI)			***$13,341,296***	SO_2 Emissions[g]:	1,009.6	tpy	Total Annual Costs/Controlled SO_2 Emissions:	
				Controlled SO_2 Emissions:	959.1	tons of SO_2 removed annually		***$4,281***

[a] Wet scrubber equipment quote from LDX Solutions (includes scrubber, stack, instrumentation, and engineering). Installed fan cost from H. Clay Moore & Associates (estimated between $2.5 and $5 million for new fan, installed), 2020.

[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995. Added a line item for cost of re-certifying the re-located NOx CEMS and COMS, equal to the performance test line.

[c] Based on 8,760 operating hours.

[d] Mill specific rates.

[e] Utility cost represents the electrical consumption (scrubber at 472 kW from LDX Solutions and the increase for the H. Clay Moore & Associates fan of 500 hp or 373 kW), chemical use, water consumption, and wastewater disposal of a LDX Solutions wet scrubber system.

[f] 95 percent reduction was quoted by LDX.

[g] Projected 2028 emissions.

[h] U.S. EPA indicates that a retrofit factor is appropriate when estimating the cost to install a control system on an existing facility in order to address the unexpected magnitude of anticipated cost elements. A retrofit factor of 1.3 was applied to the total capital cost as the vendor cost estimate was conducted remotely, an engineering study has not been performed, and production will be lost due to an extended Mill outage that is required for scrubber installation.

Table A-2

Domtar Plymouth - No. 2 Hog Fuel Boiler

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

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	78	889 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.52	Fuel and pulp mill gases, 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% reduction can be achieved without an increase in PM emissions.
Heat Input	J	Btu/hr	8.89E+08	889 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	2.66	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	2.14	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	12.88	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.68	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	0.052	Mill specific electricity cost
Operating Labor Rate	U	$/hr	65	Labor cost including all benefits
Operating Hours		hr/yr	7989	Based on 2019 actual hours.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	1009.6
Controlled SO_2 Emissions:	504.8

Capital Costs					
Direct Costs					
BM (Base Module)	-	$	$	10,963,475	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	1,096,348	10% BM
Labor adjustment	A2	$	$	548,174	5% BM
Contractor profit and fees	A3	$	$	548,174	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	13,156,170	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	657,809	5% CECC
Total project cost w/out AFUDC	TPC	$	$	13,813,979	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**13,813,979**	CECC+B1+B2

Table A-2

Domtar Plymouth - No. 2 Hog Fuel 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	$	$	270,400	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	109,635	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	9,428	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**389,462**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	3,618,598.9	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	6,001,503.5	(N+P)*S
Additional auxiliary power required	VOMP	$	$	179.10	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**9,620,281.5**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	276,280	
Property Tax	1%	of TCI	$	138,140	
Insurance	1%	of TCI	$	138,140	
Capital Recovery	7.86%	x TCI	$	1,085,094	
Total Indirect Annual Costs			**$**	**1,637,654**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**11,647,397**	
Total Annual Costs/SO_2 Emissions			**$**	**23,074**	

[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

LDX Solutions Cost Estimate for the SO_2 Scrubber

June 15, 2020

Reference: P-203063, Rev. 00

Attention: Mr. Ken Hardison

Subject: SO_2 Scrubber for Boiler Emission Control

Domtar
1375 NC-149
Plymouth, NC 27962

Dear Mr. Hardison:

LDX Solutions is pleased to provide the following budgetary proposal for one (1) wet scrubber system for the SO_2 emissions from the upstream No. 2 hog fuel boiler at Domtar's Plymouth, North Carolina facility.

The design conditions have been provided via January, March, and May 2020 emission test reports. Please review the 'Design Base' section of our proposal and confirm the assumed values. As noted, we have not received confirmation of HCl loading concentrations and have assumed a reference value from similar applications. Accurate HCl loading information will affect the blowdown and scrubber consumption rates.

The scrubber system has been designed to achieve a 95% collection efficiency of SO_2 emissions or down to 20 $ppmv_d$, whichever is less stringent, using US EPA Method 6/6C. The reduction in emissions will drastically reduce the blue haze that is currently emitted from the existing dry ESP exhaust stack.

The scope includes a short section of quench duct into the main scrubber vessel body and a top-mounted exhaust stack. We have included all major components of the scrubber recycle system that will be required: tanks, pumps, and instrumentation. We have excluded structural steel, external piping, manual valves, and interconnecting ductwork from upstream equipment to the inlet of the quench duct. Additionally, the scrubber system is assumed use the available static in the upstream dry ESP ID fan. Pressure drop requirements are listed in our proposal but will need to be confirmed with the existing fan curves/fan supplier.

Installation (mechanical/demolition/electrical/civil and safety services) and freight have been excluded from our current supply.

Please let us know if you have any questions or comments. LDX Solutions appreciates the opportunity to present this proposal and look forward to your favorable consideration.

Sincerely,

Pete Rose

Pete Rose
LDX Solutions
East Coast Regional Sales Manager

BUDGETARY PRICING (+/- 15%)

LDX Solutions offers the following budgetary pricing per the detailed scope of work as described within:

Description	Price ($ USD)
Supply of scrubber equipment and ancillary recycle/flush systems (excludes freight). Includes system engineering.	$3,187,000
Construction supervision, on-site services, and training	$125,000
Estimated equipment freight	$128,000
Total	**$3,440,000**

DESIGN BASE

The following information comprises the design conditions that were used to develop this proposal.

DRY ESP EXHAUST STREAM CONDITIONS		
Flow Rate	444,829	ACFM
	285,000	SCFM (wet)
Temperature	375	°F
Moisture	18.5	% volume
SO_2 Loading	≤ 225	$ppmv_d$
	515	lb/hr
PM Loading	≤ 11.3	lb/hr
	0.0057	gr/dscf
HCl Loading	35.5	lb/hr*
	28	$ppmv_d$*
EXPECTED SPRAY TOWER OUTLET CONDITIONS		
Flow Rate	358,789	ACFM
	311,599	SCFM (wet)
Temperature	150	°F
Moisture	25.5	% volume (saturated)
	11.2	$ppmv_d$
SO_2 Loading	≤ 25.75	lb/hr (95% removal efficiency)

*HCl loading provided via June 12th email from Don Wynne, using worst case HCl loading (Jan-19 0.0411 lb/MMBTU) and a boiler MCR of 889 MMBTU/hr.

DESIGN BASE - CONTINUED

SPRAY TOWER REQUIREMENTS		
Evaporation Rate	150.0	gpm
Blowdown Rate	66.5	gpm (At 3% solids by weight, maximum expected)
Make-up Rate (Evap. + Blowdown)	216.5	gpm
Water Recirculation Rate	10,880	gpm (includes blowdown)
Estimated Electrical Consumption	472	kW
Compressed Air	80	psig
Estimated NaOH Consumption	1.61	gal/min of 50% solution**
Make-Up Water Guidelines		
• Total Hardness	< 10	mg/L
• pH	7.0	
• Chlorides	< 10	ppm***
• TSS & TDS	< 200	mg/L

**NaOH must be membrane grade with <75 ppm NaCl. Warning, diaphragm grade caustic cannot be used due to high concentration of NaCl.

***Warning, chloride concentrations in the make-up water exceeding 10 mg/L can cause severe corrosion.

Sargent & Lundy DSI Cost Methodology

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

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

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:

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

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*UI/(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 Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	**Example**		**Comments**
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

			Comments
Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	**Example**		**Comments**
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**	

Domtar Paper
Company, LLC
Plymouth Mill
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Tel: (252) 793-8111

March 2, 2021

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

Certified Mail
Return Receipt Requested

Re: Supplemental Information for Regional Haze Rule Four-Factor Analysis
Domtar Paper Company, LLC Mill in Plymouth, NC
Permit No. 04291T48/Facility ID 07/59/00069

Dear Mr. Strait:

On May 4, 2020, Domtar Paper Company, LLC – Plymouth Mill (Domtar or Mill) received a letter from the North Carolina Division of Air Quality (DAQ) requesting that Domtar review the projected 2028 Sulfur Dioxide (SO_2) emissions upon which the DAQ's contribution assessment was based for the Regional Haze Second Planning Period. Domtar reviewed the projected 2028 SO_2 emissions and provided DAQ with an updated 2028 emissions projection on May 12, 2020 using 2019 as a more representative base year (in place of 2016) to reflect the Optimization Project and the recent No. 2 Hog Fuel Boiler (HFB2) SO_2 test data.

On May 22, 2020, Domtar received a letter from the DAQ requesting that the Mill conduct a four-factor analysis for the SO_2 emission sources outlined in Part III of the May 4, 2020 letter (Nos. 1 and 2 Hog Fuel Boilers). Domtar provided the requested Regional Haze Rule Four-Factor Analysis (Analysis) to DAQ on July 21, 2020.

Domtar is providing this supplemental information as discussed with DAQ via conference call on February 5, 2021 to describe the future operation of the No. 1 Hog Fuel Boiler (HFB1) and Thermal Oxidizer.

Description of Future Operations

The Plymouth Mill has been implementing a Mill Optimization Project (Project) to improve efficiency and streamline operations since receiving approval under Title V Permit No. 04291T45 in 2018. Relevant modifications included efficiency improvements to HFB2, replacement of the HFB2 electroscrubbers with an electrostatic precipitator (ESP) for particulate matter (PM) control, and construction of a natural gas-fired Thermal Oxidizer as a backup control device for pulp mill high-volume, low-concentration (HVLC) gases for continued compliance with 40 CFR Part 60, Subpart BB and 40 CFR Part 63, Subpart S requirements. The Project allows reduced utilization of HFB1 and its associated emissions by transitioning to firing primarily natural gas or biomass, with No. 2 fuel oil as backup, and discontinuing combustion of HVLC in this boiler. Natural gas and biomass combustion result in negligible SO_2 emissions, with the majority of SO_2 emissions resulting from HVLC combustion.

In the Analysis, additional SO_2 controls were eliminated as feasible for installation on HFB1 because the boiler, if operating, burns low-sulfur fuels; and, HVLC gases are no longer combusted in HFB1. The Mill also indicated in the Analysis that HFB1 is expected to be permanently shut down during the 2021-2028 planning period; however, Domtar would like to maintain the flexibility to operate HFB1 on low-sulfur fuels should there become a future need for additional steam. An updated 2028 emissions projection is discussed in the following section.

HFB1 is no longer capable of burning HVLC gases because the connection was removed with the installation of the new Thermal Oxidizer. The Thermal Oxidizer is only used when HVLC gases cannot be controlled in HFB2. Total annual operating hours of the Thermal Oxidizer were 725 hours in 2019 and 66 hours in 2020, demonstrating the intermittent operation of this source. In 2019, HFB2 experienced an extended outage to implement the Mill Optimization Project and the Thermal Oxidizer served as the HVLC control device for most of September 2019. 2020 represents a typical year with intermittent operation of the Thermal Oxidizer when HVLC gases could not be controlled in HFB2.

Impact to SO_2 Emissions

Table 1 presents actual and projected emissions from the HFB1 and the Thermal Oxidizer. Even though Domtar will not likely ever again fire biomass in HFB1, the Mill is providing an updated 2028 projection of SO_2 emissions for HFB1 based on the maximum firing rate of the boiler while combusting biomass, representing the fuel that results in the highest annual SO_2 emissions. The annual actual emissions reduction presented in Table 1 demonstrates that HFB1 is no longer a significant source of SO_2 emissions and supports the conclusion in the Analysis that no additional SO_2 control is required since HFB1 is already burning low sulfur fuels.

The actual SO_2 emissions presented in Table 1 for the Thermal Oxidizer represent the anticipated range of emissions that could occur in years with and without extended outages of HFB2. Projected 2028 emissions for the Thermal Oxidizer were updated to average 2019 and 2020 SO_2 emissions to be a conservative representation of expected actual emissions.

Table 1 – Summary of Actual and Projected SO_2 Emissions[1]

Emissions Unit Description	2018 SO_2 Emissions (tons)	2019 SO_2 Emissions (tons)	2020 SO_2 Emissions (tons)	Projected 2028 SO_2 Emissions (tons)[2]
No. 1 Hog Fuel Boiler	223	58	0	12
HVLC System Thermal Oxidizer	N/A	86	7	47

1. 2018 and 2019 actual emissions are based on the Air Emissions Inventory Submitted to DAQ and air emissions to be reported for calendar year 2020.
2. Projected 2028 emissions for HFB1 are based on the maximum annual firing rate of HFB1 on biomass (835 MMBtu/hr, 8,760 hr/yr) and SO_2 median emission factor from Table 10.4 of NCASI Technical Bulletin 1020 (3.18E-03 lb/MMBtu). Projected 2028 Thermal Oxidizer emissions are set equal to the average of 2019 and 2020 actual emissions.

Pending Emissions Reductions

DAQ is currently reviewing an air permit application to reconfigure the lignin plant located at the Mill. Part of the lignin plant reconfiguration project includes removal of most of the lignin plant sources from the HVLC system and controlling the gases in a dedicated scrubber. This project will be implemented upon approval from DAQ and will result in reduced SO_2 emissions from combustion of HVLC gases in HFB2 and the Thermal Oxidizer.

Closing

Should the DAQ have any questions on the supplemental information provided on Domtar's Four-Factor Analysis, please contact Don Wynne by phone at (252) 793-8984 or by email at Don.Wynne@domtar.com or Claire Corta by phone at (919) 578-4195 or by email at ccorta@all4inc.com.

Sincerely,

Diane R. Hardison
EH&S Manager

Everick W. Spence
Mill Manager

cc: Don Wynne – Domtar
Claire Corta – ALL4
Betsy Huddleston – DAQ- WaRO

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

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.

Amy Marshall / Technical Director
D: 984-777-3073 / C: 919-796-3950 / Profile / LinkedIn
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ALL4 // Your environmental compliance is clearly our business.

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.

Randy Strait
Chief, Planning Section
Division of Air Quality
North Carolina Department of Environmental Quality

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217 West Jones Street
Raleigh, NC 27699-1641

From: Strait, Randy P
Sent: Wednesday, May 12, 2021 11:00 AM
To: Hardison, Diane; Claire Corta
Cc: Wynne, Don; Huddleston, Betsy; Tidd, Kurt N; Bartlett, Joshua W; Pjetraj, Michael; Abraczinskas, Michael
Subject: RE: [External] Domtar Plymouth - Regional Haze FFA

Diane and Claire,

This is to request that Domtar 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. I added a note after each comment reflecting our discussions on how to address the comments. Please let me know if your notes differ from mine.

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 for No.2 Hog Fuel Boiler: Revise from 20 to 30 years.

Equipment Life for wet scrubber for No.2 Hog Fuel Boiler: Revise from 15 to 30 years.

If you disagree with this change, please provide a detailed explanation to justify 15 years for a wet scrubber and 20 years for DSI.

3. Status of No. 1 Hog Boiler ("HFB1"): It is our understanding that ceasing to burn mill gas at HFB1 is the result of an energy efficiency project. If this is the case, you may want to document this to demonstrate any energy savings which have reduced energy consumption. We can discuss this more on a Teams call if you like. Note that EPA has not yet responded to the question revising the permit to remove mill gases.

4. Contingency Cost Estimate for Wet Scrubber: Recalculate using equation in new, draft cost manual.
5. Retrofit Factor for Wet Scrubber: Strengthen justification by including more information for retrofit factor used.
6. Parameters used in Fly Ash Waste Rate for DSI: Add references for cost calculations.
7. Documenting Cost Basis for Wet Scrubber and DSI: EPA indicated that they are looking for the unit costs for the different items identified in their comments (i.e., $/gal) and not a specific reference for the value. However, as we have discussed, you might want to indicate that the information was pulled from the accounting system and indicate the time basis (e.g., annual average for 2020 or something along this line).
8. Property Taxes for DSI: Please remove.
9. Possible Available Technologies: EPA has agreed that spray dryer absorber technology is not applicable to the No.2 Hog Fuel Boiler so you can ignore this comment.

Randy Strait
Chief, Planning Section
Division of Air Quality
North Carolina Department of Environmental Quality

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From: Hardison, Diane <Diane.Hardison@domtar.com>
Sent: Friday, May 28, 2021 10:29 AM
To: Strait, Randy P
Cc: Rogers, Todd; Wynne, Don; Clea, Micheal; Lilley, John Thomas; Claire Corta
Subject: [External] FW: Draft Regional Haze Report
Attachments: Domtar Plymouth 4-Factor Analysis 052721.pdf; Scanned Signature Authority Update
04192020.pdf

CAUTION: External email. Do not click links or open attachments unless you verify. Send all suspicious email as an
attachment to Report Spam.

Randy,

Please find attached our revised 4-factor Analysis for the Regional Haze program. As discussed with you
recently, we have addressed each of EPA's review comments and provided expanded details and
clarification, where necessary. Should you need any further information, please contact Claire Corta
with ALL4 or me.

Please note that since our last submittal to you, Everick Spence (former Mill Manager) has moved from
our facility and Todd M. Rogers is now serving as our current Mill Manager. We have submitted the
appropriate information to DAQ (scan attached) concerning this change in our Responsible Official.

Thank you and have a safe and enjoyable holiday weekend.

Diane R Hardison
Environmental Health and Safety Manager
P 252-793-8611 | F 252-793-8871 | M 252-217-2548

Domtar Paper Company, LLC
P.O. Box 747
NC Highway 149 North
Plymouth, North Carolina 27962

Regional Haze Rule Four-Factor Analysis for the Domtar Paper Company Plymouth Mill

July 2020
Revised June 2021

Submitted by:

Domtar

Domtar Paper Company – Plymouth Mill
P.O. Box 747
Highway 149 North
Plymouth, NC 27962

Submitted to:

NORTH CAROLINA Department of Environmental Quality

NC Department of Environmental Quality
Division of Air Quality
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ALL4 Contact Information: info@all4inc.com | 610.933.5246 | www.all4inc.com

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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 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 Domtar Paper Company's (Domtar) FFA for SO_2 emissions from the following units at the Plymouth, NC Mill, as requested in Part III of DAQ's May 4, 2020 letter and revised to address initial comments by the U.S. Environmental Protection Agency (EPA):

- No. 1 Hog Fuel Boiler (HFB1)
- No. 2 Hog Fuel Boiler (HFB2)

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.

MACT standards 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." Sources demonstrating compliance with MACT and BART are already well controlled. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

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, and sources that are already well-controlled. This report focuses on two of the most significant sources of SO_2 emissions at the Domtar Plymouth pulp and paper mill, as per DAQ's request, and does not evaluate other well-controlled sources. Appendix A presents the control cost calculations and Appendix B presents supporting information.

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

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 SO_2 emissions control measures are necessary to make reasonable progress toward natural visibility conditions at 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

Domtar has addressed these factors for additional SO_2 control options that could be applied to the hog fuel boilers at the mill 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 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 2028 actual emissions. 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. In addition, actual emissions are more representative of the 2021-2028 planning period than potential emissions.

An interest rate of 3.25% and the EPA recommended 30-year equipment life were used to calculate the capital recovery factor. A 3.25% interest rate represents the current prime rate; however, the prime rate dropped during the COVID-19 pandemic and has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018. Labor, chemical, and utility costs are based on mill-specific values for 2020 that were obtained from finance department records.

1.2 SUMMARY OF SOURCES EVALUATED

Table 1-1 provides basic information regarding the sources that were evaluated in detail. The boilers 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. Industrial boilers are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), which require the use of Maximum Achievable Control Technology (MACT). While the MACT standards are intended to minimize HAP emissions, they also directly reduce acid gas emissions and promote good combustion practices. NSPS Subpart D contains emission limits for SO_2. The fuels fired by the hog fuel boilers are low-sulfur fuels (natural gas, No. 2 fuel oil, and biomass). The majority of the historical SO_2 emissions from these boilers result from combustion of pulp mill gases that contain sulfur compounds. These gases are combusted to meet the HAP emissions control requirements of 40 CFR Part 63, Subpart S. The alkaline nature of the bark fly ash provides some SO_2 capture.

Table 1-1
Summary of Emissions Sources Evaluated

Emissions Unit Description	Size, MMBtu/hr	Year Installed	Permitted Fuels	Control Technology	Major Regulatory Programs	2019 Actual SO_2 Emissions (tons)	Projected 2028 Actual SO_2 Emissions (tons)
No. 1 Hog Fuel Boiler[1]	1,021 (any combination of fuels) 835 (hog fuel with any other fuels)	1977	Lignin, natural gas, biomass, No. 2 fuel oil, used oil, sludge	PM: Electroscrubbers SO_2: Low-sulfur fuels and inherent bark scrubbing	NSPS Subpart D MACT Subpart DDDDD	58.22	12
No. 2 Hog Fuel Boiler[2]	889	1982	Lignin, natural gas, biomass, No. 2 fuel oil, used oil, sludge	PM: Electrostatic precipitator (ESP) SO_2: Low-sulfur fuels and inherent bark scrubbing	NSPS Subpart D MACT Subpart DDDDD	877.87	1,009.57

[1] The No. 1 Hog Fuel boiler is permitted to combust high-volume, low-concentration (HVLC) pulp mill gases but is no longer able to combust HVLC.
[2] The No. 2 Hog Fuel boiler can also combust HVLC and low-volume, high-concentration (LVHC) pulp mill gases and stripper off-gases (SOG).

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the mill has made emissions reductions for a variety of reasons. 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.

In addition, the Mill has been implementing a Mill Optimization Project (Project) to improve efficiency and streamline operations since receiving approval under Title V Permit No. 04291T45 in 2018. Relevant modifications included efficiency improvements to HFB2, replacement of the HFB2 electroscrubbers with an electrostatic precipitator (ESP) for particulate matter (PM) control, and construction of a natural gas-fired Thermal Oxidizer as a backup control device for pulp mill high-volume, low-concentration (HVLC) gases for continued compliance with 40 CFR Part 60, Subpart BB and 40 CFR Part 63, Subpart S requirements. The Project allows reduced utilization of HFB1 and its associated emissions by transitioning the boiler to firing primarily natural gas or biomass, with No. 2 fuel oil as backup, and discontinuing combustion of HVLC in this boiler. Natural gas and biomass combustion result in low SO_2 emissions, with the majority of historical SO_2 emissions from HFB1 resulting from HVLC combustion.

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 boilers evaluated.
- **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 two industrial boilers at the mill. To evaluate the cost of compliance portion of the FFA, Domtar performed the following steps:

- 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 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. Fuel switching from biomass to 100% natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. 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. 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] It is not reasonable as part of this analysis to require boilers at a forest products mill to cease burning biomass and fire only natural gas because biomass boilers at forest products mills fire the biomass residuals from the mill processes as a readily available and relatively inexpensive source of fuel. In addition, biomass is a low-sulfur fuel and the alkaline nature of bark fly ash serves to provide some SO_2 emissions capture from combustion of pulp mill gases in HFB2.

2.1.1 Available SO_2 Control Technologies

Natural gas, No. 2 fuel oil, and biomass are considered low-sulfur fuels and are fired by the boilers included in this report. Natural gas and biomass combustion result in negligible SO_2 emissions. However, as mentioned above, the majority of the historical emissions from the hog fuel boilers (and the future actual SO_2 emissions from HFB2) are from combustion of HVLC, LVHC, and SOG that contain sulfur compounds that oxidize to SO_2. LVHC gases are treated by a white liquor

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

scrubber for reduction of sulfur compounds prior to combustion in HFB2, resulting in lower SO_2 emissions. The potentially feasible add-on control technologies for reducing emissions of SO_2 from industrial boilers are discussed in detail in this section.

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 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 and the amount of gas to liquid contact and residence time. 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 and prior to 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 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, hydrochloric acid 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. 1 Hog Fuel Boiler currently burns only natural gas and hog fuel, with low-sulfur No. 2 fuel oil as backup. HVLC gases are no longer combusted in HFB1 as of July 2019 (the Mill has removed the capability to do so) and SO_2 emissions have been reduced from 223 tpy in 2018 to a 2028 projection of 12 tpy SO_2. Projected 2028 emissions for HFB1 are based on the maximum annual firing rate of HFB1 on biomass (835 MMBtu/hr, 8,760 hr/yr) and the SO_2 median emission factor from Table 10.4 of National Council for Air and Stream Improvement (NCASI) Technical Bulletin 1020 (3.18E-03 lb/MMBtu), representing the fuel that results in the highest annual SO_2 emissions. Emissions of SO_2 from HFB1 have already been reduced to less than 15 tpy by firing low-sulfur fuels. No additional SO_2 controls were evaluated for this boiler because no additional controls would be reasonable.

Installing a wet scrubber following the HFB2 ESP is considered technically feasible and was evaluated. Installing DSI in the form of trona injection prior to the No. 2 Hog Fuel Boiler ESP is also considered technically feasible and was evaluated.

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, source-specific vendor cost estimates, 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. Projected actual emissions and a typical expected control efficiency were used as the basis for emissions reductions.

Capital, operating, and total annual 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 site-specific engineering studies.

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. For example, 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

[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.

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 are 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 on HFB2 include space constraints. 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 – Wet Scrubber

The wet scrubber capital cost is based on a cost estimate provided by LDX Solutions on June 15, 2020 and the fan upgrade cost is from H. Clay Moore & Associates Inc. The cost estimate was based on design conditions obtained from 2020 air emissions testing on No. 2 Hog Fuel Boiler and discussions with the Mill. Operating costs were estimated using the factors in the OAQPS Cost Manual (Section 5, Chapter 1), operating data provided by LDX Solutions, and site-specific labor, chemical, and utility costs.

U.S. EPA indicates that a retrofit factor is appropriate when estimating the cost to install a control system on an existing facility, in order to address the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the

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

cost of correcting design errors. A retrofit factor can be used to reflect additional difficulty associated with installing auxiliary equipment, special care in placing equipment, additional insulation and painting of piping and ductwork, additional site preparation, extra engineering or supervision during installation, and unanticipated delays that cause lost production costs. The manual states that at the study cost level, a retrofit factor of as much as 50% is justified, and even at the detailed cost level, a retrofit factor is often added.

A retrofit factor of 1.3 was applied to the total capital cost because the vendor cost estimate was conducted remotely and a detailed engineering study has not been performed to account for unexpected siting or engineering costs that were not included in the initial vendor quote. The vendor quote did not include the cost to replace the induced draft (ID) fan required for the additional down-stream pressure added by the scrubber. An engineering study is required to fully access which fan replacement option would be required (the options ranged from $2,000,000 to $5,500,000). The installed cost for a new fan included in the cost analysis was $3,000,000 and the retrofit factor would help cover the higher cost option and other potential engineering or siting challenges.

The retrofit factor also accounts for unanticipated delays. While the cost manual[7] notes that shutdown for installation of a control device should be a well-planned event and included in the indirect costs, unexpected delays can still occur that were not specifically quantified in the initial indirect cost that extend a Mill outage beyond that of a typical outage. HFB2 is essential for Mill operation because it is the primary source of additional steam for the Mill, making up for steam that the recovery furnace cannot produce. HFB2 is also a control device for all non-condensable gases and is used for compliance with 40 CFR Part 60, Subpart BB and 40 CFR Part 63, Subpart S requirements. The Mill must balance timing of maintenance on NCG combustion equipment so that NCG control devices are operating during startup of the Mill. Finally, a constructability

[7]https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

analysis is required to be conducted to fully assess the length of the tie-in process when HFB2 is shutdown.

Table 2-2
Wet Scrubber Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
No. 2 Hog Fuel Boiler	$14,527,766	$3,509,946	$3,660

Installing a wet scrubber is not considered cost effective because the estimated capital cost is more than $14 million and the cost effectiveness value is over $3,400/ton of SO_2 removed.

2.3.3 SO_2 Economic Impacts – DSI

The capital cost for a system to inject milled trona prior to the ESP on the No. 2 Hog Fuel Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[8] Site-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing PM emissions. Table 2-3 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology for the No. 2 Hog Fuel Boiler, based on operating data and the projected 2028 actual SO_2 emissions.

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

Table 2-3
Trona Injection System Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
No. 2 Hog Fuel Boiler	$13,813,979	$11,151,907	$22,092

Installing trona injection is not considered cost effective because the estimated capital cost is more than $13 million and the cost effectiveness value is over $20,000/ton of SO_2 removed.

2.3.4 Energy and Non-Air Related Impacts

This section describes the energy and non-air environmental impacts associated with each add-on control option evaluated.

Additional electricity and water would be needed to run a wet scrubber and additional fan power would be required overcome the additional pressure drop through the wet scrubber. Other environmental and energy impacts associated with operating a wet scrubber include generation and disposal of wastewater. Additional electricity would be needed to operate a DSI system and it would create additional solid waste.

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 and would have to undergo substantial re-engineering 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.

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 SOURCES

Both hog fuel boilers have a remaining useful life of twenty years or more.

2.6 CONCLUSION

Based on the FFA presented above, no additional SO_2 emissions controls were determined to be cost effective for the No. 2 Hog Fuel Boiler and the No. 1 Hog Fuel Boiler has already reduced emissions by no longer firing HVLC and combusting only low-sulfur fuels.

3. SUMMARY OF FINDINGS

The emission sources at the Domtar Plymouth Mill evaluated in this report are already subject to various stringent emission limits. However, in response to a request from DAQ, Domtar evaluated whether additional emissions controls for SO_2 are reasonable for the hog fuel boilers.

As part of the FFA, the following information was reviewed: site-specific emissions and control 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 on the hog fuel boilers are not reasonable. 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:

- The boilers included in the FFA are subject to Boiler MACT emission limits and work practices that became effective in 2020. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the boilers only start up on clean fuel.
- 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 additional controls on non-EGU combustion units are not cost effective.

APPENDIX A -
CONTROL COST ESTIMATES

Table A-1

Domtar Plymouth - No. 2 Hog Fuel Boiler

Capital and Annual Costs Associated with Wet Scrubbing

CAPITAL COSTS[a]				ANNUALIZED COSTS				
COST ITEM	COST FACTOR		COST ($)	COST ITEM	COST FACTOR		RATE	COST ($)
Direct Costs				***Direct Annual Costs***				
Purchased Equipment Costs				***Operating Labor***				
(a) ***A*** Equipment Costs - wet scrubber			***$3,187,000***	(b) Operator[c]	0.5	hours/shift	$65.00 per hour[d]	$35,588
(a) Instrumentation			$0	(b) Supervisor	15%	of operator labor		$5,338
(b) Sales Tax	0.03	A	$95,610	***Maintenance***				
(b) Freight	0.05	A	$159,350	(b) Maintenance labor[c]	0.5	hours/shift	$65.00 per hour[d]	$35,588
B Total Purchased Equipment Cost			***$3,441,960***	(b) Maintenance materials	100%	of maintenance labor		$35,588
				Utilities [e]				
Direct Installation Costs				Electricity	845	kW	$0.052 per kWh[d]	$383,212
(b) Foundations and Supports	0.12	B	$413,035	Chemicals	1,209	lb/hr NaOH	$0.16 per lb NaOH[d]	$1,694,892
(b) Handling and erection	0.40	B	$1,376,784	Fresh water usage	217	gpm	$0.28 per 1000 gallon[d]	$32,062
(b) Electrical	0.01	B	$34,420	Wastewater disposal	66.5	gpm	$0.55 per 1000 gallon[d]	$19,238
(b) Piping	0.30	B	$1,032,588	***Total Direct Annual Costs***				***$2,241,505***
(b) Insulation for ductwork	0.01	B	$34,420					
(b) Painting	0.01	B	$34,420					
Direct Installation Cost			***$2,925,666***	***Indirect Annual Costs***				
(a) ***Installed Cost for New Fan***			***$3,000,000***	(b) Overhead	60%	Labor and Material Costs		$67,260
Total Direct Costs			***$9,367,626***	(b) General and administrative	2%	of TCI		$290,555
				(b) Property taxes	0%	of TCI		$0
Indirect Costs				(b) Insurance	1%	of TCI		$145,278
(a) Engineering			$0	(b) Capital recovery	0.053	x TCI		$765,348
(b) Construction Management	0.10	B	$344,196	Life of the control:	30	years at	3.25% interest	
(b) Contractor fees	0.10	B	$344,196					
(b) Start-up	0.01	B	$34,420	***Total Indirect Annual Costs***				***$1,268,441***
(b) Performance test	0.01	B	$34,420					
(b) Re-certification of monitors in new locations	0.01	B	$34,420					
Total Indirect Costs			***$791,651***	***Total Annual Costs***				***$3,509,946***
(b) Contingencies	0.1	DC+IC	$1,015,928					
(h) ***Retrofit Factor***	0.3		$3,352,561	***Cost Effectiveness ($/ton)***				
				SO_2 Control Efficiency[f]:	95%			
Total Capital Investment (TCI)			***$14,527,766***	SO_2 Emissions[g]:	1,009.6	tpy	Total Annual Costs/Controlled SO_2 Emissions:	
				Controlled SO_2 Emissions:	959.1	tons of SO_2 removed annually		***$3,660***

[a] Wet scrubber equipment quote from LDX Solutions (includes scrubber, stack, instrumentation, and engineering). Installed fan cost from H. Clay Moore & Associates (estimated between $2 and $5.5 million for new fan, installed), 2020.

[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995 and April 2021. Added a line item for cost of re-certifying the re-located NOx CEMS and COMS, equal to the performance test line.

[c] Based on 8,760 operating hours.

[d] Mill specific rates from Finance Department Records.

[e] Utility cost represents the electrical consumption (scrubber at 472 kW from LDX Solutions and the increase for the H. Clay Moore & Associates fan of 500 hp or 373 kW), chemical use, water consumption, and wastewater disposal of a LDX Solutions wet scrubber system.

[f] 95 percent reduction was quoted by LDX.

[g] Projected 2028 emissions.

[h] U.S. EPA indicates that a retrofit factor is appropriate when estimating the cost to install a control system on an existing facility in order to address the unexpected magnitude of anticipated cost elements. A retrofit factor of 1.3 was applied to the total capital cost as the vendor cost estimate was conducted remotely, an engineering study and constructability study have not been performed, and for unexpected delays.

Table A-2

Domtar Plymouth - No. 2 Hog Fuel Boiler

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

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	78	889 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.52	Fuel and pulp mill gases, 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% reduction can be achieved without an increase in PM emissions.
Heat Input	J	Btu/hr	8.89E+08	889 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	2.66	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	2.14	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate [(b)]	P	ton/hr	12.88	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.68	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in Sargent & Lundy Report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash in Sargent & Lundy Report
Aux Power Cost	T	$/kWh	0.052	Mill specific electricity cost from Finance Department Records
Operating Labor Rate	U	$/hr	65	Mill specific labor cost including all benefits from Finance Department Records
Operating Hours		hr/yr	7989	Based on 2019 actual hours.

SO_2 Control Efficiency:	50%
2028 SO_2 Emissions:	1009.6
Controlled SO_2 Emissions:	504.8

Capital Costs					
Direct Costs					
BM (Base Module)	-	$	$	10,963,475	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	1,096,348	10% BM
Labor adjustment	A2	$	$	548,174	5% BM
Contractor profit and fees	A3	$	$	548,174	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	13,156,170	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	657,809	5% CECC
Total project cost w/out AFUDC	TPC	$	$	13,813,979	B1+CECC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**13,813,979**	CECC+B1+B2

Table A-2

Domtar Plymouth - No. 2 Hog Fuel 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	$	$	270,400	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	109,635	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	9,428	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**389,462**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	3,618,598.9	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	6,001,503.5	(N+P)*S
Additional auxiliary power required	VOMP	$	$	179.10	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**9,620,281.5**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	276,280	
Property Tax	0%	of TCI	$	-	
Insurance	1%	of TCI	$	138,140	
Capital Recovery	5.27%	x TCI	$	727,744	
Total Indirect Annual Costs			**$**	**1,142,163**	
Life of the Control:	30	years		3.25%	interest
Total Annual Costs			**$**	**11,151,907**	
Total Annual Costs/SO_2 Emissions			**$**	**22,092**	

[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.

[b] Variables within the Fly Ash Waste Rate are based on typical parameters - Bark HHV4,600 Btu/lb wet: AP-42 Chapter 1.6 HHV ranges from 4,500 (wet) - 8,000 Btu/lb (dry). Boiler Ash removal 0.2 is provided in the Sargent and Lundy Report. Ash in bark 0.05: typical range is 5-10% per https://bioresources.cnr.ncsu.edu/resources/the-impact-of-bark-content-of-wood-biomass-on-biofuel-properties/#:~:text=The%20ash%20content%20of%20bark,wood%2C%20and%2075%25%20bark.

APPENDIX B -
SUPPORTING INFORMATION

LDX Solutions Cost Estimate for the SO_2 Scrubber

June 15, 2020

Reference: P-203063, Rev. 00

Attention: Mr. Ken Hardison

Subject: SO_2 Scrubber for Boiler Emission Control

Domtar
1375 NC-149
Plymouth, NC 27962

Dear Mr. Hardison:

LDX Solutions is pleased to provide the following budgetary proposal for one (1) wet scrubber system for the SO_2 emissions from the upstream No. 2 hog fuel boiler at Domtar's Plymouth, North Carolina facility.

The design conditions have been provided via January, March, and May 2020 emission test reports. Please review the 'Design Base' section of our proposal and confirm the assumed values. As noted, we have not received confirmation of HCl loading concentrations and have assumed a reference value from similar applications. Accurate HCl loading information will affect the blowdown and scrubber consumption rates.

The scrubber system has been designed to achieve a 95% collection efficiency of SO_2 emissions or down to 20 $ppmv_d$, whichever is less stringent, using US EPA Method 6/6C. The reduction in emissions will drastically reduce the blue haze that is currently emitted from the existing dry ESP exhaust stack.

The scope includes a short section of quench duct into the main scrubber vessel body and a top-mounted exhaust stack. We have included all major components of the scrubber recycle system that will be required: tanks, pumps, and instrumentation. We have excluded structural steel, external piping, manual valves, and interconnecting ductwork from upstream equipment to the inlet of the quench duct. Additionally, the scrubber system is assumed use the available static in the upstream dry ESP ID fan. Pressure drop requirements are listed in our proposal but will need to be confirmed with the existing fan curves/fan supplier.

Installation (mechanical/demolition/electrical/civil and safety services) and freight have been excluded from our current supply.

Please let us know if you have any questions or comments. LDX Solutions appreciates the opportunity to present this proposal and look forward to your favorable consideration.

Sincerely,

Pete Rose

Pete Rose
LDX Solutions
East Coast Regional Sales Manager

BUDGETARY PRICING (+/- 15%)

LDX Solutions offers the following budgetary pricing per the detailed scope of work as described within:

Description	Price ($ USD)
Supply of scrubber equipment and ancillary recycle/flush systems (excludes freight). Includes system engineering.	$3,187,000
Construction supervision, on-site services, and training	$125,000
Estimated equipment freight	$128,000
Total	**$3,440,000**

DESIGN BASE

The following information comprises the design conditions that were used to develop this proposal.

DRY ESP EXHAUST STREAM CONDITIONS		
Flow Rate	444,829	ACFM
	285,000	SCFM (wet)
Temperature	375	°F
Moisture	18.5	% volume
SO_2 Loading	≤ 225	$ppmv_d$
	515	lb/hr
PM Loading	≤ 11.3	lb/hr
	0.0057	gr/dscf
HCl Loading	35.5	lb/hr*
	28	$ppmv_d$*
EXPECTED SPRAY TOWER OUTLET CONDITIONS		
Flow Rate	358,789	ACFM
	311,599	SCFM (wet)
Temperature	150	°F
Moisture	25.5	% volume (saturated)
	11.2	$ppmv_d$
SO_2 Loading	≤ 25.75	lb/hr (95% removal efficiency)

*HCl loading provided via June 12th email from Don Wynne, using worst case HCl loading (Jan-19 0.0411 lb/MMBTU) and a boiler MCR of 889 MMBTU/hr.

DESIGN BASE - CONTINUED

SPRAY TOWER REQUIREMENTS		
Evaporation Rate	150.0	gpm
Blowdown Rate	66.5	gpm (At 3% solids by weight, maximum expected)
Make-up Rate (Evap. + Blowdown)	216.5	gpm
Water Recirculation Rate	10,880	gpm (includes blowdown)
Estimated Electrical Consumption	472	kW
Compressed Air	80	psig
Estimated NaOH Consumption	1.61	gal/min of 50% solution**
Make-Up Water Guidelines		
• Total Hardness	< 10	mg/L
• pH	7.0	
• Chlorides	< 10	ppm***
• TSS & TDS	< 200	mg/L

**NaOH must be membrane grade with <75 ppm NaCl. Warning, diaphragm grade caustic cannot be used due to high concentration of NaCl.

***Warning, chloride concentrations in the make-up water exceeding 10 mg/L can cause severe corrosion.

Sargent & Lundy DSI Cost Methodology

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

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Eastern Research Group, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

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:

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

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*UI/(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 Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	**Example**		**Comments**
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

			Comments
Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	**Example**		**Comments**
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**	

Appendix G-2b

Domtar Paper Company - Permit No. 04291T50

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ROY COOPER
Governor
ELIZABETH S. BISER
Secretary
MICHAEL ABRACZINSKAS
Director

NORTH CAROLINA
Environmental Quality

March 9, 2022

Todd Rogers
General Manager
Domtar Paper Company, LLC
Post Office Box 747
Plymouth, North Carolina 27962

SUBJECT: Air Quality Permit No. 04291T50
Facility ID: 5900069
Domtar Paper Company, LLC
Plymouth, North Carolina
Martin County
Fee Class: Title V
PSD Class: Major

Dear Mr. Rogers:

In accordance with your completed Air Quality Permit Application for a PSD modification of your Title V Permit, we are forwarding herewith Air Quality Permit No. 04291T50 authorizing the construction and operation, of the emission source(s) and associated air pollution control device(s) specified herein. Additionally, any emissions activities determined from your Air Quality Permit Application as being insignificant per 15A North Carolina Administrative Code 02Q .0503(8) have been identified as such in the permit. Please note the requirements for the annual compliance certification are contained in General Condition P in Section 3. The current owner is responsible for submitting a compliance certification for the entire year regardless of who owned the facility during the year.

As the designated responsible official it is your responsibility to review, understand, and abide by all of the terms and conditions of the attached permit. It is also your responsibility to ensure that any person who operates any emission source and associated air pollution control device subject to any term or condition of the attached permit reviews, understands, and abides by the condition(s) of the attached permit that are applicable to that particular emission source.

If any parts, requirements, or limitations contained in this Air Quality Permit are unacceptable to you, you have the right to file a petition for contested case hearing in the North Carolina Office of Administrative Hearings. Information regarding the right, procedure, and time limit for permittees and other persons aggrieved to file such a petition is contained in the attached "Notice Regarding the Right to Contest A Division of Air Quality Permit Decision."

The construction of new air pollution emission source(s) and associated air pollution control device(s), or modifications to the emission source(s) and air pollution control device(s) described in this permit must be covered under an Air Quality Permit issued by the Division of Air Quality prior to construction unless the Permittee has fulfilled the requirements of NCGS 143-215.108A(b) and received written approval from the Director of the Division of Air Quality to commence construction. Failure to receive an Air Quality Permit or written approval prior to commencing construction is a violation of NCGS 143-215.108A and may subject the Permittee to civil or criminal penalties as described in NCGS 143-215.114A and 143-215.114B.

Martin County has triggered increment tracking under PSD for SO_2 and PM_{10}. However, this permit does not consume or expand increments for any pollutants.

This Air Quality Permit shall be effective from March 9, 2022, until May 31, 2026, is nontransferable to future owners and operators, and shall be subject to the conditions and limitations as specified therein.

Should you have any questions concerning this matter, please contact Ms. Heather Sands at (919) 707-8725 or heather.sands@ncdenr.gov.

Sincerely yours,

Mark J. Cuilla, EIT, CPM, Chief, Permitting Section
Division of Air Quality, NCDEQ

Enclosure
c: Michael Sparks, EPA Region 4 (Permit and review)
Washington Regional Office
Connie Horne, Central Office (Cover letter only)
Central Files

NOTICE REGARDING THE RIGHT TO CONTEST A DIVISION OF AIR QUALITY PERMIT DECISION

Right of the Permit Applicant or Permittee to File a Contested Case: Pursuant to NCGS 143-215.108(e), a permit applicant or permittee who is dissatisfied with the Division of Air Quality's decision on a permit application may commence a contested case by filing a petition under NCGS 150B-23 in the Office of Administrative Hearings within 30 days after the Division notifies the applicant or permittee of its decision. If the applicant or permittee does not file a petition within the required time, the Division's decision on the application is final and is not subject to review. The filing of a petition will stay the Division's decision until resolution of the contested case.

Right of Other Persons Aggrieved to File a Contested Case: Pursuant to NCGS 143-215.108(e1), a person other than an applicant or permittee who is a person aggrieved by the Division's decision on a permit application may commence a contested case by filing a petition under NCGS 150B-23 within 30 days after the Division provides notice of its decision on a permit application, as provided in NCGS 150B-23(f), or by posting the decision on a publicly available Web site. The filing of a petition under this subsection does not stay the Division's decision except as ordered by the administrative law judge under NCGS 150B-33(b).

General Filing Instructions: A petition for contested case hearing must be in the form of a written petition, conforming to NCGS 150B-23, and filed with the Office of Administrative Hearings, 1711 New Hope Church Road, Raleigh NC, 27609, along with a fee in an amount provided in NCGS 150B-23.2. A petition for contested case hearing form may be obtained upon request from the Office of Administrative Hearings or on its website at https://www.oah.nc.gov/hearings-division/filing/hearing-forms. Additional specific instructions for filing a petition are set forth at 26 NCAC Chapter 03.

Service Instructions: A party filing a contested case is required to serve a copy of the petition, by any means authorized under 26 NCAC 03 .0102, on the process agent for the Department of Environmental Quality:

William F. Lane, General Counsel
North Carolina Department of Environmental Quality
1601 Mail Service Center
Raleigh, North Carolina 27699-1601

If the party filing the petition is a person aggrieved other than the permittee or permit applicant, the party **must also** serve the permittee in accordance with NCGS 150B-23(a).

* * *

Additional information is available at https://www.oah.nc.gov/hearings-division/hearing-process/filing-contested-case. Please contact the OAH at 984-236-1850 or oah.postmaster@oah.nc.gov with all questions regarding the filing fee and/or the details of the filing process.

Summary of Changes to Permit

The following changes were made to the Domtar Paper Company – Plymouth, Air Permit No. 04291T49:*

Page No.	Section	Description of Changes
Cover letter and attachments	NA	• Updated permit revision and dates. • Revised cover letter to reflect current shell language. • Added notice regarding the right to contest a Division of Air Quality permit decision • Updated summary of changes to permit.
Cover Letter Attachment	Insignificant Activities list	• Moved insignificant activities to Section 2.3 of the permit. • Renamed the following sources as specified in Permit Application No. 5900069.19B: Wash Water Tank (ID No. IES-09-27-2900); Acid Sump Pit (ID No. IES-09-27-3700); Alkaline Sump Pit (ID No. IES-09-27-3600); LRP Lignin Conveyor No. 3 (ID No. IES-09-27-3400)
Permit Cover Page	NA	• Revised permit application number and dates. • Added the date the next renewal application will be due.
1 – 113	All	• Updated Permit Revision Number in header. • Updated language to current permit shell.
3 – 17	Section 1	• Moved list of acronyms to beginning of permit. • Updated the equipment table to rename the LSRP sources as requested in Permit Application No. 5900069.19B; • Updated the LSRP sources so that the current configuration of the LSRP with controlled LSRP sources vented through the HVLC system to either the No. 2 Hog Fuel Boiler, No. 1 Hog Fuel Boiler, No. 5 Recovery Boiler, or the Thermal Oxidizer. Also added the LSRP reconfiguration as specified in Permit Application No. 5900069.19B. o The Agitated Acid Conditioning Tank (ID No. ES-09-27-2800) is routed through the Carbonator Tower (ID No. ES-09-27-1400) to the HVLC System and to the combustion control devices. this tank will be repurposed to replace the Stage 2 Filtrate Tank 2 (ID No. ES-09-27-3200), renamed as the No. 2 Lignin Filter Filtrate Tank and vented to the new scrubber as described in the September 2020 addendum to Permit Application No. 5900069.19B. o Added a new tank, which will serve in the reconfigured plant operation as the new Acidic Lignin Conditioning Tank, ID No. ES-09-27-2800 and will be controlled in the new scrubber. o Added a dust collection system with a wet cyclone, ID No. CD-09-27-3900 under the reconfigured scenario to control emissions from the No. 2 Lignin Filter Horizontal Conveyor (ID No. ES-09-27-3000). Under the current configuration, this source is permitted with PM emissions uncontrolled. o Added the Lignin Rotary Feeder (ID No. ES-09-27-2660) and Lignin Lump Breaker (ID No. ES-09-27-2600) as these sources were inadvertently omitted from the permit application. • Removed affected source designation associated with Section 2.2 F from the permit. The permit was modified to incorporate these designation directly in Section 2.2 F
	Section 2.1 J	• Added condtition for 02D .0521 - Visible Emissions. The HVLC gases are controlled in a combustion source, therefore 02D .0521 applies. • Updated condition for 02D .0516 – Sulfur Dioxide Emisisons to clarify that the 2.3-lb/MMBtu emission limit applies at the outlet of the thermal oxidizer.
	Section 2.1 Q	• Revised to reflect current configuration of the Domtar Mill.

Page No.	Section	Description of Changes
		• Added insignificant activities to list of equipment because these sources are subject to the BACT standards. • Updated all conditions in Section 2.1 Q so that when the new proposed ssrubber is operating Section 2.1 Q will no longer be applicable and 2.1 T will apply. • Updated emission limits and standards table to clarify affected sources subject to the 02D .0516 and .0521 regulations. • Revised condition Q.1 to cross reference the SO_2 condition in Section 2.1 J.1 so that it is clear that compliance is demonstrated at the thermal oxidizer outlet. • Added condition Q.2 for 02D .0521
	N/A	• Added new Section 2.1 T to reflect the LSRP reconfiguration.
	Section 2.2 C	• Revised to reflect the new 02D .0530(u) recordkeeping requirement for the new reconfigured LSRP.
	Section 2.2 D	• Updated TAP limits to reflect latest approved modeling for sources being modified or affected by the LSRP Reconfiguration Project.
	Section 2.3	• Moved insignificant activities list from an attachment to the permit to new Section 2.3.
	Section 3	• Updated to current version of the General Conditions (version 6.0, dated 01/07/2022)

* This list is not intended to be a detailed record of every change made to the permit but a summary of those changes.

State of North Carolina
Department of Environmental Quality
Division of Air Quality

AIR QUALITY PERMIT

Permit No.	Replaces Permit No.	Effective Date	Expiration Date
04291T50	04291T49	March 9, 2022	May 31, 2026

NOTE: Per General Condition K, a permit application for the renewal of this Title V permit shall be submitted no later than November 30, 2025.

Until such time as this permit expires or is modified or revoked, the below named Permittee is authorized to operate, as outlined in Part I, A. Air Quality Title V Operation Permit, and to construct and operate, as outlined in Part II, A. Air Quality Construction and Operation Permit, the emission source(s) and associated air pollution control device(s) specified herein, in accordance with the terms, conditions, and limitations within this permit. This permit is issued under the provisions of Article 21B of Chapter 143, General Statutes of North Carolina as amended, and Title 15A North Carolina Administrative Codes (15A NCAC), Subchapters 02D and 02Q, and other applicable Laws.

Pursuant to Title 15A NCAC, Subchapter 02Q, the Permittee shall not construct, operate, or modify any emission source(s) or air pollution control device(s) without having first submitted a complete Air Quality Permit Application to the permitting authority and received an Air Quality Permit, except as provided in this permit.

Permittee:	**Domtar Paper Company, LLC**
Facility ID:	**5900069**
Primary SIC Code:	**2611 and 2621**
NAICS Code:	**322121**
Facility Site Location:	**NC Highway 149 North**
City, County, State, Zip:	**Plymouth, Martin County, North Carolina 27962**
Mailing Address:	**Post Office Box 747**
City, State, Zip:	**Plymouth, North Carolina 27962**
Application Numbers:	**5900069.19B**
Complete Application Date:	**February 28, 2019, amended September 10, 2020**
Division of Air Quality, Regional Office Address:	**Washington Regional Office 943 Washington Square Mall Washington, North Carolina 27889**

Permit issued this the 9th day of March, 2022

Mark J. Cuilla, EIT, CPM, Chief, Permitting Section
By Authority of the Environmental Management Commission

Table of Contents

List of Acronyms

AOS	Alternative Operating Scenario
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CEDRI	Compliance and Emissions Data Reporting Interface
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
CSAPR	Cross-State Air Pollution Rule
DAQ	Division of Air Quality
DEQ	Department of Environmental Quality
EMC	Environmental Management Commission
EPA	Environmental Protection Agency
FR	Federal Register
GACT	Generally Available Control Technology
GHGs	Greenhouse Gases
HAP	Hazardous Air Pollutant
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology
NAA	Non-Attainment Area
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NCAC	North Carolina Administrative Code
NCGS	North Carolina General Statutes
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
OAH	Office of Administrative Hearings
PAE	Projected Actual Emissions
PAL	Plantwide Applicability Limitation
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with Nominal Aerodynamic Diameter of 2.5 Micrometers or Less
PM_{10}	Particulate Matter with Nominal Aerodynamic Diameter of 10 Micrometers or Less
POS	Primary Operating Scenario
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
tpy	Tons Per Year
VOC	Volatile Organic Compound

SECTION 1- PERMITTED EMISSION SOURCE(S) AND ASSOCIATED AIR POLLUTION CONTROL DEVICE(S) AND APPURTENANCES

The following table contains a summary of all permitted emission sources and associated air pollution control devices and appurtenances:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
POWER OPERATIONS			
No. 1 Hog Fuel Boiler			
ES-64-25-0290 **NSPS D,** **PSD BACT,** **MACT DDDDD** **<u>As Control Device</u>** **NSPS BB,** **MACT S**	No. 1 Hog Fuel Boiler firing lignin, natural gas, biomass fuel (including paper cores and bleached and unbleached pulp stock),[1] No. 2 fuel oil, used oil, sludge,[2] and gases collected in the high volume low concentration (HVLC) with a maximum heat input of 1,021 million Btu per hour when firing any combination of fuels and 835 million Btu per hour when firing hog fuel in combination with any other fuel.	CD-64-45-0100, CD-64-45-0230 and CD-64-60-0120, CD-64-60-0420, CD-64-60-0720	Primary Multicyclone (570 nine-inch cones) and Secondary Multicyclone (1,224 nine-inch cones) and West Electroscrubber Central Electroscrubber and East Electroscrubber
ES-64-60-0180	West De-entrainment Vessel	CD-64-60-0900	Baghouse West (approximately 1,058 square feet of filter area)
ES-64-60-0480	Central De-entrainment Vessel	CD-64-60-0910	Baghouse Central (approximately 1,058 square feet of filter area)
ES-64-60-0780	East De-entrainment Vessel	CD-64-60-0920	Baghouse East (approximately 1,058 square feet of filter area)
ES-64-60-0960	Scrubber Ash Silo	CD-64-60-0961 and CD-64-60-0962	West Bagfilter (approximately 105 square feet of filter area) and East Bagfilter (approximately 105 square feet of filter area)
No. 2 Hog Fuel Boiler			
ES-65-25-0310 **NSPS D,** **PSD BACT, and** **MACT DDDDD** **<u>As Control Device</u>** **NSPS BB,** **MACT S**	No. 2 Hog Fuel Boiler firing lignin, natural gas, biomass fuel (including paper cores and bleached and unbleached pulp stock),[1] No. 2 fuel oil, used oil, sludge,[2] gases collected in the HVLC system, low volume high concentration (LVHC) gases from LVHC white liquor scrubber except for periods of scrubber maintenance, and stripper off gases (SOG) with a maximum heat input of 889 million Btu per hour when firing any combination of fuel	CD-65-45-0100 and CD-65-58-2000	Multicyclone (356 nine-inch cones) and Electrostatic precipitator
ES-65-50-0160	Ash Transport Steam Exhauster	CD-65-50-0160	Air Washer
ES-65-50-0190	Boiler Ash Silo	CD-65-50-0170 and CD-65-50-0180	East Bagfilter (approximately 105 square feet of filter area) and West Bagfilter (approximately 105 square feet of filter area)

[1] Biomass fuel shall meet the clean cellulosic biomass definition as provided in 40 CFR 241.2 or the specific non-hazardous secondary material (NHSM) categories in 40 CFR 241.4. For any fuel that is not clearly defined by 40 CFR 241.1 or 241.4, the Permittee shall make a NHSM determination in accordance with 40 CFR 241.3 and submit a permit application to the Division of Air Quality for adding a new permitted fuel.

