TENTATIVE AGENDA
STATE OF TENNESSEE
REGULAR MEETING
AIR POLLUTION CONTROL BOARD
Nashville Room, 3rd Floor Tennessee Tower
312 Rosa L. Parks Avenue
In Person and
Remote Access Via WebEx link

Wednesday, February 08, 2023
9:30 A.M.

	Item	Presenter	Page
1.	Roll Call		
2.	Approval of the January 11, 2023, Board Meeting Minutes		2
3.	Sullivan County SO2 SIP BO 23-002	Travis Blake	6
4.	General Business 1. NESAHP Rule Update	Mark Reynolds	118

Air Pollution Control Board
of the
State of Tennessee
Regular Meeting

On Wednesday January 11, 2023, at 9:30 A.M., the Air Pollution Control Board of the State of Tennessee, (hereinafter, referred to as the "Board"), began its meeting on the 3rd Floor of the Tennessee Tower. The following Board members were physically present.

Dr. Ronne' Adkins
Dr. Shawn Hawkins
Mr. Mike Haverstick
Mr. Richard Holland
Ms. Caitlin Jennings
Mayor Ken Moore
Ms. Amy Spann
Mayor Larry Waters
Mr. Jimmy West

The following Board members joined the meeting via WebEx:
Dr. John Benitez
Dr. Chunrong Jia
Mr. Stephen Moore

The following Board member was absent:
Dr. Joshua Fu

Since the Chairman, David Salyers, P.E., could not attend the meeting, Dr. Ronne' Adkins represented the Chairman by proxy. Ms. Michelle Owenby, Director, Division of Air Pollution Control, served as Technical Secretary.

Ms. Michelle Owenby, Technical Secretary, welcomed Board members and those attending via WebEx.

The first item on the agenda was to elect a Vice Chair for 2023. Mayor Larry Waters was nominated for Vice Chair by Mr. Holland and Mr. West seconded the nomination.

The Technical Secretary call for a roll call and the response was as follows:

Dr. Adkins	Yes	Dr. Benitez	Yes
Mr. Haverstick	Yes	Dr. Hawkins	Yes
Mr. Holland	Yes	Dr. Jia	Yes
Mayor Moore	Yes	Mr. Moore	Yes
Ms. Spann	Yes	Mayor Waters	Abstain
Mr. West	Yes		

The motion carried with Eleven (11) affirmative votes; Mayor Waters accepted the nomination

The Vice-Chairman, Mayor Larry Waters, called the meeting to order and asked for a roll call and the response was as follows:

Dr. Adkins	Present	Dr. Benitez	Present
Dr. Fu	Absent	Mr. Haverstick	Present
Dr. Hawkins	Present	Mr. Holland	Present
Ms. Jennings	Absent	Dr. Jia	Present
Mayor Moore	Present	Mr. Moore	Present
Ms. Spann	Present	Mayor Waters	Present
Mr. Jimmy West	Present		

Eight (8) Board members were present, three (3) participated via WebEx and two (2) were absent. Ms. Jennings arrived at 9:35

The next item on the agenda was the approval of the minutes from the October 11, 2022, Board meeting. The Vice-Chairman requested a motion to approve the minutes. Mayor Moore made a motion to approve the minutes and Ms. Spann seconded the motion. The Vice-Chairman asked if there were any additions or corrections to the minutes. Hearing none, the Vice-Chair asked for a roll call and the response was as follows:

Dr. Adkins	Yes	Dr. Benitez	Yes
Mr. Haverstick	Yes	Dr. Hawkins	Yes
Mr. Holland	Yes	Dr. Jia	Yes
Ms. Jennings	Yes	Mayor Moore	Yes
Mr. Moore	Yes	Ms. Spann	Yes
Mayor Waters	Yes	Mr. West	Yes

The motion carried with Twelve (12) affirmative votes; the minutes were approved as presented.

The Vice-Chairman called on Mr. Steve Stout, Office of General Counsel, to discuss the annual Disclosure of Financial Interests or Other Potential Conflicts of Interest. Mr. Stout discussed the need for the annual disclosure and collected the signed documents. Mr. Stout stated that he would review the documents and present the results later in the meeting.

The Vice-Chairman called on Mr. Travis Blake with Air Pollution Control to present the Eastman Chemical Company variance request, Board Order number 23-001.

Mr. Travis Blake with the Division of Air Pollution Control presented a request from Eastman Chemical Company BO 23-001 for a variance from the prompt notification requirements of TAPCR 1200-03-20-.03 for excess SO_2 emissions of less than 24 hours duration. Mr. Blake answered the Board's questions.

The Vice-Chairman requested a motion to approve the Eastman Chemical Variance Board Order number 23-001. Mr. Holland made a motion to approve the Board Order and Mayor Moore seconded the motion. The Vice-Chair asked for a roll call and the response was as follows:

Dr. Adkins	Yes	Dr. Benitez	Yes
Mr. Haverstick	Yes	Dr. Hawkins	Yes
Mr. Holland	Yes	Dr. Jia	Yes
Ms. Jennings	Yes	Mayor Moore	Yes
Mr. Moore	Abstain	Ms. Spann	Yes
Mayor Waters	Yes	Mr. West	Yes

The Vice-Chairman called on Ms. Mary-Margaret Chandler with the Division of Air Pollution Control to provide the Title V Financial and Fee Diversification Update.