[2] Domtar Paper Company, LLC, Plymouth, may burn sludge from the Domtar Plymouth and IP's New Bern waste treatment facilities as supplementary fuel in Nos. 1 and 2 Hog Fuel Boilers.

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-65-60-0860	Scrubber Ash Silo	CD-65-60-0870 and CD-65-60-0880	East Bagfilter (approximately 84 square feet of filter area) and West Bagfilter (approximately 84 square feet of filter area)
Temporary Boilers			
ES-RB1	Temporary Boiler firing low-sulfur No. 2 fuel oil-fired (85.7 million Btu per hour maximum heat input)	NA	NA
ES-RB2	Temporary Boiler firing low-sulfur No. 2 fuel oil-fired (85.7 million Btu per hour maximum heat input)	NA	NA
Storage and Handling			
FS-007	No. 1 and No. 2 Hog Fuel Conveying	NA	NA
FS-011	Hogged Fuel Storage Pile at Boilers	NA	NA
HVLC GAS COLLECTION SYSTEM			
HVLC.06-10-2380 **NSPS BB, MACT S**	No. 6 Fiberline Chip Bin Relief Condenser	ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000	No. 2 Hog Fuel Boiler or No. 1 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer ***Thermal Oxidizer is a new source see Section 2.2 F [.0530(u)]***
HVLC.06-21-1100 **NSPS BB, MACT S**	No. 6 Fiberline Pressure Diffuser Filtrate Tank ***Note: Gases from this source are vented to the No. 6 Fiblerline Digester Blow Tank (HVLC.06-21-1200)***		
HVLC.06-21-1200 **NSPS BB, MACT S**	No. 6 Fiberline Digester Blow Tank		
HVLC.06-22-1080 **MACT S**	No. 6 Fiberline Secondary Knotter		
HVLC.06-22-1100 **MACT S**	No. 6 Fiberline Screen Dilution Tank		
HVLC.06-23-1200 **MACT S**	No. 6 Fiberline Decker Hood		
HVLC.06-23-1220 **MACT S**	No. 6 Fiberline Decker Filtrate Tank		
HVLC.06-22-1280 **MACT S**	No. 6 Fiberline Quaternary Screen		
HVLC.07-10-2380 **NSPS BB, MACT S**	No. 7 Fiberline Chip Bin Relief Condenser		
HVLC.07-21-1100 **NSPS BB, MACT S**	No. 7 Fiberline Pressure Diffuser Filtrate Tank ***Note: Gases from this source are vented to the No. 7 Fiblerline Digester Blow Tank (HVLC.07-21-1200)***		
HVLC.07-21-1200 **NSPS BB, MACT S**	No. 7 Fiberline Digester Blow Tank		
HVLC.07-22-1080 **NSPS BB, MACT S**	No. 7 Fiberline Secondary Knotter		
HVLC.07-22-1280 **MACT S**	No. 7 Fiberline Quaternary Screen		
HVLC.07-22-1100 **MACT S**	No. 7 Fiberline Screen Dilution Tank		

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
HVLC.07-23-1200 **MACT S**	No. 7 Fiberline Decker Hood		
HVLC.07-23-1220 **MACT S**	No. 7 Fiberline Decker Filtrate Tank		
HVLC.08-66-1000	Screen Rejects Tank		
LVHC GAS COLLECTION SYSTEM			
LVHC.06-10-2420 **NSPS BB, MACT S**	No. 6 Fiberline Digester Flash Condenser	CD-14-55-2020 and ES-14-60-3000 or CD-14-55-2020 and ES-65-25-0310	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler
LVHC.07-10-2420 **NSPS BB, MACT S**	No. 7 Fiberline Digester Flash Condenser		
LVHC.08-61-1000 **MACT S**	Turpentine Decanter Tank		
LVHC.08-61-1020 **MACT S**	Turpentine Decanter Weir		
LVHC.08-61-1040 **MACT S**	Turpentine Underflow Tank		
LVHC.08-61-1080 **MACT S**	Turpentine Tank (32,000-gallon capacity)		
LVHC.09-20-0320 **MACT S**	No. 6 Black Liquor Evaporator System		
LVHC.09-25-0510 **NSPS BB, MACT S**	No. 7 Black Liquor Evaporator System		
LVHC.09-35-0200 **MACT S**	Concentrator Hotwell		
LVHC.09-DECANT$^{\Delta}$ **MACT S**	Secondary Turpentine Decanter Tank		
LVHC.09-WEIR$^{\Delta}$ **MACT S**	Secondary Turpentine Decanter Weir		
LVHC.09-UND$^{\Delta}$ **MACT S**	Secondary Turpentine Underflow Tank		
LVHC.09-STOR$^{\Delta}$ **MACT S**	Secondary Turpentine Storage Tank		
LVHC.07-10-2480 **MACT S**	No. 6 and 7 Digester Contaminated Condensate Tank		
LVHC.09-25-1000 **MACT S**	Condensate Stripper Feed Tank		
SOG.09-25-1050 **NSPS BB, MACT S**	Condensate Stripper Reflux Condenser	ES-14-60-3000 or ES-65-25-0310	No. 5 Lime Kiln or No. 2 Hog Fuel Boiler
FIBERLINE OPERATIONS			
No. 6 Fiberline (rated a nominal at 800 bone dry tons per day)			
ES-06-05-2000	Chip Silo B	NA	NA
ES-06-05-3000	Chip Silo C	NA	NA
No. 6 Bleach Plant			
ES-06-31-0180 **PSD BACT, MACT S**	Oxygen Delignification System	NA	No control required per Clean Condensate Alternative under 40 CFR 63.447

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-06-31-1000 **PSD BACT MACT S**	1st Stage O_2 Surge Tank	NA	
ES-06-32-2060 **PSD BACT, MACT S**	2nd Stage O_2 Reactor Blow Tube	NA	
ES-06-32-2100 **PSD BACT, MACT S**	2nd Stage Wash Tower	NA	
ES-06-32-2120 **PSD BACT, MACT S**	2A/2B Filtrate Tank	NA	
ES-06-32-2300 **PSD BACT**	No. 28 High Density Tank	NA	NA
ES-06-32-2340 **PSD BACT**	No. 29 High Density Tank	NA	NA
ES-06-32-2380 **PSD BACT**	No. 30 High Density Tank	NA	NA
ES-06-32-2460 **PSD BACT**	2C Washer	NA	NA
ES-06-32-2480 **PSD BACT**	2C Washer Filtrate Tank	CD-06-35-8100	No. 6 Bleach Plant White Liquor Scrubber (45 gallons per minute minimum circulation flow and minimum pH of 10)
ES-06-33-3060 **PSD BACT, MACT S**	3rd Stage Tower - ClO_2 Stage		
ES-06-34-4080 **PSD BACT**	4th Stage Extraction Tower *NOTE: Extraction Stage is not subject to MACT Subpart S.*		
ES-06-34-4100 **PSD BACT**	4th Stage Extraction Filtrate Tank *NOTE: Extraction Stage is not subject to MACT Subpart S.*		
ES-06-35-5060 **PSD BACT, MACT S**	5th Stage Tower – ClO_2 Stage		
ES-06-35-5080 **PSD BACT, MACT S**	5th Stage Filtrate Tank – ClO_2 Stage		
ES-08-67-1400 **PSD BACT**	Acid Sewer	CD-07-36-8000	No. 7 Bleach Plant White Liquor Scrubber (105 gallons per minute minimum circulation flow and minimum pH of 10)
ES-06-6SFCO **PSD BACT**	6th Stage Feed Chute Overflow Line	CD-06-35-8100[3]	No. 6 Bleach Plant White Liquor Scrubber (45 gallons per minute minimum circulation flow and minimum pH of 10)[3]
ES-06-P2	6th Stage Peroxide Reactor Blow Tube	NA	NA
ES-06-P3	6th Stage Peroxide Stage Washer, Filtrate Tank, Vacuum Pump, and Exhaust Blower	NA	NA
FS-003 **PSD BACT**	Building Fugitives	NA	NA

[3] Not required for compliance.

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
No. 7 Fiberline (rated at a nominal 1,250 bone dry tons per day)			
ES-07-05-1000	Chip Silo A	NA	NA
ES-07-05-2000	Chip Silo B	NA	NA
No. 7 Bleach Plant			
ES-07-31-1000 **PSD BACT MACT S**	1st Stage O_2 Surge Tank	NA	No control required per Clean Condensate Alternative under 40 CFR 63.447
ES-07-31-1100 **PSD BACT MACT S**	Oxygen Delignification System		
ES-07-31-1140 **PSD BACT MACT S**	1st Stage O_2 Reactor Blow Tube		
ES-07-31-1180 **PSD BACT MACT S**	1st Stage Wash Tower		
ES-07-31-1200 **PSD BACT, MACT S**	1A/1B Filtrate Tank		
ES-07-33-3000 **PSD BACT MACT S**	3rd Stage Feed Tank		
ES-07-33-3080 **PSD BACT MACT S**	3rd Stage Tower - ClO_2 Stage	CD-07-36-8000	No. 7 Bleach Plant White Liquor Scrubber (105 gallons per minute minimum circulation flow and minimum pH of 10)
ES-07-35-5060 **PSD BACT, MACT S**	5th Stage Tower – ClO_2 Stage		
ES-07-35-5080 **PSD BACT, MACT S**	5th Stage Filtrate Tank		
ES-07-33-Blendbox **PSD BACT**	Blend Box (sump)		
FS-004 **PSD BACT**	Building Fugitives	NA	NA
ES-07-34-4080 **PSD BACT**	4th Stage Extraction Tower *NOTE: Extraction Stage is not subject to MACT Subpart S.*	NA	NA
ES-07-34-4100 **PSD BACT**	4th Stage Extraction Filtrate Tank *NOTE: Extraction Stage is not subject to MACT Subpart S.*	NA	NA
ES-07-36-6040 **PSD BACT**	Peroxide 6th Stage Extraction Tower *NOTE: Extraction Stage is not subject to MACT Subpart S.*	NA	NA
ES-07-36-6060 **PSD BACT**	Peroxide 6th Stage Extraction Filtrate Tank *NOTE: Extraction Stage is not subject to MACT Subpart S.*	NA	NA
No. 6 & 7 Fiberline (common facilities)			
ES-05-30-1300	No. 5 Hot Water Tank/Evaporator Condensate	NA	NA
ES-08-40-1000	No. 32 High Density Pulp Tank	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-08-50-3140 **PSD BACT**	10% Sulfuric Acid Day Tank	CD-07-36-8000	No. 7 Bleach Plant White Liquor Scrubber (105 gallons per minute minimum circulation flow and minimum pH of 10)
ES-08-50-3020*	Sulfuric Acid Storage Tank (24,000 gallon capacity)*	NA	NA
ES-08-52-1060	R8/10 Chlorine Dioxide Generator (20,075 tons per year capacity)	CD-08-52-1860	White liquor scrubber (70 gallons per minute minimum caustic wetting rate)
ES-08-52-1760, ES-08-52-1770, and ES-08-52-1780	Three Chlorine Dioxide Tanks		
ES-08-65-1060	Spill Collection Tank	NA	NA
ES-08-70-0900	White Liquor Surge Tank	NA	NA
ES-08-67-1200 **PSD BACT**	Base Effluent Neutralization Tank	CD-07-36-8000	No. 7 Bleach Plant White Liquor Scrubber (105 gallons per minute minimum circulation flow and minimum pH of 10)
ES-08-67-1300 **PSD BACT**	Acid Effluent Neutralization Tank		
ES-08-70-1000	White Liquor Oxidation Tank		
FS-002*	Building Fugitives*	NA	NA
EVAPORATOR OPERATIONS			
ES-09-05-0100**	West 18% Liquor Tank**	NA	NA
ES-09-05-0150**	18% Liquor Mix Tank (West)**	NA	NA
ES-09-05-0200**	East 18% Liquor Tank**	NA	NA
ES-09-05-0210	South Weak Black Liquor Storage Tank	NA	NA
ES-09-10**	Four Soap Storage Tanks**	NA	NA
ES-09-19-0020**	East Liquor Heater**	NA	NA
ES-09-19-0030**	West Liquor Heater**	NA	NA
ES-09-20-0070**	No. 6 Evaporator Soap Skim Tank**	NA	NA
ES-09-25-0140**	No. 7 Evaporator Soap Skimmer Tank**	NA	NA
ES-09-25-0340**	Diverter Tank**	NA	NA
ES-09-25-0540**	No. 7 Evaporator Boilout Tank**	NA	NA
ES-09-30-0030**	Soap Collection Tank**	NA	NA
ES-09-30-0010**	North 48% Black Liquor Storage Tank**	NA	NA
ES-09-30-0020**	South 48% Black Liquor Storage Tank**	NA	NA
ES-09-40-0010**	East 65% Liquor Storage Tank**	NA	NA
ES-09-40-0020**	West 65% Liquor Storage Tank**	NA	NA
ES-09-95**	Four Saveall Tanks**	NA	NA
ES-09-12-0250**	No. 5 Soap Storage Tank**	NA	NA
ES-09-12-0050**	Black Liquor Separator Tank**	NA	NA
PULPING PROCESS CONDENSATE			
ES-09-20-0250**	Combined Condensate Tank**	NA	NA
ES-09-35-0140	C3 Condensate To Sewer	NA	NA
ES-09-20-0010*	5th Effect of No. 6 Evaporator System Condensate To Sewer and/or Process*	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
RECOVERY BOILER OPERATIONS			
ES-10-08-0010	Salt Cake Mix Tank	CD-14-05-0750	South Ducon Alkaline Scrubber (50 gallons per minute minimum rod box flow, 75 gallons per minute minimum spray header flow, and 3.0 inches of water minimum pressure drop)
ES-10-25-0110 **NSPS BB,** **PSD BACT,** **MACT MM** **As control device:** **MACT S** **NSPS BB**	No. 5 Recovery Boiler firing natural gas, black liquor solids, low sulfur No. 2 fuel oil, and HVLC gases (130 tons per hour of black liquor solids)	CD-10-45-0010 and CD-10-45-0220	North Electrostatic Precipitator (approximately-169,164 square feet of collecting plate area) and South Electrostatic Precipitator (approximately-169,164 square feet of collecting plate area)
ES-10-45-0450**	No. 5 Precipitator Mix Tank**	NA	NA
ES-10-45-0520	North Precipitator Mix Tank	NA	NA
ES-10-45-0580	South Precipitator Mix Tank	NA	NA
ES-10-45-0630*	Precipitator Purge Tank *	NA	NA
SMELT DISSOLVING/GREEN LIQUOR CLARIFICATION OPERATIONS			
ES-14-05-0050 **MACT MM**	North Smelt Tank	CD-14-05-0700	North Ducon Alkaline Scrubber (50 gallons per minute minimum rod box flow, 75 gallons per minute minimum spray header flow, and 3.0 inches of water minimum pressure drop)
ES-14-05-0300 **MACT MM**	South Smelt Tank	CD-14-05-0750	South Ducon Alkaline Scrubber (50 gallons per minute minimum rod box flow, 75 gallons per minute minimum spray header flow, and 3.0 inches of water minimum pressure drop)
ES-14-10-1000**	No. 5 Green Liquor Clarifier**	NA	NA
ES-14-15-0600**	Dregs Surge Tank**	NA	NA
ES-14-15-0800**	Dregs Filter**	NA	NA
ES-14-15-0900**	Dregs Filter Vacuum System**	NA	NA
ES-14-15-DREGS**	Dregs Dumpster**	NA	NA
SLAKING/CAUSTICIZING OPERATIONS			
ES-14-20-2020	East Lime Slaker	CD-14-20-2035	East Slaker Wet Scrubber (45 gallons per minute minimum liquid injection rate)
ES-14-20-2040	No. 1 East Causticizing Line		
ES-14-20-2050	No. 2 East Causticizing Line		
ES-14-20-2060	No. 3 East Causticizing Line		
ES-14-20-2085	West Lime Slaker	CD-14-20-2100	West Slaker Wet Scrubber (45 gallons per minute minimum liquid injection rate)
ES-14-20-2105	No. 1 West Causticizing Line		
ES-14-20-2115	No. 2 West Causticizing Line		
ES-14-20-2125	No. 3 West Causticizing Line		
ES-14-20-GRITS*	Slaker (Grits) Dumpster*	NA	NA
ES-14-25-0050	Hydrosulfide Storage Tank	NA	NA
ES-14-25-0150	Synthetic Liquor Mix Tank	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-14-25-0450**	No. 3 White Liquor Clarifier**	NA	NA
ES-14-25-0800**	No. 4 White Liquor Clarifier**	NA	NA
ES-14-25-0350**	No. 5 White Liquor Clarifier**	NA	NA
LIME MUD FILTERS AND LIME KILN OPERATIONS			
ES-14-30-0310	Lime Mud Mix Tank	NA	NA
ES-14-30-0350	No. 2 Lime Mud Wash Tank	NA	NA
ES-14-30-0700	No. 3 Lime Mud Wash Tank	NA	NA
ES-14-30-1450	Lime Mud Storage Tank	NA	NA
ES-14-30-5040 and ES-14-30-6040	Two Lime Mud Filter Vacuum Systems	NA	NA
ES-14-30-6060	Lime Mud Filtrate Tank	NA	NA
ES-14-70-2020	Scrubber Water Clarifier	NA	NA
ES-14-70-2045	Lime Kiln Scrubber Water Standpipe	NA	NA
ES-14-30-5000	East Lime Mud Filter – Hood Exhaust	CD-14-30-6025	Lime Mud Scrubber/Mist Eliminator (48 gallons per minute minimum liquid injection rate)
ES-14-30-6000	West Lime Mud Filter - Hood Exhaust		
ES-14-60-3000 **NSPS BB** **MACT MM** **<u>As Control Device</u>** **NSPS BB,** **MACT S,** **PSD BACT**	No. 5 Lime Kiln firing natural gas, No. 2 fuel oil, LVHC gases, and stripper off gases (SOG) (500 tons per day of reburned lime nominal capacity)	CD-14-70-2012	Lime Kiln Venturi Scrubber (896 gallons per minute minimum liquid injection rate, 5.0 inches of water maximum pressure drop, and 240 psig to 275 psig scrubber nozzle header pressure range)
ES-14-60-3015	Reburned Lime Crusher	CD-14-70-2012 or CD-14-65-1075	Lime Kiln Venturi Scrubber (896 gallons per minute minimum liquid injection rate, 5.0 inches of water maximum pressure drop, and 240 psig to 275 psig scrubber nozzle header pressure range) or Lime dust baghouse (approximate 1,608 square feet of filter area)
ES-14-65-1000	Reburned Lime Conveyor	CD-14-65-1075	Lime Dust Baghouse (approximate 1,608 square feet of filter area)
ES-14-65-1020	Reburned Lime Bucket Elevator		
ES-14-65-1030	Reburned Lime Bin		
ES-14-65-1080	Fresh Lime Bin	CD-14-65-1082	Lime Dust Baghouse (approximate 360 square feet of filter area)
PULP OPERATIONS			
NC-2 Line			
ES-32-25-0200 and ES-32-25-0240	White Water Tanks	NA	NA
ES-32-93-0100	Building Roof Vents	NA	NA
ES-32-STOCKTANKS	HD and LD Stock Tanks	NA	NA
ES-32-IO-VACPUMPS	Inside/Outside Vacuum Pumps	NA	NA
ES-32-HOODS	Dryer Hoods	NA	NA
NC-5 Line			
ES-45-93-0100	Building Fugitives	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-FP-STOCKTANKS	HD and LD Stock Tanks	NA	NA
ES-45-40-VACP	Inside/Outside Vacuum Pumps	NA	NA
ES-45-40-HOOD	Dryer Hoods	NA	NA
WOODYARD OPERATIONS			
HR-01*	Haul Roads*	NA	NA
ES-00-30-4480	North Chip Pile	NA	NA
ES-00-30-4240	South Chip Pile	NA	NA
ES-00-35-1000	Screen House	NA	NA
ES-00-50-3280	Hogged Bark Fuel Storage Pile	NA	NA
ES-11-10-1500	Debarking and Chipping Line	NA	NA
ES-11-30-1020	Emergency Chip Pile with Traversing Stacker	NA	NA
ES-11-50-4500-1 and ES-11-50-4500-2	Two Bark Hogs	NA	NA
FS-010	Hog Fuel Handling and Transfer in Woodyard	NA	NA
FS-012	Chip Conveying to Pulping	NA	NA
FS-013	Chip Handling and Transfer System in Woodyard	NA	NA
FS-021	Hog Fuel Handling and Transfer to Boiler Area	NA	NA
ES-TEMP-CHIP	One or More Portable Log Chipper(s)	NA	NA
WASTEWATER TREATMENT OPERATIONS			
ES-73-05-2000	Power/Recovery Channel and Sewer	NA	NA
ES-73-05-5200	Fiber Line Sewer Lift Station	NA	NA
ES-73-05-6000	Paper And Bleach Plant Sewer Ditches	NA	NA
ES-73-05-7080	Ammonium Hydroxide Storage Tank	NA	NA
ES-73-10-1000	No. 1 Settling Pond	NA	NA
ES-73-10-2000	No. 2 Settling Pond	NA	NA
ES-73-10-2510	No. 2 Lift Station	NA	NA
ES-73-10-3000	Aeration Basin	NA	NA
ES-73-10-3920	Riffler	NA	NA
ES-73-10-4000	No. 1 Retention Pond	NA	NA
ES-73-10-4500	No. 2 Retention Pond	NA	NA
ES-73-10-5030	No. 1 Lift Station & Receiving Pond	NA	NA
ES-73-25-1100 and ES-73-25-1120	No. 3 Landfill Clean Filtrate/Leachate Sumps	NA	NA
FS-018	Site-wide Sumps	NA	NA
MAINTENANCE OPERATIONS			
ES-94-15	Carpenter Shop Woodworking Operations	CD-94-15-0450	Cyclone
LANDFILL OPERATIONS			
ES-73-40*	No. 3 Landfill, Active (up to 95 acres)*	NA	NA

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
EMERGENCY RECIPROCATING INTERNAL COMBUSTION ENGINES			
ES-14-60-3000a **MACT ZZZZ**	Spare Diesel Engine Backup (81 hp)	NA	NA
ES-53-40-0130 **MACT ZZZZ**	Fine Paper Fire Pump Diesel Engine (237 hp)	NA	NA
ES-53-40-0140 **MACT ZZZZ**	Warren Neck Creek East Fire Pump Diesel Engine (260 hp)	NA	NA
ES-53-40-0145 **MACT ZZZZ**	Warren Neck Creek West Fire Pump Diesel Engine (180 hp)	NA	NA
ES-71-95-0500 **MACT ZZZZ**	Backup Communication System Diesel Generator (738 hp)	NA	NA
ES-73-05-4570 **MACT ZZZZ**	Backup Lift Station Runoff Collection Diesel Engine (210 hp)	NA	NA
ES-73-05-4580 **MACT ZZZZ**	Backup Fiberline Lift Station Diesel Engine (210 hp)	NA	NA
LIGNIN SOLIDS REMOVAL PROCESS (LSRP)			
ES-09-27-1100 **PSD BACT**	No. 1 Feed Liquor Cooler	ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000 OR CD-09-27-3800	No. 2 Hog Fuel Boiler or No. 1 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer OR Two-phase packed bed caustic scrubber
ES-09-27-1200 **PSD BACT**	No. 1 Lignin Filter Filtrate Storage Tank		
ES-09-27-1800 **PSD BACT**	Lignin Slurry Conditioning Tank		
ES-09-27-2000 **PSD BACT**	Lignin Slurry Buffer Tank		
ES-09-27-2100 **PSD BACT**	No. 1 Lignin Filter		
ES-09-27-2300 **PSD BACT**	No. 1 Lignin Filter Cloth Wash Tank		
ES-09-27-2400 **PSD BACT**	No. 1 Lignin Filter Filtrate Tank		
ES-09-27-2500 **PSD BACT**	No. 1 Lignin Filter Filtrate Buffer Tank		
ES-09-27-2600 **PSD BACT**	Lignin Lump Breaker		
ES-09-27-2610 **PSD BACT**	No. 1 Lignin Filter Horizontal Conveyor		
ES-09-27-2620 **PSD BACT**	No. 1 Lignin Filter Incline Conveyor		
ES-09-27-2660 **PSD BACT**	Lignin Rotary Feeder		
ES-09-27-3200 **PSD BACT**	No. 2 Lignin Filter Acidic Filtrate Tank		
ES-09-27-3100 **PSD BACT**	No. 2 Lignin Filter Cloth Wash Tank	NA OR CD-09-27-3800	NA OR Two-phase packed bed caustic scrubber

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-09-27-2800 **PSD BACT**	Acidic Lignin Conditioning Tank	ES-09-27-1400 and ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000 OR CD-09-27-3800	Feed Liquor Carbonator, and No. 2 Hog Fuel Boiler or No. 1 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer OR Two-phase packed bed caustic scrubber
ES-09-27-2700 **PSD BACT**	Lignin Acidification Tank	ES-09-27-1400 and ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000	Feed Liquor Carbonator, and No. 2 Hog Fuel Boiler or No. 1 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer
ES-09-27-2770 **PSD BACT**	Lignin Foam Tank		
ES-09-27-1400 **PSD BACT**	Feed Liquor Carbonator	ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000	No. 2 Hog Fuel Boiler or No. 1 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer
ES-09-27-3000 **PSD BACT**	No. 2 Lignin Filter	NA OR CD-09-027-3900	NA OR Dust collection system with wet cyclone
ES-09-27-1000 **PSD BACT**	Lignin Feed Liquor Tank	NA	NA

* Sources identified with an asterisk have no applicable requirements under the North Carolina SIP, but their emissions are greater than the thresholds under 15A NCAC 02Q .0503(8).

** These sources are only regulated under 02D .1100 "Control of Toxic Air Pollutants" in Section 2.2 of this permit.

Δ These emission sources (ID Nos. LVHC.09-DECANT, LVHC.09-WEIR, LVHC.09-UND, LVHC.09-STOR) are listed as a 15A NCAC 02Q .0501(b)(2) modification per Permit Application No. 5900069.17A. These sources have not yet been installed. The Permittee shall file a Title V Air Quality Permit Application on or before 12 months the first piece of equipment is placed into operation in accordance with General Condition NN.1. The permit shield described in General Condition R does not apply and compliance certification as described in General Condition P is not required.

SECTION 2 - SPECIFIC LIMITATIONS AND CONDITIONS

2.1 Emission Source(s) and Control Devices(s) Specific Limitations and Conditions

The emission source(s) and associated air pollution control device(s) listed below are subject to the following specific terms, conditions, and limitations, including the testing, monitoring, recordkeeping, and reporting requirements as specified herein:

A. Hog Fuel Boilers

- **No. 1 Hog Fuel Boiler (ID No. ES-64-25-0290) firing lignin, natural gas, biomass fuel (including paper cores and bleached and unbleached pulp stock),[4] No. 2 oil, used oil, sludge,[5] and gases collected in the HVLC system with a maximum heat input of 1,021 million Btu per hour when firing any combination of fuels, 835 million Btu per hour when firing clean cellulosic biomass in combination with any other fuel, controlled by primary multicyclone (ID No. CD-64-45-0100) and secondary multicyclone (ID No. CD-64-45-0230) operating in series, followed by electroscrubbers (ID Nos. CD-64-60-0120, CD-64-60-0420 and CD-64-60-0720) operating in parallel, and**
- **No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310) firing lignin, natural gas, biomass fuel (including paper cores and bleached and unbleached pulp stock),[4] No. 2 oil, used oil, sludge,[5] and gases collected in the HVLC system, LVHC gases from LVHC white liquor scrubber except for periods of scrubber maintenance, and SOG gases with a maximum heat input of 889 million Btu per hour when firing any combination of fuel, equipped with an oxygen trim system, and controlled by multicyclone (ID No. CD-65-45-0100) in series with an electrostatic precipitator (ID No. CD- 65-58-2000).**

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	No. 1 Hog Fuel Boiler 0.160 pounds per million Btu heat input (when firing natural gas and fuel oil only); No. 2 Hog Fuel Boiler 0.143 pounds per million Btu heat input (when firing natural gas and fuel oil only);	15A NCAC 02D .0503
Particulate matter	Both Boilers 0.22 pounds per million Btu heat input (when firing woodwaste only); or When firing woodwaste in combination with natural gas or fuel oil: $Ec = [(0.22)(Qw) + Eo(Qo)]/Qt$ Where: Ec = emission limit for combined firing (pound per million Btu); Qw = actual wood heat input including woodwaste; Eo = the emission limit for other fuels only as determined for each boiler, above (pound per million Btu); Qo = actual heat input other than wood heat input; and Qt = Qw + Qo	15A NCAC 02D .0504
Sulfur dioxide	2.3 percent sulfur content fuel when firing only wood or natural gas	15A NCAC 02D .0516
Visible emissions	20 percent opacity when firing only natural gas	15A NCAC 02D .0521

[4] Biomass fuel shall meet the clean cellulosic biomass definition as provided in 40 CFR 241.2 or the specific non-hazardous secondary material (NHSM) categories in 40 CFR 241.4. For any fuel that is not clearly defined by 40 CFR 241.1 or 241.4, the Permittee shall make a NHSM determination in accordance with 40 CFR 241.3 and submit a permit application to the Division of Air Quality for adding a new permitted fuel.

[5] Domtar Paper Company, LLC, Plymouth, may burn sludge from the Domtar Plymouth and IP's New Bern waste treatment facilities as supplementary fuel in Nos. 1 and 2 Hog Fuel Boilers.

Regulated Pollutant	Limits/Standards	Applicable Regulation
Nitrogen oxides	0.30 pounds per million Btu heat input when firing oil only, or oil and wood residue, or natural gas and wood residue; 0.20 pounds per million Btu heat input when firing natural gas only.	15A NCAC 02D .0524 (40 CFR Part 60, Subpart D)
Sulfur dioxide	0.80 pounds per million Btu heat input when firing oil only or oil and wood residue.	
Particulate matter	0.10 pounds per million Btu heat input when firing oil only, or oil and wood residue, or natural gas and wood residue.	
Visible emissions	20 percent opacity when averaged over a six-minute period, except for one six-minute period per hour of not more than 27 percent opacity.	
Criteria pollutants	**No. 1 Hog Fuel Boiler:** • 1,646 pounds of CO per hour when firing HVLC gases **No. 2 Hog Fuel Boiler:** • 1,433 pounds of CO per hour when firing HVLC gases; • 0.10 pounds of PM_{10} per million Btu heat input when firing any fuel; • 0.8 pounds of SO_2 per million Btu heat input when firing oil with wood; • 339 pounds of H_2SO_4 mist consecutive 24-hour period when firing LVHC and SOG NCG gases; and • 235 pounds of total reduced sulfur consecutive 24-hour period when firing LVHC and SOG gases	15A NCAC 02D .0530
Particulate matter	Compliance Assurance Monitoring	15A NCAC 02D .0614
Hazardous air pollutants	2.2E-02 lb HCl per million Btu of heat input 5.7E-06 lb Hg per million Btu or heat input 3,500 parts per million CO on a dry basis corrected to 3 percent oxygen, 3-run average 4.4E-01 lb filterable PM per million Btu of heat input OR 4.5E-04 lb TSM per million Btu of heat input	15A NCAC 02D .1111 [40 CFR Part 63, Subpart DDDDD]

1. ALTERNATIVE OPERATING SCENARIOS [15A NCAC 02Q .0508(j)]

The Permittee, contemporaneously with making a change from one alternative operating scenario to another, shall record in a logbook (written or electronic format) the scenario under which it is operating. [15A NCAC 02Q .0508(p)]

a. The Primary Operating Scenario (POS) is defined as the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** firing fuels other than natural gas and/or No. 2 fuel oil, controlled by two multicyclones **(ID Nos. CD-64-45-0100 and CD-64-45-0230)** in series with three electroscrubbers **(ID Nos. CD-64-60-0120, CD-64-60-0420 and CD-64-60-0720)** operating in parallel.

b. The Alternative Operating Scenario (AOS) is defined as the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** firing only natural gas and/or No. 2 fuel oil, alone with the two multicyclones **(ID Nos. CD-64-45-0100 and CD-64-45-0230)** and three electroscrubbers **(ID Nos. CD-64-60-0120, CD-64-60-0420 and CD-64-60-0720)** not operating.

c. The Permittee shall submit a notification to DAQ within 10 days of switching to the Alternative Operating Scenario.

2. 15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS

a. Emissions of particulate matter from the combustion of natural gas and fuel oil, that are discharged from the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** into the atmosphere shall not exceed the following:

i. 0.160 pounds per million Btu heat input for the No. 1 Hog Fuel Boiler; and

ii. 0.143 pounds per million Btu heat input for the No. 2 Hog Fuel Boiler.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.2.a, above, the Permittee shall be deemed in noncompliance with 15A NCAC 2D .0503.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring/recordkeeping/reporting is required for particulate emissions from the firing of natural gas and/or No. 2 fuel oil, alone, in these boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)**.

3. 15A NCAC 02D .0504: PARTICULATES FROM WOOD BURNING INDIRECT HEAT EXCHANGERS

a. Emissions of particulate matter from the combustion of wood only that are discharged from the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** into the atmosphere shall not exceed 0.22 pounds per million Btu heat input.

b. Emissions of particulate matter from the combustion of wood and other fuels in combination that are discharged from the Nos 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-031)** into the atmosphere shall not exceed an allowable emission rate as calculated by the following equation:

$$E_c = [(E_w)(Q_w) + (E_o)(Q_o)]/Q_t$$

Where:

E_C = the emission limit for combination or combined emission source(s) in pounds per million Btu.
E_W = emission limit for wood only as specified in Section 2.1 A.3.a, above, in pounds per million Btu.
E_O = emission limit for other fuels only as specified Section 2.1 A.2.a, above, in pounds per million Btu.
Q_W = the actual wood heat input to the hog fuel boiler in million Btu per hour.
Q_O = the actual other fuels heat input to the hog fuel boiler in million Btu per hour.
Q_t = $Q_W + Q_O$ and is the actual total heat input to hog fuel boiler in million Btu per hour.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.3.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0504.

Monitoring and Recordkeeping [15A NCAC 02Q .0508(f)]

d. Particulate matter emissions from the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** shall be controlled as specified in Section 2.1 A.6.i below and inspected and maintained as specified in Section 2.1 A.6.j below. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0504 if inspection and maintenance records (written or electronic format) are not created or retained.

Reporting [15A NCAC 02Q .0508(f)]

e. Within 30 days of a written request from the DAQ, the Permittee shall submit a report of any maintenance performed on the multicyclones **(ID Nos. CD-64-45-0100 and CD-65-45-0100)**, electroscrubbers installed on the No. 1 Hog Fuel Boiler **(ID Nos. CD-64-60-0120, CD-64-60-0420 and CD-64-60-0720)**, or the electrostatic precipitator installed on the No. 2 Hog Fuel Boiler **(ID No. CD-65-58-2000)**.

f. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 A.3.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all periods of noncompliance from the requirements of this permit or a statement that no periods of noncompliance occurred during the reporting period.

4. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide when firing wood or natural gas in the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the

combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard, and shall include the sulfur dioxide formed by the combustion of sulfur-containing gases in the:

i. HVLC Gas Collection System identified in Section 2.1 J below;
ii. LVHC Gas Collection System identified in Section 2.1 K (when burned in the No. 2 Hog Fuel Boiler);
iii. SOG Collection System identified in Section 2.1 L (when burned in the No. 2 Hog Fuel Boiler);
iv. LSRP Sources **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1400, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2600, ES-09-27-2610, ES-09-27-2620, ES-09-27-2660, ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, ES-09-27-3200)** prior to startup of normal operations of the two-phased packed tower caustic scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 Q.1 below;
v. LSRP Sources **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** after startup of normal operation of the two-phased packed bed scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 T.1 below.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.4.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. Monitoring, recordkeeping and reporting are not required for the combustion of wood residue and natural gas in these boilers.

5. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the combustion of only natural gas in the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emission testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.5.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring, recordkeeping, or reporting is required for visible emissions when firing natural gas in the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)**.

6. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

a. The Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements in accordance with 15A NCAC 02D .0524, "New Source Performance Standards (NSPS) as promulgated in 40 CFR Part 60, Subpart D "Standards of Performance for Fossil-Fuel-Fired Steam Generators," including Subpart A "General Provisions."

Emissions Limits [15A NCAC 02D .0524]

b. The following emission limits shall not be exceeded for each hog fuel boiler:

POLLUTANT	EMISSION LIMIT
Sulfur Dioxide	0.80 pounds per million Btu heat input when firing liquid fossil fuel or liquid fossil fuel and wood residue
Nitrogen Oxides (expressed as NO_2)	**Firing natural gas only:** 0.20 pounds per million Btu heat input when firing gaseous fossil fuel only **Firing oil or firing wood with oil or wood with natural gas** 0.30 pounds per million Btu heat input when firing liquid fossil fuel or liquid fossil fuel and wood residue or gaseous fossil fuel and wood residue

POLLUTANT	EMISSION LIMIT
	When different fossil fuels are burned simultaneously, in any combination, the applicable emission limit is determined by proration using the formula in 40 CFR 60.44(b).
Particulate Matter (filterable)	0.10 pounds per million Btu heat input when firing fossil fuel or fossil fuel and wood residue or natural gas and wood residue
Visible Emissions	**Firing oil or firing oil with wood** 20 percent opacity (except during periods of startup, shutdown and malfunction) except for one six-minute period per hour of not more than 27 percent opacity

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.6.b, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

d. Under the provisions of North Carolina General Statutes 143-215.108 and in accordance with General Condition JJ, the Permittee shall demonstrate compliance with the particulate emission limit by testing the No. 1 and No. 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** as follows:
   i. The Permittee shall test the hog fuel boilers for particulate emissions once every five years.
   ii. During testing of each boiler, the Permittee shall fire the fuel or fuel combination expected to result in the highest emissions of each pollutant and which is expected to contribute at least 10% of the 12-month average heat input for the boiler.
   iii. During the testing of each boiler, the Permittee shall operate the control devices as follows:
      (A) (POS Only) Operate only two of the three electroscrubbers installed on the No. 1 Hog Fuel Boiler for which at least 25% of the total elements have less than 1 kilovolt of voltage applied.
      (B) Operate electrostatic precipitator installed on the No. 2 Hog Fuel Boiler with a minimum of 1.5 of its electrical fields in operation.
   iv. Operation above the established maximum or below the established minimum operating limits shall constitute a period of noncompliance with the established operating limits except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. The Permittee shall confirm or reestablish operating limits during performance tests. [40 CFR 60.8(c)]
      (A) If revisions to operating parameter values are necessary to demonstrate compliance with the emission limits and are more stringent than the established minimum or maximum operating limits, the Permittee shall submit a request to revise the values in the permit at the same time as the test report is submitted as required per General Condition JJ. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.
      (B) If performance testing indicates that compliance with emission limits is demonstrated with revisions to operating parameter values that are less stringent than the established minimum or maximum operating limits, the Permittee may request to revise the values in the permit pursuant to 15A NCAC 02Q .0515.

   If the performance test is not conducted as specified above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Recordkeeping (SO_2) [15A NCAC 02Q .0508(f)]

e. The Permittee shall demonstrate compliance with the sulfur dioxide emission limit for the No. 1 and No. 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** by fuel sampling and analysis. [40 CFR 60.45(b)(2)] The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the fuel supplier certification records demonstrate that the potential sulfur dioxide emissions exceed the limit in Section 2.1 A.6.b, above.

Monitoring/Recordkeeping (Opacity) [15A NCAC 02Q .0508(f)]

f. The Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the visible emissions from the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)**, POS only as defined in Section 2.1 A.1, above, and the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** as specified in 40 CFR 60.45(a). [40 CFR 60.11, 60.13, and 60.45(a) and (b)(1)] The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the COMS is not calibrated, maintained, and operated as specified.

g. The Permittee shall demonstrate compliance with the visible emissions limit in Section 2.1 A.6.b above using six-minute averages of the COMS values. If any six-minute period average exceeds 20 percent opacity (except during

periods of startup, shutdown and malfunction) except for one six-minute period per hour of not more than 27 percent opacity, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524. [40 CFR 60.8(c) 60.45(g)(1)]

Monitoring/Recordkeeping (NO_X) [15A NCAC 02Q .0508(f)]

h. The Permittee shall install, calibrate, maintain, and operate a CEMS for measuring and recording the 1-hour average NO_X and O_2 (or CO_2) pollutant concentration. The Permittee shall calculate emission rates in pounds per million Btu heat input as specified in 40 CFR 60.45(e) and (f) during all periods of boiler operation, except for periods of CEMS breakdowns and repairs, in accordance with 40 CFR 60.13 and 60.48b. Data shall be recorded during calibration check and zero and span adjustments [40 CFR 60.13(h)(2)(vi), 60.45(e), (f), and (g)(3)]. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the 3-hour average NO_X emissions rate exceeds the emission limit in 2.1 A.6.b, above, except during periods of startup, shutdown, and malfunction pursuant to 40 CFR 60.8(c).

Monitoring/Recordkeeping (Particulate Matter) [15A NCAC 02Q .0508]

i. Particulate emissions from the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** shall be controlled as follows:
   i. POS Only: Particulate matter emissions from the combustion of lignin, biomass fuel, sludge, and HVLC gases in the No. 1 Hog Fuel Boiler shall be controlled by primary and secondary multicyclones **(ID Nos. CD-64-45-0100 and CD-64-45-0230)** operating in series with exhaust from the secondary multicyclone controlled by three electroscrubbers **(ID Nos. CD-64-60-0120, CD-64-60-0420, and CD-64-60-0720)** operating in parallel. At least two of the three electroscrubbers shall be in operation and at least 75% of total elements of the two electroscrubbers must have voltage applied at no less than 1 kilovolt per module each time a boiler operates. To ensure compliance, the Permittee shall monitor and record the following information once per day when the boiler is in operation:
      (A) the secondary voltage (in kilovolts) per module in service; and
      (B) the total number of modules in service.
   ii. Particulate matter emissions from the No. 2 Hog Fuel Boiler shall be controlled by the multicyclone **(ID No. CD-65-45-0100)** followed by an electrostatic precipitator **(ID No. CD-65-58-2000)**. The ESP shall be in operation at all times the boiler is operating with a minimum of 1.5 of its installed electrical fields in operation at any time. To ensure compliance, the Permittee shall comply with the COMS monitoring requirements specified in Section 2.1 A.6.f and A.6.g, above.
   iii. AOS Only: No monitoring is required when firing only No. 2 fuel oil or natural gas is fired in the No. 1 Hog Fuel Boiler.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the monitoring requirements are not met as specified above.

j. To ensure compliance with the particulate matter limits while firing lignin, biomass fuel, used oil, sludge and HVLC gases in the No. 1 Hog Fuel Boiler, POS only, **(ID No. ES-64-25-0290)** and when firing all fuels in the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, the Permittee shall perform inspections and maintenance as specified in the approved Basic Care Route or as recommended by the manufacturer. The dates and the results of inspection and maintenance, including any corrective measures taken, shall be maintained in written or electronic format on-site and made available to an authorized representative upon request. The Permittee shall, at a minimum, perform the inspections as follows:
   i. a monthly external visual inspection of the system ductwork, and material collection unit for leaks;
   ii. an internal inspection of the structural integrity of each multicyclone to be conducted when the boiler is internally inspected to receive its operating certificate; and
   iii. an internal inspection of each electroscrubber module installed on the No. 1 Hog Fuel Boiler and the electrostatic precipitator installed on the No. 2 Hog Fuel Boiler at a frequency dictated by excess opacity, operational performance trends and/or monthly external inspection and at a minimum of once every ten years. The inspection shall include a check of the electroscrubber packing material and the cleaning/calibration of all associated instrumentation.
   iv. When operating under the AOS, monthly external inspections and internal inspections of the electroscrubber modules associated with the No. 1 Hog Fuel Boiler are not required when only No. 2 fuel oil or natural gas is fired.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the multicyclones, electroscrubbers and electrostatic precipitator are not operated and maintained as specified above.

Recordkeeping [15A NCAC 02Q .0508(f) and 40 CFR Part 60, Subpart D]

k. Pursuant to 40 CFR 60.7(b), the Permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** and any malfunctions of the air pollution control equipment, or any periods during which a continuous monitoring system or monitoring device is inoperative [40 CFR 60.7(b)]. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the startup, shutdown, or malfunction records and records of air pollution control equipment malfunctions are not maintained as specified.

l. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection in a manner consistent with the requirements of 40 CFR 60.7(f) [40 CFR 60.7(f)]. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if these records are not maintained as specified.

m. The Permittee shall record and maintain records of the amount and type of each fuel burned during each day and keep fuel receipts from the supplier that certify potential sulfur dioxide content of fuel oil fired in the hog fuel boilers as specified in Section 2.1 A.6.e, above. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the fuel records are not maintained as specified.

Reporting [15A NCAC 02Q .0508(f), 40 CFR 60.7(c)(d)]

n. The Permittee shall submit an excess emissions and monitoring systems performance report and/or a summary report meeting the requirements of 40 CFR 60.7(c) and (d) postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December, and July 30 for the calendar year for the preceding six-month period between January and June as follows:
   i. Periods of excess emissions of nitrogen oxides, calculated quarterly, and defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards as specified under Section 2.1 A.6.b, above. [40 CFR 60.45(g)(3)]
   ii. Periods of excess emissions of opacity, calculated quarterly, and defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported. [40 CFR 60.45(g)(1)]
   iii. If the total duration of excess emissions for both quarters during the reporting period is less than 1 percent of the total operating time for the reporting period and continuous monitoring system (CMS) downtime for the reporting period is less than 5 percent of the total operating time for both quarters during the reporting period, only the summary report form shall be submitted and the excess emission report need not be submitted unless requested by the Administrator. [40 CFR 60.7(d)]
   iv. If the total duration of excess emissions for either quarter during the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for either quarter during the reporting period, the summary report form and the excess emission report shall both be submitted. [40 CFR 60.7(d)]

7. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

Emissions Limits [15A NCAC 02D .0530]

a. The following Best Available Control Technology (BACT) shall not be exceeded:

Emission Source	Fuel Fired	Regulated NSR Pollutant	BACT	Control Method
No. 1 Hog Fuel Boiler (ID No. ES-64-25-0290)	HVLC gases being fired with wood/lignin	carbon monoxide	1,646 pounds per hour	Good combustion practices
No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310)	HVLC gases being fired with wood/lignin	carbon monoxide	1,433 pounds per hour	Good combustion practices
	All fuels	PM_{10}	0.10 pounds per million Btu heat input	Series installation of multicyclone and

Emission Source	Fuel Fired	Regulated NSR Pollutant	BACT	Control Method
				electrostatic precipitator
	Oil and wood/lignin	sulfur dioxide	0.80 pounds per million Btu heat input	Combination firing of oil with bark/wood/lignin residue
	LVHC gases and SOG	H_2SO_4 mist	339 pounds per consecutive 24-hour period	Good combustion practices
	LVHC gases and SOG	Total reduced sulfur	235 pounds per consecutive 24-hour period	**LVHC and SOG:** Good combustion practices; and **LVHC Only:** White liquor scrubber except for periods of scrubber maintenance

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 A.7.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

c. During the testing for particulate matter required in Section 2.1 A.6.c through A.6.d, above, the Permittee shall determine the pounds of PM_{10} per million Btu heat input emitted from the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**. To determine the PM_{10} emissions, the Permittee shall conduct EPA Method 202 or EPA Method 201/201A (or other approved EPA test method for determining PM_{10} emissions). Operation outside of previously approved parametric operating ranges is not required during testing to reestablish parametric operating values.
   i. If the parametric operating values reestablished during performance testing are more stringent than the previously established operating parameter values, the Permittee shall submit a permit application to request revisions of the value(s) in the permit. The permit application should be submitted at the same time the test report required pursuant to General Condition JJ is submitted. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.
   ii. If the parametric operating values reestablished during periodic testing are less stringent than the previously established operating parameter values, the Permittee may request to revise the value(s) in the permit pursuant to 15A NCAC 02Q .0515.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if PM_{10}, sulfur dioxide, or total reduced sulfur are emitted above the limits specified in Section 2.1 A.6.a above.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

d. The Permittee shall follow the monitoring and recordkeeping requirements for sulfur dioxide and particulate matter in Section 2.1 A.6.e and A.6.i through A.6.m, above. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the monitoring required for PM_{10} and sulfur dioxide emissions from the No. 2 Hog Fuel Boiler is not maintained as required.

e. When LVHC gases and SOG are routed to the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, the Permittee shall:
   i. Keep records of the date and duration of the combustion of LVHC gases and SOG in the No. 2 Hog Fuel Boiler.
   ii. At all times, the Permittee shall maintain the white liquor injection rate to the White Liquor Scrubber **(ID No. CD-14-55-2020)** at or above 80 gallons per minute (3-hour rolling average) or the minimum levels confirmed or reestablished by the most recent performance test approved by DAQ that demonstrate compliance with the total reduced sulfur emission limits specified in Section 2.1 A.7.a, above.
   iii. Keep records of the date and duration the LVHC gases are directly combusted in the No. 2 Hog Fuel Boiler and have bypassed the White Liquor Scrubber **(ID No. CD-14-55-2020)**.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if records of LVHC and SOG combustion in the No. 2 Hog Fuel Boiler are not maintained as required.

f. The Permittee shall record and maintain records of the amounts of each fuel fired in the No. 1 Hog Fuel Boiler each month and the amounts of each fuel fired in the No. 2 Hog Fuel Boiler each month and make these records available

to an authorized representative of DAQ upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the amounts of fuels fired each month are not recorded.

Reporting

g. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 A.7.d through A.7.f, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all periods of noncompliance from the requirements of this permit or a statement that no periods of noncompliance occurred during the reporting period.

8. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. Per 40 CFR 64 and 15A NCAC 02D .0614, the Permittee shall comply with the following:

Background

b. Emission Units: No. 1 Hog Fuel Boiler (POS Only) **(ID No. ES-64-25-0290)**
No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**

c. Applicable Regulation, Emission Limit, and Monitoring Requirements
   i. Regulations: 15A NCAC 02D .0503: Particulates from Fuel Burning Indirect Heat Exchyangers
   15A NCAC 02D .0504: Particulates from Wood Burning Indirect Heat Exchangers
   ii. Emission Limits:
      (A) 0.160 pounds PM per million Btu heat input (when firing natural gas and fuel oil only) – No. 1 Hog Fuel Boiler
      0.143 pounds PM per million Btu heat input (when firing natural gas and fuel oil only) – No. 2 Hog Fuel Boiler:
      (B) 0.22 pounds per million Btu when firing only wood residue
   iii. Control Technology:
      (A) No. 1 Hog Fuel Boiler: two multiclones in series with parallel electroscrubbers when not firing only natural gas, when operating under the POS.
      (B) No. 2 Hog Fuel Boiler: multiclone in series with an electrostatic precipitator

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table:

Measure	No. 1 Hog Fuel Boiler Indicator (POS Only)	No. 2 Hog Fuel Boiler Indicator
I. Indicator	Opacity of electroscrubbers exhaust	Opacity of ESP exhaust
Measuring approach	COMS in electroscrubber exhaust	COMS in ESP exhaust
II. Indicator Range	The opacity indicator range is a 3-hour block average of 10 percent. An excursion occurs when the 3-hour block average measurement is greater than the indicator range. The excursions triggers corrective action and a reporting requirement. The QIP (Quality Improvement Plan) threshold is when the total duration of excursions exceeding is greater than 5 percent duration of the source operating time for a six-month reporting period. The QIP shall be prepared as required under 40 CFR 64.8	The opacity indicator range is a 3-hour block average of 10 percent. An excursion occurs when the 3-hour block average measurement is greater than the indicator range. The excursions triggers corrective action and a reporting requirement. The QIP threshold is when the total duration of excursions exceeding is greater than 5 percent duration of the source operating time for a six-month reporting period. The QIP shall be prepared as required under 40 CFR 64.8

Measure	No. 1 Hog Fuel Boiler Indicator (POS Only)	No. 2 Hog Fuel Boiler Indicator
III. Performance Criteria		
Data Representativeness	The COMS was installed at a representative location in the hog fuel boiler stack per PS-1	The COMS was installed at a representative location in the hog fuel boiler stack per PS-1
QA/QC Practices and Criteria	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
Monitoring frequency	The opacity of the electroscrubbers' exhaust is monitoried continuously (every 10 seconds).	The opacity of the ESP exhaust is monitoried continuously (every 10 seconds).
Data Collection Procedures	The data acquisition system shall retain all 6-minute data and 3-hour block averages pursuant to PS-1.	The data acquisition system shall retain all 6-minute data and 3-hour block averages pursuant to PS-1.
Averaging Period	The 10-second opacity data are used to calculate the 6-minute averages. The 6-minute averages are used to calculate the 3-hour block average.	The 10-second opacity data are used to calculate the 6-minute averages. The 6-minute averages are used to calculate the 3-hour block average.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 A.8.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations for the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

9. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

a. For the existing No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** when operating under the POS and No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, the Permittee shall comply with all applicable provisions for "units designed to burn solid fuel," including biomass/bio-based solid fuel and "hybrid suspension grate burners designed to burn biomass/bio-based solids" (as defined in 40 CFR 63.7575), including the monitoring, recordkeeping, and reporting contained in Environmental Management Commission Standard 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (MACT) as promulgated in 40 CFR Part 63, Subpart DDDDD "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters" and Subpart A "General Provisions." To be considered a "unit designed to burn solid fuel," including biomass/bio-based solid fuels and "hybrid suspension grate burners designed to burnewt biomass/bio-based solid[s]," the following apply: [40 CFR 63.7485, 63.7490(d), 63.7499(h) and (p), and 63.7575]
   i. The boilers shall burn at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.
   ii. The moisture of the biomass fuel combusted in the Nos. 1 and 2 Hog Fuel Boilers shall exceed 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis.
   iii. If the Permittee switches fuels that results in the Nos. 1 or 2 Hog Fuel Boiler being considered a different subcategory, the Permittee shall comply with the emission limits, work practice standards and operating limits for the new subcategory.

Definitions and Nomenclature

b. For the purpose of this permit condition, the definitions and nomenclature contained in 40 CFR 63.7575 shall apply. [40 CFR 63.7575]

40 CFR Part 63 Subpart A General Provisions

c. The Permittee shall comply with the requirements of 40 CFR 63 Subpart A General Provisions according to the applicability of Subpart A to such sources as identified in Table 10 to Subpart DDDDD. [40 CFR 63.7565]

Compliance Date

d. The Permittee shall be subject to the requirements of 40 CFR Part 63, Subpart DDDDD starting May 20, 2019. Note that the requirements of this standard may require action on behalf of the Permittee prior to May 20, 2019. [40 CFR 63.7510(e), 63.56(b)] The Permittee shall:
   i. Complete the initial tune up and the one-time energy assessment as required in Section 2.1 A.9.r and A.9.s no later than May 20, 2019. The initial tune-ups were completed prior to the May 20, 2019, compliance date as reported in the Notification of Compliance Status specified in Section 2.1 A.9.j, below.
   ii. Complete the initial compliance requirements in Section 2.1 A.9.k no later than November 16, 2019 and according to the applicable provisions in 40 CFR 63.7(a)(2). The initial performance tests were completed by February 13, 2019.

General Compliance Requirements

e. The Permittee shall meet the following general compliance requirements.
   i. At all times the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** are operating, the Permittee shall be in compliance with the emission standards in Section 2.1 A.9.g, below, except during periods of startup and shutdown. During startup and shutdown, the Permittee shall comply only with Section 2.1 A.9.t through A.9.u, below. [40 CFR 63.7500(f) and 63.7505(a)]
   ii. The Permittee shall develop a site-specific monitoring plan according to following requirements for the use of each CMS (including COMS or CPMS). [40 CFR 63.7505(d)]
      (A) Except as specified in Section 2.1 A.9.e.iii, below, for each COMS and CMS, including oxygen analyzer systems and operating load or steam generation monitors, the Permittee shall develop, and submit to DAQ for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in 40 CFR 63.8(d) and the following elements. The Permittee shall submit the site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation of each COMS and oxygen analyzer system.
         (1) Installation of the CMS sampling probe or other interface at a measurement location relative to each hog fuel boiler such that the measurement is representative of control of the exhaust emissions;
         (2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and
         (3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).
      (B) In each site-specific monitoring plan, the Permittee shall also address ongoing operating and maintenance procedures, ongoing data quality assurance procedures, and ongoing recordkeeping and reporting procedures in accordance with 40 CFR 63.8 and 63.10. [40 CFR 63.8 (c)(1)(ii), (c)(3), and (c)(4)(ii), 63.8(d), 63.10(c) as applicable in Table 10 to 40 CFR Part 63, Subpart DDDDD), and 63.10(e)(1) and (e)(2)(i)]
      (C) The Permittee shall conduct a performance evaluation of each CMS in accordance with the site-specific monitoring plan.
      (D) The Permittee shall operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.
   iii. The requirement to develop and submit a site-specific monitoring plan for a COMS in Section 2.1 A.9.e.ii, above, does not apply if the existing COMS installed on the Nos. 1 and 2 Hog Fuel Boilers are operated according to the performance specifications under Appendix B to 40 CFR Part 60 and that meet the requirements of 40 CFR 63.7525 and specified in Section 2.1 A.9.n, below. Using the process described in 40 CFR 63.8(f)(4), the Permittee may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in Section 2.1 A.9.e.ii, above, and, if approved, include the alternatives in the site-specific monitoring plan.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these general compliance requirements are not met.

f. At all times, then Permittee shall operate and maintain the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)**, including associated multiclones and electroscrubbers on No. 1 Hog Fuel Boiler **(ID Nos. CD-64-45-0100, CD-64-45-0230, CD-64-60-0120, CD-64-60-0420 and CD-64-60-0720)** when firing any fuel other than natural gas and/or No. 2 fuel oil and multiclone and electrostatic precipitators installed on the No. 2 Hog Fuel Boiler **(ID Nos. CD-65-45-0100 and CD-65-58-2000)** and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]

Emission Limits [15A NCAC 02Q .0508(f)]

g. The Permittee shall comply with the emission limits as follows: [40 CFR 63.7500(a)(1) and Table 2 to 40 CFR Part 63, Subpart DDDDD]
   i. The Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** shall comply with the following emission limits:

Pollutant	Emission Limit	Sample Volume or Test Run Duration for Performance Tests
Hydrochloric acid (HCl)	2.2E-02 lb per million Btu of heat input	For EPA Method 26A, collect a minimum of 1 dry standard cubic meter per run; for Method 26, collect a minimum of 120 liters per run.
Mercury (Hg)	5.7E-06 lb per million Btu of heat input	For EPA Method 29A, collect a minimum of 3 dry standard cubic meters per run; for Method 30A or Method 30B, collect a minimum sample as specified in the method; for ASTM D6784 collect a minimum of 3 dry standard cubic meters.
Carbon monoxide (CO)	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1-hour minimum sampling time.
Filterable particulate matter (PM)	4.4E-01 lb per million Btu of heat input	Collect a minimum of 1 dry standard cubic meters per run.

   ii. The Permittee, as an alternative to meeting the emission limits in paragraph (i) above for PM, HCl, or mercury on a boiler-specific basis, may demonstrate compliance by emissions averaging, if the averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in 40 CFR 63.7522. An implementation plan shall be submitted to the DAQ no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

Testing [15A NCAC 02Q .0508(f)]

h. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. The Permittee shall conduct performances tests according to the procedures specified in 40 CFR 63.7520, including the following. [40 CFR 63.7520]
   i. Develop a site-specific stack test plan according to the requirements of 40 CFR 63.7(c). [40 CFR 63.7520(a)]
   ii. Conduct each performance test according to the requirements in Table 5 to 40 CFR Part 63, Subpart DDDDD. [40 CFR 63.7520(b)]
   iii. Conduct each performance test under the specific conditions listed in Tables 5 and 7 to 40 CFR Part 63, Subpart DDDDD. The Permittee shall conduct performance stack tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury and the Permittee shall demonstrate initial compliance and establish operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, the Permittee shall comply with the operating limit for operating loads specified in Table 4 to 40 CFR Part 63, Subpart DDDDD. [40 CFR 63.7520(c)]
      (A) Operation outside of previously approved parametric operating ranges is not required during testing to reestablish parametric operating values.
      (B) If the parametric operating values reestablished during periodic testing are more stringent than the previously established operating parameter values, the Permittee shall submit a permit application to request revisions of the value(s) in the permit. The permit application should be submitted at the same time

the test report required pursuant to General Condition JJ is submitted. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.

(C) If the parametric operating values are reestablished during periodic testing are less stringent than the previously established operating parameter values, the Permittee may request to revise the value(s) in the permit pursuant to 15A NCAC 02Q .0515.

iv. Conduct a minimum of three separate test runs for each required performance test. Each test run must comply with the minimum applicable sampling times or volumes specified in Section 2.1 A.9.g, above. [40 CFR 63.7520(b)]

v. Convert measured particulate matter (PM), HCl, and mercury concentrations resulting from the performance test to pounds per million Btu heat input emission rates as specified in 40 CFR 63.7520(e).

If the results of this test(s) are above the limit given in Section 2.1 A.9.g, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111.

Fuel Analysis [15A NCAC 02Q .0508(f)]

i. The Permittee shall conduct fuel analyses for solid and liquid fuels for chloride and mercury. The Permittee is not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. Gaseous and liquid fuels are exempt from the sampling requirements in Section 2.1 A.9.i.ii and A.9.i.iii, below. [40 CFR 63.7521(a) through (e)]

i. The Permittee shall develop a site-specific fuel monitoring plan according to the requirements and procedures specified in 40 CFR 63.7521(b) and in Table 6 to 40 CFR Part 63, Subpart DDDDD.

ii. The Permittee shall obtain composite fuel samples for each fuel type according to the procedures in 40 CFR 63.7521(c)(1) or (2), or the methods listed in Table 6 to 40 CFR Part 63, Subpart DDDDD, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, the Permittee shall obtain three composite samples. For monthly fuel analyses, at a minimum, the Permittee shall obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in 40 CFR 63.7510(a), the Permittee shall obtain a composite fuel sample during each performance test run.

iii. The Permittee shall prepare each composite sample according to the procedures in 40 CFR 63.7521(d)(1) through (7).

iv. The Permittee shall determine the concentration of pollutants in the fuel (mercury and/or chlorine) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to 40 CFR Part 63, Subpart DDDDD, for use in Equations 7, 8, and 9 of 40 CFR Part 63, Subpart DDDDD.

v. Fuel analyses are not required for the following: [40 CFR 63.7510(a)(2)]

(A) Natural gas, refinery gas, or “other gas 1 fuels” that are co-fired with other fuels.

(B) Non-Gas 1 gaseous fuels that are subject to another subpart of 40 CFR Part 60, Part 61, Part 63, or Part 65.

(C) Chlorine content of any gaseous fuel and mercury content of gaseous fuels exempted from (A) or (B) above.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the fuel analyses are not conducted as specified.

Notifications [15A NCAC 02Q .0508(f)]

j. The Permittee shall submit the following notifications:

i. The Permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin. [40 CFR 63.7545(d)]

ii. For the initial compliance demonstration for each hog fuel boiler, the Permittee submitted the Notification of Compliance Status per 40 CFR 63.7545(e), including all performance test results and fuel analyses for the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** by May 15, 2019**.**

iii. If the Permittee switches fuels and the fuel switch results in the applicability of a different subcategory, the Permittee shall provide notice of the date upon which the fuel was switched within 30 days of the switch. The notification shall contain the following information [40 CFR 63.7545(h)]:

(A) The Permittee’s name, the location of the mill, the boiler(s) that have switched fuels, and the date of the notice.

(B) The currently applicable subcategory under this subpart.

(C) The date upon which the fuel switch occurred.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these notification requirements are not met.

Initial compliance requirements [15A NCAC 02Q .0508(f)]

k. Effective May 15, 2019, the Permittee has demonstrated initial compliance with the limits in Section 2.1 A.9.g, above, by [40 CFR 63.7510(a) and 63.7530]:
   i. Conducting the initial performance test(s) as specified in Section 2.1 A.9.h, above, for each pollutant [40 CFR 63.7530(a)].
   ii. Conducting the fuel analyses as specified in Section 2.1 A.9.i, above, and establish maximum fuel pollutant input levels using the procedures specified in 40 CFR 63.7530(b)(1) through (b)(3);
   iii. Establishing operating limits as specified in Section 2.1 A.9.p and A.9.q, below [40 CFR 63.7510(a)(3) and 63.7530(b)(4)].
   iv. Submitting the Notification of Compliance Status as specified in Section 2.1 A.9.j, above [40 CFR 63.7530(e)];
   v. Meeting the work practice standards in Section 2.1 A.9.r through A.9.u, below [40 CFR 63.7530(h)]; and
   vi. Installing monitoring systems and conducting continuous monitoring system (CMS) evaluation(s) as necessary as specified in Section 2.1 A.9.n and A.9.o, below [40 CFR 63.7530(a)].

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these initial compliance requirements are not met.

Continuous compliance requirements [15A NCAC 02Q .0508(f)]

l. The Permittee shall conduct subsequent periodic performance tests and fuel analyses as necessary according to 40 CFR 63.7515 and as follows:
   i. Conduct all applicable performance tests according to the requirements in Section 2.1 A.9.h, above, on an annual basis, except as specified below. Annual performance tests must be completed no more than 13 months after the previous performance test. [40 CFR 63.7515(a)]
      (A) If performance tests for a given pollutant for at least 2 consecutive years show that emissions are at or below 75 percent of the applicable emission limit specified in Section 2.1 A.9.g, above, and if there are no changes in the operation of the boiler or air pollution control equipment that could increase emissions, the Permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If demonstrating compliance using emission averaging under 40 CFR 63.7522, the Permittee shall continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. [40 CFR 63.7515(b)]
      (B) If a performance test shows that emissions exceeded the emission limit or 75 percent of the applicable emission limit specified in Section 2.1 A.9.g, above, the Permittee shall conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, specified in Section 2.1 A.9.g, above). [40 CFR 63.7515(c)]
   ii. If the Permittee demonstrates compliance with the HCl or mercury emission limitations based on fuel analysis alone, a monthly fuel analysis shall be conducted according to 40 CFR 63.7521 for each type of fuel burned that is subject the emission limits in Section 2.1 A.9.g, above. The Permittee may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If a new type of fuel is burned in the hog fuel boiler, the Permittee shall conduct a fuel analysis before burning the new type of fuel in the boiler. [40 CFR 63.7515(e)]
   iii. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the Permittee may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or beginning to burn a new type of fuel, the Permittee shall return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply. [40 CFR 63.7515(e)]
   iv. The Permittee shall conduct a performance test according to the requirements in Section 2.1 A.9.h, above, within 180 days after startup of normal operation of the electrostatic precipitator. The electrostatic precipitator began operation on September 26, 2019, and the initial performance test was completed on December 5, 2019, and approved on February 25, 2020.
   v. If the boiler has not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the Permittee shall complete subsequent compliance demonstrations no later than 180 days after the re-start of the affected source and according to 40 CFR 63.7(a)(2) as cited in Table 10 of 40 CFR Part 63, Subpart DDDDD. [40 CFR 63.7515(g)]

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if subsequent performance tests and fuel analyses are not conducted as required above.

m. The Permittee shall demonstrate continuous compliance with each applicable emission limit, operating limit and work practice standard according to 40 CFR 63.7540 and Table 8 of 40 CFR Part 63, Subpart DDDDD, and as follows:
   i. Keep records as specified in Section 2.1 A.9.v, below [40 CFR 63.7540(a)(2)];
   ii. When planning to burn a new type of fuel or a new mixture of fuels, the Permittee shall recalculate maximum chlorine and mercury input as specified in the equations in 40 CFR 63.7530(b)(1) through (b)(3). If the results of recalculating the maximum chlorine or mercury input are greater than the maximum input levels established during the previous performance test, then the Permittee shall conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in Section 2.1 A.9.h, above, to demonstrate that the HCl or mercury emissions do not exceed the emission limits specified in Section 2.1 A.9.g, above. The Permittee shall also establish new operating limits based on this performance test according to the procedures in Section 2.1 A.9.p and A.9.q, below. [40 CFR 63.7540(a)(4), (a)(6) and (a)(16)]
   iii. The Permittee shall conduct tune-ups of the hog fuel boilers as specified in Section 2.1 A.9.r, below. [40 CFR 63.7540(10)]
   iv. For startup and shutdown, the Permittee shall meet the work practice standards specified in Section 2.1 A.9.s and A.9.t, below. [40 CFR 63.7540(d)]
   v. Operation above the established maximum or below the established minimum operating limits shall constitute a period of noncompliance of established operating limits listed in Table 4 of 40 CFR Part 63, Subpart DDDDD except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests. [40 CFR 63.7540(a)(1)]
   vi. For demonstrating continuous compliance with the oxygen content operating parameter limits, the Permittee shall: [40 CFR 63.7540(a) and Table 8 to 40 CFR Part 63, Subpart DDDDD]
      (A) Continuously monitor oxygen content from the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** using an oxygen analyzer system according to Section 2.1 A.8.n, below. The No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** is equipped with an oxygen trim system and is not required to monitor oxygen content.
      (B) Reduce the oxygen content data to 30-day rolling averages; and
      (C) Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test in Section 2.1 A.8.h, above.
   vii. For demonstrating continuous compliance with the boiler operating load operating parameter limits, the Permittee shall: [Table 8 to 40 CFR Part 63, Subpart DDDDD]
      (A) Collect operating load data or steam generation data every 15 minutes.
      (B) Reduce the data to 30-day rolling averages; and
      (C) Maintain the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test in Section 2.1 A.8.h, above.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the continuous compliance requirements are not met as specified in above.

Monitoring requirements [15A NCAC 02Q .0508(f)]

n. The Permittee shall install, operate, and maintain each continuous monitoring system on the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** as follows. [40 CFR 63.8(c) through (e) and (g), and 63.7525(c)]
   i. Install, operate and maintain each COMS according to Performance Specification 1 in Appendix B of 40 CFR Part 60 and as follows:
      (A) Conduct a performance evaluation of each COMS according to the requirements in 40 CFR 63.8(e) and Performance Specification 1 in Appendix B to 40 CFR Part 60.
      (B) Each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
      (C) Reduce the COMS data must be reduced as specified in 40 CFR 63.8(g)(2).
      (D) The site-specific monitoring plans shall include procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in 40 CFR 63.8(d). At a minimum, the monitoring plan shall include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.
      (E) Operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of 40 CFR 63.8(e). The Permittee shall identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control

and data are not available for a required calculation constitutes period of noncompliance from the monitoring requirements.

(F) Determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

ii. An oxygen analyzer system to monitor the oxygen content of the No. 1 Hog Fuel Boiler according to the requirements of Section 2.1 A.8.p, below. [40 CFR 63.7525(a)]

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the requirements for monitoring systems installed on the Nos. 1 and 2 Hog Fuel Boilers are not met as specified above.

o. The Permittee shall install, operate, and maintain each continuous monitoring system specified in Section 2.1 A.9.n, above, including oxygen analyzer systems and operating load or steam generation monitors, as follows: [40 CFR 63.7525(a) and (d)]

i. The continuous monitoring system must complete a minimum of one cycle of operation every 15-minutes. A minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, is required to have a valid hour of data. [40 CFR 63.7525(d)(1)]

ii. The continuous monitoring system shall be operated according to and comply with the data calculation requirements specified below. [40 CFR 63.7525 (d)(2) and 63.7535(b) and (c)]

(A) The Permittee shall operate the monitoring system and collect data at all required intervals at all times that each hog fuel boiler is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods [see 40 CFR 63.8(c)(7)], and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in the site-specific monitoring plan required under Section 2.1 A.9.e.ii, above. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. The Permittee is required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable. [40 CFR 63.7535(b)]

(B) The Permittee shall not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. The Permittee shall record, and make available upon request, results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with the site-specific monitoring plan. The Permittee shall use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system. [40 CFR 63.7535(c)]

iii. Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a period of noncompliance from the monitoring requirements. Other situations that constitute monitoring noncompliance are specified in 40 CFR 63.7535(d). [40 CFR 63.7525(d)(3)]

iv. The Permittee shall determine the 30-day rolling average of all recorded readings, except as provided in Section 2.1 A.9.o.ii.(B), above.

v. The Permittee shall record the results of each inspection, calibration, and validation check.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the requirements for CPMS operation above are not met.

Operating Limits [15A NCAC 02Q .0508(f)],

p. The Permittee shall comply with the following operating limits at the operating load conditions established during performance testing conducted according to Section 2.1 A.9.h, above, for the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)**. [40 CFR 63.7500, Table 4 to 40 CFR Part 63, Subpart DDDDD]

i. The Permittee shall maintain the opacity limit (daily block average) visible emissions from the Nos. 1 and 2 Hog Fuel Boilers to demonstrate compliance with the PM emission limitation as determined in the February 12 and 13, 2019, approved performance tests as follows:

(A) For the No. 1 Hog Fuel Boiler, opacity shall be less than 14 percent on a daily block average; and

(B) For the No. 2 Hog Fuel Boiler, opacity shall be less than 10 percent on a daily block average.

ii. When demonstrating compliance with the CO emission limit, the Permittee shall maintain the 30-day rolling average oxygen content for the No. 1 Hog Fuel Boiler at or above 3.82 percent, as determined during the February 13, 2019, approved performance test.

iii. When demonstrating compliance with the CO emission limit, the Permittee shall operate the oxygen trim system installed on the No. 2 Hog Fuel Boiler with the oxygen level set no lower than 3.73 percent, as determined during the March 10, 2020, approved performance test.

iv. When demonstrating compliance with the emission limits specified in Section 2.1 A.9.g, above, the Permittee shall maintain the 30-day rolling average operating load of the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** as follows:
   (A) The average boiler steam load on the No. 1 Hog Fuel Boiler shall not exceed 475.62 thousand pounds per hour, based on the February 12, 2019, approved test report.
   (B) The average boiler steam load on the No. 2 Hog Fuel Boiler shall not exceed 472.74 thousand pounds per hour, based on the February 24, 2021, approved test report.

v. Operation above the established maximum or below the established minimum operating limits shall constitute a period of noncompliance with the established operating limits listed in Table 4 to 40 CFR Part 63, Subpart DDDDD except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. The Permittee shall confirm or reestablish operating limits during performance tests. [40 CFR 63.7540(a)(1)]
   (A) If revisions to operating parameter values are necessary to demonstrate compliance with the emission limits and are more stringent than the established minimum or maximum operating limits, the Permittee shall submit a request to revise the values in the permit at the same time as the test report is submitted as required per General Condition JJ. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.
   (B) If performance testing indicates that compliance with emission limits is demonstrated with revisions to operating parameter values that are less stringent than the established minimum or maximum operating limits, the Permittee may request to revise the values in the permit pursuant to 15A NCAC 02Q .0515.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the operating limits above are not met.

q. During the performance tests conducted according to Section 2.1 A.9.h, above, the Permittee shall establish each site-specific operating limit in Section 2.1 A.9.p, above, for the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** as follows: [40 CFR 63.7530(b) and Table 7 to 40 CFR Part 63, Subpart DDDDD]

i. Using data from the oxygen analyzer system installed on the No. 1 Hog Fuel Boiler and operated according to Section 2.1 A.9.o, above, establish a unit-specific minimum oxygen level according to the following requirements [40 CFR 63.7530(b)(4)(viii) and Table 7 of 40 CFR Part 63, Subpart DDDDD]
   (A) Collect oxygen data every 15 minutes during the entire period of the CO performance tests.
   (B) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
   (C) Determine the lowest hourly average established during the performance test as the minimum operating limit.
   (D) If multiple performance tests are conducted, the minimum oxygen level shall be set at the lower of the minimum values established during the performance tests.

ii. The Permittee shall establish the operating limit for oxygen as the lowest hourly average oxygen concentration measured during the most recent CO performance test on the No. 2 Hog Fuel Boiler. [40 CFR 63.7525(a)(7)]

iii. If the Permittee elects to comply with a site-specific opacity operating limit as allowed in Section 2.1 A.9.p.i, above, the opacity limit shall be established using data from the COMS installed and operated according to Section 2.1 A.9.p, above, during the PM performance test according to the following requirements: [Table 7 of 40 CFR Part 63, Subpart DDDDD]
   (A) Collect opacity readings every 15 minutes during the entire period of the performance tests.
   (B) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run.
   (C) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM emission limitation.

iv. Using data from the operating load monitors or from steam generation monitors installed and operated as specified in Section 2.1 A.9.o, above, establish a unit-specific limit for maximum operating load according to Section 2.1 A.9.h.iii, above, as follows: [Table 7 to 40 CFR Part 63, Subpart DDDDD]
   (A) Collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
   (B) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.

(C) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as the operating limit.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the operating limits are not established according to the requirements above.

Work Practice Standards [15A NCAC 02Q .0508(f)]

r. Tune-up Requirements. The Permittee shall conduct a tune-up of the Nos. 1 and 2 Hog Fuel Boilers **(ID Nos. ES-64-25-0290 and ES-65-25-0310)** as specified below. The Permittee shall conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. [40 CFR 63.7500(a) and 63.7540(a)(10)]

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the Permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown;

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the inspection may be delayed until the next scheduled unit shutdown);

iv. Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject; and

v. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

vi. Each tune-up shall be conducted according to the following schedule: [40 CFR 63.7515(d)]

(A) POS Only: The tune-up for the No. 1 Hog Fuel Boiler shall be conducted once per year and no more than 13 months after the previous tune-up.

(B) The tune-up for the No. 2 Hog Fuel Boiler shall be conducted once every five years and no more than 61 months after the previous tune-up.

vii. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [40 CFR 63.7540(a)(13) and 63.7515(g)]

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the tune-up requirements above are not met.

s. Energy Assessment Requirements. The Permittee shall have a one-time energy assessment performed by a qualified energy assessor. The energy assessment must address the requirements in 40 CFR 63 Subpart 5D, Table 3, Item 4, with the extent of the evaluation for items (a) to (e) in Table 3, Item 4 appropriate for the on-site technical hours listed in 40 CFR 63.7575. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these requirements are not met. [40 CFR 63.7500(a)(1), Table 3 of 40 CFR Part 63, Subpart DDDDD]

t. Startup Requirements. The Permittee shall comply with all applicable emission limits at all times except during startup and shutdown periods. During startup, the Permittee shall meet the work practice requirements below. [40 CFR 63.7500 and Table 3 of 40 CFR Part 63, Subpart DDDDD]

i. All CMS shall be operated during startup.

ii. For startup of the boiler **(ID No. ES-64-25-0290 or ES-65-25-0310)**, one or a combination of the following clean fuels shall be used: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl and mercury emission standards by fuel analysis.

iii. The Permittee has the option of complying using either of the following work practice standards.

(A) If complying using definition (1) of "startup" in 40 CFR 63.7575, once the Permittee starts firing fuels that are not clean fuels, the Permittee shall vent emissions to the main stack(s) and engage all of the applicable control devices. Startup ends when steam or heat is supplied for any purpose, OR

(B) If complying using definition (2) of "startup" in 40 CFR 63.7575, once the Permittee starts to feed fuels that are not clean fuels, the Permittee shall vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. The Permittee shall engage and operate PM control within one hour of first feeding fuels that are not clean fuels. The Permittee shall start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a

permit limit or a rule other than this section that require operation of the control devices. The Permittee shall develop and implement a written startup and shutdown plan, as specified in 40 CFR 63.7505(e).

iv. The Permittee shall collect monitoring data during periods of startup, as specified in Section 2.1 A.9.o.ii.(B), above.

v. The Permittee shall keep records during periods of startup and provide reports concerning activities and periods of startup, as specified in 40 CFR 63.7555.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the startup procedures are not followed.

u. Shutdown Requirements. The Permittee shall comply with all applicable emission limits at all times except during startup and shutdown periods. During shutdown periods, the Permittee shall meet the work practice requirements below. [40 CFR 63.7500 and Table 3 of 40 CFR Part 63, Subpart DDDDD]

i. The Permittee shall operate all CMS during shutdown.

ii. While firing fuels that are not clean fuels during shutdown, the Permittee shall vent emissions to the main stack(s) and operate all applicable control devices when necessary to comply with other standards applicable to the source that require operation of the control device.

iii. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.

iv. The Permittee shall collect monitoring data during periods of shutdown, as specified in 40 CFR 63.7535(b).

v. The Permittee shall keep records during periods of shutdown.

vi. The Permittee shall provide reports concerning activities and periods of shutdown, as specified in 40 CFR 63.7555.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the shutdown procedures are not followed.

Recordkeeping Requirements [15A NCAC 02Q .0508(f)]

v. The Permittee shall keep the following records:

i. A copy of each notification and report submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status, or semiannual compliance report that has been submitted. [40 CFR 63.10(b)(2)(xiv) and 63.7555(a)(1)]

ii. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations pursuant to 40 CFR 63.10(b)(2)(viii). [40 CFR 63.7555(a)(2)]

iii. Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (A) through (C) below: [40 CFR 63.7540(a)(10)(vi)]

(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) the type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

iv. For each continuous monitoring system, including COMS, oxygen analyzer systems and operating load or steam generating monitors, the following records. [40 CFR 63.7555(b)]

(A) Records described in 40 CFR 63.10(b)(2)(vii) through (xi).

(B) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in 40 CFR 63.6(h)(7)(i) and (ii).

(C) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

(D) Records of the date and time that each period of noncompliance started and stopped.

v. Records required in Table 8 to 40 CFR Part 63, Subpart DDDDD including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies. [40 CFR 63.7555(c)]

vi. The Permittee shall keep records of the type and amount of all fuels burned in the Nos. 1 and 2 Hog Fuel Boilers to demonstrate that all fuel types and mixtures of fuels burned would result in either the following [40 CFR 63.7540(a)(2)]:

(A) equal to or lower emissions of HCl, mercury than the applicable emission limit for each pollutant, if compliance is demonstrated through fuel analysis;

(B) Equal to or lower fuel input of chlorine and mercury than the maximum values calculated during the last performance test, if compliance is demonstrated through performance testing.

vii. Applicable records in paragraphs 40 CFR 63.7555(d)(1) through (13).

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the records specified above are not kept.

w. The Permittee shall maintain records as follows: [40 CFR 63.10(b)(1) and 63.7560]
   i. Maintain records in a form suitable and readily available for expeditious review;
   ii. Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record; and
   iii. Keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee can keep the records offsite for the remaining 3 years.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the records are not maintained as required above.

Reporting Requirements [15A NCAC 02Q .0508(f)]

x. The Permittee shall submit a compliance report to the DAQ on a semiannual basis, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. The Permittee shall determine excess emissions and monitoring system performance specified in Section 2.1 A.9.y.iii and A.9.y.iv, below, on a quarterly basis. The compliance reports shall also be submitted electronically to the EPA via the procedures in 40 CFR 63.7550(h).

y. The compliance report shall contain: [Table 9 to Subpart DDDDD of Part 63]
   i. The information in 40 CFR 63.7550(c), (d) and (e), as applicable.
      (A) All compliance reports shall contain the following information [40 CFR 63.7550(c)(5)(i) through (iii) and (xvii)]:
         (1) Company and Facility name and address;
         (2) Process unit information, emissions limitations, and operating parameter limitations;
         (3) Date of report and beginning and ending dates of the reporting period; and
         (4) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
      (B) When compliance is demonstrated using fuel analysis, or with applicable emission limits with performance testing and/or with applicable emission limits using continuous monitoring systems compliance reports shall also include the following information [40 CFR 63.7550(c)(5)(vi), (xiii), and (xviii)]:
         (1) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
         (2) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.
         (3) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR 63.7555(d).
      (C) When compliance is demonstrated using fuel analysis, the compliance report shall also include a summary of any monthly fuel analyses conducted to demonstrate compliance according Section 2.1 A.9.i and A.9.k, above, for the boilers subject to emission limits [40 CFR 63.7550(c)(5)(x)].
      (D) When compliance with an emission limit is demonstrated using performance testing, the compliance report shall also contain the following information [40 CFR 63.7550(c)(5)(vii) and (viii)]:
         (1) If you are conducting performance tests once every 3 years consistent with Section 2.1 A.9.l.i.(A) or A.9.l.i.(B), above, the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.
         (2) A statement indicating that no new types of fuel were boiler in a boiler subject to an emission limit. Or, if a new type of fuel is burned in the Nos. 1 or 2 Hog Fuel Boiler, the Permittee shall submit the calculation of HCl emission rate using Equation 16 of 40 CFR 63.7530 that demonstrates that the hog

fuel boiler is still meeting the emission limit for HCl emissions. If a new type of fuel was burned in the Nos. 1 or 2 Hog Fuel Boiler, the Permittee shall submit the calculation of mercury emission rate using Equation 17 of 40 CFR 63.7530 that demonstrates that the hog fuel boiler is still meeting the emission limit for mercury emissions.

(E) The compliance report shall also contain the date of the most recent tune-up for each hog fuel boiler. The Permittee shall also include the date of the most recent burner inspection for the No. 1 Hog Fuel Boiler if it was not done annually (POS Only), or for the No. 2 Hog Fuel Boiler on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)].

(F) When demonstrating compliance with the emission limits using a CMS, including CEMS, COMS, or CPMS, the Permittee shall include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit. If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in 40 CFR 63.8(c)(7), the Permittee shall also include a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period [40 CFR 63.7550(c)(5)(v) and (xvi)].

ii. If there are no periods of noncompliance with any applicable emission limitation (emission limit and operating limit) and there are no periods of noncompliance from the applicable requirements for work practice standards for periods of startup and shutdown specified in Section 2.1 A.9.t and A.9.u, above, a statement that there were no periods of noncompliance from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including CEMS, continuous opacity monitoring systems, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period [40 CFR 63.7550(c)(5)(xi) and (xii)]; and

iii. If there is a period of noncompliance with any applicable emission limit or operating limit where a CMS is not used to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in 40 CFR 63.7550(d).

iv. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), or otherwise not operating, the report must contain the information in §63.7550(e).

z. Within 60 days after the date of completing each performance test including any associated fuel analyses and/or CMS performance evaluation as required by 40 CFR Part 63, Subpart DDDDD the Permittee shall submit the results to the DAQ pursuant to 40 CFR 63.10(d)(2) and to the EPA via the procedures in 40 CFR 63.7550(h). This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to 40 CFR 63.7530 and Table 7 to 40 CFR Part 63, Subpart DDDDD, as applicable. [40 CFR 63.7515(f) and 63.7550(h)]

11. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

a. When operating the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** under the AOS, as defined in Section 2.1 A.1, above, for, the Permittee shall comply with all applicable provisions for the "unit designed to burn gas 1 subcategory," including the monitoring, recordkeeping, and reporting contained in Environmental Management Commission Standard 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (MACT) as promulgated in 40 CFR Part 63, Subpart DDDDD . "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters" and Subpart A "General Provisions." [40 CFR 63.7485, 63.7490(d), 63.7499(l)]

b. In order for the No. 1 Hog Fuel Boiler **(ID Nos. ES-64-25-0290)** to be considered in the "unit designed to burn gas 1 subcategory," the Permittee shall only burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, and during periods of gas curtailment or gas supply interruptions of any duration. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the No. 2 fuel oil is burned in the boiler for periodic testing of liquid fuel, maintenance or operator training for more than 48 hours during any calendar year or if No. 2 fuel oil is burned in the boiler during any periods other than gas curtailment or gas supply interruption. [40 CFR 63.7575]

Definitions and Nomenclature [40 CFR 63.7575]

c. For the purpose of Section 2.1 A.10, the definitions and nomenclature contained in 40 CFR 63.7575 shall apply.

40 CFR Part 63, Subpart A - General Provisions [40 CFR 63.7565]

d. The Permittee shall comply with the requirements of 40 CFR 63 Subpart A, General Provisions, pursuant to the applicability of Subpart A to such sources as identified in Table 10 to 40 CFR Part 63, Subpart DDDDD.

Compliance Date [40 CFR 63.7495]

e. When the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** is operating under the AOS, as defined in Section 2.1 A.1, above, the Permittee shall be in compliance with the applicable existing source provisions of 40 CFR Part 63, Subpart DDDDD on the effective date of the fuel switch or physical change. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the compliance date is not met. [40 CFR 63.7495(h)]

Notifications [40 CFR 63.7545]

f. The Permittee shall submit a Notification that the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** is operating under the AOS, as defined in Section 2.1 A.1, above, within 30 days of switching fuels. The notification shall identify the following [40 CFR 63.7545(h)]:
   i. The name of the Permittee, the location of the source, the name of the No. 1 Hog Fuel Boiler, and the date of the notice;
   ii. The currently applicable subcategory;
   iii. The date upon which the fuel switch occurred.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if this Notification is not submitted.

g. After switching to the AOS as defined in Section 2.1 A.1, above, the Permittee shall submit a Notification of Compliance Status for the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)**. The notification must be signed by a responsible official and postmarked before the close of business within 60 days of the compliance date specified in Section 2.1 A.10.e, above. The notification shall contain the following [40 CFR 63.7545(e)(8) and 63.7530(e), and (f)]:
   i. A description of the No. 1 Hog Fuel Boiler, including a statement that the boiler is in "the unit designed to burn gas 1 subcategory," the design heat input capacity of the boilers, and description of the fuel(s) burned.
   ii. A signed certification that the facility completed the required initial tune-up for the No. 1 Hog Fuel Boiler pursuant to the procedures Section 2.1 A.10.k, below.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the Notification of Compliance Status is not submitted.

h. When operating under the AOS as defined in Sevction 2.1 A.1, above, the Permittee shall submit a notification of intent to fire an alternative fuel in the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** within 48 hours of the declaration of each period of natural gas curtailment or supply interruption. The notification must include the following information[40 CFR 63.7545(f)]:
   i. Company name and address;
   ii. Identification of the affected boiler;
   iii. Reason the Permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began;
   iv. The type of alternative fuel the Permittee intends to use; and
   v. Dates when the alternative fuel use is expected to begin and end.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the notification of intent to fire an alternative fuel is not submitted.

General Compliance Requirements

i. When operating the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** under the AOS defined in Section 2.1 A.1, above, the Permittee shall comply with the work practice standards in Section 2.1 A.10.k, below at all times [40 CFR 63.7500(f) and 63.7505(a)]. The Permittee shall demonstrate

j. At all times, the Permittee shall operate and maintain the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)**, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to DAQ that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source [40 CFR 63.7500(a)(3)]. The Permittee shall be deemed in noncompliance with 15A

NCAC 02D .1111 if the boiler is not operated in a manner consistent with safety and good air pollution control practices for minimizing emissions.

Work Practice Standards [15A NCAC 02Q .0508(f)]

k. When operating under the AOS as defined in Section A.1, above, the Permittee shall conduct a tune-up of the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** as specified below. The Permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the boiler of the 12 months prior to the tune-up. [40 CFR 63.7500(a) and 63.7540(a)(10)]
   i As applicable, the Permittee shall inspect the burner, and clean or replace any components of the burner as necessary. The Permittee may perform the burner inspection at any time prior to the tune-up or delay the burner inspection until the next scheduled or unscheduled shutdown.
   ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
   iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly. The Permittee may delay the inspection until the next scheduled unit shutdown.
   iv. Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject.
   v. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.
   vi. The oxygen level shall be set no lower than the oxygen concentration measured during the most recent tune-up.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these work practice standards are not met.

l. When operating under the AOS as defined in Section 2.1 A.1, above, the tune-up for the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** shall be conducted pursuant to the following schedule. [Table 3 of Subpart DDDDD]
   i. The initial tune-up for the No. 1 Hog Fuel Boiler shall be no later than 60 days of the effective date of switching to the AOS, as defined in Section A.1, above. [40 CFR 63.7510(k) and 63.7515(d)]
   ii. Subsequent tune-ups for the No. 1 Hog Fuel Boiler shall be conducted every year and no more than 13 months after the previous tune-up. [40 CFR 63.7540(a)(12), 63.7515(d)]
   iii. The tune-up for the No. 1 Hog Fuel Boiler may be delayed until the next scheduled or unscheduled unit shutdown, but the Permittee shall inspect each burner at least once every 36 months. [40 CFR 63.7540(a)(10)]
   iv. If the No. 1 Hog Fuel Boiler is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [40 CFR 63.7515(g) and 63.7540(a)(13)]

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the initial and subsequent tune-ups are not conducted as specified.

Recordkeeping Requirements [15A NCAC 02Q .0508(f)]

m. When operating the No.1 Hog Fuel Boiler **(ID No. ES-64-25-02900)** under the AOS as defined in Section 2.1 A.1, above, the Permittee shall keep the following records:
   i. A copy of each notification and report submitted to comply with Section 2.1 A.10, including all documentation supporting any Initial Notification or Notification of Compliance Status, or compliance report that has been submitted, pursuant to the requirements in 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.7555(a)(1)]
   ii. A report, maintained on-site and submitted to DAQ if requested, containing the information in paragraphs (A) through (C) below [40 CFR 63.7540(a)(10)(vi)]:
      (A) The concentrations of carbon monoxide in the effluent stream of the No. 1 Hog Fuel Boiler in parts per million by volume, and oxygen in volume percent, measured before and after the tune-ups of the boiler;
      (B) A description of any corrective actions taken as a part of the tune-up; and
      (C) The type and amount of fuel used over the 12 months prior to the tune-ups, but only if the boiler was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.
   iii. The associated records for compliance with the work practice standards in Section 2.1 A.10.k and A.10.l, above, including the occurrence and duration of each malfunction of operation (i.e., process equipment) or the required air pollution control and monitoring equipment. [40 CFR 63.10(b)(2)]
   iv. Records of the total hours per calendar year that alternative fuel is burned in the No. 1 Hog Fuel Boiler when operating under the AOS as defined in Section 2.1 A.1, above, and the total hours per calendar year that the boiler operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these records are not maintained.

n. The Permittee shall:
   i. maintain records in a form suitable and readily available for expeditious review;
   ii. keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record; and
   iii. keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee can keep the records offsite for the remaining 3 years.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if records are not maintained as specified above. [40 CFR 63.7560 and 63.10(b)(1)]

Reporting Requirements [15A NCAC 02Q .0508(f)]

o. When operating under the AOS as defined in Section 2.1 A.1, above, the Permittee shall submit compliance reports to the DAQ every five years. The first report shall cover the period beginning on the compliance date specified in Section 2.1 A.10.e, above, and ending on December 31 within five years after the compliance date in Section 2.1 A.10.e, above. Subsequent reports shall cover the five-year periods from January 1 to December 31. The compliance reports shall be postmarked on or before January 31. [40 CFR 63.7550(a), (b) and 63.10(a)(4) and (5)]

p. The Permittee shall submit the annual compliance report via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange, CDX.) The Permittee shall use the appropriate electronic report in CEDRI 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for this 40 CFR Part 63, Subpart DDDDD, the Permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (http://www.epa.gov/ttn/chief/cedri/index.html), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the Permittee shall submit the report to DAQ. The Permittee shall begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. [40 CFR 63.7550(h)(3)]

q. The Permittee shall include the following information in the 5-year compliance report [40 CFR 63.7550(a) and (c)(1), (c)(5)(i) through (iii), (c)(5)(xiv), (c)(5)(xvii), and Table 9]:
   i. Company and facility name and address;
   ii. Process unit information, emissions limitations, and operating parameter limitations;
   iii. Date of report and beginning and ending dates of the reporting period;
   iv. The date of the most recent tune-up for the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** required pursuant to Section 2.1 A.10.k and A.10.l, above. Include the date of the most recent burner inspection if it was not done as scheduled and was delayed until the next scheduled or unscheduled unit shutdown; and
   v. If there are no periods of noncompliance from the requirements of the work practice requirements in Section 2.1 A.10.k, above, a statement that there were no deviations from the work practice standards during the reporting period.

r. If the Permittee has a period of noncompliance with a work practice standard for periods of startup and shutdown during the reporting period, the compliance report must also contain the following information [40 CFR 63.7540(b), 63.7550(a) and (d) and Table 9]:
   i. A description of the period of noncompliance and which work practice standard from which the Permittee was in noncompliance; and
   ii. Information on the number, duration, and cause of periods of noncompliance (including unknown cause), as applicable, and the corrective action taken.

B. Temporary low sulfur No. 2 fuel oil-fired boilers (ID Nos. ES-RB1 and ES-RB2; 85.7 million Btu per hour maximum heat input each)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	0.16 pounds per million Btu heat input	15A NCAC 02D .0503
Sulfur dioxide	2.3 percent sulfur content fuel	15A NCAC 02D .0516
Visible emissions	20 percent opacity	15A NCAC 02D .0521
Toxic air pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100
Sulfur dioxide and visible emissions	On site less than 180 days per consecutive twelve month period and use of low sulfur fuels	15A NCAC 02Q .0317 (15A NCAC 02D .0524 Avoidance)
Hazardous air pollutants	On site less than 180 days per consecutive twelve month period.	15A NCAC 02Q .0317 (15A NCAC 02D .1111 Avoidance)

1. 15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS

a. Emissions of particulate matter from the combustion of fuel oil that are discharged from the Temporary Boilers (**ID Nos. ES-RB1 and ES-RB2**) into the atmosphere shall not exceed 0.16 pounds per million Btu heat input.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 B.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0503.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring/recordkeeping/reporting is required for particulate emissions from the firing of No. 2 fuel oil in the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB2)**.

2. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide from the Temporary Boilers (**ID Nos. RB-1 and RB-2**) shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 B.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. Monitoring, recordkeeping and reporting are not required for the combustion of No. 2 fuel oil in the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB2)**.

3. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Temporary Boilers (**ID Nos. RB-1 and RB-2**) shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emission testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 B.3.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring, recordkeeping, or reporting is required for visible emissions when firing No. 2 fuel oil in the boilers (**ID Nos. RB-1 and RB-2**).

4. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS and 15A NCAC 02D .1111: MAXIMUM ACHEIVABLE CONTROL TECHNOLOGY

a. The Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc) and 15A NCAC 02D .0524 are not applicable to the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB1)** because the boilers are temporary boilers, as defined in 40 CFR 60.41c, provided the following criteria are met:
   i. The boilers only fire natural gas and distillate oil;
   ii. The potential SO_2 emissions from each boiler are equal to or less than 0.060 pounds per MMBtu;
   iii. The boilers are designed to, and is capable of, being carried or moved from one location to another and is not attached to a foundation; and
   iv. The boiler remains at the location for 180 consecutive days or fewer (any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period).

b. The National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD) and 15A NCAC 02D .1111 are not applicable to the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB2)** because the boilers are temporary boilers, as defined in 40 CFR 63.7575, provided the criteria in Section 2.1 B.4.a are met.

c. The Permittee shall maintain the following records documenting that the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB2)** meet the criteria for temporary boilers. These records shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request.
   i. the first, last and total number of days the boiler remains at the location;
   ii. records of fuel usage in the boiler showing the type of fuel fired;
   iii. records of fuel sulfur content of distillate oil fired in the boiler; and;
   iv. the function of the boiler for each consecutive time period.

d. The Permittee shall submit a startup notification to the Regional Office within 15 days of startup of the Temporary Boilers **(ID Nos. ES-RB1 and ES-RB2)**.

e. The Permittee shall notify the Regional Office in writing within ten days of exceeding the 180-day period.

C. No. 5 Recovery Boiler (ID No. ES-10-25-0110) firing natural gas, black liquor solids, low sulfur No. 2 fuel oil, and HVLC gases at a maximum rate of 130 tons of black liquor solids per hour and controlled by north and south electrostatic precipitators (ID Nos. CD-10-45-0220 and CD-10-45-0010) operating in parallel

The No. 5 Recovery Boiler serves as a backup control device for the HVLC Collection System.

The following table provides a summary of limits and standards for the emission source described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	3.0 pounds per equivalent tons of air dried pulp.	15A NCAC 02D .0508
Sulfur dioxide	2.3 pounds per million Btu heat input.	15A NCAC 02D .0516
Visible emissions	Visible emissions shall not be more than 35 percent opacity.	15A NCAC 02D .0524 (40 CFR 60, Subpart BB)
Particulate matter	0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.	
Total reduced sulfur	5 ppm by volume on a dry basis, corrected to 8 percent oxygen.	
Carbon monoxide	800 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen.	15A NCAC 02D .0530
Nitrogen oxides	110 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen when firing black liquor solids.	
Sulfur dioxide	16 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen, and No. 2 distillate oil fired shall not exceed 0.05 percent sulfur by weight.	
Sulfuric acid mist	10.16 lb/hr when firing black liquor solids.	
Particulate matter	Compliance Assurance Monitoring	15A NCAC 02D .0614
Criteria pollutants	**See Section 2.2 C** Annual tracking report.	15A NCAC 02D .0530(u)
Hazardous air pollutants	**See Section 2.2 B** 40 CFR Part 63, Subpart MM	15A NCAC 02D .1111

1. 15A NCAC 02D .0508: PARTICULATES FROM PULP AND PAPER MILLS

a. Emissions from the production of pulp and paper that are discharged from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** into the atmosphere shall not exceed 3.0 pounds of particulate matter (PM) per equivalent tons of air dried pulp (ADTP).

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ found in Section 3. If the results of this test are above the limit given in Section 2.1 C.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508.

c. Under the provisions of NCGS 143-215.108, the Permittee shall demonstrate compliance with the emissions limit above by testing the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** for filterable and condensible particulate matter in accordance General Condition JJ no more than five years after the previous performance test is conducted, in accordance with a testing protocol approved by DAQ. During each test, the Permittee shall record and include in the test report the results of the monitoring requirements for this source as specified in Section 2.2 B pursuant to 40 CFR 63 Subpart MM. During each test, the Permittee shall record and include in the test report, the equivalent tons of air dried pulp production recorded during the performance test and submit the test results (as lbs/ADTP and as either in g/dscf or gr/dscm) to the DAQ along with the Section 2.2 B monitoring results. If the results of the testing demonstrate the emissions are equal to or greater than 80 percent of the limit above, the testing frequency shall be increased to once every calendar year beginning no more than 12 months after the previous test until the results

return to less than 80 percent of the limit. If any stack test demonstrates emissions are above the limit given in Section 2.1 C.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

d. Particulate matter emissions from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** shall be controlled by the north and south electrostatic precipitators **(ID Nos. CD-10-45-0220 and CD-10-45-0010).** To ensure compliance with the particulate matter standard in Section 2.1 C.1.a, above, the Permittee shall comply with the 40 CFR 63 Subpart MM monitoring, recordkeeping, and reporting requirements as specified in Section 2.2 B of this permit. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the monitoring and recordkeeping is not conducted.

e. The Permittee shall perform internal inspections of each electrostatic precipitator system when the No. 5 Recovery Boiler is interally inspected to receive its operating certificate. In addition, the Permittee shall perform periodic inspections and maintenance as specified in the approved Basic Care Route or as recommended by the equipment manufacturer. As a minimum, the inspections and maintenance shall include the following:
   i. visual checks of critical components such as rappers and ash removal equipment;
   ii. checks for any equipment that does not generate an alarm in the turned-off state to ensure it is switched on;
   iii. checks for signs of plugging of gas distribution plates and excessive buildup on inlet and outlet plenum floor surfaces;
   iv. checks for signs of hopper plugging; and
   v. checks for broken rapper rod insulators, cracked support bushing insulators, and broken or loose stabilizer bar insulators (if installed), and replacement as required.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the internal electrostatic precipitator system inspections are not conducted as required.

f. The results of all inspections and any variance from standard operating procedures, standard maintenance plans, or from conditions given in this permit (when applicable) shall be investigated with corrections made and dates of actions recorded in a logbook. Records of all maintenance activities shall also be recorded in the logbook. The logbook (in written or electronic form) shall be kept on-site and made available to DAQ personnel upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if these records are not maintained.

2. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard, and shall include the sulfur dioxide formed by the combustion of sulfur-containing gases in the:
   i. HVLC Gas Collection System identified in Section 2.1 J below;
   ii. LSRP Sources **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1400, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2600, ES-09-27-2610, ES-09-27-2620, ES-09-27-2660, ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, ES-09-27-3200)** prior to startup of normal operations of the two-phased packed tower caustic scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 Q.1 below;
   iii. LSRP Sources **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** after startup of normal operation of the two-phased packed bed scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 T.1 below.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 C.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring, recordkeeping and reporting are required for sulfur dioxide emissions from the firing of natural gas and No. 2 fuel oil in the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**.

3. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

a. For the No. 5 Revovery Boiler **(ID No. ES-10-25-0110)**, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 “New Source Performance Standards

(NSPS)" as promulgated in 40 CFR Part 60 Subpart BB "Standards of Performance for Kraft Pulp Mills," including Subpart A "General Provisions."

Emissions Limitations [15A NCAC 02D .0524]

b. The Permittee shall not cause particulate matter emissions from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** to exceed:
   i. 0.10 g/dscm (0.044 gr/dscf) of particulate matter corrected to 8 percent oxygen. [40 CFR 60.282(a)(1)(i)];
   ii. 35 percent opacity [40 CFR 60.282(a)(1)(ii)]; and
   iii. 5 ppm of total reduced sulfur by volume on a dry basis, corrected to 8 percent oxygen based on a 12-hour average [40 CFR 60.283(a)(2) and 60.284(c)].

Testing [15A NCAC 02Q .0508(f)]

c. Under the provisions of NCGS 143-215.108, the Permittee shall demonstrate compliance with the particulate matter limit above by testing the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** for particulate matter in accordance with General Condition JJ and a testing protocol approved by the DAQ. The Permittee shall perform stack testing no more than five years after the previous performance test and submit the test results to the DAQ. If the results of the testing demonstrate the emissions are equal to or greater than 80 percent of the particulate limit in 2.1 C.3.b.i, above, the testing frequency shall be increased to once every calendar year until the results return to less than 80 percent of the limit. If any stack test demonstrates emissions are above the limit given in Section 2.1 C.3.b.i, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f) and 02D .0524]

d. Particulate matter emissions from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** shall be controlled by electrostatic precipitators **(ID Nos. CD-10-45-0220 and CD-10-45-0010)** operating in parallel. To ensure compliance, the Permittee shall comply with the 40 CFR 63 Subpart MM monitoring, recordkeeping and reporting requirements as specified in Section 2.2 B of this permit. The Permittee shall be deemed in non-compliance with 15A NCAC 02D .0524 if these parameters are not monitored or if records are not maintained.

e. The Permittee shall calibrate, maintain, and operate a continuous opacity monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**. The span of this system shall be set at 70 percent opacity. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the opacity is not monitored or these records are not maintained. [40 CFR § 60.284(a)(1)]

f. The Permittee shall calibrate, maintain, and operate a CEMS to monitor and record the concentration of total reduced sulfur emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere. The CEMS shall be operated in accordance with the applicable requirements of 40 CFR 60 Appendix B and Appendix F unless an alternative monitoring and quality assurance program is approved by the DAQ. The Permittee shall locate the CEMS downstream of the electrostatic precipitators **(ID Nos. CD-10-45-0220 and CD-10-45-0010)** and set the CEMS spans as follows: [40 CFR 60.284(a)(2)]
   i. At a total reduced sulfur concentration of 30 ppm for the total reduced sulfur CEMS.
   ii. At 25 percent oxygen for the oxygen CEMS.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if total reduced sulfur and oxygen are not monitored or these records are not maintained.

Reporting [15A NCAC 02Q .0508(f) and 02D .0524]

g. The Permittee shall determine quarterly excess emissions from the No. 5 Recovery Boiler as follows: [40 CFR 60.284(d)]
   i. Excess emissions are all 12-hour averages of total reduced sulfur concentrations above 5 ppm by volume. One percent of the total number of possible contiguous periods of excess total reduced sulfur emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) is not considered to be a period of noncompliance.
   ii. Excess opacity emissions are all 6-minute average opacities that exceed 35 percent. Six percent of the total number of possible contiguous periods of excess opacity emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) is not considered to be a period of noncompliance.

h. The Permittee shall submit a semiannual summary report of the monitoring and recordkeeping activities given in Section 2.1 C.3.d through C.3.f, above, determined on a quarterly basis and postmarked on or before January 30 of

each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

4. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. Emissions that are discharged from the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** into the atmosphere shall not exceed the following BACT emission limits:
   i. Carbon monoxide emissions of 800 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen.
   ii. Nitrogen oxides emissions of 110 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen when firing black liquor solids.
   iii. Sulfur dioxide emissions of 16 ppm by volume on a dry basis (24-hour block average), corrected to 8 percent oxygen when firing black liquor solids.
   ii. Sulfuric acid mist emissions of 10.16 lb/hr when firing black liquor solids.

b. The sulfur content of No. 2 distillate oil burned in the recovery boiler shall not exceed 0.05 percent by weight.

Testing [15A NCAC 02Q .0508(f) and 02D .0530]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limits given in Section 2.1 C.4.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

d. Under the provisions of NCGS 143-215.108, the Permittee shall demonstrate compliance with the emission limit(s) above by testing the No. 5 Recovery Boiler **(ID No. ES-10-25-0110),** while firing BLS or ultra low sulfur No. 2 fuel oil blended with BLS, for carbon monoxide and nitrogen oxides in accordance with General Condition JJ. The Permittee shall perform the testing no more than once every five years after the previously conducted performance test. If stack test results for any pollutant are equal to or greater than 80 percent of the limit in Section 2.1 C.4.a above, the testing frequency shall be increased to once every calendar year for carbon monoxide and nitrogen oxides until stack test results return to less than 80 percent of the limit for each pollutant. If any stack test demonstrates emissions are above the limit(s) given in Section 2.1 C.4.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

Monitoring/ Recordkeeping [15A NCAC 02Q .0508(f) and 02D .0530]

e. The maximum sulfur content of any distillate oil received and burned in the boiler shall not exceed 0.05 percent by weight (as SO_2). The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the sulfur content of the fuel oil fired exceeds this limit.

f. To ensure compliance with the fuel sulfur content limit specified in Section 2.1 C.4.e, above, the Permittee shall monitor the sulfur content of the fuel oil by using fuel oil supplier certification per month. The results of the fuel oil supplier certifications shall be recorded in a logbook (written or electronic format) on a quarterly basis and include the following information:
   i. the name of the fuel oil supplier;
   ii. the maximum sulfur content of the fuel oil received during the quarter;
   iii. the method used to determine the maximum sulfur content of the fuel oil; and
   iv. a certified statement signed by the Permittee's Responsible Official that the records of fuel oil supplier certification submitted represent all of the fuel oil fired during the period.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the sulfur content of the oil is not monitored and recorded.

g. The amount of black liquor solids fired in the recovery boiler shall not exceed 130 tons per hour. The Permittee shall monitor the hourly firing rate of black liquor solids in the recovery boiler, maintain the firing rates in written or electronic format on-site and make available to an authorized representative upon request. The records shall include the following:
   i. the date and time of each recorded action; and
   ii. the black liquor solids firing rate.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the firing rate of black liquor solids is not monitored and recorded or if the maximum black liquor solids firing rate is exceeded.

Reporting [15A NCAC 02Q .0508(f)]

h. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 C.4.e through C.4.g, above, calculated on a quarterly basis and postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period.

5. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. For the electrostatic precipitators **(ID Nos. CD-10-45-0010 and CD-10-45-0220)** associated with the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, the Permittee shall comply with 40 CFR part 64 pursuant to 15A NCAC 02D .0614 to ensure that the recovery boiler complies with the emission limits of 15A NCAC 02D .0508.

Background

b. Emission Units: No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**

c. Applicable Regulation, Emission Limitation, and Monitoring Requirements:

i. Regulation: 15A NCAC 02D .0508: Particulates from Pulp and Paper Mills
15A NCAC 02D .0524: New Source Performance Standards - 40 CFR Part 60, Subpart BB

ii. Emission Limits:
PM: 3.0 pounds of particulate matter per equivalent tons of air dried pulp
PM 0.044 grains per dry standards cubic feet, corrected to 8 percent oxygen

iii. Control Technology: two electrostatic precipitators operating in parallel

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criterial are presented in the following table.

Measure	Indicator No. 5 Recovery Boiler
I. Indicator	Opacity of ESP exhaust
Measuring approach	Continuous opacity monitoring system (COMS) in ESP exhaust
II. Indicator Range[a]	The opacity indicator range is a 1-hour average opacity of 20 percent. An excursion occurs when any 1-hour average opacity is greater than 20 percent. The excursion triggers corrective action and reporting requirement. The QIP threshold is when the total duration of excursions is greater than 5 percent of the source operating time during any 6-month period. The QIP shall be prepared as required under 40 CFR 64.8.
III. Performance Criteria	
Data Representativeness	The COMS was installed at a representative location in the recovery boiler ESP exhaust prior to being combined with the No. 1 Hog Fuel Boiler exhaust per 40 CFR 60, Appendix B, Performance Specification (PS-1)
QA/QC Practices and Criteria	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
Monitoring Frequency	The opacity of the ESP exhaust is monitored continuously (every 10 seconds)
Data Collection Procedures	The data acquisition system shall retain all 6-minute data and 1-hour block averages pursuant to PS-1.
Averaging Period	The 10-second opacity data are used to calculate the 6-minute averages. The 6-minute averages are used to calculate the 1-hour block average.

[a]During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 C.5.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

D. North Smelt Tank (ID No. ES-14-05-0050) with associated Ducon alkaline scrubber (North) (ID No. CD-14-05-0700); and South Smelt Tank (ID No. ES-14-05-0300) with associated Ducon alkaline scrubber (South) (ID No. CD-14-05-0750)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	0.6 pounds per equivalent ton of air-dried pulp.	15A NCAC 02D .0508
Visible emissions	20 percent opacity.	15A NCAC 02D .0521
Total reduced sulfur	0.032 pounds per ton of black liquor solids (dry weight) from any smelt dissolving tank.	15A NCAC 02D .0528
Particulate matter	Compliance assurance monitoring	15A NCAC 02D .0614
Hazardous air pollutants	**See Section 2.2 B** 40 CFR Part 63, Subpart MM	15A NCAC 02D .1111

1. 15A NCAC 02D .0508: PARTICULATES FROM PULP AND PAPER MILLS

a. Emissions from the production of pulp and paper that are discharged from the North Smelt Tank **(ID No. ES-14-05-0050)** and South Smelt Tank **(ID No. ES-14-05-0300)** into the atmosphere shall not exceed 0.6 pounds of particulate matter per equivalent tons of air dried pulp. [15A NCAC 02D .0508(a)]

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 D.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. Particulate emissions from the North and South Smelt Tanks shall be controlled by the associated scrubbers **(ID Nos. CD-144-05-0700 and CD-14-05-0750)**. To ensure compliance with the particulate matter emission limit in Section 2.1 D.1.a, above, the Permittee shall comply with the 40 CFR Part 63 Subpart MM monitoring, recordkeeping, and reporting requirements as specified in Section 2.2 B, below. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the required monitoring and recordkeeping are not conducted.

d. The Permittee shall perform periodic inspections and maintenance of the scrubbers **(ID Nos. CD-14-05-0700 and CD-14-05-0750)** as specified in the approved Basic Care Route or as recommended by the manufacturer. In addition, the Permittee shall perform at a minimum an annual internal inspection of each of the scrubber systems. As a minimum, the annual internal inspection will include inspection of spray nozzles, packing material, chemical feed system (if so equipped), and the cleaning/calibration of all associated instrumentation annually. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the required inspections are not conducted as specified.

e. The results of all inspections and any variance from standard operating procedures, standard maintenance plans, or from conditions given in this permit (when applicable) shall be investigated with corrections made and dates of actions recorded in a logbook. Records of all maintenance activities shall also be recorded in the logbook. The logbook (in written or electronic form) shall be kept on-site and made available to DAQ personnel upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the required records are not maintained.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the North and South Smelt Tanks **(ID Nos ES-14-05-0050 and ES-14-05-0300)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 D.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring [15A NCAC 02Q .0508(f)]

c. The North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)** are equipped with wet scrubbers and, therefore, visible emissions are only present due to uncombined water. Pursuant to 15A NCAC 02D .0521, no monitoring, recordkeeping, and reporting is required for visible emissions from these sources.

3. 15A NCAC 02D .0528: TOTAL REDUCED SULFUR FROM KRAFT PULP MILLS

a. The emissions of total reduced sulfur shall not exceed 0.032 pounds per ton of black liquor solids (dry weight) from any smelt dissolving tank. [15A NCAC 02D .0528]

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 D.3.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0528

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. Monitoring, recordkeeping and reporting are not required.

4. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. For the Ducon alkaline scrubbers **(ID Nos. CD-14-05-0700 and CD-14-05-0750)** associated with the North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, respectively, the Permittee shall comply with 40 CFR part 64 pursuant to 15A NCAC 02D .0614 to ensure that the smelt tanks comply with the emission limits of 15A NCAC 02D .0508.

Background

b. Emission Units: North Smelt Tank **(ID No. ES-14-05-0050)**
South Smelt Tank **(ID No. ES-14-05-0300)**

c. Applicable Regulation, Emission Limitation, and Monitoring Requirements:
   i. Regulation: 15A NCAC 02D .0508: Particulates from Pulp and Paper Mills
   ii. Emission Limits:
   PM: 0.6 pounds of particulate matter per equivalent tons of air dried pulp.

   iii. Control Technology: Ducon alkaline scrubbers

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criterial are presented in the following table.

Measure		Indicator	
		North Smelt Tank	**South Smelt Tank**
I.	Indicator	Scrubber pressure drop, total liquid injection rate	Scrubber pressure drop and total liquid injection rate
	Measuring approach	Install pressure drop and flow rate continuous monitors	Install pressure drop and flow rate continuous monitors
II.	Indicator Range[a]	Pressure drop indicator range: minimum 3-hour average 3 inches of H_2O Flow rate indicator ranges: scrubber spray header flow minimum 3-hour average 75 gallons per minute and rod box flow minimum 3-hour average 50 gallons per minute	Pressure drop indicator range: minimum 3-hour average 3 inches of H_2O Flow rate indicator ranges: scrubber spray header flow minimum 3-hour average 75 gallons per minute and rod box flow minimum 3-hour average 50 gallons per minute

Measure	Indicator	
	North Smelt Tank	**South Smelt Tank**
	An excursion occurs when the 3-hour average measurement is less than the indicator range. The excursion triggers corrective action and reporting requirement. No more than one excursion will be attributed in any given 24-hour period. The QIP threshold is a total of 5 excursions during any 6-month period. The QIP shall be prepared as required under 40 CFR 64.8.	An excursion occurs when the 3-hour average measurement is less than the indicator range. The excursion triggers corrective action and reporting requirement. No more than one excursion will be attributed in any given 24-hour period. The QIP threshold is a total of 5 excursions during any 6-month period. The QIP shall be prepared as required under 40 CFR 64.8.
III. Performance Criteria		
Data Representativeness	Pressure drop tabs installed before and after the scrubber. Flow measurement devices located prior to liquid injection point.	Pressure drop tabs installed before and after the scrubber. Flow measurement devices located prior to liquid injection point.
QA/QC Practices and Criteria	Annual calibration of pressure drop and flow monitoring devices.	Annual calibration of pressure drop and flow monitoring devices.
Monitoring Frequency	Continuous pressure drop and flow measurements	Continuous pressure drop and flow measurements
Data Collection Procedures	The data acquisition system shall retain all 15-minute data and 3-hour block averages.	The data acquisition system shall retain all 15-minute data and 3-hour block averages.
Averaging Period	The 15-minute pressure drop and liquid injection rate data are used to calculate the 3-hour block average.	The 15-minute pressure drop and liquid injection rate data are used to calculate the 3-hour block average.

[a]During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 D.4.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

E. No. 5 Lime Kiln (ID No. ES-14-60-3000) firing natural gas, No. 2 fuel oil, and LVHC and SOG gases (500 tons of reburned lime per day nominal capacity) and controlled by the Lime Kiln Venturi Scrubber (ID No. CD-14-70-2012)

The No. 5 Lime Kiln serves as the primary control device for the LVHC Collection System

The following table provides a summary of limits and standards for the emission source described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	0.5 pounds per equivalent ton of air dried pulp	15A NCAC 02D .0508
Sulfur dioxide	2.3 pounds per million Btu heat input	15A NCAC 02D .0516
Visible emissions	20 percent opacity	15A NCAC 02D .0521
Particulate matter (filterable only)	0.13 gr/dscf corrected to 10 percent oxygen while firing oil 0.066 gr/dscf corrected to 10 percent oxygen while firing natural gas	15A NCAC 02D .0524 (40 CFR 60, Subpart BB)
Total reduced sulfur	8 ppm by volume on a dry basis, corrected to 10 percent oxygen based on a 12-hour average	15A NCAC 02D .0524 (40 CFR 60, Subpart BB)
Carbon monoxide	14.6 lb/hr while firing LVHC/SOG gases.	15A NCAC 02D .0530
Particulate matter	182,500 bone dry tons of reburned lime (as CaO) per consecutive 12-month period	15A NCAC 02Q .0317 (15A NCAC 02D .0530 Avoidance)
Particulate matter	Compliance Assurance Monitoring	15A NCAC 02D .0614
Hazardous air pollutants	**See Section 2.2 B** 40 CFR Part 63, Subpart MM	15A NCAC 02D .1111

1. 15A NCAC 02D .0508: PARTICULATES FROM PULP AND PAPER MILLS

a. Emissions from the production of pulp and paper that are discharged from the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** into the atmosphere shall not exceed 0.5 pounds of particulate matter per equivalent tons of air dried pulp (ADTP).

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 E.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508.

c. Under the provisions of NCGS 143-215.108 and in accordance with General Condition JJ, the Permittee shall demonstrate compliance with the emissions limit above by testing the No. 5 Lime Kiln (**ID No. ES-14-60-3000)** for particulate matter (filterable and condensable, unless otherwise exempted per 15A NCAC 02D .2609). Periodic performance tests shall be conducted no more than five years after the previous performance test is conducted in accordance with a testing protocol approved by DAQ. During each test, the Permittee shall record, and include in the test report, the results of the monitoring requirements for this source as specified in Section 2.2 B pursuant to 40 CFR Part 63, Subpart MM and the equivalent ADTP production during the performance test and submit the test results (as pounds per ADTP and in gr/dscf) to the DAQ along with the Section 2.2 B parameter monitoring results. Test results shall be recorded as lbs/ADTP and as g/dscm (or gr/dscf). If the results of the testing demonstrate the PM emissions are equal to or greater than 80 percent of the limit above, the testing frequency for the affected fuel (natural gas or oil) shall increase to once every calendar year until the results return to less than 80 percent of the limit or until the fuel is no longer a primary fuel. If any stack test demonstrates emissions are above the limit given in Section 2.1 E.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

d. Particulate matter emissions from the lime kiln (**ID No ES-14-60-3000**) shall be controlled by a venturi scrubber (**ID No. CD-14-70-2012**). To ensure compliance with the particulate matter limitation, the Permittee shall comply with the 40 CFR Part 63 Subpart MM monitoring, recordkeeping and reporting requirements as specified in

Section 2.2 B, below. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if these parameters are not monitored or these records are not maintained.

e. The Permittee shall perform periodic inspections and maintenance of scrubbers **(ID Nos. CD-14-70-2012)** as specified in the approved Basic Care Route or as recommended by the manufacturer. In addition, the Permittee shall perform at a minimum an annual internal inspection of each of the scrubber systems. As a minimum, the annual internal inspection shall include inspection of spray nozzles, packing material, chemical feed system (if so equipped), and the cleaning/calibration of all associated instrumentation annually. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the inspections and maintenance of the scrubbers are not conducted as required.

f. The results of all inspections and any variance from standard operating procedures, standard maintenance plans, or from conditions given in this permit (when applicable) shall be investigated with corrections made and dates of actions recorded in a logbook. Records of all maintenance activities shall also be recorded in the logbook. The logbook (in written or electronic form) shall be kept on-site and made available to DAQ personnel upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0508 if the records are not maintained as required.

2. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide from the No. 5 lime kiln **(ID No. ES-14-60-3000)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 E.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. No monitoring and recordkeeping is required for sulfur dioxide emissions from the firing of natural gas alone in the No. 5 Lime Kiln **(ES-14-60-3000)**.

d. The maximum sulfur content of any fuel oil received and burned in the kiln shall not exceed 2.1 percent by weight. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516 if the sulfur content of the fuel oil exceeds this limit.

e. To ensure compliance with the fuel sulfur content specified in Section 2.1 E.2.d, above, the Permittee shall monitor the sulfur content of the fuel oil by using fuel oil supplier certification per month. The results of the fuel oil supplier certifications shall be recorded in a logbook (written or electronic format) on a quarterly basis and include the following information:
   i. the name of the fuel oil supplier;
   ii. the maximum sulfur content of the fuel oil received during the quarter;
   iii. the method used to determine the maximum sulfur content of the fuel oil; and

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516 if the sulfur content of the oil is not monitored and recorded.

f. The Permittee shall calculate and record in a logbook (written or electronic format) the pounds of sulfur dioxide per million Btu heat content of No. 2 fuel oil per month using the information given in Section 2.1 E.2.e, above. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516 if records of sulfur dioxide emissions are not recorded or if the sulfur dioxide emissions exceed the limits given in Section 2.1 E.2.a, above.

Reporting [15A NCAC 02Q .0508(f)]

g. No reporting is required for sulfur dioxide emissions from the firing of natural gas in the No. 5 Lime Kiln **(ES-14-60-3000)**.

h. The Permittee shall submit a summary report of the fuel oil supplier certifications and calculated emission rates given in Section 2.1 E.2.d through E.2.f, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-

month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. The Permittee shall submit a certified statement signed by the responsible official that the records of fuel oil supplier certification submitted represent all of the fuel oil fired during the period.

3. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 E.3.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The No. 5 Lime Kiln **(ID No. ES-14-60-3000)** is equipped with a wet scrubber and therefore, visible emissions are only present due to uncombined water. Pursuant to 15A NCAC 02D .0521(e), no monitoring, recordkeeping, and reporting is required for visible emissions from this source.

4. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

a. For the No. 5 Lime Kiln **(ID No. ES-14-60-3000)**, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards" as promulgated in 40 CFR Part 60 Subpart BB "Standards of Performance for Kraft Pulp Mills," including Subpart A "General Provisions."

Emissions Limitations [15A NCAC 02D .0524]

b. Emissions from the No. 5 Lime Kiln shall not exceed the following limits:
   i. 0.13 gr/dscf of PM corrected to 10 percent oxygen while firing oil [40 CFR Part 60, Subpart 60.282(a)(3)(i)], and
   ii. 0.066 gr/dscf of PM corrected to 10 percent oxygen while firing natural gas [40 CFR Part 60, Subpart 60.282(a)(3)(i)], and
   iii. 8 ppm of total reduced sulfur by volume on a dry basis, corrected to 10 percent oxygen based on a 12-hour average[40 CFR Part 60, Subpart 60.283(a)(5) and 60.284(c)].

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 E.4.a, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

d. Under the provisions of NCGS 143-215.108, the Permittee shall conduct periodic stack testing of the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** for particulate matter (filterable and condensable, unless otherwise exempted per 02D .2609) for the worst-case fuel (natural gas and/or oil combined with LVHC gases and SOG) that averages at least 10 percent of the heat input to the lime kiln during any calendar year period during the previous five years. Periodic performance tests shall be conducted no more than five years after the previous performance test is conducted in accordance with a testing protocol approved by DAQ. During each test, the Permittee shall record, and include in the test report, the results of the monitoring requirements for this source as specified in Section 2.2 B pursuant to 40 CFR Part 63, Subpart MM and the equivalent ADTP production during the performance test and submit the test results (as pounds per ADTP and in gr/dscf) to the DAQ along with the Section 2.2 B parameter monitoring results. Test results shall be recorded as lbs/ADTP and as g/dscm (or gr/dscf). If the results of the testing demonstrate the emissions are equal to or greater than 80 percent of the limit in Section 2.1 E.4.b above, the testing frequency in shall increase to once every calendar year until the results return to less than 80 percent of the above limit. If any stack test demonstrates emissions are above the limit given in Section 2.1 E.4.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

e. Particulate matter emissions from the lime kiln shall be controlled by a venturi scrubber **(ID No. CD-14-70-2012)**. To ensure compliance with the emissions limitation, the Permittee shall comply with the 40 CFR 63 Subpart MM monitoring, recordkeeping and reporting requirements as specified in Section 2.2 B of this permit. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if these parameters are not monitored or these records are not maintained.

f. the Permittee shall calibrate, maintain, and operate a CEMS to monitor and record the concentration of total reduced sulfur emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere These systems shall be located downstream of the control device and the spans of these continuous monitoring system shall be set: [40 CFR 60.284(a)(2)]
   i. At a total reduced sulfur concentration of 30 ppm for the total reduced sulfur system monitoring the lime kiln operation.
   ii. At 25 percent oxygen for the continuous oxygen monitoring system.

g. The Permittee shall calculate and record the 12-hour average total reduced sulfur concentrations for the two consecutive periods of each operating day in accordance with 40 CFR 60.284(c). The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if total reduced sulfur concentrations are not monitored or if they exceed the limit in Section 2.1.E.4.b above.

Reporting [15A NCAC 02Q .0508(f)]

h. The Permittee shall calculate periods of excess emissions on a quarterly basis from the No. 5 Lime Kiln. Excess emissions are all 12-hour average total reduced sulfur concentration above 8 ppm by volume. [40 CFR 60.284(d)(2)]

i. The Permittee shall submit a semiannual summary report of the monitoring and recordkeeping activities given in Section 2.1 E.4.d through E.4.h, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

5. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION:

Emissions Limits [15A NCAC 02D .0530]

a. For the No. 5 Lime Kiln, the following Best Available Control Technology (BACT) limits shall not be exceeded:

Emission Source	Fuel Fired	Pollutant	Emission Limit
No. 5 Lime Kiln **(ID No. ES-14-60-3000)**	LVHC gases /SOG	Carbon monoxide (CO)	14.6 pounds per hour

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the result of any test is greater than the limit given above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall record and maintain records of the amount of time LVHC/SOG gases burned in the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** each month and make these records available to an authorized representative of the DAQ upon request.

d. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 E.5.c, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period.

6. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for
15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. In order to avoid applicability of 15A NCAC 02D .0530(g) for major sources and major modifications, the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** shall not produce more than 182,500 bone dry tons of reburned lime (as CaO) per consecutive 12-month period.

Monitoring/ Recordkeeping [15A NCAC 02Q .0508(f)]

b. The Permittee shall maintain record and maintain records of the amount (in bone dry tons) of reburned lime produced in the lime kiln during each day. These records shall be made available to an authorized representative of DAQ upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the daily reburned lime production rates are not recorded.

Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 E.6.b, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period. The report shall contain the following:
   i. the monthly quantities of lime produced in the kiln for the previous 17 months. The total quantities burned must be calculated for each of the 12-month periods over the previous 17 months; and
   ii. All instances of deviations from the requirements of this permit must be clearly identified.

7. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. For the venturi scrubber **(ID No. CD-14-70-2012)** associated with the No. 5 Lime Kiln **(ID No. ES-14-60-3000)**, the Permittee shall comply with 40 CFR part 64 pursuant to 15A NCAC 02D .0614 to ensure that the lime kiln complies with the emission limits of 15A NCAC 02D .0508.

Background

b. Emission Units: No. 5 Lime Kiln **(ID No. ES-14-60-3000)**

c. Applicable Regulation, Emission Limitation, and Monitoring Requirements:
   i. Regulation: 15A NCAC 02D .0508: Particulates from Pulp and Paper Mills
   15A NCAC 02D .0524: New Source Performance Standards – 40 CFR Part 60, Subpart BB
   ii. Emission Limits:
   PM (total): 0.5 pounds of particulate matter per equivalent tons of air dried pulp.
   Filterable PM: 0.13 gr/dscf of PM corrected to 10 percent oxygen while firing oil.
   Filterable PM: 0.066 gr/dscf of PM corrected to 10 percent oxygen while firing natural gas

   iii. Control Technology: venturi scrubber

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criterial are presented in the following table.

Measure		Indicator No. 5 Lime Kiln
I.	Indicator	Scrubber pressure drop, total liquid injection rate
	Measuring approach	Install pressure drop and flow rate continuous monitors
II.	Indicator Range[a]	Scrubber pressure drop indicator range: maximum 3-hour average of 5 inches of H_2O Liquid nozzle header pressure range: maximum 3-hour average of 240 psig to 3-hour average maximum of 275 psig. Scrubber liquid flow rate indicator range: minimum 3-hour average 896 gallons per minute (venturi plus quench liquid flow rate)

Measure	Indicator No. 5 Lime Kiln
	An excursion occurs when the 3-hour average measurement is less than the minimum indicator range or greater than the maximum indicator range. The excursion triggers corrective action and reporting requirement. No more than one excursion will be attributed in any given 24-hour period. The QIP threshold is a total of 5 excursions during any 6-month period. The QIP shall be prepared as required under 40 CFR 64.8.
III. Performance Criteria	
Data Representativeness	Pressure drop tabs installed before and after the scrubber. Flow measurement devices located prior to liquid injection point.
QA/QC Practices and Criteria	Annual calibration of pressure drop and flow monitoring devices.
Monitoring Frequency	Continuous pressure drop and flow measurements.
Data Collection Procedures	The data acquisition system shall retain all 15-minute data and 3-hour block averages.
Averaging Period	The 15-minute pressure drop and liquid injection rate data are used to calculate the 3-hour block average.

[a]During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 E.7.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

F. No. 1 Hog Fuel Boiler De-Entrainment Vessels:
West De-Entrainment Vessel (ID No. ES-64-60-0180) with Baghouse West (ID No. CD-64-60-0900);
Central De-Entrainment Vessel (ID No. ES-64-60-0480) with Baghouse Central (ID No. CD-64-60-0910); and
East De-Entrainment Vessel (ID No. ES-64-60-0780) with Baghouse East (ID No. CD-64-60-0920)

No. 1 Hog Fuel Boiler Ash Storage and Handling:
Scrubber Ash Silo (ID No. ES-64-60-0960) with East and West Bagfilters (ID Nos. CD-64-60-0961 and CD-64-60-0962)

No. 2 Hog Fuel Boiler Ash Storage and Handling:
Boiler Ash Silo (ID No. ES-65-50-0190) with East and West Bagfilters (ID Nos. CD-65-50-0170 and CD-65-50-0180);
Scrubber Ash Silo (ID No. ES-65-60-0860) with East and West Bagfilters (ID Nos. CD-65-60-0870 and CD-65-60-0880); and Ash Transport Steam Exhauster (ID No. ES-65-50-0160) with Air Washer (ID No. CD-65-50-0160)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate Matter	$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons per hour, -OR- $E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons per hour Where: E = allowable emission rate in pound per hour P = process weight rate in tons per hour	15A NCAC 02D .0515
Visible Emissions	20 percent opacity	15A NCAC 02D .0521
Criteria Pollutants	**See Section 2.2 C** Annual tracking report.	15A NCAC 02D .0530(u)
PM_{10}	**Affected Source - De-entrainment Vessels and Ash Silos** Compliance Assurance Monitoring	15A NCAC 02D .0614
Toxic Air Pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

a. Emissions of particulate matter from the No. 1 Hog Fuel Boiler De-Entrainment Vessels, No. 1 Hog Fuel Boiler Ash Storage and Handling, No. 2 Hog Fuel Boiler Ash Storage and Handling, as identified above, shall not exceed an allowable emission rate as calculated by one of the following equations:

$E = 4.10 \times P^{0.67}$ for process rates $\leq$ 30 tons per hour, or
$E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

Where: E = allowable emission rate in pound per hour
P = process weight rate in tons per hour

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 F.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515.

Monitoring [15A NCAC 02Q .0508(f)]

c. Particulate emissions, from No. 1 Hog Fuel Boiler De-Entrainment Vessels, No. 1 Hog Fuel Boiler Ash Storage and Handling, No. 2 Hog Fuel Boiler Ash Storage and Handling, as identified above, shall be controlled by bagfilters and air washers. To ensure compliance, the Permittee shall perform inspections and maintenance as specified in the approved Basic Care Route, or as recommended by the manufacturer. The Permittee shall, as a minimum, perform the following:
   i. a monthly visual inspection of the system ductwork and material collection unit for leaks; and
   ii. an annual (for each 12 month period following the initial inspection) internal inspection of the bagfilter's structural integrity.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the ductwork and bagfilters are not inspected and maintained.

d. Inspection and maintenance is not required for the air washers.

Recordkeeping [15A NCAC 02Q .0508(f)]

e. The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each inspection;
   iii. the results of any maintenance performed on the ductwork and bagfilters; and
   iv. any variance from manufacturer's recommendations, if any, and corrections made.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit the results of any maintenance performed on the ductwork and bagfilters within 30 days of a written request by the DAQ.

g. The Permittee shall submit a summary report of monitoring and recordkeeping activities given in Section 2.1 F.1.c through F.1.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from those sources identified above shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 F.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring [15A NCAC 02Q .0508(f)]

c. To ensure compliance, the Permittee shall observe the emission points (at the control device vent) of the De-Entrainment Vessels and the Scrubber Ash Silos **(ID Nos. ES-64-60-0480, ES-64-60-0780, ES-64-60-0960, and ES-65-60-0860)** once each week for any visible emissions above normal. The weekly observation must be made for each week of the calendar year period to ensure compliance with this requirement. If visible emissions from any source are observed to be above normal, the Permittee shall either:
   i. take appropriate action to correct the above-normal emissions within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
   ii. demonstrate that the percent opacity from the emission points of the de-entrainment vessels and scrubber ash silos in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limit given in Section 2.1 F.2.a above.

   The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the weekly observations are not conducted as required; if the above-normal emissions are not corrected within the monitoring period; or the percent opacity demonstration cannot be made.

d. To ensure compliance, the Permittee shall observe the emission points of Boiler Ash Silo and Ash Transport Steam Exhauster **(ID Nos. ES-65-50-0190, and ES-65-50-0160)** once each month for any visible emissions above normal. The monthly observation must be made for each month of the calendar year period to ensure compliance with this requirement. If visible emissions from any source are observed to be above normal, the Permittee shall either:
   i. take appropriate action to correct the above-normal emissions within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
   ii. demonstrate that the percent opacity from the emission points of the emission source in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limit given in Section 2.1 F.2.a above.

   The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the monthly observations are not conducted as required; if the above-normal emissions are not corrected within the monitoring period; or the percent opacity demonstration cannot be made.

Recordkeeping [15A NCAC 02Q .0508(f)]

e. The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
   iii. the results of any corrective actions performed.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 F.2.c through F.2.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

3. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. For the De-Entrainment Vessel Baghouses **(ID Nos. CD-64-60-0900, CD-64-60-0910, and CD-64-60-0920)** and the Ash Storage and Handling Bagfilters and Air Washers **(ID Nos. CD-65-50-0170, CD-65-50-0180, and CD-64-50-0160)**, the Permittee shall comply with 40 CFR Part 64 pursuant to 15A NCAC 02D .0614 to ensure that the De-Entrainment Vessels, and Ash Storage and Handling sources comply with the emission limits of 15A NCAC 02D .0515.

Background

b. Emission Units: West de-entrainment vessel **(ID No. ES-64-60-0180)**
   Central de-entrainment vessel **(ID No. ES-64-60-0480)**
   East de-entrainment vessel **(ID No. ES-64-60-0780)**
   Ash silo **(ID No. ES-65-50-0190)**

c. Applicable Regulation, Emission Limit, and Monitoring Requirements
   i. Regulation: 15A NCAC 02D .0515
   ii. Emission limits:
   Particulate matter emissions shall not exceed the following limits

   $E = 4.10 \times P^{0.67}$ for process rates $\leq$ 30 tons per hour, or
   $E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

   Where: E = allowable emission rate in pound per hour
   P = process weight rate in tons per hour

   iii. Control Technology: Baghouses/Bagfilters

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table.

Measure	Indicator
I. Indicator	Visible emissions
Measuring approach	Visible emissions (VE) from each baghouse/bagfilter will be observed daily using EPA Reference Method 22-like procedures.
II. Indicator Range	An excursion is defined as the presence of visible emissions. Excursion triggers a demonstration of compliance with the 20 percent opacity standard in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes; `an inspection, corrective action, and a reporting requirement. The QIP threshold is excursions occurring on three days (consecutive or non-consecutive days) in a six-month reporting period for which the Permittee did not perform a demonstration of compliance with the 20 percent opacity standard in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes. The QIP shall be prepared within 30 days of reaching the QIP threshold and shall contain procedures for evaluating control performance problems.
III. Performance Criteria	
Data Representativeness	Visible emissions shall be observed at the emissions point (baghouse exhaust).
QA/QC Practices and Criteria	The observer shall be familiar with EPA Reference Method 22 and follow Method 22-like procedures when VE is observed. Method 9 observations are conducted by a certified Reference Method 9 observer.
Monitoring frequency	A VE observation shall bes performed daily, when operating.
Data Collection Procedures	The VE observation is recorded by the observer.
Averaging Period	N/A

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 F.3.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations for the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

G. East Lime Slaker (ID No. ES-14-20-2020) and Nos. 1, 2, and 3 East Causticizing Lines (ID Nos. ES-14-20-2040, ES-14-20-2050 and ES-14-20-2060) with associated East Slaker Wet Scrubber, 45 gallons per minute minimum liquid injection rate (ID No. CD-14-20-2035); and

West Lime Slaker (ID No. ES-14-20-2085) and Nos. 1, 2, and 3 West Causticizing Lines (ID Nos. ES-14-20-2105, ES-14-20-2115 and ES-14-20-2125) with associated West Slaker Wet Scrubber, 45 gallons per minute minimum liquid injection rate (ID No. CD-14-20-2100)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons per hour, -OR- $E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons per hour Where: E = allowable emission rate in pound per hour P = process weight rate in tons per hour	15A NCAC 02D .0515
Visible emissions	20 percent opacity	15A NCAC 02D .0521
Toxic air pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

a. Emissions of particulate matter from the Lime Slakers and Causticizing Lines identified above shall not exceed an allowable emission rate as calculated by one of the following equations:

$E = 4.10 \times P^{0.67}$ for process rates $\leq$ 30 tons per hour, or
$E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

Where: E = allowable emission rate in pound per hour
P = process weight rate in tons per hour

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 G.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. Particulate matter emissions from the East Lime Slaker and Nos. 1, 2, and 3 East Causticizing Lines **(ID Nos. ES-14-20-2020, -2040, -2050, and -2060)** shall be controlled by East Slaker Wet Scrubber **(ID No. CD-14-20-2035).** Particulate matter emissions from the West Lime Slaker and Nos. 1, 2, and 3 West Causticizing Lines **(ID Nos. ES-14-20-2185, -2105, -2115, and -2125)** shall be controlled by West Slaker Wet Scrubber **(ID No. CD-14-20-2100)**. The Permittee shall install, operate, and maintain a continuous flow meter on each scrubber to monitor and record the scrubber injection rate for each scrubber. The Permittee shall maintain the scrubber injection rate at or above 45 gallons per minute on three-hour rolling average basis. The Permittee shall be allowed three (3) days of absent observations per semi-annual period. The readings shall be recorded in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. To ensure quality, the flow rate gauges or devices shall be checked annually to ensure they are functioning properly. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the three-hour average injection rate for either scrubber is not maintained at or above 45 gallons per minute based on three-hour rolling averages, or if these records are not maintained.

d. If a flow reading is observed to be below the minimum rate, the Permittee shall inspect the scrubber for malfunctions and clean or repair, as necessary. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the inspections, cleaning, and repairs are not performed.

e. The results of inspection and maintenance activities, discussed above for the scrubber, shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative of DAQ upon request. The logbook shall record the following:
   i. the date and time of each recorded action
   ii. the results of each inspection;
   iii. the causes for any variance from the allowable operating range for the scrubber; and
   iii. corrective actions taken.
   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit the results of any maintenance performed on the ductwork and scrubbers within 30 days of a written request by the DAQ.

g. The Permittee shall submit a summary report of monitoring and recordkeeping activities given in Section 2.1 G.1.c through G.1.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Lime Slakers and Causticizing Lines identified above shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity. [15A NCAC 02D .0521 (d)]

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 G.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Lime Slakers and Causticizing Lines identified above are equipped with wet scrubbers and, therefore, visible emissions are only present due to uncombined water. Pursuant to 15A NCAC 02D .0521(e), no monitoring, recordkeeping, and reporting is required for visible emissions from this source.

H. Lime Operations:

- **Reburned Lime Conveyor, Bucket Elevator, and Bin (ID Nos. ES-14-65-1000, ES-14-65-1020 and ES-14-65-1030) each controlled by Lime Dust Baghouse (ID No. CD-14-65-1075);**
  - **Fresh Lime Bin (ID No. ES-14-65-1080) controlled by Lime Dust Baghouse (ID No. CD-14-65-1082)**
  - **Reburned Lime Crusher (ID No. ES-14-60-3015) controlled by baghouse (ID No. CD-14-65-1075) –OR- by Lime Kiln Venturi Scrubber (ID No. CD-14-70-2012)**

The following table provides a summary of limits and standards for the emission source described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons per hour, -OR- $E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons per hour Where: E = allowable emission rate in pound per hour P = process weight rate in tons per hour	15A NCAC 02D .0515
Visible emissions	20 percent opacity	15A NCAC 02D .0521
Particulate matter	Compliance Assurance Monitoring	15A NCAC 02D .0614

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

a. Emissions of particulate matter from the Lime Operations shall not exceed an allowable emissions rate as calculated by one of the following equations:

$E = 4.10 \times P^{0.67}$ Where E = allowable emission rate in pounds per hour
P = process weight in tons per hour

$E = 55(P)^{0.11} - 40$ Where E = allowable emission rate in pounds per hour
P = process weight input in tons per hour (greater than 30 tons per hr)

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 H.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. Particulate matter emissions from the Reburned Lime Conveyor, Bucket Elevator, and Bin **(ID Nos. ES-14-65-1000, ES-14-65-1020, and ES-14-65-1030)** shall be controlled by the Lime Dust Baghouse **(ID No. CD-14-65-1075)**. Particulate matter emissions from the Fresh Lime Bin **(ID No. ES014-65-1080)** shall be controlled by the Lime Dust Baghouse **(ID No. Cd-14-65-1082)**. Particulate matter emissions from the Reburned Lime Crusher **(ID No. ES-14-60-3015)** shall be controlled by either a baghouse or a venturi scrubber.

i. When the Lime Kiln Venturi Scrubber **(ID No. CD-14-70-2012)** is used for particulate matter control for the Reburned Lime Crusher **(ID No. ES-14-60-3015),** the Permittee shall follow the 40 CFR Part 63, Subpart MM monitoring, recordkeeping, and reporting requirements applicable to the No. 5 Lime Kiln in Section 2.2 B.1, below.

ii. When the Lime Dust Baghouses **(ID Nos. CD-14-65-1075 and CD-14-65-1082)** are used for particulate matter control of the Lime Operations, the Permittee shall perform inspections and maintenance of the baghouse as specified by the approved Basic Care route or as recommended by the manufacturer. In addition to the manufacturer's inspection and maintenance recommendations, or if there is no manufacturer's inspection and maintenance recommendations, as a minimum, the inspection and maintenance requirement shall include the following:

(A) a monthly visual inspection of the system ductwork and material collection unit for leaks; and

(B) an annual (for each 12-month period following the initial inspection) internal inspection of the bagfilter's structural integrity.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the ductwork and baghouse are not inspected and maintained.

d. The results of inspection and maintenance shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each inspection;
   iii. the results of any maintenance performed on the baghouse; and
   iv. any variance from the manufacturer's recommendations, if any, and corrections made.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

e. The Permittee shall submit the results of any maintenance performed on the baghouse within 30 days of a written request by the DAQ.

f. The Permittee shall submit a summary report of monitoring and recordkeeping activities given in Section 2.1 H.1.c and H.1.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the exhaust stack of the Lime Operations Baghouses **(ID Nos. CD-14-65-1075 and CD-14-65-1082)** exhaust stack shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity. [15A NCAC 02D .0521 (d)]

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 H.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. When the Reburned Lime Crusher **(ID No. ES-14-60-3015)** emissions are routed to the Lime Kiln Venturi Scrubber **(ID No. CD-14-70-2012)**, visible emissions are only present due to uncombined water. Pursuant to 15A NCAC 02D .0521(e), no monitoring, recordkeeping, and reporting is required for visible emissions from these sources.

Monitoring 15A NCAC 02Q .0508(f)]

d. To ensure compliance when the Lime Dust Baghouses **(ID Nos. CD-14-65-1075 and CD-14-65-1082)** are used for control, the Permittee shall observe the emission points of the baghouse once each month for any visible emissions above normal. The monthly observation must be made for each month of the calendar year period to ensure compliance with thie requirement. If visible emissions from any source are observed to be above normal, the Permittee shall either:
   i. take appropriate action to correct the above-normal emissions as soon as practicable and within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
   ii. demonstrate that the percent opacity from the emission points baghouses in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limit given in Section 2.1 H.2.a, above.

   The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the required monthly observations are not conducted as required; if the above-normal emissions are not corrected within the monitoring period; or the percent opacity demonstration cannot be made.

Recordkeeping [15A NCAC 02Q .0508(f)]

e. The results of the Lime Dust Baghouses **(ID Nos. CD-14-65-1075 and CD-14-65-1082)** visible emissions observations shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:

i. the date and time of each recorded action;
ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
iii. the results of any corrective actions performed.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section H.2.c through H.2.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

3. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. For the Lime Operation Baghouses **(ID Nos. CD-14-65-1075 and CD-14-65-1082)**, the Permittee shall comply with 40 CFR Part 64 pursuant to 15A NCAC 02D .0614 to ensure that the Lime Operations comply with the emission limits of 15A NCAC 02D .0515.

Background

b. Emission Units: Reburned lime bin **(ID No. ES-14-65-1030)**
Fresh lime bin **(ID No. ES-14-65-1080)**

c. Applicable Regulation, Emission Limit, and Monitoring Requirements
i. Regulation: 15A NCAC 02D .0515
ii. Emission limits:
Particulate matter emissions shall not exceed the following limits

$E = 4.10 \times P^{0.67}$ for process rates $\leq$ 30 tons per hour, or
$E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

Where: E = allowable emission rate in pound per hour
P = process weight rate in tons per hour

iii. Control Technology: Baghouses/Bagfilters

Monitoring Approach

d. The key elements of the monitoring approach for particulate matter, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table.

Measure	Indicator
I. Indicator	Visible emissions
Measuring approach	Visible emissions (VE) from each baghouse/bagfilter will be observed daily using EPA Reference Method 22-like procedures.
II. Indicator Range	An excursion is defined as the presence of visible emissions. Excursion triggers a demonstration of compliance with the 20 percent opacity standard in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes; an inspection, corrective action, and a reporting requirement. The QIP threshold is excursions occurring on three days (consecutive or non-consecutive days) in a six-month reporting period for which the Permittee did not perform a demonstration of compliance with the 20 percent opacity standard in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes. The QIP shall be prepared within 30 days of reaching the QIP threshold and shall contain procedures for evaluating control performance problems.

Measure	Indicator
III. Performance Criteria	
Data Representativeness	Visible emissions shall be observed at the emissions point (baghouse exhaust).
QA/QC Practices and Criteria	The observer shall be familiar with EPA Reference Method 22 and follow Method 22-like procedures when VE is observed. Method 9 observations are conducted by a certified Reference Method 9 observer.
Monitoring frequency	A VE observation shall bes performed daily, when operating.
Data Collection Procedures	The VE observation is recorded by the observer.
Averaging Period	N/A

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 H.3.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations for the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

I. No. 6 Fiberline:
Chip Silos B and C (ID Nos. ES-06-05-2000 and ES-06-05-3000)

No. 7 Fiberline:
Chip Silos A and B (ID Nos. ES-07-05-1000 and ES-07-05-2000)

Boiler Fuel Storage and Handling:
No. 1 and No. 2 Hog Fuel Conveying (ID No. FS-007)

Woodyard Operations:
North and South Chip Piles (ID Nos. ES-00-30-4480 and ES-00-30-4240), Screen House (ID No. ES-00-35-1000); Debarking and Chipping Line (ID No. ES-11-10-1500); two Bark Hogs (ID No. ES-11-50-4500-1 and ES-11-50-4500-2); Hog Fuel Handling and Transfer in Woodyard (ID No. FS-010); Chip Conveying to Pulping (ID No. FS-012); Chip Handling and Transfer System in Woodyard (ID No. FS-013); and Hog Fuel Handling and Transfer to Boiler Area (ID No. FS-021)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate matter	$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons per hour, -OR- $E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons per hour Where: E = allowable emission rate in pound per hour P = process weight rate in tons per hour	15A NCAC 02D .0515
Visible emissions	**Screen House (ID No. ES-00-35-1000); Hog Fuel Handling and Transfer in Woodyard (ID No. FS-010); Chip Conveying to Pulping (ID No. FS-012); Chip Handling and Transfer System in Woodyard (ID No. FS-013); and Hog Fuel Handling and Transfer to Boiler Area (ID No. FS-021):** 40 percent opacity standard **All other sources:** 20 percent opacity standard	15A NCAC 02D .0521
Criteria pollutants	**See Section 2.2 C** Chip Silos (ID Nos. ES-06-05-2000, ES-06-05-3000, ES-07-05-1000 and ES-07-05-2000) Annual tracking report	15A NCAC 02D .0530(u)
Toxic air pollutants	**State-Enforceable Only** **(See Section 2.2 D.2**	15A NCAC 02D .1100
Volatile organic compounds	**For North and South Chip Piles (ID Nos. ES-00-30-4480 and ES-00-30-4240), Debarking and Chipping Line (ID No. ES-11-10-1500); two Bark Hogs (ID No. ES-11-50-4500-1 and ES-11-50-4500-2; Chip Handling and Transfer System in Woodyard (ID No. FS-013); Hog Fuel Handling and Transfer in Woodyard (ID No. FS-010); and Hog Fuel Handling and Transfer to Boiler Area (ID No. FS-021):** No more than 2,238,545 green tons of softwood species may be processed (logs converted onsite into chips) through the wood yard per any consecutive 12-month period.	15A NCAC 02Q .0317 (15A NCAC 02D .0530 Avoidance)
Volatile organic compounds	120 tons per consecutive 12-month period	15A NCAC 02Q .0317 (15A NCAC 02D .0530 Avoidance)

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

a. Emissions of particulate matter from Nos. 6 and 7 Fiberline Chip Bins, Boiler Fuel Storage and Handling sources and Woodyard Operation sources identified above shall not exceed an allowable emissions rate as calculated by one of the following equations:

$E = 4.10 \times P^{0.67}$ for process rates $\leq$ 30 tons per hour, or
$E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

Where: E = allowable emission rate in pound per hour
P = process weight rate in tons per hour

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 I.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall maintain production records such that the process rates "P," in tons per hour, as specified by the formulas contained above, can be derived and shall make these records available to a DAQ authorized representative upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the production records are not maintained or the types of materials are not monitored.

d. No reporting is required for particulate emissions from the Nos. 6 and 7 Fiberline Chip Bins, Boiler Fuel Storage and Handling sources and Woodyard Operation sources identified above.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Chip Silos, the No. 1 and No. 2 Hog Fuel Conveying, Debarking And Chipping Line, and the two Bark Hogs **(ID Nos. ES-06-05-2000, ES-06-05-3000, ES-07-05-1000, ES-07-05-2000, FS-007, ES-11-10-1500, ES-11-50-4500-1, and ES-11-50-4500-2, respectively)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

b. Visible emissions from the Screen House; the Hog Fuel Handling and Transfer in Woodyard; Chip Conveying to Pulping; the Chip Handling and Transfer System in Woodyard; and the Hog Fuel Handling and Transfer to Boiler Area **(ID Nos. ES-00-35-1000, FS-010, FS-012, FS-013, and FS-021**, **respectively)** shall not be more than 40 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 40 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 90 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 I.2.a or I.2.b, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring [15A NCAC 02Q .0508(f)]

d. To ensure compliance, once a quarter, the Permittee shall observe the emission points of these sources for any visible emissions above normal. The quarterly observation must be made for each quarter of the calendar year period to ensure compliance with this requirement. The Permittee may limit the observation of each transport system to one location where the highest visible emissions are most likely to occur. If visible emissions from any source are observed to be above normal, the Permittee shall either:
   i. take appropriate action to correct the above-normal emissions as soon as practicable and within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
   ii. demonstrate that the percent opacity from the emission points of the emission source in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limits given in Section 2.1 I.2.a or 2.1.I.2.b. above.

The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the quarterly observations are not conducted as required; if the above-normal emissions are not corrected within the monitoring period; or the percent opacity demonstration cannot be made.

Recordkeeping [15A NCAC 02Q .0508(f)]

e. The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
   iii. the results of any corrective actions performed.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 I.2.d and I.2.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for

3. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. In order to avoid applicability of 15A NCAC 02D .0530 (g) for major sources and major modifications, emissions of volatile organic compounds (VOCs) from the modified Woodyard Operations, including North and South Chip Piles **(ID Nos. ES-00-30-4480 and ES-00-30-4240)**, Debarking and Chipping Line **(ID No. ES-11-10-1500);** two Bark Hogs **(ID No. ES-11-50-4500-1 and ES-11-50-4500-2)**; and Chip Handling and Transfer System in Woodyard **(ID No. FS-013)**, Hog Fuel Handling and Transfer in Woodyard **(ID No. FS-010)**, and Hog Fuel Handling and Transfer to Boiler Area **(ID No. FS-021)** shall be less than 120 tons per consecutive twelve-month period.

b. The Permittee shall process no more than 2,238,545 green tons of softwood species (logs converted onsite into chips) through the woodyard per any consecutive 12-month period.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. To ensure compliance, the Permittee shall record the monthly green tons of softwood species processed through the woodyard. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the required quantity of softwood processed is not recorded.

Reporting [15A NCAC 02Q .0508(f)]

d The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 I.3.c, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall contain the monthly green tons of softwood processed onsite for the previous seventeen (17) months. The tonnage must be calculated for each of the three twelve-month periods over the previous seventeen months.

J. High Volume Low Concentration (HVLC) Gas Collection System: Gases are collected via the HVLC non-condensible gas (NCG) collection system routed to the No. 2 Hog Fuel Boiler as primary control (ID No. ES-64-25-0290), the No. 1 Hog Fuel Boiler as secondary control (ID No. ES-65-25-0310), No. 5 Recovery Boiler as backup (ID No. ES-10-25-0110) or Thermal Oxidizer as backup (ID No. CD-64-22-2000).

No. 6 Fiberline Sources:
Chip Bin Relief Condenser (ID No. HVLC.ES-06-10-2380), Digester Blow Tank (ID No. HVLC.06-21-1200), Pressure Diffuser Filtrate Tank (ID No. HVLC.06-21-1100), Secondary Knotter (ID No. HVLC.06-22-1080), Screen Dilution Tank (ID No. HVLC.06-22-1100), Quaternary Screen (ID No. HVLC.06-22-1280), Decker Hood (ID No. HVLC.06-23-1200), and Decker Filtrate Tank (ID No. HVLC.06-23-1220)

No. 7 Fiberline Sources:
Chip Bin Relief Condenser (ID No. HVLC.07-10-2380), Digester Blow Tank (ID No. HVLC.07-21-1200), Pressure Diffuser Filtrate Tank (ID No. HVLC.07-21-1100), Secondary Knotter (ID No. HVLC.07-22-1080), Screen Dilution Tank (ID No. HVLC.07-22-1100), Quaternary Screen (ID No. HVLC.07-22-1280), Decker Hood (ID No. HVLC.07-23-1200), and Decker Filtrate Tank (ID No. HVLC.07-23-1220)

Nos. 6 and 7 Fiberlines (Common Sources):
Screen Rejects Tank (ID No. ES-80-66-1000)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Sulfur dioxide	**Affected Source:** HVLC Gas Collection System Gases are controlled in the Thermal Oxidizer 2.3 pounds per million Btu heat input	15A NCAC 02D .0516
Visible emissions	**Affected Source**: HVLC Gas Collection System Gases are controlled in the Thermal Oxidizer 20 percent opacity	15A NCAC 02D .0521
Total reduced sulfur	5 ppm by volume on a dry basis, corrected to 10 percent oxygen.	15A NCAC 02D .0524 (40 CFR Part 60 Subpart BB)
Total reduced sulfur	Compliance Assurance Monitoring	15A NCAC 02D .0614
Hazardous air pollutants	**See Section 2.2 A** 40 CFR Part 63, Subpart S	15A NCAC 02D .1111

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide from the Thermal Oxidizer **(ID No. CD-64-22-2000)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard and shall include the sulfur dioxide formed by the combustion of sulfur containing gases in the:
   i. HVLC Gas Collection System sources identified above;
   ii. LSRP Sources **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1400, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2600, ES-09-27-2610, ES-09-27-2620, ES-09-27-2660, ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, ES-09-27-3200)** prior to startup of normal operations of the two-phased packed tower caustic scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 Q.1 below;
   iii. LSRP Sources **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** after startup of normal operation of the two-phased packed bed scrubber **(ID No. CD-09-27-3800)** as specified in Section 2.1 T.1 below.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition. If the results of this test are above the limit given in Section 2.1 J.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. The Permittee is required to calculate and record in a logbook (written or electronic format) the pounds of sulfur dioxide emissions per million Btu heat content, including the waste gases identified in Section 2.1 J.1.a above, and natural gas burned in the thermal oxidizer. The Permittee shall submit the method of calculation to DAQ for approval. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516 if these records are not kept or if the results show an exceedance of the limit given in Section 2.1 J.1.a above.

Reporting [15A NCAC 02Q .0508(f)]

d. The Permittee shall submit a summary report of the calculations of the pounds of sulfur dioxide per million Btu heat content from burning HVLC gases and natural gas given in Sections 2.1 J.1.c, above post marked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Thermal Oxidizer **(ID No. CD-64-22-2000)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 J.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas and waste gases from the HVLC System Sources identified above in the Thermal Oxidizer **(ID No. CD-64-22-2000)**.

3. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

a. For the HVLC Gas Collection System Sources identified above, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards" as promulgated in 40 CFR Part 60 Subpart BB "Standards of Performance for Kraft Pulp Mills," including Subpart A "General Provisions."

Emissions Limitations [15A NCAC 02D .0524]

b. The Permittee shall not cause to be discharged into the atmosphere any gases which contain total reduced sulfur in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met [40 CFR Part 60, Subpart 60.283(a)(1)(i), (ii), or (iii)]:
   i. The gases are combusted in the No. 1 or No. 2 Hog Fuel Boiler **(ID Nos. ES-64-25-0290 or ES-65-25-0310)**;
   ii. The gases are combusted in the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** subject to and complying with 40 CFR 60.283(a)(2), as specified in Section 2.1 C.3, above; or
   iii. The gases are combusted in the Thermal Oxidizer **(ID No. CD-64-22-2000)** and are subjected to a minimum temperature of 1200 °F for at least 0.5 seconds.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 J.3.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f) and 02D .0524]

d. The Permittee shall comply with the closed vent inspection procedures specified in Section 2.2 A.1, below, to ensure that emissions from the sources collected in the HVLC Gas Collection system are routed to either the No. 1 Hog Fuel Boiler **(ID No. ES-65-25-0290)** or No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** or the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** or the Thermal Oxidizer **(ID No. CD-64-22-2000)**, as specified in Section 2.1 J.3.b, above. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if these procedures are not followed or if the records are not maintained.

e. The Permittee shall install, calibrate, maintain and operate a continuous monitoring device for the Thermal Oxidizer **(ID No. CD-64-22-2000)** to measure and record the combustion temperature at the point at which the gases collected in the HVLC Gas Collection System are incinerated. The monitoring device shall be certified by the manufacturer to be accurate within $\pm$ 1 percent of the temperature being measured. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if these procedures for the continuous temperature monitoring device are not followed or if the records are not maintained. [40 CFR 60.284(b)(1)]

f. Per EPA Applicability Deterrmination No. 020009, temperature monitoring is not required when the HVLC sources are combusted in the No. 2 Hog Fuel Boiler.

Reporting [15A NCAC 02Q .0508(f) and 02D .0524]

g. The Permittee shall report excess emission from the HVLC Gas Collection System sources identified above. Excess emissions are all periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200^{O}F when the gases are combusted in the thermal oxidizer, as specified in Section 2.1 J.3.b.i or J.3.b.ii, above. [40 CFR 60.284(d)]

h. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 J.3.d through J.3.f, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

4. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. Per 40 CFR 64 and 15A NCAC 02D .0614, the Permittee shall comply with the following:

Background

b. Emission Units: Sources collected in the HVLC Gas Collection System and controlled in the No. 2 Hog Fuel Boiler as the primary control device, the No. 1 Hog Fuel Boiler or Thermal Oxidizer as backup devices:
   - No. 6 Fiberline Sources: Chip Bin Relief Condenser, Digester Blow Tank, Pressure Diffuser Filtrate Tank, Secondary Knotter, Screen Dilution Tank, Quaternary Screen, Decker Hood, Decker Filtrate Tank
   - No. 7 Fiberline Sources: Chip Bin Relief Condenser, Digester Blow Tank, Pressure Diffuser Filtrate Tank, Secondary Knotter, Screen Dilution Tank, Quaternary Screen, Decker Hood, Decker Filtrate Tank
   - Nos. 6 and 7 Fiberlines (Common Sources): Screen Rejects Tank

c. Applicable Regulation, Emission Limit, and Monitoring Requirements
   i. Regulations: 15A NCAC 02D .0524: New Source Performance Standards (40 CFR Part 60, Subpart BB)
   ii. Emission Limits: total reduced sulfur emissions shall not exceed 5 ppm by volume on a dry basis, corrected to 10 percent oxygen
   iii. Control Technology:
      (A) No. 2 Hog Fuel Boiler (primary)
      (B) No. 1 Hog Fuel Boiler (backup)
      (C) Thermal Oxidizer with a minimum temperature of 1200 °F for at least 0.5 seconds (backup)

Monitoring Approach

d. The key elements of the monitoring approach for total reduced sulfur, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table:

HVLC Gas Collection System Sources			
Measure	**No. 2 Hog Fuel Boiler (primary control)**	**No. 1 Hog Fuel Boiler (backup control device)**	**Thermal Oxidizer (backup control device)**
I. Indicator	Steam rate	Steam rate	Exit stack temperature
Measuring approach	The steam rate will be measured using a steam load flow meter.	The steam rate will be measured using a steam load flow meter.	The exit stack temperature is monitored with a thermocouple.
II. Indicator Range	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.	An excursion is defined as temperature readings less than 1,260^{O}F; excursions trigger an inspection corrective action and a reporting requirement.
QIP Threshold	The excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.	Thhe excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.	No more than six excursions below the indicator range in any semiannual reporting period.
III. Performance Criteria			
Data Representativeness	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.	The sensor is located in the exit stack to the thermal oxidizer. The minimum tolerance of the thermocouple is ± 4^{O}F or ± 75 percent (of temperature measured in degrees Celcius), whichever is greater. The minimum chart recorder sensitivity (minor division) is 20^{O}F.
QA/QC Practices and Criteria	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.	The thermocouple shall be calibrated and inspected according to manufacturer's recommendations.
Monitoring frequency	Measured Continuously	Measured Continuously	Measured Continuously
Data Collection Procedures	Recorded continuously on a data acquisition system.	Recorded continuously on a data acquisition system.	Recorded continuously in the information management system.
Averaging Period	The averaging period is hourly.	The averaging period is hourly.	No average is taken.

[a] During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 J.4.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

K. Low Volume High Concentration (LVHC) Gas Collection System: Routed to through LVHC White Liquor Scrubber (ID No. CD-14-55-2020) to the No. 5 Lime Kiln (ID No. ES-14-60-3000) as primary control or through the LVHC White Liquor Scrubber (ID No. CD-14-55-2020), Except For Periods Of Scrubber Maintenance, to the No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310) as backup.

Evaporator Operations:
No. 6 Black Liquor Evaporator System (ID No. LVHC.09-20-0320), Concentrator Hotwell (ID No. LVHC.09-35-0200), No. 7 Black Liquor Evaporator System (ID No. LVHC.09-25-0510) , Secondary Turpentine Decanter Tank[6] (ID No. LVHC.09-DECANT), Secondary Turpentine Decanter Weir[6] (ID No. LVHC.09-WEIR), Secondary Turpentine Underflow Tank[6] (ID No. LVHC.09-UND), Secondary Turpentine Storage Tank[6] (ID No. LVHC.09-TURPSTOR)

Nos. 6 and 7 Fiberline Sources:
No. 6 Fiberline Digester Flash Condenser (ID No. LVHC.06-10-2420), No. 7 Fiberline Digester Flash Condenser (ID No. LVHC.07-10-2420), Turpentine Decanter Weir (ID No. LVHC.08-61-1020), Turpentine Tank (ID No. LVHC.08-61-1080), Turpentine Decanter Tank (ID No. LVHC.08-61-1000), and Turpentine Decanter Underflow Tank (ID No. LVHC.08-61-1040)

Pulping Process Condensate
Nos. 6 and 7 Digester Contaminated Condensate Tank (ID No. LVHC.07-10-2480): Condensates are collected from the Chip Bin Relief Condensers (ID Nos. HVLC.06-10-2380 and HVLC.07-10-2380), Digester Flash Condensers (ID Nos. LVHC.06-10-2420 and LVHC.07-10-2420), and/or Turpentine Decanter (ID No. LVHC.08-61-1000).

Condensate Stripper Feed Tank (ID No. LVHC.09-25-1000): Condensates received from the Nos. 6 and 7 Digester Contaminated Condensate Tank (ID No. LVHC.07-10-2480) and /or Turpentine system, Nos. 6 and 7 Black Liquor Evaporator Systems (ID Nos. LVHC.09-20-0320 and LVHC.09-25-0510), Concentrator Hotwell (ID No. LVHC.09-35-0200), and Condensate Pots associated with the SOG Collection System, LVHC Collection System and HVLC Collection System.

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Total reduced sulfur	5 ppm by volume on a dry basis, corrected to 10 percent oxygen.	15A NCAC 02D .0524 (40 CFR Part 60 Subpart BB)
Hazardous air pollutants	**See Section 2.2 A** 40 CFR Part 63 Subpart S	15A NCAC 02D .1111
Total reduced sulfur	Compliance Assurance Monitoring	15A NCAC 02D .0614

1. 15A NCAC 02D .0524: NSPS 40 CFR 60 SUBPART BB

a. For the LVHC Gas Collection System Sources identified above, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards" as promulgated in 40 CFR Part 60 Subpart BB "Standards of Performance for Kraft Pulp Mills," including Subpart A "General Provisions."

[6] These sources have not been constructed.

Emissions Limitations [15A NCAC 02D .0524]

b. The Permittee shall not cause to be discharged into the atmosphere any gases which contain total reduced sulfur in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met [40 CFR 60.283(a)(1)(i) and (iii)]:
   i. The gases are combusted in the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** subject to and complying with the provisions of 40 CFR 60.283(a)(5) as specified in Sectionn 2.1 E.4, above, or
   ii. The gases are combusted in the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 K.1.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring [15A NCAC 02Q .0508(f) and 02D .0524]

d. The Permittee shall comply with the closed vent inspection procedures specified in Section 2.2 A.1, below, to ensure that emissions from the LVHC Gas Collection System Sources identified above are routed to either the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** or the No. 2 Hog Fuel Boiler, as specified in Section 2.1 K.1.b, above. The Permittee shall be deemed in noncompliance with 02D .0524 if these procedures are not followed or if the records are not maintained.

e. Per EPA Applicability Determination No. 020009, temperature monitoring is not required when the LVHC sources are combusted in the No. 2 Hog Fuel Boiler.

Reporting/ Recordkeeping [15A NCAC 02Q .0508(f) and 02D .0524]

f. The Permittee shall report excess emission from the LVHC Gas Collection System Sources identified above. Excess emissions are all periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200^{O}F when the gases are combusted in the No. 2 Hog Fuel Boiler as specified in Section 2.1 K.1.b.ii, above. [40 CFR 60.284(d)(3)(ii)]

g. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 K.1.d through K.1.f, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. Per 40 CFR Part 64 and 15A NCAC 02D .0614, the Permittee shall comply with the following:

Background

b. Emission Units: Sources collected in the LVHC Gas Collection System and controlled in the No. 2 Hog Fuel Boiler as the backup device:
   - No. 6 Black Liquor Evaporator System,
   - Concentrator Hotwell,
   - No. 7 Black Liquor Evaporator System,
   - Secondary Turpentine Decanter Tank (after construction of this source),
   - Secondary Turpentine Decanter Weir (after construction of this source),
   - Secondary Turpentine Underflow Tank (after construction of this source),
   - Secondary Turpentine Storage Tank (after construction of this source),
   - No. 6 Fiberline Digester Flash Condenser,
   - No. 7 Fiberline Digester Flash Condenser,
   - Turpentine Decanter Weir,
   - Turpentine Tank,
   - Turpentine Decanter Tank,
   - Turpentine Decanter Underflow Tank,
   - Nos. 6 and 7 Digester Contaminated Condensate Tank, and
   - Condensate Stripper Feed Tank

c. Applicable Regulation, Emission Limit, and Monitoring Requirements
   i. Regulations: 15A NCAC 02D .0524: New Source Performance Standards (40 CFR Part 60, Subpart BB)
   ii. Emission Limits: total reduced sulfur emissions shall not exceed 5 ppm by volume on a dry basis, corrected to 10 percent oxygen
   iii. Control Technology: No. 2 Hog Fuel Boiler (backup)

Monitoring Approach

d. The key elements of the monitoring approach for total reduced sulfur, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table:

Measure	LVHC Gas Collection System Sources No. 2 Hog Fuel Boiler (backup control device)
I. Indicator	Steam rate
Measuring approach	The steam rate will be measured using a steam load flow meter.
II. Indicator Range	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.
QIP Threshold	The excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.
III. Performance Criteria	
Data Representativeness	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.
QA/QC Practices and Criteria	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.
Monitoring frequency	Measured Continuously
Data Collection Procedures	Recorded continuously on a data acquisition system.
Averaging Period	The averaging period is hourly.

[a] During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 K.2.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

L. Stripper Off-gas (SOG) Collection System routed to the No. 5 Lime Kiln (ID No. ES-14-60-3000) for primary control or No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310) as backup:

Condensate Stripper Reflux Condenser (ID No. SOG.09-25-1050)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Total reduced sulfur	5 ppm by volume on a dry basis, corrected to 10 percent oxygen	15A NCAC 02D .0524 (40 CFR Part 60 Subpart BB)
Total reduced sulfur	Compliance Assurance Monitoring	15A NCAC 02D .0614
Hazardous air pollutants	**See Section 2.2 A** 40 CFR Part 63, Subpart S	15A NCAC 02D .1111

1. 15A NCAC 02D .0524: NSPS 40 CFR 60 SUBPART BB

a. For the SOG Collection System Sources identified above, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards (NSPS)" as promulgated in 40 CFR Part 60 Subpart BB "Standards of Performance for Kraft Pulp Mills," including Subpart A "General Provisions."

Emissions Limitations [15A NCAC 02D .0524]

b. No owner or operator shall cause to be discharged into the atmosphere any gases which contain total reduced sulfur in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met [40 CFR 60.283(a)(1)(i) and (iii)]:
   i. The gases are combusted in the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** subject to and complying with the provisions of 60.283(a)(5) as specified in Section 2.1 E.4, above; or
   ii. The gases are combusted in the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 L.1.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f) and 02D .0524]

d The Permittee shall follow the closed vent inspection procedures per Specific Condition 2.2 A to ensure that the SOG Collection System emissions are routed to either the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** or the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** as specified in Section 2.1 L.1.b, above. The Permittee shall be deemed in noncompliance with 02D .0524 if these procedures are not followed or if the records are not maintained.

Reporting [15A NCAC 02Q .0508(f) and 02D .0524]

e. The Permittee shall report excess emission from the SOG Collection System Sources identified above. Excess emissions are all periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200°F when the gases are combusted in the No. 2 Hog Fuel Boiler as specified in Section 2.1 L.1.b.ii, above. [40 CFR 60.284(d)(3)(ii)]

f. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 L.1.d and L.1.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. Per 40 CFR 64 and 15A NCAC 02D .0614, the Permittee shall comply with the following:

Background

b. Emission Units: Sources collected in the SOG Collection System (Condensate Stripper Reflux Condenser) controlled in the No. 5 Lime Kiln as the primary control device and the No. 2 Hog Fuel Boiler as the backup control device.

c. Applicable Regulation, Emission Limit, and Monitoring Requirements

i. Regulations: 15A NCAC 02D .0524: New Source Performance Standards (40 CFR Part 60, Subpart BB)

ii. Emission Limits: Total reduced sulfur emissions shall not exceed 5 ppm by volume on a dry basis, corrected to 10 percent oxygen

iii. Control Technology: No. 2 Hog Fuel Boiler (backup)

Monitoring Approach

d. The key elements of the monitoring approach for total reduvced sulfur, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table:

Measure	SOG Collection System No. 2 Hog Fuel Boiler
I. Indicator	Steam rate
Measuring approach	The steam rate will be measured using a steam load flow meter.
II. Indicator Range	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.
QIP Threshold	The excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.
III. Performance Criteria	
Data Representativeness	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.
QA/QC Practices and Criteria	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.
Monitoring frequency	Measured Continuously
Data Collection Procedures	Recorded continuously on a data acquisition system.
Averaging Period	The averaging period is hourly.

[a] During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

e. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 L.2.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:

i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

M. Fiberline Operations

- **No. 6 Bleach Plant:**
  Sources Controlled by No. 6 Bleach Plant White Liquor Scrubber (ID No. CD-06-35-8100): 2C Washer Filtrate Tank (ID No. ES-06-32-2480); ClO_2 3rd Stage Tower (ID No. ES-06-33-3060); 4th Stage Extraction Tower and Filtrate Tank (ID Nos. ES-06-34-4080 and ES-06-34-4100); ClO_2 5th Stage Tower (ID No. ES-06-35-5060); 6th Stage Feed Chute Overflow Line (ID No. ES-06-6SFCO); and 5th Stage Filtrate Tank (ID No. ES-06-35-5080)
  Note: The control of the 2C Washer Filtrate Tank is not required for compliance with any regulation.
  Uncontrolled Sources: Oxygen Delignification System (ID No. ES-06-31-0180), 1st Stage O_2 Surge Tank (ID No. ES-06-31-1000); 2nd Stage O_2 Reactor Blow Tube (ID No. ES-06-32-2060); 2nd Stage Wash Tower (ID No. ES-06-32-2100); 2A/2B Filtrate Tank (ID No. ES-06-32-2120); No. 28 High Density Tank (ID No. ES-06-32-2300); No. 29 High Density Tank (ID No. ES-06-32-2340); No. 30 High Density Tank (ID No. ES-06-32-2380); 2C washer (ID No. ES-06-32-2460); 6th Stage Peroxide Reactor Blow Tube (ID No. ES-06-P2); 6th Stage Peroxide Stage Washer, Filtrate Tank, Vacuum Pump, and Exhaust Blower (ID No. ES-06-P3) and Building Fugitives (ID No. FS-003)
- **No. 7 Bleach Plant:**
  Sources Controlled by No. 7 Bleach Plant White Liquor Scrubber (ID No. CD-07-36-8000): ClO2 3rd Stage Tower (ES-07-33-3080); ClO2 5th Stage Tower (ID No. ES-07-35-5060); 5th Stage Filtrate Tank (ID No. ES-07-35-5080); Blend Box (Sump) (ID No. ES-07-33-Blendbox); Base Effluent Neutralization Tank (ID No. ES-08-67-1200); Acid Effluent Neutralization Tank (ID No. ES-08-67-1300); White Liquor Oxidation Tank (ID No. ES-08-70-1000); and Acid Sewer (ID No. ES-08-67-1400) all controlled by White Liquor Scrubber (ID No. CD-07-36-8000)
  Uncontrolled Sources: Oxygen Delignification System (ID No. ES-07-31-1100): 1st Stage O_2 Surge Tank (ID No. ES-07-31-1000); 1st Stage O_2 Reactor Blow Tube (ID No. ES-07-31-1140); 1st Stage Wash Tower (ID No. ES-07-31-1180); 1A/1B Filtrate Tank (ID No. ES-07-31-1200); 3rd Stage Feed Tank (ID No. ES-07-33-3000); 4th Stage Extraction Tower and Filtrate Tank (ID Nos. ES-07-34-4080 and ES-07-34-4100); 6th Stage Peroxide Tower and Filtrate Tank (ID Nos. ES-07-36-6040 and ES-07-36-6060); and Building Fugitives (ID No. FS-004)
- **No. 6 and No. 7 Fiberline Common Facilities:**
  10% Sulfuric Acid Day Tank (ID No. ES-08-50-3140) controlled by No. 7 Bleach Plant White Liquor Scrubber (ID No. CD-07-36-8000)
  No. 32 High Density PulpTank (ID No. ES-08-40-1000)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Carbon Monoxide	**No. 6 Bleach Plant** Total CO emissions shall not exceed 73.3 pounds per hour and 321.1 tons per consecutive 12-month period (based on the BACT emission factor of 2.2 pounds CO per bone dry ton of unbleached pulp). **No. 7 Bleach Plant** Total CO emissions shall not ex ceed 114.6 pounds per hour and 502.0 tons per consecutive 12-month period (based on the BACT emission factor of 2.2 pounds CO per bone dry ton of unbleached pulp).	15A NCAC 02D .0530

Regulated Pollutant	Limits/Standards	Applicable Regulation
Hazardous air pollutants	**See Section 2.2 A** 40 CFR Part 63, Subpart S	15A NCAC 02D .1111
Criteria Pollutants	**See Section 2.2 C** Annual tracking report.	15A NCAC 02D .0530(u)

1. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION:

a. Carbon monoxide emissions from the No. 6 Bleach Plant that are discharged into the atmosphere shall not exceed 73.3 pounds per hour and 321.1 tons per consecutive twelve month period.

b. Carbon monoxide emissions from the No. 7 Bleach Plant that are discharged into the atmosphere shall not exceed 114.6 pounds per hour and 502.0 tons per consecutive twelve month period.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with 15A General Condition JJ. If the results of this test are above the limits given in Section 2.1 M.1.a or M.1.b, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

Monitoring/ Recordkeeping [15A NCAC 02Q .0508(f)]

d. To ensure that emissions are less than the above-specified limits, the Permittee shall not operate the No. 6 Bleach Plant at a production rate in excess of 800 bone dry tons of unbleached pulp per day and shall not operate the No. 7 Bleach Plant at a production rate in excess of 1,250 bone dry tons of unbleached pulp per day. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the amount of unbleached pulp processed in a bleach plant exceeds the applicable limit.

e. To ensure compliance, the Permittee shall maintain records as follows:
   i. The Permittee shall record and maintain records of the amounts (in bone dry tons) of unbleached pulp processed in the No. 6 Bleach Plant during each day and each month,
   ii. The Permittee shall record and maintain records of the amounts (in bone dry tons) of unbleached pulp processed in the No. 7 Bleach Plant during each day and each month, and;
   iii. The records of the amounts unbleached pulp (in bone dry tons) processed during each day and month in the No. 6 Bleach Plant and the No. 7 Bleach Plant shall be made available to an authorized representative of DAQ upon request.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the daily process amount of unbleached pulp exceeds the applicable limit or if the daily and monthly unbleached pulp process rates are not recorded each month.

Reporting [15A NCAC 02Q .0508(f)]

f. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 M.1.d through M.1.e, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period. The report shall contain the following:
   i. the monthly quantities of unbleached pulp processed in the No. 6 Bleach Plant for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months;
   ii. the monthly quantities of unbleached pulp processed in the No. 7 Bleach Plant for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months; and

   All instances of deviations from the requirements of this permit must be clearly identified.

N. East And West Lime Mud Filter – hood exhausts (ID Nos. ES-14-30-5000 and ES-14-30-6000) with associated scrubber/mist eliminator (ID No. CD-14-30-6025)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Toxic air pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100

O. Carpentry Woodworking Operations (ID No. ES-94-15) with Cyclone (ID No. CD-94-15-0450)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate Matter	Adequate duct work and properly designed collectors	15A NCAC 02D .0512
Visible Emissions	40 percent opacity	15A NCAC 02D .0521

1. 15A NCAC 02D .0512: PARTICULATES FROM MISCELLANEOUS WOOD PRODUCTS FINISHING PLANTS

a. The Permittee shall not cause, allow, or permit particulate matter caused by the working, sanding, or finishing of wood to be discharged from any stack, vent, or building into the atmosphere without providing, as a minimum for its collection, adequate duct work and properly designed collectors. In no case shall the ambient air quality standards be exceeded beyond the property line.

Monitoring [15A NCAC 02Q .0508(f)]

b. Particulate matter emissions from the Carpentry Woodworking Operations **(ID No. ES-94-15)** are controlled by a cyclone **(ID No. CD-94-15-0450)**. To ensure compliance, the Permittee shall perform inspections and maintenance as specified in the approved Basic Care Route or as recommended by the manufacturer. The Permittee shall, as a minimum, perform monthly external inspection of the ductwork and cyclone noting the structural integrity. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0512 if the ductwork and cyclone are not inspected and maintained.

Recordkeeping [15A NCAC 02Q .0508(f)]

c. The results of inspection and maintenance for the cyclone **(ID No. CD-94-15-0450)** shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each inspection; and
   iii. the results of maintenance performed on any filters or cyclone.
   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0512 if these records are not maintained.

Reporting [15A NCAC 02Q .0508 (f)]

d. The Permittee shall submit the results of any maintenance performed on the cyclone **(ID No. CD-94-15-0450)** within 30 days of a written request by the DAQ.

e. The Permittee shall submit a summary report of monitoring and recordkeeping activities given in Section 2.1 O.1.b and O.1.c, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from Carpentry Woodworking Operations **(ID No. ES-94-15)** shall not be more than 40 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 40 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 90 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 O.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring [15A NCAC 02Q .0508(f)]

c. To ensure compliance, once a month the Permittee shall observe the emission points of Carpentry Woodworking Operations **(ID No. ES-94-15)** for any visible emissions above normal. The monthly observation must be made for each month of the calendar year period to ensure compliance with this requirement. If visible emissions from the source are observed to be above normal, the Permittee shall either:
   i. take appropriate action to correct the above-normal emissions as soon as practicable and within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
   ii. demonstrate that the percent opacity from the emission points of the emission source in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limit given in Section 2.1 O.2.a, above.

   The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the required monthly observations are not conducted as required or if the above-normal emissions are not corrected within the monitoring period or the percent opacity demonstration cannot be made.

Recordkeeping [15A NCAC 02Q .0508(f)]

d. The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
   iii. the results of any corrective actions performed.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

e. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 O.2.c and O.2.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

P. Seven Diesel-Fired Emergency Engines:

- **Spare Diesel Engine Backup (ID No. ES-14-60-3000a) with a rating of 81 horsepower (hp);**
- **Fine Paper Fire Pump Diesel Engine (ID No. ES-53-40-0130) with a rating of 237 hp;**
- **Warren Neck Creek East Fire Pump Diesel Engine (ID No. ES-53-40-0140) with a rating of 260 hp;**
- **Warren Neck Creek West Fire Pump Diesel Engine (ID No. ES-53-40-0145) with a rating of 180 hp;**
- **Backup Communication System Diesel Engine (ID No. ES-71-95-0500) with a rating of 738 hp;**
- **Backup Lift Station Runoff Collection Diesel Engine (ID No. ES-73-05-4570) with a rating of 210 hp;**
- **Backup Fiberline Lift Station Diesel Engine (ID No. ES-73-05-4580) with a rating of 210 hp**

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Sulfur dioxide	2.3 pounds per million Btu heat input	15A NCAC 02D .0516
Visible emissions	20 percent opacity each	15A NCAC 02D .0521
Hazardous air pollutants	Work practices	15A NCAC 02D .1111 40 CFR Part 63, Subpart ZZZZ
Nonmethane hydrocarbon (NMHC), carbon monoxide, and particulate matter	Purchase an engine certified to meet emission standards.	15A NCAC 02D .0524 40 CFR Part 60, Subpart IIII

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES

a. Emissions of sulfur dioxide from the Diesel-Fired Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition. If the results of this test are above the limit given in Section 2.1 P.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0516.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring, recordkeeping, or reporting is required for sulfur dioxide emissions from firing diesel fuel in the Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)**.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Diesel-Fired Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)** shall not be more than 20 percent opacity each when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ found in Section 3. If the results of this test are above the limit provided in Section 2.1 P.2.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring, recordkeeping, or reporting is required for visible emissions from the firing of diesel fuel in the Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)**.

3. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

a. For the Diesel-Fired Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0130, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)**, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .1111 "Maximum Achievable Control Technology" as promulgated in 40 CFR Part 63 Subpart ZZZZ "National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)," including Subpart A "General Provisions."

Stationary RICE Subject to Regulations under 40 CFR Part 60 [15A NCAC 02D .1111]

b. The Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** shall meet the requirements of 40 CFR Part 63, Subpart ZZZZ by meeting the requirements of 40 CFR Part 60 Subpart IIII. No further requirements apply for this engine under 40 CFR Part 63. The Permittee shall be deemed in noncompliance with 15A NCAC 2D .1111 if the requirements in Section 2.1 F.4, below, are not met. [40 CFR 63.6590(c)(6)]

Operating Conditions [40 CFR 63.6595(a)]

c. The Spare Diesel Engine Backup, Warren Neck Creek East and West Fire Pump Diesel Engines, Backup Lift Station Runoff Collection Diesel Engine, and Backup Fiberline Lift Station Diesel Engine **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-73-05-4570, ES-73-05-4580)** shall be operated with a non-resettable hour meter. [40 CFR 63.6625(f)]

d. The Permittee shall operate each existing Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)** as follows to maintain its status as an "emergency" engine [40 CFR 63.6640 (f)(1), (f)(2)(i) and (f)(3)]:

i. The Permittee may operate the emergency engine in emergency situations as needed with unrestricted hours. [40 CFR 63.6640(f)(1)]

ii. The Permittee shall limit the operation of the engine in non-emergency situations to 50 hours per year. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid. [40 CFR 63.6640(f)(3)]

iii. The Permittee shall limit the operation of the engines for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine, to 100 hours per year unless records indicate that Federal, State, or local standards require maintenance and testing for more than 100 hours per year. The Permittee may petition DAQ for approval of additional hours to be used for maintenance checks and readiness testing. All non-emergency operation of the RICE count towards the 100 hours per year provided for maintenance and testing. [40 CFR 63.6640(f)(2)(i)]

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the non-emergency operation of the engines, with the exception of routine maintenance, exceeds 50 hours during any calendar year or if maintenance checks and readiness testing exceed 100 hours per year.

e. At all times the Permittee shall operate and maintain the Emergency Engines **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-71-95-0500, ES-73-05-4570, ES-73-05-4580)** in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Work Practices Applicable to Stationary CI Emergency Engines No More Than 500 HP [40 CFR 63.6602, 63.6625(h), and 63.6640; Table 2c]

f. For the Spare Diesel Engine Backup, Warren Neck Creek East and West Fire Pump Diesel Engines, Backup Lift Station Runoff Collection Diesel Engine, and Backup Fiberline Lift Station Diesel Engine **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-73-05-4570, ES-73-05-4580)**, the Permittee shall change oil and filter every 500 hours of operation or annually, whichever comes first. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. [40 CFR Part 63, Subpart ZZZZ Table 2c.1]

g. An oil analysis program may be used to extend the time required in 2.1 P.3.f above between oil changes. The analysis program must, at a minimum, analyze the (1) total base number, (2) viscosity, and (3) percent water content. If one of the limits in the following paragraphs is exceeded, the owner or operator must change the oil within 2 days of receiving the results of the analysis or before commencing operation, whichever is later. If using an oil analysis program to extend the time between oil changes, the owner or operator must keep records of the results of the analysis and the oil changes for the engine and include the analysis program in the maintenance plan for the engine. An oil change is not required if all three of the following conditions are meet:
   i. the total base number is greater than or equal to 30 percent of the total base number of the oil when new;
   ii. the viscosity of the oil has not changed by more than 20 percent from the viscosity of the oil when new; and
   iii. the percent water content (by volume) is less than or equal to 0.5.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the oil analysis program is used to extend the time between oil changes but does not meet the oil analysis program requirements.

h. For the Spare Diesel Engine Backup, Warren Neck Creek East and West Fire Pump Diesel Engines, Backup Lift Station Runoff Collection Diesel Engine, and Backup Fiberline Lift Station Diesel Engine **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-73-05-4570, ES-73-05-4580)**, the Permittee shall meet the following requirements, except during startup: [Table 2c.1 to 40 CFR Part 63, Subpart ZZZZ and 40 CFR 63.6602 and 63.6625(h)]
   i. the Permittee shall inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first.
   ii. the Permittee shall inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary or follow approved alternate work practice.
   iii. the Permittee shall minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes for each existing emergency engine.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the work practice requirements are not followed as specified.

Operation/Maintenance/Recordkeeping Requirements Applicable to Stationary CI Emergency Engines No More Than 500 HP [15A NCAC 02Q .0508(f) and 40 CFR 63.6625, 63.6655 and Table 6 to 40 CFR Part 63, Subpart ZZZZ]

i. The Permittee shall operate and maintain the Spare Diesel Engine Backup, Warren Neck Creek East and West Fire Pump Diesel Engines, Backup Lift Station Runoff Collection Diesel Engine, and Backup Fiberline Lift Station Diesel Engine **(ID Nos. ES-14-60-3000a, ES-53-40-0140, ES-53-40-0145, ES-73-05-4570, ES-73-05-4580)**, according to the manufacturer's emission-related operation and maintenance instructions; OR develop and follow a site specific maintenance plan which provides to the extent practicable for the maintenance and operation of the engine in a manner consistent with good practice for minimizing air emissions maintenance checks and readiness testing. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the emergency engines are not operated and maintained as specified [40 CFR 63.6625(e) and Table 6.9 to 40 CFR Part 63, Subpart ZZZZ].

j. The Permittee shall keep records of maintenance performed and the hours of operation of each engine that is recorded through the non-resettable hour meter and document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response. The Permittee shall be

deemed in noncompliance with 15A NCAC 02D .1111 if maintenance performed on the emergency engines is not recorded and maintained on site for a period of two years. [40 CFR 63.6655(f)]

Reporting Requirements Applicable to Stationary CI Emergency Engines No More Than 500 HP [15A NCAC 02Q .0508(f)]

k. The Permittee shall submit a semi-annual compliance report of work practice and recordkeeping activities given in Section 2.1 P.3.d through P.3.j, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. The report must contain a description and the corrective actions taken for all deviations from any operating limitation and any malfunction during the reporting period. If there are no deviations from any operating limitations (work practice requirements), provide a statement that there were no deviations during the reporting period.

4. 15A NCAC 02D .0524: NEW SOURCE PERFORMANCE STANDARDS

a. For the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)**, the Permittee shall comply with all applicable provisions, including the requirements for emission standards, notification, testing, reporting, record keeping, and monitoring, contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards (NSPS)" as promulgated in 40 CFR Part 60 Subpart IIII, "Standards of Performance for Stationary Compression Internal Combustion Engines" including Subpart A "General Provisions."

Emission Standards [15A NCAC 02Q .0508(f) and 40 CFR 60.4205]

b. The Permittee shall operate and maintain the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** certified by the manufacturer to meet the following exhaust emission standards over the entire life of the engine. The Permittee shall install and configure the Fine Paper Fire Pump Diesel Engine according to the manufacturer's emission-related specifications [40 CFR 60.4205(b), 60.4202(a)(2), 60.4206, 60.4211(c), and 89.112(a)]:
   i. NMHC and NOx emissions (combined) shall not exceed 4.0 g/kW-hr;
   ii. CO emissions shall not exceed 3.5 g/kW-hr; and
   iii. PM emissions shall not exceed 0.20 g/kW-hr.

Fuel Standards [15A NCAC 02Q .0508(f) and 40 CFR 60.4207]

c. The Permittee shall use diesel fuel in the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** that meets the following per-gallon fuel standards. [40 CFR 60.4207(b) and 80.510(b)]:
   i. A sulfur content of less than 15 ppm; and
   ii. Cetane index or aromatic content, as follows:
      (A) A minimum cetane index of 40; or
      (B) A maximum aromatic content of 35 volume percent.

Testing [15A NCAC 02Q .0508(f)]

d. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the exhaust emission standards in Section 2.1 P.4.b, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524.

Monitoring/Operating Requirements [15A NCAC 02Q .0508(f) and 40 CFR 60.4206, 60.4209, and 60.4211]

e. The Permittee shall operate the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** that is certified to achieve the emissions standards specified in Section 2.1 P.4.b, above, according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer, over the entire life of the engine. The Permittee may only change engine settings that are permitted by the manufacturer. The Permittee shall also meet the requirements of 40 CFR Parts 89, 94 and/or 1068, as applicable. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524, if the specified engine operation requirements are not met. [40 CFR 60.4206 and 60.4211(a)]

f. If the Permittee does not operate and maintain the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** according to the manufacturer's emission-related written instructions or if the Permittee changes emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall: [40 CFR 60.4211(g)(2)]
   i. Keep a maintenance plan and records of conducted maintenance and shall, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practices for minimizing emissions;
   ii. Conduct an initial performance test as specified in 40 CFR 60.4212 and Section 2.1 P.4.d, above, to demonstrate compliance with the applicable emission standards within 1 year after the engine is no longer installed, configured,

operated, and maintained in accordance with manufacturer's emission-related written instructions, or within 1 year after the emission related settings are changed in a way that is not permitted by the manufacturer.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the operating conditions specified above are not met.

g. If the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** does not meet the standards specified in Section 2.1 P.4.b, above, the engine shall be equipped with a non-resettable hour meter. [40 CFR 60.4209(a)] The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if the engine does not meet the standards as specified above and the engine is not equipped with a non-resettable hour meter.

h. The Permittee shall operate the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** as emergency engines according to the following paragraphs. In order to be considered emergency engines the Permittee shall not operate the engines under operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for more than 50 hours per year. The Permittee may operate the Fine Paper Fire Pump Diesel Engine for up to 50 hours per calendar years in nonemergency situations. The 50 hours of operating in nonemergency situations shall be counted as part of the 100 hours per calendar year for maintenance and testing provided in the following paragraphs. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity unless all of the applicable conditions in 40 CFR 60.4211(f)(3)(i) are met. [40 CFR 60.4211(f)]

i. there is no time limit on the use of the Fine Paper Fire Pump Diesel Engine in emergency situations;
ii. the Permittee may operate the Fine Paper Fire Pump Diesel Engine for maintenance checks and readiness testing for up to 100 hours per year provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine.
iii. The Permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524, if the emergency engine requirements in this section are not met.

Recordkeeping [15A NCAC 02Q .0508(f) and 40 CFR 60.4214]

i. If the Permittee does not operate and maintain the Fine Paper Fire Pump Diesel Engine **(ID No. ES-53-40-0130)** according to the manufacturer's emission-related written instructions or if the Permittee changes emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter required as specified in Section 2.1 P.4.f, above. The Permittee shall record the time of operation of the engine and the reason the engine was in operation during that time. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524, if these records are not maintained. [40 CFR 60.4214(b)]

Reporting [15A NCAC 02Q .0508(f)]

j The Permittee shall submit a summary report of monitoring and recordkeeping activities given in Section 2.1 P.4.e through P.4.i, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit shall be clearly identified.

Q. LSRP prior to normal operation of the two-phase packed bed caustic scrubber (ID No. CD-09-27-3800):
Main Sources - *These sources are collected in the HVLC collection system and controlled in the No. 2 Hog Fuel Boiler (ID No. ES-64-25-0290), the No. 1 Hog Fuel Boiler (ID No. ES-65-25-0310), the No. 5 Recovery Boiler (ID No. ES-10-25-0110), or the Thermal Oxidizer (ID No. CD-64-22-2000)***)**
No. 1 Feed Liquor Cooler (ID No. ES-09-27-1100)
No. 1 Lignin Filtrate Storage Tank (ID No. ES-09-27-1200)
Feed Liquor Carbonator (ID No. ES-09-27-1400)
Lignin Slurry Conditioning Tank (ID No. ES-09-27-1800)
Lignin Slurry Buffer Tank (ID No. ES-09-27-2000)
No. 1 Lignin Filter (ID No. ES-09-27-2100) - *partially controlled by vacuum pull to HVLC system*
No. 1 Lignin Filter Cloth Wash Tank (ID No. ES-09-27-2300)
No. 1 Lignin Filter Filtrate Tank (ID No. ES-09-27-2400)
No. 1 Lignin Filter Filtrate Buffer Tank (ID No. ES-09-27-2500)
Lignin Lump Breaker (ES-09-27-2600)
No. 1 Lignin Filter Horizontal Conveyor (ID No. ES-09-27-2610)
No. 1 Lignin Filter Incline Conveyor (ID No. ES-09-27-2620)
Lignin Rotary Feeder (ES-09-27-2660)
No. 2 Lignin Filter Acidic Filtrate Tank (ES-09-27-3200)

- **Alkaline Stage Sources –** *These sources are uncontrolled*
  Lignin Feed Liquor Tank (ID No. ES-09-27-1000)
  LRP Primary Filter Press (ID No. ES-09-27-2100 *– partially uncontrolled*

- **Acid Stage Sources** *– These sources are uncontrolled*
  No. 2 Lignin Filter (ID No. ES-09-27-3000)
  No. 2 Lignin Filter Cloth Wash Tank (ID No. ES-09-27-3100)

- **Acid Stage Sources –** *These sources are routed through the Feed Liquor Carbonator (ID No. ES-09-27-1400)*
  Lignin Acidification Tank (ID No. ES-09-27-2700)
  Acidic Lignin Conditioning Tank (ID No. ES-09-27-2800)
  Lignin Foam Tank (ID No. ES-09-27-2770)

- **Insignificant Activities** *– These sources are uncontrolled*
  Acid Wash Water Tank (ID No. IES-09-27-2900)
  Lignin Acid Area Sump (ID No. IES-09-27-3700)
  No. 2 Lignin Filter Horizontal Conveyor (ID No. IES-09-27-3400)
  Lignin Liquor Area Sump (ID No. IES-09-27-3600)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Sulfur dioxide	**Affected Source: Main Sources controlled in the Thermal Oxidizer as identified above** 2.3 pounds per million Btu heat input	15A NCAC 02D .0516
Visible emissions	**Affected Source: Main Sources are controlled in the Thermal Oxidizer as identified above** 20 percent opacity	15A NCAC 02D .0521

Regulated Pollutant	Limits/Standards	Applicable Regulation
Total reduced sulfur (as H_2S) and Hydrogen sulfide	25.9 tons total reduced sulfur (as H_2S) per year (12-month running total) 23.6 tons H_2S per year (12-month running total)	15A NCAC 02D .0530
Criteria pollutants	**See Section 2.2 C** Annual tracking report.	15A NCAC 02D .0530(u)
Toxic air pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100
Total reduced sulfur (as H_2S) and Hydrogen sulfide	Compliance Assurance Monitoring	15A NCAC 02D .0614

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSION

a. The following conditions are enforceable until the startup of normal operations of the two-phased packed tower caustic scrubber as described in Section 2.1 T below. After such time as this condition (Section 2.1 Q.1) is no longer applicable, the Permittee shall meet the requirements of Section 2.1 T.1 below.

b. Emissions of sulfur dioxide from the Thermal Oxidizer **(ID No. CD-64-22-2000)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard and shall include the sources specified in Section 2.1 J.1.a above.

Testing/Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall demonstrate compliance with Section 2.1 Q.1.b above by meeting the requirements given in Section 2.1 J.1 above.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. The following conditions in this section are enforceable until the startup of normal operations of the two-phased packed tower caustic scrubber as described in Section 2.1 T below. After such time as this condition (Section 2.1 Q.2) is no longer applicable, the Permittee shall meet the requirements of Section 2.1 T below.

b. Visible emissions from the Thermal Oxidizer **(ID No. CD-64-22-2000)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 Q.2.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

d. No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas and the LSRP Main Sources identified above in the Thermal Oxidizer **(ID No. CD-64-22-2000)**.

3. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. The following conditions in this section are enforceable until the startup of normal operations of the two-phased packed tower caustic scrubber as described in Section 2.1 T below. After such time as this condition (Section 2.1 Q.1) is no longer applicable, the Permittee shall meet the requirements of Section 2.1 T.1 below.

Emissions Limits [15A NCAC 02D .0530]

b. Total reduced sulfur (as H_2S) emissions from the LSRP Operations **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1400, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2600, ES-09-27-2610, ES-09-27-2620, ES-09-27-2660, ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, ES-09-27-3000, ES-09-27-3100, ES-09-27-3200, ES-09-27-3000, ES-09-27-1000, IES-09-27-2900, IES-09-**

27-3700, IES-09-27-3400, IES-09-27-3600) that are discharged into the atmosphere shall not exceed 25.9 tons per consecutive twelve-month period.

c. Hydrogen sulfide emissions from the LSRP Operations **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1400, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2600, ES-09-27-2610, ES-09-27-2620, ES-09-27-2660, ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, ES-09-27-3000, ES-09-27-3100, ES-09-27-3200, ES-09-27-3000, , and ES-09-27-1000, IES-09-27-2900, IES-09-27-3700, IES-09-27-3400, IES-09-27-3600)** that are discharged into the atmosphere shall not exceed 23.6 tons per consecutive twelve-month period.

Testing [15A NCAC 02Q .0508(f)]

d. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test indicate that the annual emission rates would exceed the limits given in Section 2.1 Q.3.b or 2.1 Q.3.c above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

Monitoring/ Recordkeeping [15A NCAC 02Q .0508(f)]

e. To ensure that emissions are less than the above-specified limits, the Permittee shall not operate the LSRP at a production rate in excess of 32,850 oven dried metric tons of lignin solids per consecutive 12-month period. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the amount of lignin processed exceeds the applicable limit.

f. To ensure compliance, the Permittee shall maintain records as follows:
   i. The Permittee shall record and maintain records of the amounts (in oven dried metric tons) of lignin processed in the LSRP each month,
   ii. The Permittee shall record and maintain records of the total reduced sulfur (as H_2S) and hydrogen sulfide emissions from the LSRP Operations each month, and;
   iii. The records of the amounts lignin (in oven dried metric tons) processed during each month in the LSRP and the total reduced sulfur (as H_2S) and hydrogen sulfide emissions shall be made available to an authorized representative of DAQ upon request.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the processed lignin, total reduced sulfur (as H_2S) emissions and hydrogen sufide emissions exceed the applicable limits or if the monthly records are not maintained each month.

Reporting [15A NCAC 02Q .0508(f)]

g. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 Q.3.e and 2.1 Q.3.f above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period. The report shall contain the following:
   i. the monthly total reduced sulfur (as H_2S) emissions from the LSRP Operations for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months;
   ii. the monthly hydrogen sulfide emissions from the LSRP Operations for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months;
   iii. the monthly quantities of lignin processed in the LSRP for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months; and
   iv. All instances of deviations from the requirements of this permit must be clearly identified.

4. 15A NCAC 02D .0614: COMPLIANCE ASSURANCE MONITORING

a. The following conditions in this section are enforceable until the startup of normal operations of the two-phased packed tower caustic scrubber as described in Section 2.1 T below.

b. Per 40 CFR Part 64 and 15A NCAC 02D .0614, the Permittee shall comply with the following:

Background

c. Emission Units: LSRP Main Sources identified above **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-**

2610, ES-09-27-2620, ES-09-27-1400, ES-09-27-3200) collected in the HVLC collection system and controlled in the No. 2 Hog Fuel Boiler, the No. 1 Hog Fuel Boiler, or Thermal Oxidizer**.**

d. Applicable Regulation, Emission Limit, and Monitoring Requirements
   i. Regulations: 15A NCAC 02D .0530: Prevention of Significant Determination
   ii. Emission Limits: Total Reduced Sulfur (as H_2S): 25.9 tons per year (12-month running total) and
   H_2S: 23.6 tons per year (12-month running total)
   iii. Control Technology: No. 2 Hog Fuel Boiler
   No. 1 Hog Fuel Boiler
   Thermal Oxidizer with a minimum temperature of 1200^{O}F for at least 0.5 seconds

Monitoring Approach

e. The key elements of the monitoring approach for total reduced sulfur and H_2S, including parameters to be monitored, parameter ranges and performance criteria are presented in the following table:

	LSRP Main Sources (ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2610, ES-09-27-2620, ES-09-27-1400, ES-09-27-3200) Collected in HVLC Collection System for Control in One of the Following Control Devices		
Measure	**No. 2 Hog Fuel Boiler**	**No. 1 Hog Fuel Boiler**	**Thermal Oxidizer**
I. Indicator	Steam rate	Steam rate	Exit stack temperature
Measuring approach	The steam rate will be measured using a steam load flow meter.	The steam rate will be measured using a steam load flow meter.	The exit stack temperature is monitored with a thermocouple.
II. Indicator Range	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.	An excursion is defined as a steam rate less than 126 thousand pounds per hour; excursions trigger an inspection corrective action and a reporting requirement.	An excursion is defined as temperature readings less than 1,260^{O}F; excursions trigger an inspection corrective action and a reporting requirement.
QIP Threshold	The excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.	The excursions exceeding 3 percent duration of the emission unit's operating for any semiannual reporting period.	No more than six excursions below the indicator range in any semiannual reporting period.
III. Performance Criteria			
Data Representativeness	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.	To have a valid hour of data, at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.	The sensor is located in the exit stack to the thermal oxidizer. The minimum tolerance of the thermocouple is ± 4^{O}F or ± 75 percent (of temperature measured in degrees Celcius), whichever is greater. The minimum chart recorder sensitivity (minor division) is 20^{O}F.
QA/QC Practices and Criteria	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.	The steam load flow meter is calibrated and inspected according to manufacturer's recommendations and according to Site Specific Monitoring Plan for Boiler MACT Compliance.	The thermocouple shall be calibrated and inspected according to manufacturer's recommendations.
Monitoring frequency	Measured Continuously	Measured Continuously	Measured Continuously
Data Collection Procedures	Recorded continuously on a data acquisition system.	Recorded continuously on a data acquisition system.	Recorded continuously in the information management system.
Averaging Period	The averaging period is hourly.	The averaging period is hourly.	No average is taken.

[a] During performance testing, the established continuous compliance monitoring parameters shall not apply. Performance tests will serve to provide the monitoring during these periods.

Reporting [15A NCAC 02Q .0508(f) and 40 CFR 64.9(a)]

f. The Permittee shall submit a summary report of all monitoring activities given in Section 2.1 Q.4.e above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified. In addition, the summary report shall contain the following information, as applicable:
   i. Summary information on the number, duration, and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   ii. Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   iii. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR 64.8. Upon completion of a QIP, the Permittee shall include, in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances.

R. C3 Condensate (ID No. ES-09-35-0140)

The following table provides a summary of limits and standards for the emission source described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Total reduced sulfur	C3 Condensate (**ID No. ES-09-35-0140)** may be routed to the Waste Water Treatment Plant (**ID No. ES-73-05-2000**) without first being processed through the condensate stripper reflux condenser (**ID No. ES-09-25-1050**) for no more than 30 days in any consecutive twelve month period.	15A NCAC 02Q .0317 (15A NCAC 02D .0530 Avoidance)
Toxic Air Pollutants	**State-Enforceable Only** **See Section 2.2 D.2** Affected Source: Waste Water Treatment Plant (ID No. ES-73-05-2000)	15A NCAC 02D .1100
Odors	**State-Enforceable Only** **See Section 2.2 D.1** The Permittee shall implement management practices, as necessary, to prevent odorous emissions from the C3 Condensate (**ID No. ES-09-35-0140)** sewering from causing or contributing to objectionable odors beyond the facility's boundary.	15A NCAC 02D .1806

15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for

1. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. In order to avoid applicability of 15A NCAC 02D .0530(g) for major sources and major modifications, emissions total reduced sulfur from the direct sewering of the C3 Condensate (**ID No. ES-09-35-0140)** shall be less than 10 tons per consecutive twelve (12) month period.

b. The Permittee may route the C3 Condensate (**ID No. ES-09-35-0140)** directly to the waste water treatment plant (**ID No. ES-73-05-2000**) without first being processed through the condensate stripper reflux condenser (**ID No. ES-09-25-1050**) for no more than 30 days in any consecutive twelve month period.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. To ensure compliance, for each time the C3 Condensate (**ID No. ES-09-35-0140)** is discharged directly to the waste water treatment plant (**ID No. ES-73-05-2000**), the Permittee shall record the dates and the total number of gallons of C3 condensate sewered.. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the required dates and volume of C3 condensate sewered are not recorded.

Reporting [15A NCAC 02Q .0508(f)]

d The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 R.1.c, above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall contain the number of days and volume of direct C3 condensate sewered and the associated total reduced sulfur emissions for each consecutive twelve month period during the reporting period.

S. Portable log chipper(s) (ID No. ES-TEMP-CHIP)

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate Matter	$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons per hour, -OR- $E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons per hour Where: E = allowable emission rate in pound per hour P = process weight rate in tons per hour	15A NCAC 02D .0515
Visible Emissions	20 percent opacity standard	15A NCAC 02D .0521
PM_{10}	No more than 14.9 tons emitted per consecutive 12-month period.	15A NCAC 02Q .0317 (15A NCAC 02D .0530 Avoidance)

1. 15A NCAC 02D .0515: PARTICULATES FROM MISCELLANEOUS INDUSTRIAL PROCESSES

a. Emissions of particulate matter from the Portable Log Chipper(S) **(ID No. ES-TEMP-CHIP)** shall not exceed an allowable emission rate as calculated by one of the following equations:

$E = 4.10 \times P^{0.67}$ for process rates ≤ 30 tons per hour, or
$E = 55.0 \times P^{0.11} - 40$ for process rates > 30 tons per hour

Where: E = allowable emission rate in pound per hour
P = process weight rate in tons per hour

Liquid and gaseous fuels and combustion air are not considered as part of the process weight.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 S.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall maintain production records such that the process rates "P" in tons per hour, as specified by the formulas specified in Section 2.1 S.1.a, above, can be derived and shall make these records available to a DAQ authorized representative upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0515 if the production records are not maintained or the types of materials are not monitored.

d. No reporting is required for particulate matter emissions from the Portable Log Chipper(s) **(ID No. ES-TEMP-CHIP)**.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. Visible emissions from the Portable Log Chipper(S) **(ID No. ES-TEMP-CHIP)** shall not be more than 20 percent opacity each when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit provided in Section 2.1 S.2.a, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring [15A NCAC 02Q .0508(f)]

c. The Permittee shall observe once each month the emission points of Portable Log Chipper(s) **(ID No. ES-TEMP-CHIP)** for any visible emissions above normal. The monthly obersvation must be made for each month of the calendar year period when the Portable Log Chipper(s) is(are) in operation on site to ensure compliance with this

requirement. If visible emissions from the emission source(s) are observed to be above normal, the Permittee shall either:

i. take appropriate action to correct the above-normal emissions as soon as practicable and within the monitoring period and record the action taken as provided in the recordkeeping requirements below, or
ii. demonstrate that the percent opacity from the emission points of the Portable Log Chipper(s) in accordance with 15A NCAC 02D .2610 (Method 9) for 12 minutes is below the limit given in Section 2.1 S.2.a, above.

The Permittee shall be deemed to be in noncompliance with 15A NCAC 02D .0521 if the required daily observations are not conducted as required; if the above-normal emissions are not corrected within the monitoring period or the percent opacity demonstration cannot be made.

Recordkeeping [15A NCAC 02Q .0508(f)]

d. The results of the monitoring shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The logbook shall record the following:
   i. the date and time of each recorded action;
   ii. the results of each observation and/or test noting those sources with emissions that were observed to be in noncompliance along with any corrective actions taken to reduce visible emissions; and
   iii. the results of any corrective actions performed.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]

e. The Permittee shall submit a summary report of the monitoring and recordkeeping activities given in Section 2.1 S.2.c and S.2.d, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

3. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for
15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. In order to avoid applicability of 15A NCAC 02D .0530 (g) for major sources and major modifications, the Portable Log Chipper(s) **(ID No. ES-TEMP-CHIP)** shall discharge into the atmosphere no more than 14.9 tons of PM_{10} per consecutive twelve-month period.

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limits given in Section 2.1 S.3.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

Monitoring/Recordkeeping [15A NCAC 02Q .0508(f)]

c. During each period the portable log chipper(s) **(ID No. ES-TEMP-CHIP)** operate(s) on site, the Permittee shall record and maintain the following records in a logbook (written or electronic format):
   i. the tons of logs processed through the Portable Log Chipper(s) during the previous month; and
   ii. the tons of PM_{10} emissions from Portable Log Chipper(s) for the previous month.

   The monthly records, as specified above, shall be made available to an authorized representative of DAQ upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the records in are not maintained or if PM_{10} emissions exceed the limit in 2.1 S.3.a above.

Reporting [15A NCAC 02Q .0508(f)]

d. Following each period the Portable Log Chipper(s) **(ID No. ES-TEMP-CHIP)** operate(s) on site, the Permittee shall submit a semi-annual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 S.3.c, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall contain the monthly PM_{10} emissions for each consecutive twelve month period during the previous 17 months.

T. Reconfigured LSRP – After beginning normal operation of the two-phase packed bed caustic scrubber (ID No. CD-09-27-3800)

- **Main Sources -** *These sources are controlled by the Two-Phase Packed Bed Caustic Scrubber (ID No. CD-09-27-3800).*
  No. 1 Feed Liquor Cooler (ID No. ES-09-27-1100)
  No. 1 Lignin Filtrate Storage Tank (ID No. ES-09-27-1200)
  Lignin Slurry Conditioning Tank (ID No. ES-09-27-1800)
  Lignin Slurry Buffer Tank (ID No. ES-09-27-2000)
  No. 1 Lignin Filter Cloth Wash Tank 1 (ID No. ES-09-27-2300)
  No. 1 Lignin Filtrate Tank 1 (ID No. ES-09-27-2400)
  No. 1 Lignin Filtrate Buffer Tank (ID No. ES-09-27-2500)
  Lignin Lump Breaker (ID No. ES-09-27-2600)
  No. 1 Lignin Filter Horizontal Conveyor (ID No. ES-09-27-2610)
  No. 1 Lignin Filter Incline Conveyor (ID No. ES-09-27-2620)
  Lignin Rotary Feeder (ID No. ES-09-27-2660)
  No. 2 Lignin Acidic Filtrate Tank (ID No. ES-09-27-3200)
  No. 1 Lignin Filter (ID No. ES-09-27-2100)
  No. 2 Lignin Filter Cloth Wash Tank (ID No. ES-09-27-3100)
  Acidic Lignin Conditioning Tank (ID No. ES-09-27-2800)

- **HVLC Sources -** *These sources are fed through the Feed Liquor Carbonator (ID No. ES-09-27-1400) and routed to the HVLC Collection System and controlled in the No. 2 Hog Fuel Boiler (ID No. ES-64-25-0290), the No. 1 Hog Fuel Boiler (ID No. ES-65-25-0310), the No. 5 Recovery Boiler (ID No. ES-10-25-0110), or the Thermal Oxidizer (ID No. CD-64-22-2000).*
  Lignin Acidification Tank (ID No. ES-09-27-2700)
  Lignin Foam Tank (ID No. ES-09-27-2770)

- **Dust Collection Sources -** *These sources are collected and controlled controlled in a dust collection system with a wet cyclone (ID No. CD-09-27-3900).*
  No. 2 Lignin Filter (ID No. ES-09-27-3000)
  No. 2 Lignin Filter Horizontal Conveyor (ID No. IES-09-27-3400)

- **Other Sources -** *These sources are uncontrolled.*
  Lignin Feed Liquor Tank (ID No. ES-09-27-1000)
  Acid Wash Water Tank (ID No. IES-09-27-2900)
  Lignin Acid Area Sump (ID No. IES-09-27-3700)
  Lignin Liquor Area Sump (ID No. IES-09-27-3600)

The following table provides a summary of limits and standards for the emission sources described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Sulfur dioxide	When LSRP HVLC Sources are controlled in the Thermal Oxidizer: 2.3 pounds per million Btu heat input	15A NCAC 02D .0516
Visible emissions	When LSRP HVLC Sources are controlled in the Thermal Oxidizer: 20 percent opacity	15A NCAC 02D .0521

Regulated Pollutant	Limits/Standards	Applicable Regulation
Total reduced sulfur and H_2S	**Affected Sources: Main Sources** 11.6 pounds of TRS per hour (24-hour block average) 5.4 pounds of H_2S per hour (24-hour block average) **Affected sources: HVLC Sources** 1.3 tons TRS per year (12-month running total) 1.1 tons H_2S per year (12-month running total) **Affected sources: Dust Collection Sources and Other Sources** 2.6 tons TRS per year (12-month running total) 2.0 tons H_2S per year (12-month running total)	15A NCAC 02D .0530
Criteria pollutants	**See Section 2.2 C.1** Annual tracking report	15A NCAC 02D .0530(u)
Toxic air pollutants	**State-Enforceable Only** **See Section 2.2 D.2**	15A NCAC 02D .1100

1. 15A NCAC 02D .0516: SULFUR DIOXIDE EMISSIONS

a. The following conditions are enforceable following the startup of normal operations of the two-phased packed tower caustic scrubber as described above. After such time as Section 2.1 Q.1 above, is no longer applicable, the Permittee shall meet the requirements of this condition (Section 2.1 T.1).

b. Emissions of sulfur dioxide from the Thermal Oxidizer **(ID No. CD-64-22-2000)** shall not exceed 2.3 pounds per million Btu heat input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard and shall include the sources specified in Section 2.1 J.1.a above.

Testing/Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. The Permittee shall demonstrate compliance with Section 2.1 T.1.b above by meeting the requirements given in Section 2.1 J.1 above.

2. 15A NCAC 02D .0521: CONTROL OF VISIBLE EMISSIONS

a. The following conditions are enforceable following the startup of normal operations of the two-phased packed tower caustic scrubber as described above. After such time as Section 2.1 Q.2 above, is no longer applicable, the Permittee shall meet the requirements of this condition (Section 2.1 T.2).

b. Visible emissions from the Thermal Oxidizer **(ID No. CD-64-22-2000)** when burning natural gas and the LSRP HVLC Sources identified above **(ID Nos. ES-09-27-2700, ES-09-27-2770, and ES-09-27-1400)** shall not be more than 20 percent opacity when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent not more than once in any hour and not more than four times in any 24-hour period. In no event shall the six-minute average exceed 87 percent opacity.

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limit given in Section 2.1 T.2.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0521.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

d. No monitoring/recordkeeping/reporting is required for visible emissions from the firing of natural gas and the LSRP HVLC Sources identified above in the Thermal Oxidizer **(ID No. CD-64-22-2000)**.

3. 15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

a. The following conditions are enforceable following the startup of normal operations of the two-phased packed tower caustic scrubber as described above. After such time as Section 2.1 Q.3 above, is no longer applicable, the Permittee shall meet the requirements of this condition (Section 2.1 T.3).

Emissions Limits [15A NCAC 02D .0530]

b. The following Best Available Control Technology (BACT) shall not be exceeded:

Emission Source ID No.	Emission Source	BACT for TRS	BACT for H_2S	Control Method
Main Sources				
ES-09-27-1100	No. 1 Feed Liquor Cooler	11.6 lb/hr (24-hour block average)	5.4 lb/hr (24-hour block average)	Two-phase packed bed caustic scrubber (ID No. CD-09-27-3800)
ES-09-27-1200	No. 1 Lignin Filter Filtrate Storage Tank			
ES-09-27-1800	Lignin Slurry Conditioning Tank			
ES-09-27-2000	Lignin Slurry Buffer Tank			
ES-09-27-2100	No. 1 Lignin Filter			
ES-09-27-2300	No. 1 Lignin Filter Cloth Wash Tank			
ES-09-27-2400	No. 1 Lignin Filter Filtrate Tank			
ES-09-27-2500	No. 1 Lignin Filter Filtrate Buffer Tank			
ES-09-27-2600	Lignin Lump Breaker			
ES-09-27-2610	No. 1 Lignin Filter Horizontal Conveyor			
ES-09-27-2620	No. 1 Lignin Filter Incline Conveyor			
Es-09-27-2660	Lignin Rotary Feeder			
ES-09-27-2800	Acidic Lignin Conditioning Tank			
ES-09-27-3100	No. 2 Lignin Filter Cloth Wash Tank			
ES-09-27-3200	No. 2 Lignin Filter Acidic Filtrate Tank			
HVLC Sources				
ES-09-27-2700	Lignin Acidification Tank	1.3 tpy per consecutive 12-month period	1.1 tpy per consecutive 12-month period	HVLC Collection System controlled by: No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310) or No. 1 Hog Fuel Boiler (ID No. ES-64-25-0290) or No. 5 Recovery Boiler (ID No. ES-20-25-0110) or Thermal Oxidizer (ID No. CD-64-22-2000)
ES-09-27-2770	Lignin Foam Tank			
ES-09-27-1400	Feed Liquor Carbonator			
Other LSRP Sources				
ES-09-27-1000	Lignin Feed Liquor Tank	2.6 tpy per consecutive 12-month period	2.0 tpy per consecutive 12-month period	No controls for TRS or H_2S emissions
ES-09-27-3000	No. 2 Lignin Filter			
IES-09-27-2900	Acid Wash Water Tank			
IES-09-27-3700	Lignin Acid Area Sump			
IES-09-27-3400	No. 2 Lignin Filter Horizontal Conveyor			
IES-09-27-3600	Lignin Liquor Area Sump			

Testing [15A NCAC 02Q .0508(f)]

c. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test indicate that the annual emission rates would exceed the limits given in Section 2.1 T.3.b above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.

d. Under the provisions of NCGS 143-215.108, the Permittee shall demonstrate compliance with the TRS and H_2S emissions limits as follows:
   i. For the LSRP Main Sources identified above **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2800, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2610, ES-09-27-2620, ES-09-27-3100, and ES-09-27-3200)**, the Permittee shall conduct a performance test at the outlet of the two-phase packed bed caustic scrubber **(ID No. CD-09-27-3800)** no later than 180 days after the startup of normal operation of the scrubber unless an alternate date is approved by DAQ. During the performance test, the Permittee shall measure and record the scrubbing liquid flow rate and the pH of the scrubber effluent to use in determining the operating parameters required in Section 2.1 T.3.e below.
   ii. During each performance test, the Permittee shall record the lignin solids production rate (in oven dried tons of lignin solids).
   iii. Subsequent performance tests shall be conducted once every five years, no more than 60 months between tests.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the performance tests are not conducted as required.

Monitoring [15A NCAC 02Q .0508(f)]

e. Total reduced sulfur and hydrogen sulfide emissions from the Main Sources identified above **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, ES-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2610, ES-09-27-2620, ES-09-27-2800, ES-09-27-3100, and ES-09-27-3200)** shall be controlled by the two-phase packed bed caustic scrubber **(ID No. CD-09-27-3800)**. To ensure compliance, the Permittee shall install, calibrate, operate, and maintain a continuous pH indicator and a scrubbing liquid flow meter on the scrubber pursuant to manufacturer's specification to measure the pH of the scrubber effluent and the scrubber flowrate.
   i. The Permittee shall establish the minimum liquid flow rate and minimum pH on a 24-hour block average basis during performance testing required in Section 2.1 T.3.c and 2.1 T.3.d above. The parametric values confirmed or re-established from the most recent performance test approved by DAQ do not apply during performance testing.
      (A) If revisions to operating parameter values are necessary to demonstrate compliance with the emission limits and are more stringent than the established minimum or maximum operating limits, the Permittee shall submit a request to revise the values in the permit at the same time as the test report is submitted as required per General Condition JJ. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.
      (B) If performance testing indicates that compliance with emission limits is demonstrated with revisions to operating parameter values that are less stringent than the established minimum or maximum operating limits, the Permittee may request to revise the values in the permit pursuant to 15A NCAC 02Q .0515.
   ii. Prior to performance testing, the Permittee shall maintain the scrubbing liquid flow rate and pH of the scrubber effluent from the two-phase packed bed caustic scrubber **(ID No. CD-09-27-3800)** above the minimum or below the maximum manufacturer's recommended values.
   iii. If the scrubber liquid flow rate or pH readings are observed to be outside the allowable range, the Permittee shall inspect the scrubber(s) for malfunctions and clean or repair, as necessary.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the liquid flowrate or pH are not maintained within the prescribed limits or if the scrubber liquid flowmeter and pH indicator are not operated and maintained as required.

f. The HVLC Sources identified above **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** shall be controlled in the No. 2 Hog Fuel Boiler **(ID No. ES-64-25-0290)**, the No. 1 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, or the Thermal Oxidizer **(ID No. CD-64-22-2000)**. To ensure that emissions are less than the above-specified limits in Section 2.1 T.3.b the Permittee shall:
   i. burn the HVLC sources in the No. 2 Hog Fuel Boiler, No. 1 Hog Fuel Boiler, or No. 5 Recovery Boiler. No monitoring is necessary when burned in these control devices; or
   ii. install, calibrate, operate, and maintain a temperature monitoring device pursuant to manufacturer's specification to measure the Thermal Oxidzer **(ID No. CD-64-22-2000)** temperature when the HVLC sources are burned in the Thermal Oxidizer to ensure the exit temperature is above the minimum temperature of 1200°F.
   iii. If the exit stack temperature is observed to be outside the allowable range, inspect the thermal oxidizer for malfunctions and clean or repair, as necessary.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the temperature is not maintained within the prescribed limits temperature monitor is not operated and maintained as required.

g. To ensure that emissions from the Other Sources identified above **(ID Nos. ES-09-27-1000, ES-09-27-3000, IES-09-27-2900, IES-09-27-3700, IES-09-27-3400, IES-09-27-3600)** are less than the limits specified in Section 2.1 T.3.b above, the Permittee shall not operate the Lignin Recovery Process at a production rate in excess of 38,581 oven dried tons of lignin solids per consecutive 12-month period. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the amount of lignin processed exceeds the applicable limit.

Recordkeeping [15A NCAC 02Q .0508(f)]

h. To ensure compliance, the Permittee shall maintain records as follows:
   i. The Permittee shall record and maintain records of the amounts (in oven dried tons) of lignin processed in the Lignin Solids Removal Process each month,
   ii. The Permittee shall record and maintain records of the total reduced sulfur and hydrogen sulfide emissions from the Lignin Solids Removal Process Operations each month. Records should reflect the averaging periods specified in Section 2.1 T.3.b above, and

iii. The records of the amounts lignin (in oven dried tons) processed during each month in the Lignin Recovery Process and the total reduced sulfur and hydrogen sulfide emissions shall be made available to an authorized representative of DAQ upon request.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the processed lignin, total reduced sulfur emissions and hydrogen sufide emissions exceed the applicable limits or if the monthly records are not maintained each month.

Reporting [15A NCAC 02Q .0508(f)]

i. The Permittee shall submit a semiannual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities given in Section 2.1 T.3.e through 2.1 T.3.h above, postmarked on or before January 30 of each calendar year for the preceding six-month periods between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. The report shall identify all instances of deviations from the requirements of this permit or a statement that no deviations occurred during the reporting period. The report shall contain the following:
   i. the 24-hour block average total reduced sulfur emissions from the LSRP Main Sources identified above **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, Es-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2610, ES-09-27-2620, ES-09-27-2800, ES-09-27-3100, and ES-09-27-3200)** calculated daily for the previous 17 months.
   ii. the 24-hour block average H_2S emissions from the LSRP Main Sources identified above **(ID Nos. ES-09-27-1100, ES-09-27-1200, ES-09-27-1800, ES-09-27-2000, Es-09-27-2100, ES-09-27-2300, ES-09-27-2400, ES-09-27-2500, ES-09-27-2610, ES-09-27-2620, ES-09-27-2800, ES-09-27-3100, and ES-09-27-3200)** calculated daily for the previous 17 months.
   iii. the monthly total reduced sulfur emissions from the HVLC Sources identified above **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** and Other LSRP Sources **(ID Nos. ES-09-27-1000, ES-09-27-3000, IES-09-27-2900, IES-09-27-3700, IES-09-27-3400, IES-09-27-3600)** for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months;
   iv. the monthly hydrogen sulfide emissions from the HVLC Sources identified above **(ID Nos. ES-09-27-1400, ES-09-27-2700, ES-09-27-2770)** and Other LSRP Sources **(ID Nos. ES-09-27-1000, ES-09-27-3000, IES-09-27-2900, IES-09-27-3700, IES-09-27-3400, IES-09-27-3600)** for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months;
   v. the monthly quantities of lignin processed in the Lignin Solids Removal Process for the previous 17 months. The total quantities must be calculated for each of the 12-month periods over the previous 17 months; and
   vi. All instances of deviations from the requirements of this permit must be clearly identified.

2.2 Multiple Emission Sources Specific Limitations and Conditions

A. 40 CFR Part 63, Subpart S Affected Sources

Table 2.2 A-1

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
HVLC Sources			
No. 6 Fiberline			
HVLC.ES-06-10-2380	Chip Bin Relief Condenser	ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000	Emissions collected in the HVLC collection system and routed to No. 2 Hog Fuel Boiler (primary) or No. 1 Hog Fuel Boiler (secondary) or No. 5 Recovery Boiler (as backup) or Thermal Oxidizer (as backup)
HVLC.ES-06-21-1100	Pressure Diffuser Filtrate Tank *Emissions collected routed to Digester Blow Tank (ID No. HVLC.ES-06-21-1200)*		
HVLC.ES-06-21-1200	Digester Blow Tank		
HVLC.ES-06-22-1080	Secondary Knotter		
HVLC.ES-06-22-1280	Quaternary Screen		
HVLC.ES-06-22-1100	Screen Dilution Tank		
HVLC.ES-06-23-1200	Decker Hood		
HVLC.ES-06-23-1220	Decker Filtrate Tank		
No. 6 Oxygen Delignification			
ES-06-31-0180	Oxygen Delignification System	NA	No control required per Clean Condensate Alternative under 40 CFR 63.447 (Permittee uses methanol biodegradation by the wastewater treatment system to offset methanol emissions from the O_2 delignification sources)
ES-06-31-1000	1st Stage O_2 Surge Tank	NA	
ES-06-32-2060	2nd Stage O_2 Reactor Blow Tube	NA	
ES-06-32-2100	2nd Stage Wash Tower	NA	
ES-06-32-2120	2A/2B Filtrate Tank	NA	
No. 7 Fiberline			
HVLC.ES-07-10-2380	Chip Bin Relief Condenser	ES-65-25-0310 or ES-64-25-0290 or ES-10-25-0110 or CD-64-22-2000	Emissions collected in the HVLC collection system and routed to No. 2 Hog Fuel Boiler (primary) or No. 1 Hog Fuel Boiler (secondary) or No. 5 Recovery Boiler (as backup) or Thermal Oxidizer (as backup)
HVLC.ES-07-21-1100	Pressure Diffuser Filtrate Tank *Emissions routed to Digester Blow Tank (ID No. HVLC.ES-07-21-1200).*		
HVLC.ES-07-21-1200	Digester Blow Tank		
HVLC.ES-07-22-1080	Secondary Knotter		
HVLC.ES-07-22-1280	Quaternary Screen		
HVLC.ES-07-22-1100	Screen Dilution Tank		
HVLC.ES-07-23-1200	Decker Hood		
HVLC.ES-07-23-1220	Decker Filtrate Tank		
No. 7 Oxygen Delignification			
ES-07-31-1100	Oxygen Delignification System	NA	No control required per Clean Condensate Alternative under 40 CFR 63.447 (Permittee uses
ES-07-31-1000	1st Stage O_2 Surge Tank	NA	
ES-07-31-1140	1st Stage O_2 Reactor Blow Tube	NA	

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-07-31-1180	1st Stage Wash Tower	NA	methanol biodegradation by the wastewater treatment system to offset methanol emissions from O_2 delignificaiton sources)
ES-07-31-1200	1A/1B Filtrate Tank	NA	
ES-07-33-3000	3rd Stage Feed Tank	NA	
LVHC SOURCES			
No. 6 Fiberline			
LVHC.06-10-2420	Digester Flash Condenser	CD-14-55-2020 and ES-14-60-3000 or ES-65-25-0310	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln (primary) or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler (backup)
No. 7 Fiberline			
LVHC-07-10-2420	Digester Flash Condenser	CD-14-55-2020 and ES-14-60-3000 or ES-65-25-0310	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln (primary) or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler (backup)
No. 6 & 7 Fiberline (common facilities)			
LVHC.08-61-1020	Turpentine Decanter Weir	ES -65-25-0310 or CD-14-55-2020 and ES-14-60-3000	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln (primary) or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler (backup)
LVHC.08-61-1080	Turpentine Tank		
LVHC.08-61-1000	Turpentine Decanter Tank		
LVHC.08-61-1040	Turpentine Underflow Tank		

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
Chemical Recovery: Evaporator Operations			
LVHC.09-20-0320	No. 6 Black Liquor Evaporator System	ES -65-25-0310 or CD-14-55-2020 and ES-14-60-3000	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln (primary) or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler (backup)
LVHC.09-35-0200	Concentrator Hotwell		
LVHC.09-25-0510	No. 7 Black Liquor Evaporator System		
LVHC.09-DECANT	Secondary Turpentine Decanter Tank*		
LVHC.09-WEIR	Secondary Turpentine Decanter Weir*		
LVHC.09-UND	Secondary Turpentine Underflow Tank*		
LVHC.09-STOR	Secondary Turpentine Storage Tank*		
Bleaching System Sources			
No. 6 Bleach Plant			
ES-06-33-3060	3rd Stage ClO_2 Tower	CD-06-35-8100	White liquor scrubber (45 gallons per minute minimum circulation flow, pH $\geq$ 10, and scrubber fan operations status)
ES-06-35-5060	5th Stage ClO2 Tower		
ES-06-35-5080	5th Stage Filtrate Tank		
No. 7 Bleach Plant			
ES-07-33-3080	3rd Stage Tower - ClO_2 Stage	CD-07-36-8000	White liquor scrubber (105 gallons per minute minimum circulation flow, and min pH of 10, and scrubber fan operations status
ES-07-35-5060	5th Stage Tower – ClO_2 Stage		
ES-07-35-5080	5th Stage Filtrate Tank		
Pulping Process Condensates Sources			
ES-07-10-2480	Nos. 6 and 7 Digester Foul Condensate Tank *Emissions routed to LVHC System cooler and routed to a control device. Condensates are collected from the Chip Bin Relief Condensers (ID Nos. ES-06-10-2380 and ES-07-10-2380), Digester Flash Steam Condensers (ID Nos. ES-06-10-2420 and ES-07-10-2420), and/or Turpentine Decanter (ID No. ES-08-61-1000).*	NA	NA
ES-09-25-1000	Condensate Stripper Feed Tank *Emissions collected in LVHC System and routed to control device. Condensates received from Nos. 6 and 7 Digester Foul Condensate Tank (ID No. ES-07-10-2480), Nos. 6 and 7 Black Liquor Evaporator Systems (ID Nos. ES-09-20-0320 and ES-09-25-0510), Concentrator Hotwell (ES-09-35-0200), LVHC Collection System and HVLC Collection System for treatment in the Condensate Stripper System.*	ES -65-25-0310 or CD-14-55-2020 and ES-14-60-3000	LVHC White Liquor Scrubber (80 gallons per minute minimum white liquor injection rate) and No. 5 Lime Kiln (primary) or LVHC White Liquor Scrubber except for periods of scrubber maintenance (80 gallons per minute minimum white liquor injection rate) and No. 2 Hog Fuel Boiler (backup)

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
ES-09-25-1050	Condensate Stripper Reflux Condenser	ES -14-60-3000 or ES-65-25-0310	Emissions collected in SOG collection system and routed to the No. 5 lime kiln or No. 2 hog fuel boiler

*These sources have not been constructed.

Table 2.2 A-2

The following table provides a summary of limits and standards for the emission sources describe above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Hazardous air pollutants	**Bleaching System** 10 ppmv total chlorinated HAP or 99 percent reduction by weight **LVHC Collection System** Route system vents to White Liquor Scrubber followed by the No. 5 Lime Kiln or to White Liquor Scrubber except for periods of scrubber maintenance followed by the No. 2 Hog Fuel Boiler or LVHC **HVLC Collection System** Route the listed Nos. 6 and 7 fiberline HVLC vents to the No. 1 or No. 2 Hog Fuel Boiler or No. 5 Recovery Boiler or Thermal Oxidizer. Comply with Clean Condensate Alternative Delignification System. **Pulping Condensate Collection System** Collect a minimum 11.1 pounds per ton oven died pulp (ODP) followed by treatment in the Steam Stripper meeting: 92 percent HAP removal, or 10.2 pounds per ton ODP removal	15 A NCAC 02D .1111 (40 CFR 63 Subpart S)

1. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

a. For the sources specified in Table 2.2 A-1, above, the Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .1111 "Maximum Achievable Control Technology" as promulgated in 40 CFR Part 63 Subpart S "National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry, including Subpart A "General Provisions" as defined per 40 CFR 63.440(g) and indicated per Table 1 of Subpart S. These emission standards shall apply at all times except as specified in 40 CFR 63.443(e) and 63.446(g). Terms used throughout this section are defined in the Clean Air Act as amended in 1990 and in 40 CFR 63.2 and 63.441. Units and abbreviations are defined in 40 CFR 63.3.

Standards for the Bleaching System [40 CFR 63.445]

b. The Permittee shall meet the following control requirements for bleaching systems using chlorinated compounds [40 CFR 63.445]:
   i. The equipment at each bleaching stage of the bleaching systems identified in Table 2.2 A-1, above, where chlorinated compounds are introduced, shall be enclosed and vented into a closed vent system meeting the requirements specified in Section 2.2 A.1.h, below, and introduced into the Nos. 6 and 7 Bleach Plant White Liquor Scrubbers **(ID Nos. CD-06-35-8100 and CD-07-36-8000)**;
   ii. The Nos. 6 and 7 Bleach Plant White Liquor Scrubbers **(ID Nos. CD-06-35-8100 and CD-07-36-8000)** shall achieve a treatment device outlet concentration of 10 ppmv or less of total chlorinated HAP or achieve a 99 percent reduction by weight; and
   iii. The Permittee shall not use hypochlorite or chlorine for bleaching in the Nos. 6 and 7 bleaching systems listed above.

Standards for the LVHC and HVLC pulping systems at kraft processes [40 CFR 63.443(a)].

c. The Permittee shall meet the following control requirements for the total HAP emissions from the LVHC system sources identified in Table 2.2 A-1, above [40 CFR 63.443]:
   i. Each LVHC system component shall be enclosed and vented into a closed-vent system meeting the requirements of Section 2.2 A.1.h, below, and routed to [40 CFR 63.443(d)]:
      (A) The White Liquor Scrubber **(ID No. CD-14-55-2020)** followed by the No. 5 Lime Kiln **(ID No. ES-14-60-3000)** by introducing the HAP emission stream with the primary fuel or into the flame zone: or
      (B) The White Liquor Scrubber **(ID No. CD-14-55-2020)**, except during periods of scrubber maintenance followed by the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310),** when the boiler is operating at a heat input capacity greater than 150 million Btus per hour, by introducing the HAP emissions stream with the combustion air/primary fuel/into flame zone.
   ii. Periods of excess emissions reported under Section 2.2 A.1.v, below, shall not be a violation of these control requirements provided that the time of excess emissions (excluding periods of startup, shutdown, and malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed one (1) percent for control devices used to reduce the total HAP emissions from the LVHC system or four percent for the control devices used to reduce the total HAP emissions from both the LVHC system sources and the HVLC system sources identified in Section 2.2 A.1.d, below. [40 CFR 63.443(e)(1) and (3)]

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the LVHC system sources are not controlled as required.

d. The Permittee shall meet the following control requirements for the HAP emissions from the HVLC system souces identified in Table 2.2 A-1, above [40 CFR 63.443]
   i. The Permittee shall enclose each HVLC system source identified in Table 2.2 A-1, above, and vent into a closed vent system, meeting the requirements of Section 2.2 A.1.h, below, and routed to:
      (A) the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310),** with the primary fuel into flame zone or operating at a heat input capacity greater than 150 million Btus per hour, by introducing the HAP emissions stream with the combustion air [40 CFR 63.443(d)(4)(i) and (ii)]; or
      (B) the No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290),** with the primary fuel into the flame zone or operating at a heat input capacity greater than 150 million Btus per hour, by introducing the HAP emissions stream with the combustion air [40 CFR 63.443(d)(4)(i) and (ii)]; or
      (C) the No. 5 Recovery Boiler **(ID No. Es-10-25-0110)**, by introducing the HAP emissions stream with the combustion air or with the primary fuel into the flame zone [40 CFR 63.443(d)(4)(i)]; or
      (D) the Thermal Oxidizer **(ID No. CD-64-22-2000)**, designed and operated at a minimum temperature of 871^{O}C (1600^{O}F) and a minimum residence time of 0.75 seconds [40 CFR 63.443(d)(3)].
   ii. Periods of excess emissions reported under Section 2.2 A.1.v, below, shall not be a violation of these control reqquirements provided that the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed the four percent for control devices used to reduce the total HAP emissions from the HVLC system or four percent for the control devices used to reduce the total HAP emissions from both the LVHC systems controlled according to Section 2.2 A.1.c, above, and HVLC system sources [40 CFR 63.443(e)(2) and (3)].

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the HVLC system sources are not controlled as required.

e. The Permittee shall meet the requirement to control the oxygen delignification system sources identified in Table 2.2 A-1, above, using the Clean Condensate Alternative (CCA) under 40 CFR 63.447. The Permittee shall demonstrate to DAQ that the methanol (surrogate for total HAP) emissions reductions achieved by the CCA technology are equal to or greater than the baseline methanol (surrogate for total HAP) emissions of 0.502 pounds of methanol per ton of oven dried pulp (ODP) that would have been achieved by controlling the oxygen delignification system sources according to Section 2.2 A.1.d, above. The CCA plan was approved by DAQ with submittal of final calculations on January 19, 2008. To demonstrate compliance with the CCA, the Permittee shall determine the ratio of biologicial oxygen demand (BOD) to aerator horsepower (hp) on a 30-day rolling average, not to exceed 36.9 BOD/hp. If determining the ratio is not possible, the Permittee shall measure dissolved oxygen on a daily basis between zones 2 and 3 to ensure methanol is being adequately destroyed. Dissolved oxygen shall be greater than 0.5 milligrams per liter to ensure the treatment system is operating to reduce methanol emissions. [40 CFR 63.447]

Standards for kraft pulping process condensates [40 CFR 63.446]

f. The Permittee shall collect pulping process condensates from a combination of one or more of the systems identified below that in total contain a methanol (as a surrogate for HAP) mass of 11.1 pounds per ton ODP [40 CFR 63.446(b) and (c)(3)]:
   i. Chip Bin Relief Condensers (ID Nos. ES-06-10-2380 and ES-07-10-2380);
   ii. Digester Flash Steam Condensers (ID Nos. ES-06-10-2420 and ES-07-10-2420);
   iii. Turpentine Decanter (ID No. ES-08-61-1000);
   iv. LVHC Collection System;
   v. HVLC Collection System;
   vi. 6th effect in the No. 6 Evaporator System (ID No. ES-09-20-0320);
   vii. 6th and 7th effects in the No. 7 Evaporator System (ID No. ES-09-25-0510); and
   vii. Concentrator hotwell.

g. The pulping process condensates identified in Section 2.2 A.1.f, above, shall be conveyed in a closed collection system that is designed and operated to meet the following requirements [40 CFR 63.446(d), (e), and (g)]:
   i. Each closed collection system shall meet the individual drain system requirements specified in 40 CFR 63.960, 63.961, and 63.962, except for closed-vent systems and control devices;
   ii. Closed vent systems shall be designed and operated in accordance with Section 2.2 A.1.h, below;
   iii. The Condensate Stripper Feed Tank **(ID No. ES-09-25-1000)** shall meet the following requirements [40 CFR 63.446(d)(2)]:
      (A) The fixed roof and all openings (e.g., access hatches, sampling ports, gauge wells) shall be designed and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million, measured as methanol, above background.
      (B) The Condensate Stripper Feed Tank **(ID No. ES-09-25-1000)** shall be vented into a closed-vent system that meets the requirements in Section 2.2 A.1.h, below, and routed to either the No. 5 Lime Kiln **(ID Nos. ES-09-14-60-3000)** by introducing the HAP emission stream with the primary fuel or into the flame zone or the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** by introducing the HAP emission stream with the primary fuel or into the flame zone or operating the boiler with a heat input of 150 million Btu/hr or greater by introducing the emission stream with the combustion air [40 CFR 63.443(d)(4)(i) and (ii)]; and
      (C) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that the tank contains pulping process condensates or any HAP removed from a pulping process condensate stream except when it is necessary to use the opening for sampling, removal, or for equipment inspection, maintenance, or repair.
   iv. The collected pulping process condensates identified in Section 2.2 A.1.f, above, shall be treated by the Condensate Stripper Reflux Condenser **(ID No. ES-09-25-1050)** which shall [40 CFR 63.446(e)(2)]:
      (A) Reduce or destroy the total HAPs by at least 92 percent or more by weight [40 CFR 63.446(e)(3)]; or
      (B) Remove a minimum of 10.2 pounds per ton of ODP [40 CFR 63.446(e)(5).
      (C) Each HAP removed in the Condensate Stripper Reflux Condenser shall be vented into a closed-vent system that meets the requirements in Section 2.2 A.1.h, below, and routed to the No. 5 Lime Kiln **(ID Nos. ES-09-14-60-3000)** by introducing the HAP emission stream with the primary fuel or into the flame zone or the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)** by introducing the HAP emission stream with the primary fuel or into the flame zone or operating the boiler with a heat input of 150 million Btu/hr or greater by introducing the emission stream with the combustion air [40 CFR 63.446(f)].
   v. For the Condensate Stripper Reflux Condenser **(ID No. ES-09-25-1050)** used to comply with the requirements specified above, periods of excess emissions reported in Section 2.2 A.1.v, below, shall not be a violation of Section 2.2 A.1.g provided that the time of excess emissions (including periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 10 percent.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the pulping process condensates are not collected an controlled as required above.

Standards for Enclosures and Closed-Vent Systems

h. The Permittee shall meet the following standards for enclosures and closed-vent systems for capturing and transporting vent streams that contain hazardous air pollutants. [40 CFR 63.450]
   i. Each enclosure or hood opening closed during the initial performance test shall be maintained in the same closed and sealed position as during the performance test at all times except when necessary to use the opening for sampling, inspection, maintenance, or repairs.

ii. For each enclosure, the Permittee shall maintain negative pressure at each enclosure or hood opening as demonstrated by the procedures specified below: [40 CFR 63.457(e)]
(A) An anemometer to demonstrate flow into the enclosure opening;
(B) Measure the static pressure across the opening;
(C) Smoke tubes to demonstrate flow into the enclosure opening; or
(D) Any other industrial ventilation test method demonstrated to the satisfaction of DAQ.

iii. Each component of the closed-vent system that is operated at positive pressure and located prior to a control device shall be designed for and operated with no detectable leaks as measured by the procedures specified below: [40 CFR 63.457(d)]
(A) A leak is indicated by an instrument reading of 500 parts per million by volume or greater, measured as methanol, above background,
(B) The Permittee shall comply with Method 21, of 40 CFR Part 60, Appendix A-7;
(C) The instrument specified in Method 21 shall be calibrated before use pursuant to the procedures specified in Method 21 on each day that leak checks are performed. The following calibration gases shall be used:
(1) Zero air (less than 10 parts per million by volume of hydrocarbon in air); and
(2) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 parts per million by volume methane or n-hexane.

iv. For each bypass line in the closed-vent system that could divert vent streams containing HAP to the atmosphere without meeting the emission limitations Section 2.2 A.1.b through A.1.d, above, shall comply with either of the following requirements [40 CFR 63.450(d)]:
(A) On each bypass line, the Permittee shall install, calibrate, maintain, and operate pursuant to the manufacturer's specifications a flow indicator that is capable of taking periodic readings at least once every 15 minutes. The flow indicator shall be installed in the bypass line in such a way as to indicate flow in the bypass line; or
(B) For bypass line valves that are not computer controlled, the Permittee shall maintain the bypass line valve in the closed position with a car seal or a seal placed on the valve or closure mechanism in such a way that valve or closure mechanism cannot be opened without breaking the seal.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the enclosures and closed-vent system standards are not met as specified above.

Testing [15A NCAC 02Q .0508(f) and 40 CFR 63.457]

i. If emissions testing is required, the testing shall be performed in accordance General Condition JJ. If the results of this test are above the limits given in Section 2.2 A.1.b through A.1.f, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111.

j. The Permittee shall conduct repeat periodic performance tests at five-year intervals for emission sources specified in Section 2.2 A.1.b through A.1.f, above, except for emission sources controlled by the No. 5 Lime Kiln **(ID Nos. ES-14-60-3000)**, No. 1 Hog Fuel Boiler **(ID No. ES-64-225-0290)**, No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, No. 5 Recovery Boler **(ID No. ES-10-25-0110)**, and Thermal Oxidizer **(ID No. CD-64-22-2000)**. [40 CFR 63.457(a)]
i. Each periodic performance test shall be conducted within 60 months from the date of the previous performance test. Performance testing shall be conducted pursuant to 40 CFR 63.457.
ii. The Permittee may seek to establish or reestablish the monitoring parameter values specified in Section 2.2 A.1.k, A.1.l, A.1.m through A.1.o, below. The Permittee shall establish or reestablish the value for each operating parameter during initial or subsequent periodic performance tests, using the following procedures 40 CFR 63.453(n)]:
(A) During the initial or any subsequent performance test, the Permittee shall continuously record the operating parameter;
(B) Determinations shall be based on the control performance and parameter data monitored during the performance test, supplemented if necessary by engineering assessments and the manufacturer's recommendations;
(C) The Permittee shall provide, for the DAQ approval, the rationale for the selected operating parameter value, and monitoring frequency, and averaging time. Include all data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the applicable emission standard.

iii. The established continuous compliance monitoring parameters shall not apply during any required subsequent testing.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if periodic performance tests are not conducted as required.

Monitoring for the Bleaching System Scrubber [40 CFR 63.453]

k. The Permittee shall install, calibrate, certify, operate, and maintain pursuant to manufacturer's specifications, a continuous monitoring system (CMS), on the No. 6 Bleach Plant White Liquor Scrubber (**ID No. CD-06-35-8100)**. The CMS shall include a continuous recorder. The CMS shall be operated to ensure the following operational parameters are maintained [40 CFR 63.453(c) and (o)]:
   i. The minimum pH of the scrubber effluent shall be 10.0 (3 hour average);
   ii. The scrubber inlet vent gas fan operating status of "on" (on or off based on motor load); and
   iii. The minimum scrubber liquid recirculation rate shall be 45 gallons per minute (3 hour rolling average);
   iv. Operation of the Ns. 6 Bleach Plant White Liquor Scrubbers below the minimum operating parameters listed above shall constitute a violation of the emission standard of Section 2.2 A.1.b, above, and shall be reported as a period of excess emissions in accordance with Section 2.2 A.1.v, below.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 If any monitoring parameter values are exceeded or if the monitoring procedures are not followed or if an operational parameter is exceeded, except as provided in Section 2.2 A.1.j.iii, above, or if the monitoring procedures are not followed.

l. The Permittee shall install, calibrate, certify, operate, and maintain pursuant to manufacturer's specifications, a continuous monitoring system (CMS), on the No. 7 Bleach Plant White Liquor Scrubbers (**ID No. CD-07-36-8000)**. The CMS shall include a continuous recorder. The CMS shall be operated to ensure the following operational parameters are maintained [40 CFR 63.453(c) and (o)]:
   i. The minimum pH of the scrubber effluent shall be 10.0 (3 hour average);
   ii. The scrubber inlet vent gas fan operating status of "on" (on or off based on motor load); and
   iii. The minimum scrubber liquid recirculation rate shall be 105 gallons per minute (3 hour rolling average).
   iv. Operation of the No. 7 Bleach Plant White Liquor Scrubber below the minimum operating parameters listed above shall constitute a violation of the emission standard of Section 2.2 A.1.b, above, and shall be reported as a period of excess emissions in accordance with Section 2.2 A.1.v, below.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 If any monitoring parameter values are exceeded or if the monitoring procedures are not followed or if an operational parameter is exceeded, except as provided in Section 2.2 A.1.j.iii, above, or if the monitoring procedures are not followed.

Monitoring for the LVHC and HVLC Pulping Systems Control Devices [15A NCAC 02Q .0508(f)]

m. The Permittee shall install, calibrate, certify, operate, and maintain according to the manufacturer's specifications, a continuous monitoring system as specified below. The CMS shall include a continuous recorder. [40 CFR 63.453(b) and (o)]
   i. No control device parameter monitoring is required for pulping vent systems routed to the No. 5 Lime Kiln **(ID No. ES-14-60-3000)**, No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, No. 1 Hog Fuel Boiler **(ID No. ES-64-25-0290)** or the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**.
   ii. The Permittee shall operate a CMS to measure the temperature in the firebox or in the ductwork downstream from the firebox and before any substantial heat exchange for the Thermal Oxidizer **(ID No. CD-64-22-2000)**. The minimum temperature shall be 1600°F. [40 CFR 63.453(b)]
   iii. Except as provided in the excess emissions condition in Section 2.2 A.1.c, above, operation of the Thermal Oxidizer below the minimum temperature listed above shall constitute a violation of the emission standard of Section 2.2 A.1.d, above, and shall be reported as a period of excess emissions in accordance with Section 2.2 A.1.v, below. [40 CFR 63.453(o) and 63.443(e)]

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the CMS on thermal oxidizer is not installed, calibrated, certified, operated and maintained as specified above.

Monitoring for the Pulping Process Condensate Collection [15A NCAC 02Q .0508(f)]

n. To ensure compliance, the Permittee shall monitor the condensate collection system in accordance with the Methanol Factor Statistical Model, approved by the NC DAQ on June 24, 2011. Condensate samples from the stripper feed tank shall be collected on Monday, Wednesday, and Friday each week (unless there is a valid reason which results in the lab technician being unable to collect a sample on one of these days) and a weekly composite shall be analyzed to ensure that the minimum of 11.1 pounds of HAP per ton of oven dried pulp produced (based on a 30-day rolling average) is collected. The Permittee shall be deemed in noncompliance with 15A NCAC 02D

.1111 if any monitoring parameter demonstrates collection less than 11.1 pounds of HAP per oven dried pulp (based on a 30-day rolling average) or if the monitoring procedures are not followed.

Monitoring for the Condensate Stripper Reflux Condenser: [15A NCAC 02Q .0508(f)]

o. The Permittee shall install, calibrate, certify, operate, and maintain CMS on the Condensate Stripper Reflux Condenser **(ID No ES-09-25-1050).** The CMS shall measure stripper feed rate, steam feed rate, and column feed temperatures and each CMS shall include a continuous recorder. The CMS shall be operated to ensure the following [40 CFR 63.453(g)]:
   i. The column feed temperature shall be greater than 150°F;
   ii. The stripper feed rate and steam feed rate CMS shall be operated to ensure the steam to feed ratio is maintained at a minimum of 17 percent calculated daily on a rolling 30-day average.
   iii. Operation of the Condensate Stripper Reflux Condenser below the minimum operating parameters listed above shall constitute a violation of the emission standard of Section 2.2 A.1.g, above, and shall be reported as a period of excess emissions, except as provided in Section 2.2 A.1.g.v, above, or if the monitoring procedures are not followed.

   The Permittee shall be deemed in noncompliance with 02D .1111 if any monitoring parameter value is exceeded or if the monitoring procedures are not followed,

Monitoring/Inspections for Enclosures, Closed-Vent, and Closed Collection Systems [15A NCAC 02Q .0508(f)]

p. Each enclosure and closed vent system shall meet the following monitoring requirements [40 CFR 63.453(k)]:
   i. The Permittee shall conduct a visual inspection of the closure mechanism of each enclosure specified in Section 2.2 A.1.h, above, shall be performed at least once every 30 days to ensure the opening is maintained in the closed position and sealed. The Permittee shall demonstrate initially and annually that each enclosure opening is maintained at negative pressure as specified in Section 2.2 A.1.h, above.
   ii. The Permittee shall visually inspect each closed-vent system every 30 days and at other times as requested by the DAQ. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects.
   iii. For positive pressure closed-vent systems or portions of closed-vent systems, the Permittee shall demonstrate no detectable leaks as specified in Section 2.2 A.1.h, above, measured initially and annually by the procedures in Section 2.2 A.1.h.
   iv. The Permittee shall inspect the valve or closure mechanism specified in Section 2.2 A.1.h.iii.(B), above, at least once every 30 days to ensure that the valve is maintained in the closed position and the emission point gas stream is not diverted through the bypass line.
   v. If a required inspection identifies visible defects in ductwork, piping, enclosures or connections to covers required, or if an instrument reading of 500 parts per million by volume or greater above background is measured (as methanol), or if enclosure openings are not maintained at negative pressure, then the Permittee shall take following corrective actions as soon as practicable.
      (A) A first effort to repair or correct the closed-vent system shall be made as soon as practicable but no later than 5 calendar days after the problem is identified.
      (B) The repair or corrective action shall be completed no later than 15 calendar days after the problem is identified. Delay of repair or corrective action is allowed if the repair or corrective action is technically infeasible without a process unit shutdown or if the Permittee determines that the emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed by the end of the next process unit shutdown.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the monitoring is not performed as specified.

q. For each pulping process condensate closed collection system used to comply with Section 2.2 A.1.f and A.1.g, above, shall comply with the requirements specified below [40 CFR 63.453(l)]:
   i. The Permittee shall visually inspect each pulping process condensate closed collection system every 30 days and shall comply with the inspection and monitoring requirements specified in 40 CFR Part 63, Subpart RR [40 CFR 63.964], except:
      (A) The Permittee shall comply with the recordkeeping requirements Section 2.2 A.1 instead of the requirements specified in 40 CFR 63.964(a)(1)(vi) and (b)(3) (Subpart RR).
      (B) The Permittee shall comply with the inspection and monitoring requirements for closed-vent systems and control devices specified in Section 2.2 A.1.p, above, instead of the requirements specified in 40 CFR 63.964(a)(2) (Subpart RR).

ii. Each condensate tank used in the closed collection system shall be operated with no detectable leaks as specified in Section 2.2 A.1.g.iv.(C), above, measured initially and annually by the procedures specified in Section 2.2 A.1.g.ii, above.
iii. If an inspection required by this section identifies visible defects in the closed collection system, or if an instrument reading of 500 parts per million or greater above background is measured, then the Permittee shall take the corrective actions specified in 40 CFR 63.964(b) (Subpart RR).

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the closed collection system is not inspected as required above.

r. The Permittee shall prepare and maintain a site-specific inspection plan, including a drawing or schematic of the components of affected equipment and shall record the following for each inspection for each enclosure opening, closed-vent system, and closed collection system [40 CFR 63.454(b)]:
i. Date of inspection;
ii. The equipment type and identification;
iii. Results of negative pressure tests for enclosures;
iv. Results of leak detection tests;
v. The nature of the defect or leak and the method of detection (i.e., visual inspection or instrument detection);
vi. The date the defect or leak was detected and the date of each attempt to repair the defect or leak;
vii. Repair methods applied in each attempt to repair the defect or leak;
viii. The reason for the delay if the defect or leak is not repaired within 15 days after discovery;
ix. The expected date of successful repair of the defect or leak if the repair is not completed within 15 days;
x. The date of successful repair of the defect or leak;
xi. The position and duration of opening of bypass line valves and the condition of any valve seals; and
xii. The duration of the use of bypass valves on computer-controlled valves.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these inspection records are not maintained.

Startup, Shutdown, and Malfunction [15A NCAC 02D .1111]

s. The Permittee shall operate and maintain the Subpart S affected sources at all times, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the DAQ which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these practices are not conducted. [40 CFR 63.453(q)]

Recordkeeping [15A NCAC 02Q .0508(f)]

t. The results of the CMS monitoring, the enclosure system monitoring, and the closed-vent system monitoring shall be maintained (in written or electronic format) per the requirements of 40 CFR 63.454(a). The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if these records are not maintained.

u. The Permittee shall maintain the following records of malfunctions [40 CFR 63.454(g)]:
i. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
ii. Records of actions taken during periods of malfunction to minimize emissions in accordance with Section 2.2 A.1.s, above, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if records of malfunctions are not maintained as required.

Reporting [15A NCAC 02Q .0508(f)]

v. The Permittee shall submit a summary report of excess emissions as specified in Section 2.2 A.1.c.ii, A.1.d.ii, and A.1.g.v, above, postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December, July 30 of each calendar year for the preceding six-month period between January and June. The Permittee shall determine excess emissions and monitoring performance on a quarterly basis. All instances of deviations from the requirements of this permit must be clearly identified. When no exceedences of an operating parameter have occurred, such information shall be included in the report. [40 CFR 63.10(e)(3) and Table 1 of 40 CFR Part 63, Subpart S]

w. The Permittee shall comply with the reporting requirements of 40 CFR Part 63, Subpart A as specified in Table 1 of 40 CFR 63.440. The Permittee shall include results of the CCA measurement requirements and a demonstration that the pounds of methanol emissions per ton of ODP from the CCA is greater than the baseline of 0.502 pounds of methanol per ton of ODP as determined in Section 2.2 A.1.e, above.

x. If a malfunction occurred during the reporting period, the summary report must include the number, duration and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with Section 2.2, A.1.r, above, including actions taken to correct a malfunction. [40 CFR 63.455(g)]

y. The Permittee shall submit performance test reports as specified in 40 CFR 63.455(h).

B. 40 CFR Part 63, Subpart MM Affected Sources:

Table 2.2 B-1

Source ID No.	Source Description	Control ID No	Control Description
ES-10-25-0110	No. 5 Recovery Boiler	CD-10-45-0220 and CD-10-45-0010	North and South Electrostatic Precipitators
ES-14-05-0050	North Smelt Tank	CD-14-05-0700	Ducon alkaline scrubber
ES-14-05-0300	South Smelt Tank	CD-14-05-0750	Ducon alkaline scrubber
ES-14-60-3000	No. 5 Lime Kiln	CD-14-70-2012	Venturi scrubber

Table 2.2 B-2

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Hazardous air pollutants	**No. 5 Recovery Boiler** • PM emissions shall be no greater than 0.044 gr/dscf corrected to 8% oxygen. • Opacity shall not be greater than 35 percent for more than 2 percent of the operating time within any semiannual period. **North Smelt Tank** • PM emissions shall be no greater than 0.073 gr/dscf and no greater than 0.187 lb/TBLS. • Scrubber spray header flow shall be greater than 75 gallons per minute (3-hour average), rod box flow rate shall be greater than 50 gallons per minute (3-hour average), and pressure drop shall be greater than 3 in. H_2O (3-hour average). **South Smelt Tank** • PM emissions shall be no greater than 0.073 gr/dscf and no greater than 0.200 lb/TBLS. • Scrubber spray header flow shall be greater than 75 gallons per minute (3-hour average), rod box flow rate shall be greater than 50 gallons per minute (3-hour average), and pressure drop shall be greater than 3 in. H_2O (3-hour average). **No. 5 Lime Kiln** • PM emissions shall be no greater than 0.066 gr/dscf, corrected to 10% oxygen. • Scrubber liquid flow shall be no less than 896 gallons per minute (3-hour average). • Scrubber pressure drop shall be no more than 5 in H_2O (3-hour average) and the liquid nozzle header pressure range shall be from 240 to 275 psig (3-hour average). **Overall Chemical Recovery System PM Limit** • Total PM emissions from the No. 5 Recovery Boiler, North and South Smelt Tanks, and No. 5 Lime Kiln shall be no greater than 1.478 lb/TBLS.	15 A NCAC 02D .1111 (40 CFR 63 Subpart MM)

1. 15A NCAC 02D .1111: MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

a. The Permittee shall comply with all applicable provisions, including the notification, testing, reporting, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .1111 "Maximum Achievable Control Technology" as promulgated in 40 CFR Part 63, Subpart MM "National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills," including Subpart A "General Provisions" as defined per 63.440(g) and indicated per Table 1 of Subpart MM. Terms used throughout this section are defined in the Clean Air Act as amended in 1990 and in 40 CFR 63.2 and 63.861. Units and abbreviations are defined in 40 CFR 63.3.

Emission Limitations [15A NCAC 02D .1111]

b. The following emission limits apply to the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, and No. 5 Lime Kiln **(ID No. ES-14-60-3000)**:
   i. Particulate matter emissions from the recovery boiler, smelt tanks, and lime kiln shall not exceed the limits presented in Table 2.2 B-2, above. [40 CFR 63.862(a)(1)(ii) and 63.865(a)]
   ii. The chemical recovery system emission limits must be re-established if either:
      (A) the ESPs installed on the No. 5 Recovery Boiler **(ID Nos. CD-10-45-0220 and CD-14-45-0010)**, the scrubbers installed on the North and South Smelt Tanks **(ID Nos. CD-14-05-0700 and CD-14-05-0750)**, and the scrubber installed on the No. 5 Lime Kiln **(ID No. CD-14-70-2012)** are modified (as defined in 40 CFR 63.861) or replaced, or
      (B) the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, or No. 5 Lime Kiln **(ID No. ES-14-60-3000)** are shut down for more than 60 consecutive days. [40 CFR 63.862(a)(1)(ii)(D)]
   iii. At all times, the Permittee shall operate and maintain each recovery boiler, smelt tank, and lime kiln, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Permittee to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to DAQ which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.860(d)]

Testing [15A NCAC 02D .1111]

c. Emissions testing shall be performed according to the procedures in 40 CFR 63.7 and 63.865, and General Condition JJ. If the results of the testing indicate that the chemical recovery system emission rate is greater than the emission limits presented in Table 2.2 B-2, above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111. [40 CFR 63.865]

d. The Permittee shall conduct a performance test using the methods and procedures specified in Section 2.2 B.1.c, above, on the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, and No. 5 Lime Kiln **(ID No. ES-14-60-3000)** no later than October 13, 2020 and thereafter every 5 years following the previous performance test. [40 CFR 63.865]
   i. As allowed under 40 CFR 63.865, the Permittee may use a previously-conducted performance test to satisfy the October 13, 2020, testing requirement provided DAQ has approved the test. The October 13, 2020 testing requirement was satisfied using the initial performance tests conducted on the dates specified below. The next period performance tests will be required within 5 years of these dates and every 5 years thereafter.
      (A) An approved performance test on the No. 5 Recovery Boiler was conducted on June 26, 2019.
      (B) Approved performance tests on the North and South Smelt Dissolving Taks were conducted on June 27, 2019.
      (C) An approved performance test on the No. 5 Lime Kiln was conducted on July 31, 2019.
   ii. The Permittee shall conduct performance tests based on representative performance of the No. 5 Recovery Boiler, North and South Smelt Tanks, and No. 5 Lime Kiln for the period being tested. Representative conditions do not include periods of startup and shutdown.
   iii. The Permittee shall not conduct performance tests during periods of malfunction.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the periodic performance tests are not conducted as required.

Monitoring [15A NCAC 02D .1111]

e. The Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) at the outlet of No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** in accordance with Performance Specification 1 in Appendix B to 40 CFR Part 60 and the provisions in 40 CFR 63.6(h) and 63.8 and as follows: [40 CFR 63.864(d)]
   i. Each COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
   ii. Per 40 CFR 63.8(g)(2), each 6-minute COMS data average opacity shall be calculated as the average of 36 or more data points equally spaced over each 6-minute period.

   If these monitoring procedures are not followed, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111.

f. For each required continuous parameter monitoring system (CPMS), the Permittee shall meet the following requirements. [40 CFR 63.864(e)]
   i. On and after October 11, 2019, the Permittee shall maintain proper operation of automatic voltage control of the ESP installed on the No. 5 Recovery Boiler. [40 CFR 63.864(e)(1)]
   ii. The Permittee shall install, calibrate, maintain, and operate CMPS that can be used to determine and record the pressure drop, liquid nozzle header pressure, and the scrubbing liquid flow rate of the scrubber **(ID No. CD-14-70-2012)** installed on the No. 5 Lime Kiln and scrubber and the pressure drop, scrubber spray header flow rate, and rod box flow rate of the scrubbers **(ID Nos. CD-14-05-0700 and CD-14-05-0750)** installed on the North and South Smelt Tanks. These scrubber parameters shall be monitored at least once every successive 15-minute period using the procedures in 40 CFR 63.8(c), as well as the following [40 CFR 63.864(e)(10) and (13)]:
      (A) The monitoring device used for the continuous measurement of the pressure drop of the gas stream across each scrubber shall be certified by the manufacturer to be accurate to within a gauge pressure of ±2 inches of water gauge pressure; and
      (B) The monitoring device used for continuous measurement of the scrubbing liquid flow rate shall be certified by the manufacturer to be accurate within ±5 percent of the design scrubbing liquid flow rate.

   If these monitoring procedures are not followed, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111.

g. Per 40 CFR 63.8(g)(5), monitoring data recorded during periods of unavoidable CMS breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high level adjustments shall not be included in any data averages computed for compliance with Section 2.2 B.1. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if data averages are not calculated as specified above. [40 CFR 63.864(h)]

Operating Limits [15A NCAC 02D .1111]

h. The Permittee shall confirm or reestablish operating limits for the monitoring parameters identified in Table 2.2 B-2, above, during performance tests conducted per Section 2.2 B.1.c and B.1.d, above, as follows [40 CFR 63.864(j)]:
   i. The Permittee shall establish operating limits on values recorded during the performance tests conducted according to Section 2.2 B.1.c and B.1.d, above; or
   ii. The Permittee may base operating limits on values recorded during previous performance tests or conduct additional performance tests for the specific purpose of establishing operating limits, provided that test data used to establish the operating limits are or have been obtained using the test methods required in 40 CFR Part 63, Subpart MM. The Permittee shall certify that all control techniques and processes have not been modified subsequent to the testing upon which the data used to establish the operating parameter limits were established.
   iii. The Permittee may establish expanded or replacement operating limits for the monitoring parameters specified in Table 2.2 B-2, above, during subsequent performance tests using the test methods in 40 CFR 63.865.
   iv. The Permittee shall continuously monitor each parameter and determine the arithmetic average value of each parameter during each performance test run. Multiple performance tests may be conducted to establish a range of parameter values. Operating outside a previously established parameter limit during a performance test to expand the operating limit range does not constitute a monitoring period of noncompliance.
   v. The Permittee shall set the operating limits for the North and South Smelt Tanks and the No. 5 Lime Kiln Scrubbers **(ID Nos. CD-14-05-0700, CD-14-05-0750, and CD-14-70-2012)** as the lowest of the 1-hour average values associated with each test run demonstrating compliance with the applicable emission limits specified in Section 2.2 B.1.b, above.
   vi. If the new parameter value(s) to be relied upon to demonstrate compliance are more stringent, the Permittee shall submit a request to revise the value(s) in the permit at the same time the associated test report required

pursuant to General Condition JJ.4 is submitted. The permit revision will be processed pursuant to 15A NCAC 02Q .0514.

vii. If the new parameter value(s) to be relied upon to demonstrate compliance are less stringent, the Permittee may request to revise the value(s) in the permit pursuant to 15A NCAC 02Q .0515.

The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if operating limits are not established as required.

Ongoing Compliance Requirements [15A NCAC 02D .1111]

i. The Permittee is required to implement corrective action if the following monitoring exceedances occur during times when spent pulping liquor is fed to the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** or lime mud is fed to the No. 5 Lime Kiln **(ID No. ES-14-60-3000)**. Corrective action can include completion of transient startup and shutdown conditions as expediently as possible.
   i. For the No. 5 Recovery Boiler, when the average of ten consecutive 6-minute averages results in a measurement greater than 20 percent opacity; [40 CFR 63.864(k)(1)(i)]
   ii. For the No. 5 Lime Kiln or the North or South Smelt Tank **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, when any 3-hour average wet scrubber parameter value is below the minimum operating limit in Table 2.2 B-2, above, established in Section 2.2 B.1.h, above, with the exception of pressure drop during periods of startup and shutdown. [40 CFR 63.864(k)(1)(iii) and (vi)]

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the Permittee does not implement corrective action as specified.

j. The Permittee is in violation of the emission limits in Section 2.2 B.1.b, above, if the following monitoring exceedances occur during times when spent pulping liquor is being fed to the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)** or lime mud is fed to the No. 5 Lime Kiln **(ID No. ES-14-60-3000)**. [40 CFR 63.864(k)(2)]
   i. For No. 5 Recovery Boiler, when opacity is greater than 35 percent for 2 percent or more of the operating time within any semiannual period. [40 CFR 63.864(k)(2)(i)]
   ii. For the No. 5 Lime Kiln or the North or South Smelt Tank **(ID No. ES-14-05-0050 and ES-14-05-0300)**, when six or more 3-hour average parameter values within any 6-month reporting period are below the minimum operating limits specified in Table 2.2 B-2, above, with the exception of pressure drop during periods of startup or shutdown. [40 CFR 63.864(k)(2)(iv) and (viii)]

k. For purposes of determining the number of nonopacity monitoring exceedances, no more than one exceedance will be attributed in any given 24-hour period. [40 CFR 63.864(k)(3)]

Recordkeeping [15A NCAC 02D .1111]

l. In addition to the general records required by 40 CFR 63.10(b)(2)(iii) and (vi) through (xiv), the Permittee shall maintain records of the following information [40 CFR 63.866(b) and (c)]:
   i. Records of black liquor solids firing rates in units of megagram (Mg) per day (Mg/day) or ton per day (ton/day) for the No. 5 Recovery Boiler ;
   ii. Records of lime (CaO) production rates in units of ton/day for the No. 5 Lime Kiln;
   iii. Records of parameter monitoring data required under Section 2.2 B.1.e and B.1.f, above, including any period when the operating parameter levels were inconsistent with the levels established during the performance test, with a brief explanation of the cause of the monitoring exceedance, the time the exceedance occurred, the time corrective action was initiated and completed, and the corrective action taken;
   iv. Records and documentation of supporting calculations for the chemical recovery system emissions limit in Section 2.2 B.1.b, above;
   v. Records of parameter operating limits established under Section 2.2 B.1.h;
   vi. Records demonstrating compliance with the requirement specified in Section 2.2 B.1.f.i, above, to maintain proper ESP AVC.
   vii. The Permittee shall maintain records of any occurrence when corrective action is required under Section 2.2 B.1.i, above, and when a violation is noted under Section 2.2 B.1.j, above, occurs.
   viii. Records of process information that is necessary to document operating conditions during performance tests and an explanation to support that such conditions represent normal conditions.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the specified records are not maintained.

m. The Permittee shall maintain the following records [40 CFR 63.866(d)(1)]:
   i. In the event that the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, or No. 5 Lime Kiln **(ID No. ES-14-60-3000)** fails to meet an applicable standard, including any emission limit or any opacity or CPMS operating limit in Table 2.2 B-1, above, record the number of failures. For each failure record the date, start time, and duration of each failure.
   ii. For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, and the following information:
      A. For any failure to meet an emission limit in Table 2.2 B-1, above, record an estimate of the quantity of each regulated pollutant emitted over the emission limit and a description of the method used to estimate the emissions.
      B. For each failure to meet an operating limit in Table 2.2 B-1, above, maintain sufficient information to estimate the quantity of each regulated pollutant emitted over the emission limit. This information must be sufficient to provide a reliable emissions estimate if requested by DAQ.
   iii. Record actions taken to minimize emissions in accordance with Section 2.2 B.1.b.iii, above, and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

   The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the specified records are not maintained.

n. All records shall be maintained in a logbook (written or electronic format) on-site and made available to an authorized representative upon request. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the records are not maintained.

o. The Permittee shall keep CPMS data quality assurance procedures consistent with the requirements in 40 CFR 63.8(d)(1) and (2) on record for the life of the No. 5 Recovery Boiler **(ID No. ES-10-25-0110)**, North and South Smelt Tanks **(ID Nos. ES-14-05-0050 and ES-14-05-0300)**, and No. 5 Lime Kiln **(ID No. ES-14-60-3000)**. The program of corrective action should be included in the plan required under 40 CFR 63.8(d)(2). If the performance evaluation plan is revised, the Permittee shall keep previous versions on record to be made available to DAQ upon request for a period of 5 years after each revision to the plan. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .1111 if the required CPMS data quality assurance procedures are not followed. [40 CFR 63.864(f)]

Reporting [15A NCAC 02D .1111]

p. After DAQ has approved the emissions limits specified in Section 2.2 B.1.b, above, the Permittee shall notify DAQ before any of the following actions are taken [40 CFR 63.867(b)(3)]:
   i. The ESPs installed on the No. 5 Recovery Boiler **(ID Nos. CD-10-45-0220 and CD-10-45-0010)**, the scrubbers installed on the North and South Smelt Tanks **(ID Nos. CD-14-05-0700 and CD-14-05-0750)**, or the scrubber installed on the No. 5 Lime Kiln **(ID No. CD-14-70-2012)** are modified or replaced;
   ii. The No. 5 Recovery Boiler, North or South Smelt Tank, or No. 5 Lime Kiln are shut down for more than 60 consecutive days;
   iii. A continuous monitoring parameter or the value or range of values of a continuous monitoring parameter for No. 5 Recovery Boiler, North or South Smelt Tank, or No. 5 Lime Kiln is changed; or
   iv. The black liquor solids firing rate for No. 5 Recovery Boiler during any 24-hour averaging period is increased by more than 10 percent above the level measured during the most recent performance test.

q. If the Permittee shall recalculate the overall PM emissions limit for the No. 5 Recovery Boiler, North or South Smelt Tank, and No. 5 Lime Kiln as required in Section 2.2 B.1.b.ii, above, the Permittee shall resubmit the calculations and supporting documentation used in 40 CFR 63.865 to DAQ for approval. [40 CFR 63.867(b)(4)]

r. The Permittee shall submit semiannual excess emissions reports postmarked on or before January 30 of each calendar year for the preceeding six-month period between July and December and July 30 of each calendar year for the preceeding six-month period between January and June. The Permittee shall determine excess emissions and monitoring performance on a quarterly basis. Each report shall contain the following information and shall be submitted following the reporting procedures specified in 40 CFR 63.867(d). [40 CFR 63.867(c)]
   i. If the total duration of excess emissions or process control system parameter exceedances for the reporting period is less than 1 percent of the total reporting period operating time, and CMS downtime is less than 5 percent of the total reporting period operating time, only the summary report is required to be submitted. This report will be titled “Summary Report—Gaseous and Opacity Excess Emissions and Continuous Monitoring

System Performance" and must contain the information specified in 40 CFR 63.867(c)(1)(i) through (x). [40 CFR 63.867(c)(1)]

ii. If measured parameters meet any of the conditions specified in Section 2.2 B.1.i or B.1.j, above, the owner or operator of the affected source must submit a semiannual report describing the excess emissions that occurred. If the total duration of monitoring exceedances for the reporting period is 1 percent or greater of the total reporting period operating time, or the total CMS downtime for the reporting period is 5 percent or greater of the total reporting period operating time, or any violations according to Section 2.2 B.1.k, above, occurred, information from both the summary report and the excess emissions and continuous monitoring system performance report must be submitted. This report will be titled "Excess Emissions and Continuous Monitoring System Performance Report" and must contain the information specified in 40 CFR 63.867(c)(1)(i) through (x), in addition to the information required in 40 CFR 63.10(c)(5) through (14), as specified in 40 CFR 63.867(c)(3)(i) through (vi). Reporting monitoring exceedances does not constitute a violation of the applicable standard unless the violation criteria in Section 2.2 B.1.k and B.1.l, above, are reached. [40 CFR 63.867(c)(3)]

iii. If a source fails to meet an applicable standard, including any emission limit or operating limit specified in Table 2.2 B-2, the Permittee shall report such events in the semiannual excess emissions report. The Permittee shall report the number of failures to meet an applicable standard and for each instance, the date, time and duration of each failure. For each failure, the report shall include a list of the affected sources or equipment, and for any failure to meet an emission limit specified in Table 2.2 B-2, above, the Permittee shall provide an estimate of the quantity of each regulated pollutant emitted over the emission limit, and a description of the method used to estimate the emissions. [40 CFR 63.867(c)(4)]

iv. The Permittee may combine excess emissions and/or summary reports for the facility for 40 CFR Part 63, Subpart MM and Subpart S. [40 CFR 63.867(c)(5)]

C. Lignin Solids Removal Process:

- **Main Sources:**
  These sources are controlled by the Two-Phase Packed Bed Caustic Scrubber (ID No. CD-09-27-3800)
  - **No. 1 Feed Liquor Cooler (ID No. ES-09-27-1100)**
  - **No. 1 Lignin Filtrate Storage Tank (ID No. ES-09-27-1200)**
  - **Lignin Slurry Conditioning Tank (ID No. ES-09-27-1800)**
  - **Lignin Slurry Buffer Tank (ID No. ES-09-27-2000)**
  - **No. 1 Lignin Filter Cloth Wash Tank 1 (ID No. ES-09-27-2300)**
  - **No. 1 Lignin Filtrate Tank 1 (ID No. ES-09-27-2400)**
  - **No. 1 Lignin Filtrate Buffer Tank (ID No. ES-09-27-2500)**
  - **Lignin Lump Breaker (ID No. ES-09-27-2600)**
  - **No. 1 Lignin Filter Horizontal Conveyor (ID No. ES-09-27-2610)**
  - **No. 1 Lignin Filter Incline Conveyor (ID No. ES-09-27-2620)**
  - **Lignin Rotary Feeder (ID No. ES-09-27-2660)**
  - **No. 2 Lignin Acidic Filtrate Tank (ID No. ES-09-27-3200)**
  - **No. 1 Lignin Filter (ID No. ES-09-27-2100)**
  - **No. 2 Lignin Filter Cloth Wash Tank (ID No. ES-09-27-3100)**
  - **Acidic Lignin Conditioning Tank (ID No. ES-09-27-2800)**

- **HVLC Sources:**
  The following LSRP HVLC Sources controlled in the No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310) or No. 1 Hog Fuel Boiler (ID No. ES-64-25-0290) or No. 5 Recovery Boiler (ID No. ES-10-25-0110) or the Thermal Oxidizer (CD-64-22-2000)
  - **Carbonator Tower (ID No. ES-09-27-1400)**
  - **Lignin Acidification Tank (ID No. ES-09-27-2700)**
  - **Lignin Foam Tank (ID No. ES-09-27-2770)**

- **Dust Collection Sources:**
  The following Dust Collection sources will be routed to a Dust Collection System, including a Wet Cyclone (ID No. CD-09-27-3900)
  - **No. 2 Lignin Filter (ID No. ES-09-27-3000)**
  - **No. 2 Lignin Filter Horizontal Conveyor (ID No. IES-09-27-3400)**

- **Other Sources:**
  The following Other Sources will be uncontrolled
  - **Lignin Feed Liquor Tank (ID No. ES-09-27-1000)**
  - **Acid Wash Water Tank (ID No. IES-09-27-2900)**
  - **Lignin Acid Area Sump (ID No. IES-09-27-3700)**
  - **Lignin Liquor Area Sump (ID No. IES-09-27-3600)**

Other Affected Sources:

- **No. 1 Hog Fuel Boiler (ID No. ES-64-25-0290)**
- **No. 2 Hog Fuel Boiler (ID No. ES-65-25-0310)**
- **No. 2 Hog Fuel Conveying (ID No. FS-007)**
- **Hogged Fuel Storage Pile at Boilers (ID No. FS-011)**
- **No. 2 HF Ash Transport Steam Exhauster (ID No. ES-65-50-0160)**

- **No. 2 HF Ash Silo (ID No. ES-65-50-0190)**
- **No. 2 HF Scrubber Ash Silo (ID No. ES-65-60-0860)**
- **No. 5 Recovery Boiler (ID No. ES-10-25-0110)**
- **Salt Cake Mix Tank (ID No. ES-10-08-0010)**
- **No. 5 Precipitator Mix Tank (ID No. ES-10-45-0450)**
- **North & South Smelt Tanks (ID Nos. ES-14-05-0050 and ES-14-05-0300)**

1. 15A NCAC 02D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS

Reporting [15A NCAC 02Q .0508 (f)]

a. The Permittee has used projected actual emissions to avoid applicability of prevention of significant deterioration requirements pursuant to Permit Application No. 5900069.19B for the LSRP Reconfiguration Project consisting of a project to redesign the LSRP and which impacted several sources at the facility. In order to verify the assumptions used in the projected actual emissions calculations, the Permittee shall comply with the requirements in Section 2.2 C.1.b, below.

Monitoring/Recordkeeping/Reporting [15A NCAC 02D .0530(u) and 2Q .0308]

b. Upon commencement of regular operation of the two-phase packed bed caustic scrubber (**ID No. CD-09-27-3800)**, the Permittee shall perform the following:
   i. the Permittee shall maintain records of annual CO, Lead, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4 mist, VOC, Fluorides, and CO_2e emissions in tons per year, on a calendar year basis related to the LSRP Reconfiguration Project as listed above. The Permittee shall calculate these annual emissions for ten years following startup of regular operations of the two-phase packed bed caustic scrubber **(ID No. CD-09-27-3800)**.
   ii. The Permittee shall submit a report to the Director, postmarked on or before June 30th, after the end of each calendar year during which these records must be generated. The report shall contain the items listed in 40 CFR 51.166(r)(6)(v)(a) through (c).
   iii. The Permittee shall make the information documented and maintained under this condition available to the Director or the general public pursuant to the requirements in 40 CFR 70.4(b)(3)(viii).
   iv. The Permittee shall provide a comparison of the reported actual emissions (post-construction emissions) for each of the ten calendar years to the projected actual emissions (pre-construction projection) as included below:

Pollutant	Projected Actual Emissions* (tons per year)
PM (filterable only)	457
PM_{10}	366
$PM_{2.5}$	297
VOC	195
SO_2	127
NO_X	1,815
CO	7,012
F	0.22
H_2SO_4 mist	10.09
Lead	0.0861
CO_2e	2,142,738

* These projections are not enforceable limitations. If projected emissions are exceeded, consistent with 15A NCAC 02D .0530, the Permittee shall include, in its annual report, an explanation as to why the actual rates exceeded the projection.

D. All Emission Sources

STATE-ENFORCEABLE ONLY

1. 15A NCAC 02D .1806: CONTROL AND PROHIBITION OF ODOROUS EMISSIONS

The Permittee shall not operate the facility without implementing management practices or installing and operating odor control equipment sufficient to prevent odorous emissions, other than those odors resulting from No. 5 recovery boiler, the North and South Smelt Tanks, the No. 5 Lime Kiln, the No. 6 and No. 7 Fiberline Bleach Plants Systems, the No. 6 and No. 7 Black Liquor Evaporator Systems, and the Condensate Feed Tank and Reflux Stripper, from the facility from causing or contributing to objectionable odors beyond the facility's boundary.

State-Enforceable Only Requirement

2. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS

The Permitee has submitted a toxic air pollutant dispersion modeling analysis dated March 13, 2018, for the facility's toxic air pollutant emissions as listed in Tables 2.2 D.2-1 and D.2-2. The modeling analysis was reviewed and approved by the Air Quality Analysis Branch (AQAB) on April 30, 2018. The emission limits specified in Tables 2.2 D.2-1 and D.2-2 are effective prior to startup of normal operation of the two-phased packed bed caustic scrubber **(ID No. CD-09-27-3800)**. Upon startup of normal operation of the scrubber, the Permittee shall comply with the conditions in Section 2.2 D.3 below. Placement of the emission souces, configuration of the emission points, and operating of the sources shall be in accordance with the submitted dispersion modeling analysis and should reflect any changes from the original analysis submittal as outlined in the AQAB review memorandum.

Table 2.2 D.2-1: Facility Wide Toxic Air Pollutant Emission Limits[7]

TOXIC AIR POLLUTANT	TOTAL FACILITY EMISSIONS LIMIT		
	lb/hr	lb/24-hour	lb/12-month
Acetaldehyde	342.56		
Acrolein	6.76		
Arsenic & compounds			6,885.84
Benzo(a)pyrene			281,590
Beryllium			32,920.86
1,3 Butadiene			7,061.95
Cadmium			23,523.92
Carbon disulfide		702.35	
Carbon tetrachloride			51,482.49
Chlorine		20.78	
Chromium (VI)		384.44	
1,2-Dichloroethane (Ethylene dichloride)			44,906.45
Hydrogen chloride	749.44		
Manganese & compounds		34,434.04	
Mercury, aryl & inorganic Compounds		357.65	
Methylene chloride	29.05		149,474.37
Nickel, metal		6,136.47	
Phenol	137.35		
Vinyl chloride			542,027.02

[7] The NC TAP included in this table are those for which compliance was demostrated at 9.8 percent of the AAL or less. Because emission limits were optimized such that the maximum concentration is 98 percent of the AAL, the margin of compliance is sufficient such that the facility will never be able to exceed the limit based on actual emissions.

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-08-70-0900 (F11)	White Liquor Surge Tank	Benzene	8.19	lb/yr
		Formaldehyde	0.194	lb/hr
ES-06-32-2460 (F15)	2C Washer	Benzene	27.7	lb/yr
		Chloroform	1,680	lb/yr
		Cresol	0.645	lb/hr
		Formaldehyde	0.0935	lb/hr
		Hydrogen sulfide	17.3	lb/day
		Methyl mercaptan	0.0349	lb/hr
ES-06-32-2300 (F17)	No. 28 High Density Tank	Benzene	1.56	lb/yr
		Chloroform	8.43	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.26x10^{-04}$	lb/hr
		Methyl mercaptan	$4.04x10^{-06}$	lb/hr
ES-06-32-2340 (F18)	No. 29 High Density Tank	Benzene	1.56	lb/yr
		Chloroform	8.43	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.26x10^{-04}$	lb/hr
		Methyl mercaptan	$4.04x10^{-06}$	lb/hr
ES-06-32-2380 (F19)	No. 30 High Density Tank	Benzene	1.56	lb/yr
		Chloroform	8.43	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.26x10^{-04}$	lb/hr
		Methyl mercaptan	$4.04x10^{-06}$	lb/hr
ES-08-52-1060 (F34)	R8/10 chlorine dioxide generator	Chloroform	20.0	lb/yr
ES-08-65-1060 (6N7SPLTK)	Spill Collection Tank	Ammonia	0.144	lb/hr
		Benzene	1.88	lb/yr
		Chloroform	7.56	lb/yr
ES-05-30-1300 (F60)	No. 5 Hot Water Tank/ Evaporator Condensate	Formaldehyde	0.00141	lb/hr
		Hydrogen sulfide	0.0612	lb/day
		Methyl mercaptan	0.0337	lb/hr
ES-07-34-4080 and ES-07-34-4100 (EOP)	4th Stage Extraction Tower and Filtrate Tank	Benzene	5.93	lb/yr
		Chloroform	518	lb/yr
		Methyl mercaptan	0.00517	lb/hr
ES-07-36-6040 and ES-07-36-6060 (PEROX)	Peroxide Stage 6th Stage Extraction Tower and Filtrate Tank	Benzene	5.93	lb/yr
		Chloroform	518	lb/yr
		Methyl mercaptan	0.00517	lb/hr
IES-06-P1 (6FEEDTNK)	No. 6 Bleach Plant, 6th stage hydrogen peroxide tank	Benzene	5.52	lb/yr
		Chloroform	483	lb/yr
ES-06-P2 (6BLOWTBE)	6th Stage Peroxide Reactor Blow Tube	Benzene	25.9	lb/yr
		Chloroform	2,260	lb/yr
ES-06-P3 (6EXHAUST)	6th Stage Peroxide Stage Washer	Benzene	91.4	lb/yr
		Chloroform	8,000	lb/yr
ES-08-40-1000 (F35)	No. 32 High Density Pulp Tank	Benzene	0.445	lb/yr
		Chloroform	161	lb/yr
		Hydrogen sulfide	0.0658	lb/day
		Methyl mercaptan	0.00353	lb/hr

[8]Source-by-source emission limits based on optimizated emissions such that the maximum concentration is 98 percent of the AAL.

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
IES-06-10-1200 (F41)	No. 6 Digester Sand Separator Dumpster	Benzene	1.56	lb/yr
		Chloroform	8.43	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.26x10^{-4}$	lb/hr
		Methyl Mercaptan	$4.04x10^{-6}$	lb/hr
IES-07-10-1200 (F42)	No. 7 Digester Sand Separator Dumpster	Benzene	3.24	lb/yr
		Chloroform	17.6	lb/yr
		Cresol	2.83	lb/hr
		Formaldehyde	$9.70x10^{-4}$	lb/hr
		Methyl Mercaptan	$3.03x10^{-4}$	lb/hr
ES-09-05-0200 (R24)	East 18% Liquor Tank	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.0460	lb/hr
ES-09-05-0150 (R25)	18% Liquor Mix Tank (west)	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.0460	lb/hr
ES-09-05-0100 (R26)	West 18% Liquor Tank	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.0460	lb/hr
ES-09-05-0210 (SWBLTANK)	South WBL Storage Tank	Ammonia	0.00259	lb/hr
		Benzene	0.509	lb/yr
		Chloroform	2.05	lb/hr
		Formaldehyde	$1.50x10^{-04}$	lb/hr
ES-09-20-0250 (R71)	Combined Condensate Tank	Benzene	8.02	lb/yr
		Formaldehyde	$2.21x10^{-4}$	lb/hr
		Hydrogen sulfide	0.0575	lb/day
		Methyl mercaptan	0.0283	lb/hr
ES-09-30-0010 (R27)	North 48% Black Liquor Storage Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	$1.12x10^{-4}$	lb/hr
ES-09-30-0020 (R28)	South 48% Black Liquor Storage Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	$1.12x10^{-4}$	lb/hr
ES-09-40-0010 (R29)	East 65% Liquor Storage Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	$1.12x10^{-4}$	lb/hr

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-09-40-0020 (R30)	West 65% Liquor Storage Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-09-95 (R31, R32, R33, R72)	Four Saveall Tanks	Benzene	1.70	lb/yr
		Chloroform	0.829	lb/yr
		Formaldehyde	0.0135	lb/hr
		Hydrogen sulfide	4.22	lb/day
		Methyl mercaptan	0.00494	lb/hr
ES-09-10 (R40, R41, R42, R43)	Four Soap Storage Tanks	Benzene	4.06	lb/yr
		Chloroform	0.111	lb/yr
		Formaldehyde	0.00636	lb/hr
		Hydrogen sulfide	0.434	lb/day
		Methyl mercaptan	0.0184	lb/hr
ES-09-19-0020 and ES-09-19-0030 (R36)	East and West Liquor Heaters	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.00460	lb/hr
ES-09-20-0070 (R34)	No. 6 Evaporator Soap Skim Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-09-12-0250 (5SOAP)	No. 5 Soap Storage Tank	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.00460	lb/hr
ES-09-12-0050 (LIQSEP)	Black Liquor Separator Tank	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.00460	lb/hr
ES-09-25-0140 (R37)	No. 7 Evaporator Soap Skim Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-09-25-0540 (R38)	No. 7 Evaporator Boilout Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-09-30-0030 (R39)	Soap Collection Tank	Benzene	1.02	lb/yr
		Chloroform	0.0278	lb/yr
		Formaldehyde	0.00159	lb/hr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.00460	lb/hr

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-09-25-0340 (R44)	Diverter Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-10-45-0450 (R05)	No. 5 Precipitator Mix Tank	Benzene	0.819	lb/yr
		Formaldehyde	0.00712	lb/hr
		Methyl Mercaptan	0.0113	lb/hr
ES-14-25-0050 (R07)	Hydrosulfide Storage Tank	Benzene	8.19	lb/yr
		Formaldehyde	0.194	lb/hr
ES-14-10-1000 (NO5GLC)	GL Process Area: [9] No. 5 Green Liquor Clarifier	Benzene	30.0	lb/yr
		Hydrogen sulfide	0.0228	lb/day
		Methyl mercaptan	0.0464	lb/hr
ES-14-25-0450 (R16) ES-14-25-0350 (NO5WLC)	Nos. 3 and 5 White Liquor Clarifier[10]	Benzene	8.19	lb/yr
		Formaldehyde	0.194	lb/hr
ES-14-25-0800 (R17)	No. 4 WL Clarifier	Benzene	8.19	lb/yr
		Formaldehyde	0.194	lb/hr
ES-14-25-0150 (R22)	Synthetic Liquor Mix Tank	Benzene	8.19	lb/yr
		Formaldehyde	0.194	lb/hr
ES-14-70-2045 (R45)	Lime kiln scrubber water standpipe	Benzene	45.9	lb/yr
ES-14-15-0800 (R09)	Dregs Filter	Benzene	1.19	lb/yr
		Hydrogen sulfide	0.0401	lb/day
		Methyl mercaptan	0.00105	lb/hr
ES-14-15-0900 (R10)	Dregs Filter Vacuum System	Benzene	1.19	lb/yr
		Hydrogen sulfide	0.0401	lb/day
		Methyl mercaptan	0.00105	lb/hr
ES-14-15-DREGS (R12)	Dregs Dumpster	Benzene	1.19	lb/yr
		Hydrogen sulfide	0.0401	lb/day
		Methyl mercaptan	0.00105	lb/hr
ES-14-15-0600 (R13)	Dregs Surge Tank	Benzene	1.19	lb/yr
		Hydrogen sulfide	0.0401	lb/day
		Methyl mercaptan	0.00105	lb/hr
ES-14-20-2020 (R53)	East Lime Slaker	Ammonia	4.77	lb/hr
		Benzene	5.25	lb/yr
		Formaldehyde	0.00389	lb/hr
ES-14-20-2085 (R58)	West Lime Slaker	Ammonia	4.77	lb/hr
		Benzene	5.25	lb/yr
		Formaldehyde	0.00389	lb/hr
ES-14-30-5000 and ES-14-30-6000 (R50)	East and West Lime Mud Filter – Hood Exhaust	Benzene	6.77	lb/yr
		Chloroform	10.4	lb/yr
		Formaldehyde	0.0309	lb/hr
		Methyl mercaptan	0.00698	lb/hr

[9] Per 502(b)(10) notification (No. 5900069.17D), the Permittee is replacing the Nos. 3 and 4 Green Liquor Clarifiers and the No. 3 Green Liquor Storage Tank with the No. 5 Green Liquor Clarifier. The TAP limits in this table apply to all four sources.
[10] Per 502(b)(10) notification (No. 5900069.17D), the Permittee is replacing the No. 3 White Liquor Clarifier with the No. 5 White Liquor Clarifier. The TAP limits in this table apply to both sources.

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-14-30-5040 (R65) ES-14-30-6040 (R66)	Two Lime Mud Filter Vacuum Systems: • Lime Mud Vacuum System No. 1 • Lime Mud Vacuum System No. 2	Benzene	6.69	lb/yr
		Chloroform	112	lb/yr
		Hydrogen sulfide	0.0298	lb/day
		Methyl mercaptan	0.0112	lb/hr
ES-14-30-0310 (R46)	Lime mud mix tank	Benzene	2.65	lb/yr
		Hydrogen sulfide	0.147	lb/day
		Methyl mercaptan	0.0184	lb/hr
ES-14-30-1450 (R15)	Lime mud storage tank	Benzene	2.65	lb/yr
ES-14-30-0350 (R47)	Nos. 2 Lime Mud Wash Tank	Benzene	7.90	lb/yr
ES-14-30-0700 (R49)	Nos. 3 Lime Mud Wash Tank	Benzene	7.90	lb/yr
ES-14-70-2020 (R76)	Scrubber Water Clarifier	Benzene	23.0	lb/yr
ES-FP-STOCKTANKS (P27A-H)	HD and LD Stock Tanks	Benzene	38.6	lb/yr
		Chloroform	923	lb/yr
ES-32-STOCKTANKS (P09A-F)	HD and LD Stock Tanks	Benzene	16.2	lb/yr
		Chloroform	387	lb/yr
ES-32-93-0100 (NC1_2_A through M)	Line Building Roof Vents	Benzene	159	lb/yr
		Chloroform	147	lb/yr
		Formaldehyde	0.457	lb/hr
		Methyl mercaptan	0.278	lb/hr
ES-45-93-0100 (NC5_1-29)	Building Fugitives	Benzene	368	lb/yr
		Chloroform	341	lb/yr
		Formaldehyde	1.27	lb/hr
		Methyl mercaptan	0.771	lb/hr
CD-64-22-2000 (THERMALOX)	Thermal Oxidizer	Ammonia	9.61×10^{-4}	lb/hr
		Benzene	2.29	lb/yr
		Chloroform	11.6	lb/yr
		Formaldehyde	0.0258	lb/hr
		Hydrogen sulfide	20.6	lb/day
		Methyl mercaptan	3.10	lb/hr
ES-73-05-2000	WWTP operations treating wastewater including the 5th effect of evaporator No. 6 and the C3 condensate	Ammonia	37.8	lb/hr
		Chloroform	4,224	lb/yr
		Cresol	4.04×10^{-8}	lb/hr
		Formaldehyde	0.6	lb/hr
ES-09-27-3100 (LRP SCWT)	No. 2 Lignin Filter Cloth Wash Tank	Ammonia	1.07×10^{-4}	lb/hr
		Benzene	0.0210	lb/yr
		Chloroform	0.0844	lb/yr
		Formaldehyde	6.17×10^{-6}	lb/hr
		Hydrogen sulfide	3.24	lb/day
		Methyl mercaptan	0.00547	lb/hr

Table 2.2 D.2-2: Source-by-Source Toxic Air Pollutant Emission Limits[8]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-09-27-1000 (LRP 40%)	Lignin Feed Liquor Tank	Benzene	0.229	lb/yr
		Chloroform	0.267	lb/yr
		Formaldehyde	0.00398	lb/hr
		Hydrogen sulfide	1.37	lb/day
		Methyl mercaptan	1.12×10^{-4}	lb/hr
ES-09-27-3000 (LRPPRS2)	No. 2 Lignin Filter	Ammonia	1.07×10^{-4}	lb/hr
		Benzene	0.0210	lb/yr
		Chloroform	0.0844	lb/yr
		Formaldehyde	6.17×10^{-6}	lb/hr
		Hydrogen sulfide	18.9	lb/day
		Methyl mercaptan	0.127	lb/hr
ES-09-27-2100 (LRPPRS1A, LRPPRS1B)	No. 1 Lignin Filter	Ammonia	1.07×10^{-4}	lb/hr
		Benzene	0.0210	lb/yr
		Chloroform	0.0844	lb/yr
		Formaldehyde	6.17×10^{-6}	lb/hr
		Hydrogen sulfide	104	lb/day
		Methyl mercaptan	0.0925	lb/hr
ES-09-27-2700, ES-09-27-2770, ES-09-27-2800, IES-09-27-3700, IES-09-27-3600 (LRPSSUMP)	LSRP Fugitives: Lignin Acidification Tank, Lignin Foam Tank, Acidic Acid Conditioning Tank; Lignin Acid Area Pit; Lignin Liquor Area Sump	Hydrogen sulfide	3.42	lb/day
		Methyl mercaptan	0.00304	lb/hr

STATE-ENFORCEABLE ONLY

3. 15A NCAC 02D .1100: CONTROL OF TOXIC AIR POLLUTANTS

The Permitee has submitted a toxic air pollutant dispersion modeling analysis dated September 2, 2020 (and updated November 3, 2020), for the facility's toxic air pollutant emissions as listed in Tables 2.2 D.2-1 and D.2-2. The modeling analysis was reviewed and approved by the Air Quality Analysis Branch (AQAB) on November 17, 2020. The emission limits specified in Tables 2.2 D.3-1 and D.3-2 represent the LSRP Reconfiguration Project as described in Permit Application No. 5900069.19B and are effective upon startup of normal operation of the two-phased packed bed caustic scrubber **(ID No. CD-09-27-3800)**. Placement of the emission souces, configuration of the emission points, and operating of the sources shall be in accordance with the submitted dispersion modeling analysis and should reflect any changes from the original analysis submittal as outlined in the AQAB review memorandum.

Table 2.2 D.3-1: Facility Wide Toxic Air Pollutant Emission Limits[11]

TOXIC AIR POLLUTANT	TOTAL FACILITY EMISSIONS LIMIT		
	lb/hr	lb/24-hour	lb/12-month
Acetaldehyde	397.97		
Acrolein	9.94		
Arsenic & compounds			6,030.33
Beryllium			22,251.04
1,3 Butadiene			8,006.69

[11] The NC TAP included in this table are those for which compliance was demostrated at 9.8 percent of the AAL or less. Because emission limits were optimized such that the maximum concentration is 98 percent of the AAL, the margin of compliance is sufficient such that the facility will never be able to exceed the limit based on actual emissions.

TOXIC AIR POLLUTANT	TOTAL FACILITY EMISSIONS LIMIT		
	lb/hr	lb/24-hour	lb/12-month
Cadmium			20,036.43
Carbon disulfide		650.75	
Carbon tetrachloride			47,201.99
Chlorine		20.78	
Chromium (VI)		395.66	
1,2-Dichloroethane (Ethylene dichloride)			50,767.38
Fluoride	1,720.79	16,537.39	
n-Hexane		871,205.84	
Hydrogen chloride	765.93		
Manganese & compounds		35,010.50	
Mercury, aryl & inorganic Compounds		382.05	
Methylene chloride	29.01		163,819.56
Nickel, metal		5,370.54	
Phenol	191.09		
Sulfuric acid	718.11	11,143.09	
Vinyl chloride			634,409.47

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-08-70-0900 (F11)	White Liquor Surge Tank	Benzene	6.22	lb/yr
		Formaldehyde	0.225	lb/hr
ES-06-32-2460 (F15)	2C Washer	Benzene	21.0	lb/yr
		Chloroform	1,290	lb/yr
		Cresol	0.645	lb/hr
		Formaldehyde	0.108	lb/hr
		Hydrogen sulfide	28.2	lb/day
		Methyl mercaptan	0.0359	lb/hr
ES-06-32-2300 (F17)	No. 28 High Density Tank	Benzene	1.18	lb/yr
		Chloroform	6.46	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.46x10^{-04}$	lb/hr
		Methyl mercaptan	$4.16x10^{-06}$	lb/hr
ES-06-32-2340 (F18)	No. 29 High Density Tank	Benzene	1.18	lb/yr
		Chloroform	6.46	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.46x10^{-04}$	lb/hr
		Methyl mercaptan	$4.16x10^{-06}$	lb/hr
ES-06-32-2380 (F19)	No. 30 High Density Tank	Benzene	1.18	lb/yr
		Chloroform	6.46	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	$1.46x10^{-04}$	lb/hr
		Methyl mercaptan	$4.16x10^{-06}$	lb/hr
ES-08-52-1060 (F34)	R8/10 chlorine dioxide generator	Chloroform	15.3	lb/yr

[12]Source-by-source emission limits based on optimizated emissions such that the maximum concentration is 98 percent of the AAL.

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-08-65-1060 (6N7SPLTK)	Spill Collection Tank	Ammonia	0.192	lb/hr
		Benzene	1.43	lb/yr
		Chloroform	5.80	lb/yr
ES-05-30-1300 (F60)	No. 5 Hot Water Tank/ Evaporator Condensate	Formaldehyde	0.00163	lb/hr
		Hydrogen sulfide	0.0942	lb/day
		Methyl mercaptan	0.0292	lb/hr
ES-07-34-4080 and ES-07-34-4100 (EOP)	4th Stage Extraction Tower and Filtrate Tank	Benzene	4.51	lb/yr
		Chloroform	398	lb/yr
		Methyl mercaptan	0.00533	lb/hr
ES-07-36-6040 and ES-07-36-6060 (PEROX)	Peroxide Stage 6th Stage Extraction Tower and Filtrate Tank	Benzene	4.51	lb/yr
		Chloroform	398	lb/yr
		Methyl mercaptan	0.00533	lb/hr
IES-06-P1 (6FEEDTNK)	No. 6 Bleach Plant, 6th stage hydrogen peroxide tank	Benzene	4.19	lb/yr
		Chloroform	370	lb/yr
ES-06-P2 (6BLOWTBE)	6th Stage Peroxide Reactor Blow Tube	Benzene	19.7	lb/yr
		Chloroform	1,730	lb/yr
ES-06-P3 (6EXHAUST)	6th Stage Peroxide Stage Washer	Benzene	69.5	lb/yr
		Chloroform	6,130	lb/yr
ES-08-40-1000 (F35)	No. 32 High Density Pulp Tank	Benzene	0.338	lb/yr
		Chloroform	124	lb/yr
		Hydrogen sulfide	0.108	lb/day
		Methyl mercaptan	0.00363	lb/hr
IES-06-10-1200 (F41)	No. 6 Digester Sand Separator Dumpster	Benzene	1.18	lb/yr
		Chloroform	6.46	lb/yr
		Cresol	1.36	lb/hr
		Formaldehyde	1.46×10^{-04}	lb/hr
		Methyl mercaptan	4.16×10^{-06}	lb/hr
IES-07-10-1200 (F42)	No. 7 Digester Sand Separator Dumpster	Benzene	2.46	lb/yr
		Chloroform	13.5	lb/yr
		Cresol	2.83	lb/hr
		Formaldehyde	1.12×10^{-3}	lb/hr
		Methyl Mercaptan	3.12×10^{-4}	lb/hr
ES-09-05-0200 (R24)	East 18% Liquor Tank	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-05-0150 (R25)	18% Liquor Mix Tank (west)	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-05-0100 (R26)	West 18% Liquor Tank	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-09-05-0210 (SWBLTANK)	South WBL Storage Tank	Ammonia	0.00345	lb/hr
		Benzene	0.387	lb/yr
		Chloroform	1.57	lb/yr
		Formaldehyde	$1.73x10^{-04}$	lb/hr
ES-09-20-0250 (R71)	Combined Condensate Tank	Benzene	6.09	lb/yr
		Formaldehyde	$2.56x10^{-4}$	lb/hr
		Hydrogen sulfide	0.0942	lb/day
		Methyl mercaptan	0.0292	lb/hr
ES-09-30-0010 (R27)	North 48% Black Liquor Storage Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	$1.16x10^{-4}$	lb/hr
ES-09-30-0020 (R28)	South 48% Black Liquor Storage Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	$1.16x10^{-4}$	lb/hr
ES-09-40-0010 (R29)	East 65% Liquor Storage Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	$1.16x10^{-4}$	lb/hr
ES-09-40-0020 (R30)	West 65% Liquor Storage Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	$1.16x10^{-4}$	lb/hr
ES-09-95 (R31, R32, R33, R72)	Four Saveall Tanks	Benzene	1.29	lb/yr
		Chloroform	0.636	lb/yr
		Formaldehyde	0.0156	lb/hr
		Hydrogen sulfide	6.91	lb/day
		Methyl mercaptan	0.00509	lb/hr
ES-09-10 (R40, R41, R42, R43)	Four Soap Storage Tanks	Benzene	3.09	lb/yr
		Chloroform	0.0854	lb/yr
		Formaldehyde	0.00736	lb/hr
		Hydrogen sulfide	0.710	lb/day
		Methyl mercaptan	0.0190	lb/hr
ES-09-19-0020 and ES-09-19-0030 (R36)	East and West Liquor Heaters	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-20-0070 (R34)	No. 6 Evaporator Soap Skim Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	$1.16x10^{-4}$	lb/hr

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-09-12-0250 (5SOAP)	No. 5 Soap Storage Tank	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-12-0050 (LIQSEP)	Black Liquor Separator Tank	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-25-0140 (R37)	No. 7 Evaporator Soap Skimmer Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	1.16×10^{-4}	lb/hr
ES-09-25-0540 (R38)	No. 7 Evaporator Boilout Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	1.16×10^{-4}	lb/hr
ES-09-30-0030 (R39)	Soap Collection Tank	Benzene	0.772	lb/yr
		Chloroform	0.0213	lb/yr
		Formaldehyde	0.00184	lb/hr
		Hydrogen sulfide	0.177	lb/day
		Methyl mercaptan	0.00475	lb/hr
ES-09-25-0340 (R44)	Diverter Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	1.16×10^{-4}	lb/hr
ES-10-45-0450 (R05)	No. 5 Precipitator Mix Tank	Benzene	0.623	lb/yr
		Formaldehyde	0.00824	lb/hr
		Methyl Mercaptan	0.0117	lb/hr
ES-14-25-0050 (R07)	Hydrosulfide Storage Tank	Benzene	6.22	lb/yr
		Formaldehyde	0.225	lb/hr
ES-14-10-1000 (NO5GLC)	No. 5 Green Liquor Clarifier	Benzene	22.8	lb/yr
		Hydrogen sulfide	0.0373	lb/day
		Methyl mercaptan	0.0478	lb/hr
ES-14-25-0450 (R16)ES-14-25-0350 (NO5WLC)	No. 3 and 5 White Liquor Clarifier[13]	Benzene	6.22	lb/yr
		Formaldehyde	0.225	lb/hr
ES-14-25-0800 (R17)	No. 4 White Liquor Clarifier	Benzene	6.22	lb/yr
		Formaldehyde	0.225	lb/hr
ES-14-25-0150 (R22)	Synthetic Liquor Mix Tank	Benzene	6.22	lb/yr
		Formaldehyde	0.225	lb/hr
ES-14-70-2045 (R45)	Lime kiln scrubber water standpipe	Benzene	17.5	lb/yr

[13] Per 502(b)(10) notification (No. 5900069.17D), the Permittee is replacing the No. 3 White Liquor Clarifier with the No. 5 White Liquor Clarifier. The TAP limits in this table apply to both sources.

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-14-15-0800 (R09)	Dregs Filter	Benzene	0.901	lb/yr
		Hydrogen sulfide	0.0656	lb/day
		Methyl mercaptan	0.00108	lb/hr
ES-14-15-0900 (R10)	Dregs Filter Vacuum System	Benzene	0.901	lb/yr
		Hydrogen sulfide	0.0656	lb/day
		Methyl mercaptan	0.00108	lb/hr
ES-14-15-DREGS (R12)	Dregs Dumpster	Benzene	0.901	lb/yr
		Hydrogen sulfide	0.0656	lb/day
		Methyl mercaptan	0.00108	lb/hr
ES-14-15-0600 (R13)	Dregs Surge Tank	Benzene	0.901	lb/yr
		Hydrogen sulfide	0.0656	lb/day
		Methyl mercaptan	0.00108	lb/hr
ES-14-20-2020 (R53)	East Lime Slaker	Ammonia	6.36	lb/hr
		Benzene	3.99	lb/yr
		Formaldehyde	0.00450	lb/hr
ES-14-20-2085 (R58)	West Lime Slaker	Ammonia	6.36	lb/hr
		Benzene	3.99	lb/yr
		Formaldehyde	0.00450	lb/hr
ES-14-30-5000 and ES-14-30-6000 (R50)	East and West Lime Mud Filter – Hood Exhaust	Benzene	5.15	lb/yr
		Chloroform	7.95	lb/yr
		Formaldehyde	0.0357	lb/hr
		Methyl mercaptan	0.00719	lb/hr
ES-14-30-5040 (R65) ES-14-30-6040 (R66)	Two Lime Mud Filter Vacuum Systems: • Lime Mud Vacuum System No. 1 • Lime Mud Vacuum System No. 2	Benzene	5.09	lb/yr
		Chloroform	86.2	lb/yr
		Hydrogen sulfide	0.0488	lb/day
		Methyl mercaptan	0.0116	lb/hr
ES-14-30-0310 (R46)	Lime mud mix tank	Benzene	2.02	lb/yr
		Hydrogen sulfide	0.241	lb/day
		Methyl mercaptan	0.0190	lb/hr
ES-14-30-1450 (R15)	Lime mud storage tank	Benzene	2.02	lb/yr
ES-14-30-0350 (R47)	Nos. 2 Lime Mud Wash Tank	Benzene	6.01	lb/yr
ES-14-30-0700 (R49)	Nos. 3 Lime Mud Wash Tank	Benzene	6.01	lb/yr
ES-14-70-2020 (R76)	Scrubber Water Clarifier	Benzene	17.5	lb/yr
ES-FP-STOCKTANKS (P27A-H)	HD and LD Stock Tanks	Benzene	29.3	lb/yr
		Chloroform	708	lb/yr
ES-32-STOCKTANKS (P09A-F)	HD and LD Stock Tanks	Benzene	12.3	lb/yr
		Chloroform	297	lb/yr
ES-32-93-0100 (NC1_2_A through M)	Building Roof Vents	Benzene	121	lb/yr
		Chloroform	113	lb/yr
		Formaldehyde	0.529	lb/hr
		Methyl mercaptan	0.286	lb/hr
ES-45-93-0100 (NC5_1-29)	Building Fugitives	Benzene	280	lb/yr
		Chloroform	262	lb/yr
		Formaldehyde	1.47	lb/hr
		Methyl mercaptan	0.795	lb/hr
CD-64-22-2000 (THERMLOX)	Thermal Oxidizer	Benzene	262	lb/yr
		Chloroform	7.54	lb/yr
		Formaldehyde	0.0394	lb/hr
		Hydrogen sulfide	13.1	lb/day
		Methyl mercaptan	1.36	lb/hr

Table 2.2 D.3-2: Source-by-Source Toxic Air Pollutant Emission Limits[12]

Emission Source ID (Modeling ID)	Source Description	Compound	Emission Limit	Averaging Period
ES-73-05-2000	WWTP operations treating wastewater including the 5th effect of evaporator No. 6 and the C3 condensate	Ammonia	50.4	lb/hr
		Chloroform	3,220	lb/yr
		Cresol	4.04×10^{-8}	lb/hr
		Formaldehyde	0.657	lb/hr
CD-09-27-3800 (LSRPSCRB)	Two-Stage Packed Bed Caustic Scrubber	Ammonia	0.00184	lb/hr
-ES-09-27-1100	*No. 1 Feed Liquor Cooler*	Benzene	46.9	lb/yr
-ES-09-27-1200	*No. 1 Lignin Filter Filtrate Storage Tank*			
-ES-09-27-1800	*Lignin Slurry Conditioning Tank*	Chloroform	190	lb/yr
-ES-09-27-2000	*Lignin Slurry Buffer Tank*			
-ES-09-27-2100	*No. 1 Lignin Filter*			
-ES-09-27-2300	*No. 1 Lignin Filter Cloth Wash Tank*			
-ES-09-27-2400	*No. 1 Lignin Filter Filtrate Tank*			
-ES-09-27-2500	*No. 1 Lignin Filter Filtrate Buffer Tank*	Formaldehyde	0.248	lb/hr
-ES-09-27-2610	*No. 1 Lignin Filter Horizontal Conveyor*	Hydrogen sulfide	247	lb/day
-ES-09-27-2620	*No. 1 Lignin Filter Incline Conveyor*	Methyl mercaptan	4.20	lb/hr
-ES-09-27-2800	*Acidic Lignin Conditioning Tank*			
-ES-09-27-3100	*No. 2 Lignin Filter Cloth Wash Tank*			
-ES-09-27-3200	*No. 2 Lignin Filter Acidic Filtrate Tank*			
ES-09-27-1000 (LRP 40%)	Lignin Feed Liquor Tank	Benzene	0.174	lb/yr
		Chloroform	0.205	lb/yr
		Formaldehyde	0.00460	lb/hr
		Hydrogen sulfide	2.24	lb/day
		Methyl mercaptan	1.16×10^{-4}	lb/hr
ES-09-27-3000 (LRPPRS2)	No. 2 Lignin Filter	Ammonia	1.67×10^{-4}	lb/hr
		Benzene	0.0187	lb/yr
		Chloroform	0.0760	lb/yr
		Formaldehyde	8.39×10^{-6}	lb/hr
		Hydrogen sulfide	14.6	lb/day
ES-09-27-2700 ES-09-27-2770 ES-09-27-2800 IES-09-27-3700 IES-09-27-3600 (LRPSSUMP)	LSRP Fugitives: Lignin Acidification Tank Lignin Foam Tank Acidic Lignin Conditioning Tank Lignin Acid Area Sump Lignin Liquor Area Sump	Hydrogen sulfide	5.59	lb/day
		Methyl mercaptan	0.00313	lb/hr

State-Enforceable Only Requirement

4. TOXIC AIR POLLUTANT EMISSIONS LIMITATION AND REPORTING REQUIREMENTS

a. Pursuant to 15A NCAC 02Q .0711 "Emission Rates Requiring a Permit," for each of the below listed toxic air pollutants (TAPs), the Permittee has made a demonstration that actual emissions do not exceed the Toxic Permit Emission Rates (TPERs) listed in 15A NCAC 02Q .0711. The facility shall be operated and maintained in such a manner that emissions of any listed TAPs from the facility (excluding those sources exempt under 15A NCAC 02Q .0702 "Exemptions" and those sources subject to an applicable requirement under 40 C.F.R. Parts 61 or 63, or subject to a case-by-case maximum achievable control technology (MACT) permit requirement), including fugitive emissions, will not exceed TPERs listed in 15A NCAC 02Q .0711.

i. A permit to emit any of the below listed TAPs shall be required for this facility if actual emissions from all sources will become greater than the corresponding TPERs.
ii. PRIOR to exceeding any of these listed TPERs, the Permittee shall be responsible for obtaining a permit to emit TAPs and for demonstrating compliance with the requirements of 15A NCAC 02D .1100 "Control of Toxic Air Pollutants."

b. In accordance with the approved application, the Permittee shall maintain records of operational information dem onstrating that the TAP emissions from non-exempt sources do not exceed the TPERs as listed below:

TPERs Limitations				
Pollutant (CAS Number)	**Carcinogens (lb/yr)**	**Chronic Toxicants (lb/day)**	**Acute Systemic Toxicants (lb/hr)**	**Acute Irritants (lb/hr)**
Acetic Acid (64-19-7)				0.96
Benzo(a)pyrene (50-32-8)	2.2			
Chlorine				0.23
Chlorobenzene (108-90-7)		46		
Di(2-ethylhexyl)phthalate (117-81-7)		0.63		
1,4-Dichlorobenzene (106-46-7)				16.8
Dimethyl Sulfate(77-78-1)		0.063		
Hexachlorodibenzo-p-dioxin (57653-85-7)	0.0051			
Methyl chloroform (71-55-6)		250		64
Methyl ethyl ketone (78-93-3)		78		22.4
Methyl isobutyl ketone (108-10-1)		52		7.6
Nitric Acid (7697-37-2)				0.256
Styrene (100-42-5)			2.7	
Tetrachlordibenzo-p-dioxin (1746-01-6)	0.00020			
1,1,2,2-Tetrachloroethane (79-34-5)	430			
Tetrachloroethylene (127-18-4)	13,000			
Toluene (108-88-3)		98		14.4
Trichloroethylene (79-01-6)	4000			
Trichlorofluoromethane (75-69-4)			140	
Vinylidiene Chloride (75-35-4)		2.5		
Xylene (1330-20-7)		57		16.4

E. Permit Application Submittal Requirement

1. 15A NCAC 02Q .0504: OPTION FOR OBTAINING CONSTRUCTION AND OPERATION PERMIT

Permitting [15A NCAC 02Q .0504(d)]

a. For completion of the two-step significant modification process initiated with Permit Application No. 5900069.17A and pursuant to 15A NCAC 02Q .0501(b)(2) or (c)(2), as required under 15A NCAC 02Q .0501(b)(2), the Permittee shall file an amended application following the procedures of Section 15A NCAC 02Q .0500 within one year from the date of beginning operation of any of the following equipment: the Secondary Turpentine Decanter Tank **(ID No. LVHC.09-DECANT)**, Secondary Turpentine Decanter Weir **(ID No. LVHC.09-WEIR)**, Secondary Turpentine Underflow Tank **(ID No. LVHC.09-UND)** or Secondary Turpentine Storage Tank **(ID No. LVHC.09-STOR)**.

Reporting [15A NCAC 02Q .0508(f)]

b. The Permittee shall notify the Regional Office, in writing, of the date of beginning operation of the Secondary Turpentine Decanter Tank **(ID No. LVHC.09-DECANT)**, Secondary Turpentine Decanter Weir **(ID No. LVHC.09-WEIR)**, Secondary Turpentine Underflow Tank **(ID No. LVHC.09-UND)** and Secondary Turpentine Storage Tank **(ID No. LVHC.09-STOR)**, postmarked no later than 30 days after such date.

F. Facility-Wide Sources

New, Modified and Affected Sources identified in the following Table.

Emission Source ID No.	Emission Source	Emission Source ID No.	Emission Source
AFFECTED SOURCES			
POWER OPERATIONS		**FIBERLINE OPERATIONS – No. 7 Fiberline and Bleach Plant**	
ES-64-25-0290	No. 1 Hog Fuel Boiler	ES-07-05-1000	Chip Silo A
ES-64-60-0180	West De-entrainment Vessel	ES-07-05-2000	Chip Silo B
ES-64-60-0480	Central De-entrainment Vessel	ES-07-31-1000	1st Stage O_2 Surge Tank
ES-64-60-0780	East De-entrainment Vessel	ES-07-31-1100	Oxygen Delignification System
ES-64-60-0960	Scrubber Ash Silo	ES-07-31-1140	1st Stage O_2 Reactor Blow Tube
ES-65-50-0160	Ash Transport Steam Exhauster	ES-07-31-1180	1st Stage Wash Tower
ES-65-50-0190	Boiler Ash Silo	ES-07-31-1200	1A/1B Filtrate Tank
ES-65-60-0860	Scrubber Ash Silo	ES-07-33-3000	3rd Stage Feed Tank
FS-007	No. 1 and No. 2 Hog Fuel Conveying	ES-07-33-3080	3rd Stage Tower - ClO_2 Stage
FS-011	Hogged Fuel Storage Pile at Boilers	ES-07-35-5060	5th Stage Tower – ClO_2 Stage
HVLC GAS COLLECTION SYSTEM		ES-07-35-5080	5th Stage Filtrate Tank
HVLC.06-10-2380	No. 6 Fiberline Chip Bin Relief Condenser	ES-07-33-Blendbox	Blend Box (sump)
HVLC.06-21-1100	No. 6 Fiberline Pressure Diffuser Filtrate Tank	FS-004	Building Fugitives
HVLC.06-21-1200	No. 6 Fiberline Digester Blow Tank	ES-07-34-4080	4th Stage Extraction Tower
HVLC.06-22-1080	No. 6 Fiberline Secondary Knotter	ES-07-34-4100	4th Stage Extraction Filtrate Tank
HVLC.06-22-1100	No. 6 Fiberline Screen Dilution Tank	ES-07-36-6040	Peroxide 6th Stage Extraction Tower
HVLC.06-23-1200	No. 6 Fiberline Decker Hood	ES-07-36-6060	Peroxide 6th Stage Extraction Filtrate Tank
HVLC.06-23-1220	No. 6 Fiberline Decker Filtrate Tank	**FIBERLINE OPERATIONS – Nos. 6 & 7 Fiberline (common facilities)**	
HVLC.06-22-1280	No. 6 Fiberline Quaternary Screen	ES-05-30-1300	No. 5 Hot Water Tank/Evaporator Condensate
HVLC.07-10-2380	No. 7 Fiberline Chip Bin Relief Condenser	ES-08-40-1000	No. 32 High Density Pulp Tank
HVLC.07-21-1100	No. 7 Fiberline Pressure Diffuser Filtrate Tank	ES-08-50-3140	10% Sulfuric Acid Day Tank
HVLC.07-21-1200	No. 7 Fiberline Digester Blow Tank	ES-08-50-3020	Sulfuric Acid Storage Tank
HVLC.07-22-1080	No. 7 Fiberline Secondary Knotter	ES-08-52-1060	R8/10 Chlorine Dioxide Generator
HVLC.07-22-1280	No. 7 Fiberline Quaternary Screen	ES-08-52-1760 ES-08-52-1770 ES-08-52-1780	Three Chlorine Dioxide Tanks
HVLC.07-22-1100	No. 7 Fiberline Screen Dilution Tank	ES-08-65-1060	Spill Collection Tank
HVLC.07-23-1200	No. 7 Fiberline Decker Hood	ES-08-70-0900	White Liquor Surge Tank
HVLC.07-23-1220	No. 7 Fiberline Decker Filtrate Tank	ES-08-67-1200	Base Effluent Neutralization Tank
HVLC.08-66-1000	Screen Rejects Tank	ES-08-67-1300	Acid Effluent Neutralization Tank
LVHC GAS COLLECTION SYSTEM		ES-08-70-1000	White Liquor Oxidation Tank
LVHC.06-10-2420	No. 6 Fiberline Digester Flash Condenser		FS-002
LVHC.07-10-2420	No. 7 Fiberline Digester Flash Condenser	ES-05-30-1300	No. 5 Hot Water Tank/Evaporator Condensate
LVHC.08-61-1000	Turpentine Decanter Tank	ES-08-40-1000	No. 32 High Density Pulp Tank
LVHC.08-61-1020	Turpentine Decanter Weir	ES-08-50-3140	10% Sulfuric Acid Day Tank
LVHC.08-61-1040	Turpentine Underflow Tank	ES-08-50-3020	Sulfuric Acid Storage Tank
LVHC.08-61-1080	Turpentine Tank	ES-08-52-1060	R8/10 Chlorine Dioxide Generator

Emission Source ID No.	Emission Source	Emission Source ID No.	Emission Source
LVHC.09-20-0320	No. 6 Black Liquor Evaporator System	ES-08-52-1760 ES-08-52-1770 ES-08-52-1780	Three Chlorine Dioxide Tanks
LVHC.09-25-0510	No. 7 Black Liquor Evaporator System	ES-08-65-1060	Spill Collection Tank
LVHC.09-35-0200	Concentrator Hotwell	ES-08-70-0900	White Liquor Surge Tank
LVHC.09-DECANT	Secondary Turpentine Decanter Tank	ES-08-67-1200	Base Effluent Neutralization Tank
LVHC.09-WEIR	Secondary Turpentine Decanter Weir	**EVAPORATOR OPERATIONS**	
LVHC.09-UND$^{\Delta}$	Secondary Turpentine Underflow Tank	ES-09-05-0210	South Weak Black Liquor Storage Tank
LVHC.09-STOR	Secondary Turpentine Storage Tank	**RECOVERY BOILER OPERATIONS**	
LVHC.09-25-1000	Condensate Stripper Feed Tank	ES-10-08-0010	Salt Cake Mix Tank
SOG.09-25-1050	Condensate Stripper Reflux Condenser	ES-10-25-0110	No. 5 Recovery Boiler
FIBERLINE OPERATIONS – No. 6 Fiberline and Bleach Plant		ES-10-45-0450	No. 5 Precipitator Mix Tank
ES-06-05-2000	Chip Silo B	ES-10-45-0520	North Precipitator Mix Tank
ES-06-05-3000	Chip Silo C	ES-10-45-0580	South Precipitator Mix Tank
ES-06-31-0180	Oxygen Delignification System	**SMELT DISSOLVING/GREEN LIQUOR CLARIFICATION OPERATIONS**	
ES-06-31-1000	1st Stage O_2 Surge Tank	ES-14-05-0050	North Smelt Tank
ES-06-32-2060	2nd Stage O_2 Reactor Blow Tube	ES-14-05-0300	South Smelt Tank
ES-06-32-2100	2nd Stage Wash Tower	ES-14-10-1000	No. 5 Green Liquor Clarifier
ES-06-32-2120	2A/2B Filtrate Tank	ES-14-15-0600	Dregs Surge Tank
ES-06-32-2300	No. 28 High Density Tank	ES-14-15-0800	Dregs Filter
ES-06-32-2340	No. 29 High Density Tank	ES-14-15-0900	Dregs Filter Vacuum System
ES-06-32-2380	No. 30 High Density Tank	**SLAKING/CAUSTICIZING OPERATIONS**	
ES-06-32-2460	2C Washer	ES-14-20-2020	East Lime Slaker
ES-06-32-2480	2C Washer Filtrate Tank	ES-14-20-2040	No. 1 East Causticizing Line
ES-06-33-3060	3rd Stage Tower - ClO_2 Stage	ES-14-20-2050	No. 2 East Causticizing Line
ES-06-34-4080	4th Stage Extraction Tower	ES-14-20-2060	No. 3 East Causticizing Line
ES-06-34-4100	4th Stage Extraction Filtrate Tank	ES-14-20-2085	West Lime SlakeR
ES-06-35-5060	5th Stage Tower – ClO_2 Stage	ES-14-20-2105	No. 1 West Causticizing Line
ES-06-35-5080	5th Stage Filtrate Tank – ClO_2 Stage	ES-14-20-2115	No. 2 West Causticizing Line
ES-08-67-1400	Acid Sewer	ES-14-20-2125	No. 3 West Causticizing Line
ES-06-6SFCO	6th Stage Feed Chute Overflow Line	ES-14-25-0050	Hydrosulfide Storage Tank
ES-06-P2	6th Stage Peroxide Reactor Blow Tube	ES-14-25-0150	Synthetic Liquor Mix Tank
ES-06-P3	6th Stage Peroxide Stage Washer, Filtrate Tank, Vacuum Pump, and Exhaust Blower	ES-14-25-0050	Hydrosulfide Storage Tank
FS-003	Building Fugitives	ES-14-25-0150	Synthetic Liquor Mix Tank
LIME MUD FILTERS AND LIME KILN OPERATIONS		**PULP OPERATIONS**	
ES-14-30-0310	Lime Mud Mix Tank	ES-32-25-0200 ES-32-25-0240	White Water Tanks
ES-14-30-0350	No. 2 Lime Mud Wash Tank	ES-32-93-0100	Building Roof Vents
ES-14-30-0700	No. 3 Lime Mud Wash Tank	ES-32-STOCKTANKS	HD and LD Stock Tanks
ES-14-30-1450	Lime Mud Storage Tank	ES-32-IO-VACPUMPS	Inside/Outside Vacuum Pumps
ES-14-30-5040 ES-14-30-6040	Two Lime Mud Filter Vacuum Systems	ES-32-HOODS	Dryer Hoods

Emission Source ID No.	Emission Source	Emission Source ID No.	Emission Source
ES-14-30-6060	Lime Mud Filtrate Tank	**WASTEWATER TREATMENT OPERATIONS**	
ES-14-70-2020	Scrubber Water Clarifier	ES-73-05-2000	Power/Recovery Channel and Sewer
ES-14-70-2045	Lime Kiln Scrubber Water Standpipe	ES-73-05-5200	Fiber Line Sewer Lift Station
ES-14-30-5000	East Lime Mud Filter – Hood Exhaust	ES-73-05-6000	Paper And Bleach Plant Sewer Ditches
ES-14-30-6000	West Lime Mud Filter - Hood Exhaust	ES-73-05-7080	Ammonium Hydroxide Storage Tank
ES-14-60-3000	No. 5 Lime Kiln	ES-73-10-1000	No. 1 Settling Pond
ES-14-60-3015	Reburned Lime Crusher	ES-73-10-2000	No. 2 Settling Pond
ES-14-65-1000	Reburned Lime Conveyor	ES-73-10-2510	No. 2 Lift Station
ES-14-65-1020	Reburned Lime Bucket Elevator	ES-73-10-3000	Aeration Basin
ES-14-65-1030	Reburned Lime Bin	ES-73-10-3920	Riffler
ES-14-65-1080	Fresh Lime Bin	ES-73-10-4000	No. 1 Retention Pond
WOODYARD OPERATIONS		ES-73-10-4500	No. 2 Retention Pond
ES-00-30-4480	North Chip Pile	ES-73-10-5030	No. 1 Lift Station & Receiving Pond
ES-00-30-4240	South Chip Pile	ES-73-25-1100 ES-73-25-1120	No. 3 Landfill Clean Filtrate/Leachate Sumps
ES-00-35-1000	Screen House	FS-018	Site-wide Sumps
ES-00-50-3280	Hogged Bark Fuel Storage Pile	**MODIFIED SOURCES**	
ES-11-30-1020	Emergency Chip Pile with Traversing Stacker	**PULP OPERATIONS**	
ES-11-50-4500-1 ES-11-50-4500-2	Two Bark Hogs	ES-65-25-0310	No. 2 Hog Fuel Boiler
FS-010	Hog Fuel Handling and Transfer in Woodyard	ES-45-93-0100	Building Fugitives
FS-012	Chip Conveying to Pulping	ES-FP-STOCKTANKS	HD and LD Stock Tanks
FS-013	Chip Handling and Transfer System in Woodyard	ES-45-40-VACP	Inside/Outside Vacuum Pumps
FS-021	Hog Fuel Handling and Transfer to Boiler Area	ES-45-40-HOOD	Dryer Hoods

1. 15A NCAC 02D .0530(u): USE OF PROJECTED ACTUAL EMISSIONS

Reporting [15A NCAC 02Q .0508 (f)]

a. The Permittee has used projected actual emissions to avoid applicability of prevention of significant deterioration requirements pursuant to Permit Application No. 5900069.18A for the Mill Optimization Project and revised pursuant to Permit Application No. 5900069.20A, consisting of modifications to the No. 2 Hog Fuel Boiler **(ID No. ES-65-25-0310)**, including the installation of the electrostatic precipitator **(ID No. CD-65-58-2000)**; installation of the Thermal Oxidizer **(ID No. CD-64-22-2000)**; modifications to the NC-5 Pulp Machine **(ID Nos. ES-45-93-0100 and ES-FP-STOCKTANKS)**; and which impacted several sources at the facility. In order to verify the assumptions used in the projected actual emissions calculations, the Permittee shall comply with the requirements in Section 2.2 F.1.b, below.

Monitoring/Recordkeeping/Reporting [15A NCAC 02D .0530(u) and 2Q .0308]

b. The Permittee shall perform the following:
   i. Upon commencement of regular operation of the modified No. 2 Hog Fuel Boiler, the Thermal Oxidizer, and the modified NC-5 Pulp Machine, the Permittee shall maintain records of annual CO, Lead, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4 mist, H_2S, total reduced sulfur (sum of compounds), VOC, Fluorides, and CO_2e emissions in tons per year, on a calendar year basis related to the Mill Optimization Project as listed above. The Permittee shall calculate these annual emissions for five years following startup of regular operations of the modified No. 2 Hog Fuel Boiler, the Thermal Oxidizer, and the modified NC-5 Pulp Machine.

ii. The Permittee shall submit a report to the director, postmarked on or before June 30th, after the end of each calendar year during which these records must be generated. The report shall contain the items listed in 40 CFR 51.166(r)(6)(v)(a) through (c).
iii. The Permittee shall make the information documented and maintained under this condition available to the Director or the general public pursuant to the requirements in 40 CFR 70.4(b)(3)(viii).
iv. The Permittee shall provide a comparison of the reported actual emissions (post-construction emissions) for each of the five calendar years to the projected actual emissions (pre-construction projection) as included below:

Pollutant	Projected Actual Emissions* (tons per year)
CO	7,188
Pb	5.92×10^{-2}
NO_X	1,688
PM (filterable only)	531
PM_{10}	403
$PM_{2.5}$	304
SO_2	1,617
H_2SO_4 mist	11.1
H_2S	22.1
Total reduced sulfur (sum of compounds)	78.0
VOC	692
F	0.16
CO_2e	1,896,866

* These projections are not enforceable limitations. If projected emissions are exceeded, consistent with 15A NCAC 02D .0530, the Permittee shall include, in its annual report, an explanation as to why the actual rates exceeded the projection.

2.3 Insignificant Activities per 15A NCAC 02Q .0503(8)

Emission Source ID No.	Emission Source Description[1,2]
FIBERLINE OPERATIONS	
IES-06-P1	No. 6 Bleach Plant, 6th Stage Hydrogen Peroxide Tank
IES-06-10-1200	No. 6 Digester Sand Separator Dumpster
IES-06-37-1060	No. 6 Bleach Plant Condensate Flash Tank (from non-contact steam)
IES-07-10-1200	No. 7 Digester Sand Separator Dumpster
IES-07-37-1080	No. 7 Bleach Plant Condensate Flash Tank (from non-contact steam)
IES-08-50-1100	Methanol Storage Tank (19,500 gallon capacity)
IES-08-50-2060	No. 1 (East) Bulk Caustic Storage Tank
IES-08-50-2080	No. 2 (West) Bulk Caustic Storage Tank
IES-08-50-2260	North 10% Caustic Storage Tank
IES-08-50-2280	South 10% Caustic Storage Tank
IES-08-51-2060	Hydrogen Peroxide Storage Tank
IES-08-51-3040	67% Nitric Acid Storage Tank
IES-08-51-3080	No. 6 & 7 Digester Acid Cleaning Tank
IES-08-51-4060	No. 7 Chelate Tank
IES-08-51-5020	Defoamer Tank
IES-08-52-1580	Chiller Hotwell Overflow (from non-contact heat exchange)
IES-08-52-7000	Chlorine Dioxide Plant Condensate Tank (from non-contact steam)
IES-08-52-7500	Emergency Water Tank (ClO_2 Plant)
IES-08-61-1100	Turpentine Railcar Loading
IES-08-62-2000	Clean Condensate Collection Tanks (from non-contact steam)
CHEMICAL RECOVERY	
IES-14-30-8050	Acid Cleaning Tank Associated with Lime Mud Filter System
IES-53-20-0470	Acid Neutralization Tank
IES-CR-EWSSF	East and West Slaker Sample Funnels
IES-14-60-3013 **NSPS JJJJ** **MACT ZZZZ**	Natural Gas-Fired Emergency Lime Kiln Backup Engine (127 hp)
IES-LMRC	Lime Mud Reclaim Conveyor
EVAPORATOR AREA	
IES-09-12-1000, IES-09-12-1100	Soap Railcar Loadout Stations
IES-09-TRL	Secondary Turpentine Railcar Loading

Emission Source ID No.	Emission Source Description[1,2]
POWER OPERATIONS	
IES-00-95-9900	Woodyard Diesel Fuel Storage Tank (10,000 gallons, fixed roof type)
IES-10-04-0220 **NSPS Kb**	No. 2 Fuel Oil Storage Tank (360,000 gallons)
IES-14-45-0920	No. 6 Fuel Oil Day Tank (by Lime Kiln)
IES-52-05-1040 **NSPS Kb**	No. 2 Fuel Oil Storage Tank (350,000 gallons)
IES-52-10-0010	No. 6 Fuel Oil Storage Tank (602,000 gallons)
IES-52-95-0050	Bark Dozer Diesel Fuel Storage Tank (3,000 gallons)
IES-53-20-0450	93-98% Sulfuric Acid Storage Tank
IES-94-30-2300	East Diesel Storage Tank (15,500 gallons)
IES-94-30-2350	West Diesel Storage Tank (15,500 gallons)
IES-94-30-2500	Gasoline Storage Tank (15,500 gallons)
IES-POWER-BCT	Miscellaneous Boiler Condensate Collection Tanks for continual hot fresh water (from non-contact heat exchange)
IES-POWER-DR	East & West Demineralizer Reactors
IES-POWER-DSM1	Dry Scrubber Media Storage Pile and Bucket Elevator
IES-POWER-DSM2	Dry Scrubber Media Storage Silo and Vent Filter Baghouse
IES-POWER-HFSB	Nos. 1 & 2 Hog Fuel Storage Bins
PULP MACHINE OPERATIONS	
IES-44-02-1780	Caustic Boilout Tank
WOODYARD OPERATIONS	
IES-00-94-1300	Hose Cutter
WASTEWATER TREATMENT	
IES-73-05-7090	Phosphoric Acid Storage Tank
MAINTENANCE AND UTILITIES	
IES-01-10-1800	TRS Cooling Tower
IES-09-03-1000	Evaporator Cooling Tower
IES-94-30	Motor Vehicle Repair Shop
IES-MU-DO	Site-Wide Degreasing Operations
IES-MU-PT	Plant-Wide Propane Tanks
IES-MU-RE	Plant-Wide Refrigeration Equipment
IES-022	Site-Wide Painting Operations
IES - KLime	Material Reuse Handling of Various By-Product Streams at the No. 3 Landfill Location
LIGNIN SOLIDS REMOVAL PROCESS	
IES-09-27-2900	Acid Wash Water Tank

Emission Source ID No.	Emission Source Description[1,2]
IES-09-27-3700	Lignin Acid Area Sump
IES-09-27-3400	No. 2 Lignin Filter Horizontal Conveyor uncontrolled or routed to a dust collection system with wet cyclone (ID No. CD-09-27-3900)
IES-09-27-3600	Lignin Liquor Area Sump

[1] Because an activity is insignificant does not mean that the activity is exempted from an applicable requirement (Federal or State) or that the Permittee is exempted from demonstrating compliance with any applicable requirement.

[2] When applicable, emissions from stationary source activities identified above shall be included in determining compliance with the permit requirements for toxic air pollutants under 15A NCAC 02D .1100 “Control of Toxic Air Pollutants” or 02Q .0711 “Emission Rates Requiring a Permit.”

SECTION 3 - GENERAL CONDITIONS (version 6.0, 01/07/2022)

This section describes terms and conditions applicable to this Title V facility.

A. **General Provisions** [NCGS 143-215 and 15A NCAC 02Q .0508(i)(16)]
1. Terms not otherwise defined in this permit shall have the meaning assigned to such terms as defined in 15A NCAC 02D and 02Q.
2. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are binding and enforceable pursuant to NCGS 143-215.114A and 143-215.114B, including assessment of civil and/or criminal penalties. Any unauthorized deviation from the conditions of this permit may constitute grounds for revocation and/or enforcement action by the DAQ.
3. This permit is not a waiver of or approval of any other Department permits that may be required for other aspects of the facility which are not addressed in this permit.
4. This permit does not relieve the Permittee from liability for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted facility, or from penalties therefore, nor does it allow the Permittee to cause pollution in contravention of state laws or rules, unless specifically authorized by an order from the North Carolina Environmental Management Commission.
5. Except as identified as state-only requirements in this permit, all terms and conditions contained herein shall be enforceable by the DAQ, the EPA, and citizens of the United States as defined in the Federal Clean Air Act.
6. Any stationary source of air pollution shall not be operated, maintained, or modified without the appropriate and valid permits issued by the DAQ, unless the source is exempted by rule. The DAQ may issue a permit only after it receives reasonable assurance that the installation will not cause air pollution in violation of any of the applicable requirements. A permitted installation may only be operated, maintained, constructed, expanded, or modified in a manner that is consistent with the terms of this permit.

B. **Permit Availability** [15A NCAC 02Q .0507(k) and .0508(i)(9)(B)]
The Permittee shall have available at the facility a copy of this permit and shall retain for the duration of the permit term one complete copy of the application(s) and any information submitted in support of the application package. The permit and application shall be made available to an authorized representative of Department of Environmental Quality upon request.

C. **Severability Clause** [15A NCAC 02Q .0508(i)(2)]
In the event of an administrative challenge to a final and binding permit in which a condition is held to be invalid, the provisions in this permit are severable so that all requirements contained in the permit, except those held to be invalid, shall remain valid and must be complied with.

D. **Submissions** [15A NCAC 02Q .0507(e) and 02Q .0508(i)(16)]
Except as otherwise specified herein, two copies of all documents, reports, test data, monitoring data, notifications, request for renewal, and any other information required by this permit shall be submitted to the appropriate Regional Office. Refer to the Regional Office address on the cover page of this permit. For continuous emissions monitoring systems (CEMS) reports, continuous opacity monitoring systems (COMS) reports, quality assurance (QA)/quality control (QC) reports, acid rain CEM certification reports, and NOx budget CEM certification reports, one copy shall be sent to the appropriate Regional Office and one copy shall be sent to:

Supervisor, Stationary Source Compliance
North Carolina Division of Air Quality
1641 Mail Service Center
Raleigh, NC 27699-1641

All submittals shall include the facility name and Facility ID number (refer to the cover page of this permit).

E. **Duty to Comply** [15A NCAC 02Q .0508(i)(3)]
The Permittee shall comply with all terms, conditions, requirements, limitations and restrictions set forth in this permit. Noncompliance with any permit condition except conditions identified as state-only requirements constitutes a violation of the Federal Clean Air Act. Noncompliance with any permit condition is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

F. **Circumvention** - STATE ENFORCEABLE ONLY
The facility shall be properly operated and maintained at all times in a manner that will effect an overall reduction in air pollution. Unless otherwise specified by this permit, no emission source may be operated without the concurrent operation of its associated air pollution control device(s) and appurtenances.

G. **Title V Permit Modifications**
1. Administrative Permit Amendments [15A NCAC 02Q .0514]
The Permittee shall submit an application for an administrative permit amendment in accordance with 15A NCAC 02Q .0514.
2. Transfer in Ownership or Operation and Application Submittal Content [15A NCAC 02Q .0524 and 02Q .0505]
The Permittee shall submit an application for an ownership change in accordance with 15A NCAC 02Q.0524 and 02Q .0505.
3. Minor Permit Modifications [15A NCAC 02Q .0515]
The Permittee shall submit an application for a minor permit modification in accordance with 15A NCAC 02Q .0515.
4. Significant Permit Modifications [15A NCAC 02Q .0516]
The Permittee shall submit an application for a significant permit modification in accordance with 15A NCAC 02Q .0516.
5. Reopening for Cause [15A NCAC 02Q .0517]
The Permittee shall submit an application for reopening for cause in accordance with 15A NCAC 02Q .0517.

H. **Changes Not Requiring Permit Modifications**
1. Reporting Requirements [15A NCAC 02Q .0508(f)]
Any of the following that would result in new or increased emissions from the emission source(s) listed in Section 1 must be reported to the Regional Supervisor, DAQ:
   a. changes in the information submitted in the application;
   b. changes that modify equipment or processes; or
   c. changes in the quantity or quality of materials processed.

   If appropriate, modifications to the permit may then be made by the DAQ to reflect any necessary changes in the permit conditions. In no case are any new or increased emissions allowed that will cause a violation of the emission limitations specified herein.
2. Section 502(b)(10) Changes [15A NCAC 02Q .0523(a)]
   a. "Section 502(b)(10) changes" means changes that contravene an express permit term or condition. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
   b. The Permittee may make Section 502(b)(10) changes without having the permit revised if:
      i. the changes are not a modification under Title I of the Federal Clean Air Act;
      ii. the changes do not cause the allowable emissions under the permit to be exceeded;
      iii. the Permittee notifies the Director and EPA with written notification at least seven days before the change is made; and
      iv. the Permittee shall attach the notice to the relevant permit.
   c. The written notification shall include:
      i. a description of the change;
      ii. the date on which the change will occur;
      iii. any change in emissions; and
      iv. any permit term or condition that is no longer applicable as a result of the change.
   d. Section 502(b)(10) changes shall be made in the permit the next time that the permit is revised or renewed, whichever comes first.
3. Off Permit Changes [15A NCAC 02Q .0523(b)]
The Permittee may make changes in the operation or emissions without revising the permit if:
   a. the change affects only insignificant activities and the activities remain insignificant after the change; or
   b. the change is not covered under any applicable requirement.
4. Emissions Trading [15A NCAC 02Q .0523(c)]
To the extent that emissions trading is allowed under 15A NCAC 02D, including subsequently adopted maximum achievable control technology standards, emissions trading shall be allowed without permit revision pursuant to 15A NCAC 02Q .0523(c).

I.A **Reporting Requirements for Excess Emissions** [15A NCAC 02D .0535(f) and 02Q .0508(f)(2)]

1. "Excess Emissions" - means an emission rate that exceeds any applicable emission limitation or standard allowed by any rule in Sections .0500, .0900, .1200, or .1400 of Subchapter 02D; or by a permit condition; or that exceeds an emission limit established in a permit issued under 15A NCAC 02Q .0700. *(Note: Definitions of excess emissions under 02D .1110 and 02D .1111 shall apply where defined by rule.)*
2. If a source is required to report excess emissions under NSPS (15A NCAC 02D .0524), NESHAPS (15A NCAC 02D .1110 or .1111), or the operating permit provides for periodic (e.g., quarterly) reporting of excess emissions, reporting shall be performed as prescribed therein.
3. If the source is not subject to NSPS (15A NCAC 02D .0524), NESHAPS (15A NCAC 02D .1110 or .1111), or these rules do NOT define "excess emissions," the Permittee shall report excess emissions in accordance with 15A NCAC 02D .0535 as follows:
   a. Pursuant to 15A NCAC 02D .0535, if excess emissions last for more than four hours resulting from a malfunction, a breakdown of process or control equipment, or any other abnormal condition, the owner or operator shall:
      i. notify the Regional Supervisor or Director of any such occurrence by 9:00 a.m. Eastern Time of the Division's next business day of becoming aware of the occurrence and provide:
         - name and location of the facility;
         - nature and cause of the malfunction or breakdown;
         - time when the malfunction or breakdown is first observed;
         - expected duration; and
         - estimated rate of emissions;
      ii. notify the Regional Supervisor or Director immediately when corrective measures have been accomplished; and
      iii. submit to the Regional Supervisor or Director within 15 days a written report as described in 15A NCAC 02D .0535(f)(3).

I.B **Reporting Requirements for Permit Deviations** [15A NCAC 02D .0535(f) and 02Q .0508(f)(2)]

1. "Permit Deviations" - for the purposes of this condition, any action or condition not in accordance with the terms and conditions of this permit including those attributable to upset conditions as well as excess emissions as defined above lasting less than four hours.
2. Pursuant to 15A NCAC 02Q .0508(f)(2), the Permittee shall report deviations from permit requirements (terms and conditions) quarterly by notifying the Regional Supervisor or Director of all other deviations from permit requirements not covered under 15A NCAC 02D .0535. A written report to the Regional Supervisor shall include the probable cause of such deviation and any corrective actions or preventative actions taken. The responsible official shall certify all deviations from permit requirements.

I.C **Other Requirements under 15A NCAC 02D .0535**

The Permittee shall comply with all other applicable requirements contained in 15A NCAC 02D .0535, including 15A NCAC 02D .0535(c) as follows:

1. Any excess emissions that do not occur during start-up and shut-down shall be considered a violation of the appropriate rule unless the owner or operator of the sources demonstrates to the Director that the excess emissions are a result of a malfunction. The Director shall consider, along with any other pertinent information, the criteria contained in 15A NCAC 02D .0535(c)(1) through (7).
2. 15A NCAC 02D .0535(g). Excess emissions during start-up and shut-down shall be considered a violation of the appropriate rule if the owner or operator cannot demonstrate that excess emissions are unavoidable.

J. **Emergency Provisions** [40 CFR 70.6(g)]

The Permittee shall be subject to the following provisions with respect to emergencies:

1. An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the facility to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.
2. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions specified in 3. below are met.
3. The affirmative defense of emergency shall be demonstrated through properly signed contemporaneous operating logs or other relevant evidence that include information as follows:
   a. an emergency occurred and the Permittee can identify the cause(s) of the emergency;
   b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the standards or other requirements in the permit; and
d. the Permittee submitted notice of the emergency to the DAQ within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.

4. In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.
5. This provision is in addition to any emergency or upset provision contained in any applicable requirement specified elsewhere herein.

K. **Permit Renewal** [15A NCAC 02Q .0508(e) and 02Q .0513(b)]
This 15A NCAC 02Q .0500 permit is issued for a fixed term not to exceed five years and shall expire at the end of its term. Permit expiration terminates the facility's right to operate unless a complete 15A NCAC 02Q .0500 renewal application is submitted at least six months before the date of permit expiration. If the Permittee or applicant has complied with 15A NCAC 02Q .0512(b)(1), this 15A NCAC 02Q .0500 permit shall not expire until the renewal permit has been issued or denied. Permit expiration under 15A NCAC 02Q .0400 terminates the facility's right to operate unless a complete 15A NCAC 02Q .0400 renewal application is submitted at least six months before the date of permit expiration for facilities subject to 15A NCAC 02Q .0400 requirements. In either of these events, all terms and conditions of these permits shall remain in effect until the renewal permits have been issued or denied.

L. **Need to Halt or Reduce Activity Not a Defense** [15A NCAC 02Q .0508(i)(4)]
It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

M. **Duty to Provide Information (submittal of information)** [15A NCAC 02Q .0508(i)(9)]
1. The Permittee shall furnish to the DAQ, in a timely manner, any reasonable information that the Director may request in **writing** to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.
2. The Permittee shall furnish the DAQ copies of records required to be kept by the permit when such copies are requested by the Director. For information claimed to be confidential, the Permittee may furnish such records directly to the EPA upon request along with a claim of confidentiality.

N. **Duty to Supplement** [15A NCAC 02Q .0507(f)]
The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information to the DAQ. The Permittee shall also provide additional information as necessary to address any requirement that becomes applicable to the facility after the date a complete permit application was submitted but prior to the release of the draft permit.

O. **Retention of Records** [15A NCAC 02Q .0508(f) and 02Q .0508(l)]
The Permittee shall retain records of all required monitoring data and supporting information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring information, and copies of all reports required by the permit. These records shall be maintained in a form suitable and readily available for expeditious inspection and review. Any records required by the conditions of this permit shall be kept on site and made available to DAQ personnel for inspection upon request.

P. **Compliance Certification** [15A NCAC 02Q .0508(n)]
The Permittee shall submit to the DAQ and the EPA (Air Enforcement Branch, EPA, Region 4, 61 Forsyth Street SW, Atlanta, GA 30303 or through the EPA CEDRI) postmarked on or before March 1 a compliance certification (for the preceding calendar year) by a responsible official with all terms and conditions in the permit (including emissions limitations, standards, or work practices), except for conditions identified as being State-enforceable Only. It shall be the responsibility of the current owner to submit a compliance certification for the entire year regardless of who owned the facility during the year. The compliance certification shall comply with additional requirements as may be specified under Sections 114(a)(3) or 504(b) of the Federal Clean Air Act. The compliance certification shall specify:
1. the identification of each term or condition of the permit that is the basis of the certification;
2. the compliance status (with the terms and conditions of the permit for the period covered by the certification);
3. whether compliance was continuous or intermittent;
4. the method(s) used for determining the compliance status of the source during the certification period;

5. each deviation and take it into account in the compliance certification; and
6. as possible exceptions to compliance, any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (CAM) occurred.

Q. **Certification by Responsible Official** [15A NCAC 02Q .0520]
A responsible official shall certify the truth, accuracy, and completeness of any application form, report, or compliance certification required by this permit. All certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

R. **Permit Shield for Applicable Requirements** [15A NCAC 02Q .0512]
1. Compliance with the terms and conditions of this permit shall be deemed compliance with applicable requirements, where such applicable requirements are included and specifically identified in the permit as of the date of permit issuance.
2. A permit shield shall not alter or affect:
   a. the power of the Commission, Secretary of the Department, or Governor under NCGS 143-215.3(a)(12), or EPA under Section 303 of the Federal Clean Air Act;
   b. the liability of an owner or operator of a facility for any violation of applicable requirements prior to the effective date of the permit or at the time of permit issuance;
   c. the applicable requirements under Title IV; or
   d. the ability of the Director or the EPA under Section 114 of the Federal Clean Air Act to obtain information to determine compliance of the facility with its permit.
3. A permit shield does not apply to any change made at a facility that does not require a permit or permit revision made under 15A NCAC 02Q .0523.
4. A permit shield does not extend to minor permit modifications made under 15A NCAC 02Q .0515.

S. **Termination, Modification, and Revocation of the Permit** [15A NCAC 02Q .0519]
The Director may terminate, modify, or revoke and reissue this permit if:
1. the information contained in the application or presented in support thereof is determined to be incorrect;
2. the conditions under which the permit or permit renewal was granted have changed;
3. violations of conditions contained in the permit have occurred;
4. the EPA requests that the permit be revoked under 40 CFR 70.7(g) or 70.8(d); or
5. the Director finds that termination, modification, or revocation and reissuance of the permit is necessary to carry out the purpose of NCGS Chapter 143, Article 21B.

T. **Insignificant Activities** [15A NCAC 02Q .0503]
Because an emission source or activity is insignificant does not mean that the emission source or activity is exempted from any applicable requirement or that the owner or operator of the source is exempted from demonstrating compliance with any applicable requirement. The Permittee shall have available at the facility at all times and made available to an authorized representative upon request, documentation, including calculations, if necessary, to demonstrate that an emission source or activity is insignificant.

U. **Property Rights** [15A NCAC 02Q .0508(i)(8)]
This permit does not convey any property rights in either real or personal property or any exclusive privileges.

V. **Inspection and Entry** [15A NCAC 02Q .0508(l) and NCGS 143-215.3(a)(2)]
1. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow the DAQ, or an authorized representative, to perform the following:
   a. enter the Permittee's premises where the permitted facility is located or emissions-related activity is conducted, or where records are kept under the conditions of the permit;
   b. have access to and copy, at reasonable times, any records that are required to be kept under the conditions of the permit;
   c. inspect at reasonable times and using reasonable safety practices any source, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
   d. sample or monitor substances or parameters, using reasonable safety practices, for the purpose of assuring compliance with the permit or applicable requirements at reasonable times.

   Nothing in this condition shall limit the ability of the EPA to inspect or enter the premises of the Permittee under Section 114 or other provisions of the Federal Clean Air Act.

2. No person shall refuse entry or access to any authorized representative of the DAQ who requests entry for purposes of inspection, and who presents appropriate credentials, nor shall any person obstruct, hamper, or interfere with any such authorized representative while in the process of carrying out his official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

W. **Annual Fee Payment** [15A NCAC 02Q .0508(i)(10)]
1. The Permittee shall pay all fees in accordance with 15A NCAC 02Q .0200.
2. Payment of fees may be by check or money order made payable to the N.C. Department of Environmental Quality. Annual permit fee payments shall refer to the permit number.
3. If, within 30 days after being billed, the Permittee fails to pay an annual fee, the Director may initiate action to terminate the permit under 15A NCAC 02Q .0519.

X. **Annual Emission Inventory Requirements** [15A NCAC 02Q .0207]
The Permittee shall report by **June 30 of each year** the actual emissions of each air pollutant listed in 15A NCAC 02Q .0207(a) from each emission source within the facility during the previous calendar year. The report shall be in or on such form as may be established by the Director. The accuracy of the report shall be certified by a responsible official of the facility.

Y. **Confidential Information** [15A NCAC 02Q .0107 and 02Q .0508(i)(9)]
Whenever the Permittee submits information under a claim of confidentiality pursuant to 15A NCAC 02Q .0107, the Permittee may also submit a copy of all such information and claim directly to the EPA upon request. All requests for confidentiality must be in accordance with 15A NCAC 02Q .0107.

Z. **Construction and Operation Permits** [15A NCAC 02Q .0100 and .0300]
A construction and operating permit shall be obtained by the Permittee for any proposed new or modified facility or emission source which is not exempted from having a permit prior to the beginning of construction or modification, in accordance with all applicable provisions of 15A NCAC 02Q .0100 and .0300.

AA. **Standard Application Form and Required Information** [15A NCAC 02Q .0505 and .0507]
The Permittee shall submit applications and required information in accordance with the provisions of 15A NCAC 02Q .0505 and .0507.

BB. **Financial Responsibility and Compliance History** [15A NCAC 02Q .0507(d)(3)]
The DAQ may require an applicant to submit a statement of financial qualifications and/or a statement of substantial compliance history.

CC. **Refrigerant Requirements (Stratospheric Ozone and Climate Protection)** [15A NCAC 02Q .0501(d)]
1. If the Permittee has appliances or refrigeration equipment, including air conditioning equipment, which use Class I or II ozone-depleting substances such as chlorofluorocarbons and hydrochlorofluorocarbons listed as refrigerants in 40 CFR Part 82 Subpart A Appendices A and B, the Permittee shall service, repair, and maintain such equipment according to the work practices, personnel certification requirements, and certified recycling and recovery equipment specified in 40 CFR Part 82 Subpart F.
2. The Permittee shall not knowingly vent or otherwise release any Class I or II substance into the environment during the repair, servicing, maintenance, or disposal of any such device except as provided in 40 CFR Part 82 Subpart F.
3. The Permittee shall comply with all reporting and recordkeeping requirements of 40 CFR 82.166. Reports shall be submitted to the EPA or its designee as required.

DD. **Prevention of Accidental Releases - Section 112(r)** [15A NCAC 02Q .0508(h)]
If the Permittee is required to develop and register a Risk Management Plan with EPA pursuant to Section 112(r) of the Clean Air Act, then the Permittee is required to register this plan in accordance with 40 CFR Part 68.

EE. **National Emission Standards Asbestos – 40 CFR Part 61, Subpart M** [15A NCAC 02D .1110]
The Permittee shall comply with all applicable standards for demolition and renovation activities pursuant to the requirements of 40 CFR Part 61, Subpart M. The permittee shall not be required to obtain a modification of this permit in order to perform the referenced activities.

FF. **Title IV Allowances** [15A NCAC 02Q .0508(i)(1)]
This permit does not limit the number of Title IV allowances held by the Permittee, but the Permittee may not use allowances as a defense to noncompliance with any other applicable requirement. The Permittee's emissions may not exceed any allowances that the facility lawfully holds under Title IV of the Federal Clean Air Act.

GG. **Air Pollution Emergency Episode** [15A NCAC 02D .0300]
Should the Director of the DAQ declare an Air Pollution Emergency Episode, the Permittee will be required to operate in accordance with the Permittee's previously approved Emission Reduction Plan or, in the absence of an approved plan, with the appropriate requirements specified in 15A NCAC 02D .0300.

HH. **Registration of Air Pollution Sources** [15A NCAC 02D .0202]
The Director of the DAQ may require the Permittee to register a source of air pollution. If the Permittee is required to register a source of air pollution, this registration and required information will be in accordance with 15A NCAC 02D .0202(b).

II. **Ambient Air Quality Standards** [15A NCAC 02D .0501(c)]
In addition to any control or manner of operation necessary to meet emission standards specified in this permit, any source of air pollution shall be operated with such control or in such manner that the source shall not cause the ambient air quality standards in 15A NCAC 02D .0400 to be exceeded at any point beyond the premises on which the source is located. When controls more stringent than named in the applicable emission standards in this permit are required to prevent violation of the ambient air quality standards or are required to create an offset, the permit shall contain a condition requiring these controls.

JJ. **General Emissions Testing and Reporting Requirements** [15A NCAC 02Q .0508(i)(16)]
Emission compliance testing shall be by the procedures of Section .2600, except as may be otherwise required in Rules .0524, .1110, or .1111 of Subchapter 02D. If emissions testing is required by this permit or the DAQ or if the Permittee submits emissions testing to the DAQ to demonstrate compliance for emission sources subject to Rules .0524, .1110, or .1111, the Permittee shall provide and submit all notifications, conduct all testing, and submit all test reports in accordance with the requirements of 15A NCAC 02D .0524, .1110, or .1111, as applicable. Otherwise, if emissions testing is required by this permit or the DAQ or if the Permittee submits emissions testing to the DAQ to demonstrate compliance, the Permittee shall perform such testing in accordance with 15A NCAC 02D .2600 and follow the procedures outlined below:

1. The owner or operator of the source shall arrange for air emission testing protocols to be provided to the Director prior to air pollution testing. Testing protocols are not required to be pre-approved by the Director prior to air pollution testing. The Director shall review air emission testing protocols for pre-approval prior to testing if requested by the owner or operator at least **45 days** before conducting the test.
2. Any person proposing to conduct an emissions test to demonstrate compliance with an applicable standard shall notify the Director at least **15 days** before beginning the test so that the Director may at his option observe the test.
3. The owner or operator of the source shall arrange for controlling and measuring the production rates during the period of air testing. The owner or operator of the source shall ensure that the equipment or process being tested is operated at the production rate that best fulfills the purpose of the test. The individual conducting the emission test shall describe the procedures used to obtain accurate process data and include in the test report the average production rates determined during each testing period.
4. Two copies of the final air emission test report shall be submitted to the Director not later than **30 days** after sample collection unless otherwise specified in the specific conditions. The owner or operator may request an extension to submit the final test report. The Director shall approve an extension request if he finds that the extension request is a result of actions beyond the control of the owner or operator.
    a. The Director shall make the final determination regarding any testing procedure deviation and the validity of the compliance test. The Director may:
        i. Allow deviations from a method specified under a rule in this Section if the owner or operator of the source being tested demonstrates to the satisfaction of the Director that the specified method is inappropriate for the source being tested.
        ii. Prescribe alternate test procedures on an individual basis when he finds that the alternative method is necessary to secure more reliable test data.
        iii. Prescribe or approve methods on an individual basis for sources or pollutants for which no test method is specified in 15A NCAC 02D .2600 if the methods can be demonstrated to determine compliance of permitted emission sources or pollutants.
    b. The Director may authorize the DAQ to conduct independent tests of any source subject to a rule in 15A NCAC 02D to determine the compliance status of that source or to verify any test data submitted relating to that source.

Any test conducted by the Division of Air Quality using the appropriate testing procedures described in 15A NCAC 02D .2600 has precedence over all other tests.

KK. **Reopening for Cause** [15A NCAC 02Q .0517]

1. A permit shall be reopened and revised under the following circumstances:
   a. additional applicable requirements become applicable to a facility with remaining permit term of three or more years;
   b. additional requirements (including excess emission requirements) become applicable to a source covered by Title IV;
   c. the Director or EPA finds that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or
   d. the Director or EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.
2. Any permit reopening shall be completed or a revised permit issued within 18 months after the applicable requirement is promulgated. No reopening is required if the effective date of the requirement is after the expiration of the permit term unless the term of the permit was extended pursuant to 15A NCAC 02Q .0513(c).
3. Except for the state-enforceable only portion of the permit, the procedures set out in 15A NCAC 02Q .0507, .0521, or .0522 shall be followed to reissue the permit. If the State-enforceable only portion of the permit is reopened, the procedures in 15A NCAC 02Q .0300 shall be followed. The proceedings shall affect only those parts of the permit for which cause to reopen exists.
4. The Director shall notify the Permittee at least 60 days in advance of the date that the permit is to be reopened, except in cases of imminent threat to public health or safety the notification period may be less than 60 days.
5. Within 90 days, or 180 days if the EPA extends the response period, after receiving notification from the EPA that a permit needs to be terminated, modified, or revoked and reissued, the Director shall send to the EPA a proposed determination of termination, modification, or revocation and reissuance, as appropriate.

LL. **Reporting Requirements for Non-Operating Equipment** [15A NCAC 02Q .0508(i)(16)]

The Permittee shall maintain a record of operation for permitted equipment noting whenever the equipment is taken from and placed into operation. When permitted equipment is not in operation, the requirements for testing, monitoring, and recordkeeping are suspended until operation resumes.

MM. **Fugitive Dust Control Requirement** [15A NCAC 02D .0540]

As required by 15A NCAC 02D .0540 "Particulates from Fugitive Dust Emission Sources," the Permittee shall not cause or allow fugitive dust emissions to cause or contribute to substantive complaints or excess visible emissions beyond the property boundary. If substantive complaints or excessive fugitive dust emissions from the facility are observed beyond the property boundaries for six minutes in any one hour (using Reference Method 22 in 40 CFR, Appendix A), the owner or operator may be required to submit a fugitive dust plan as described in 02D .0540(f).

"Fugitive dust emissions" means particulate matter from process operations that does not pass through a process stack or vent and that is generated within plant property boundaries from activities such as: unloading and loading areas, process areas, stockpiles, stock pile working, plant parking lots, and plant roads (including access roads and haul roads).

NN. **Specific Permit Modifications** [15A NCAC 02Q .0501 and .0523]

1. For modifications made pursuant to 15A NCAC 02Q .0501(b)(2), the Permittee shall file a Title V Air Quality Permit Application for the air emission source(s) and associated air pollution control device(s) on or before 12 months after commencing operation.
2. For modifications made pursuant to 15A NCAC 02Q .0501(c)(2), the Permittee shall not begin operation of the air emission source(s) and associated air pollution control device(s) until a Title V Air Quality Permit Application is filed and a construction and operation permit following the procedures of Section .0500 (except for Rule .0504 of this Section) is obtained.
3. For modifications made pursuant to 502(b)(10), in accordance with 15A NCAC 02Q .0523(a)(1)(C), the Permittee shall notify the Director and EPA (Air Permitting Branch, EPA, Region 4, 61 Forsyth Street SW, Atlanta, GA 30303 or through the EPA CEDRI) in writing at least seven days before the change is made.
   a. The written notification shall include:
      i. a description of the change at the facility;
      ii. the date on which the change will occur;
      iii. any change in emissions; and
      iv. any permit term or condition that is no longer applicable as a result of the change.

b. In addition to this notification requirement, with the next significant modification or Air Quality Permit renewal, the Permittee shall submit a page "E5" of the application forms signed by the responsible official verifying that the application for the 502(b)(10) change/modification, is true, accurate, and complete. Further note that modifications made pursuant to 502(b)(10) do not relieve the Permittee from satisfying preconstruction requirements.

OO. **Third Party Participation and EPA Review** [15A NCAC 02Q .0521, .0522 and .0525(7)]
For permits modifications subject to 45-day review by the federal EPA, EPA's decision to not object to the proposed permit is considered final and binding on the EPA and absent a third party petition, the failure to object is the end of EPA's decision-making process with respect to the revisions to the permit. The time period available to submit a public petition pursuant to 15A NCAC 02Q .0518 begins at the end of the 45-day EPA review period.