Ms. Chandler discussed the current Title 5 finances and provided an update on the fee diversification work. The timeline for the upcoming fee rule amendment was also discussed.

The Vice-Chairman called on Mr. Marc Corrigan with Air Pollution Control to provide an update on the Shelby County Local Program Quarterly Progress Report. Mr. Corrigan informed the Board that the Division had received the 2nd quarter report and discussed the progress demonstrated in the report.

Mr. Corrigan then welcome to the podium Ms. Kasia Smith Alexander, Administrator of the Shelby County Health Department to provide further details and answer any questions the Board might have. Ms. Alexander discussed the progress made during the 2nd quarter.

The Vice-Chairman then called for a five (5) minute recess to allow Mr. Stout to finalize the annual Disclosure of Financial Interests or Other Potential Conflicts of Interest. The Board reconvened at 10:25. Mr. Stout stated that there were eight (8) of the thirteen (13) members of the Board, that "represent the public interest" as defined by Tenn. Comp. R. & Regs. 0400-30-17-.02(1).

There being no further business to discuss before the Board, nor members of the public wishing to address the Board, the meeting was adjourned at 10:30am.

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(Signed) Michelle Owenby, Technical Secretary
Tennessee Air Pollution Control Board

Approved at Nashville, Tennessee on February 8, 2023

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(Signed) Mayor Larry Waters, Vice-Chairman
Tennessee Air Pollution Control Board

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(Signed) David Salyers, Chairman
Tennessee Air Pollution Control Board

Attainment Demonstration

Sullivan County, Tennessee
SO_2 Nonattainment Area

February 8, 2023

Prepared by:

Tennessee Department of Environment and Conservation
Division of Air Pollution Control
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312 Rosa L. Parks Avenue, 15th Floor
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LIST OF ACRONYMS AND ABBREVIATIONS

AEO2014	Annual Energy Outlook, 2014
AERMET	A meteorological data preprocessor for AERMOD
AERMOD	AMS/EPA Regulatory Model. AERMOD is a steady-state Gaussian dispersion model that represents the current state-of-science dispersion model.
AQS	Air Quality System. AQS is EPA's repository of ambient air quality data.
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CFR	Code of Federal Regulations
CHIEF	Clearinghouse for Inventories and Emission Factors
DNR	Department of Natural Resources (e. g., Missouri DNR)
DSI	Duct sorbent injection
DWR	Division of Water Resources (e. g., TDEC-DWR)
EMVAP	Emissions Variability Processor
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FF	Fabric filter
FR	Federal Register
HWC	Hazardous Waste Combustor
$\mu g/m^3$	Micrograms per Cubic Meter

LIST OF ACRONYMS AND ABBREVIATIONS

LAER	Lowest Achievable Emission Rate
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million Btu of heat input
Metro 4/SESARM	Metro 4, Inc. and Southeastern States Air Resource Managers, Inc.
MPO	Metropolitan Planning Organization
MOVES	Motor Vehicle Emissions Simulator
MSOP	Major source operating permit
N	North
NAA	Nonattainment area
NAAQS	National Ambient Air Quality Standards
NCD	NMIM County Database
NEI	National Emissions Inventory
NMIM	National Mobile Inventory Model
NSR	New Source Review
$PM_{2.5}$	Particles less than 2.5 micrometers in diameter
ppb	Parts per billion
PSD	Prevention of Significant Deterioration
Q	Calendar quarter (e. g., Q1 = January 1 through March 31, etc.)
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation and Recovery Act
RFP	Reasonable Further Progress
SCC	Source Classification Code
SDA	Spray dryer absorber
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SODAR	Sonic detection and ranging
TAPCR	Tennessee Air Pollution Control Regulations
TCA	Tennessee Code Annotated
TDEC	Tennessee Department of Environment and Conservation
TDOT	Tennessee Department of Transportation
TN	Tennessee
TNO	Tennessee Operations (a division of Eastman Chemical Company)
tpy (or TPY)	Tons per year
UTM	Universal Transverse Mercator
VMT	Vehicle miles traveled
W	West

EXECUTIVE SUMMARY

The Kingsport, Tennessee SO_2 nonattainment area includes the portion of Sullivan County encompassing a circle having its center at coordinates 36.5186 N; 82.5350 W (B-253 powerhouse, Eastman Chemical Company), and having a three-kilometer radius. Between 2008 and 2010, air quality monitoring at one monitor within this region indicated that the ambient SO_2 concentrations exceeded the 75 ppb National Ambient Air Quality Standard (NAAQS), and EPA designated the area as nonattainment for the one-hour SO_2 NAAQS, effective October 4, 2013.

Tennessee submitted an attainment demonstration on May 11, 2017, and projected that the area would attain the NAAQS based on SO_2 emission reductions achieved by Eastman's conversion of the B-253 powerhouse (Boilers 25-29) from coal to natural gas operation. In 2019, monitoring data collected in the vicinity of Andrew Johnson Elementary School (AIRS ID: 47-163-6003) indicated additional exceedances of the NAAQS and triggered the contingency plan outlined in the 2017 SIP and operating permit 070072[1]. Eastman submitted a written system audit report of all emissions units subject to control under the 2017 SIP, implemented a provisional SO_2 emission control strategy (portable dry sorbent injection on B-83 Boilers 23 and 24), and began development and implementation of operational changes as necessary to prevent future monitored violations of the standard. The U. S. EPA formally determined that the nonattainment area had failed to attain the NAAQS on April 5, 2022 (87 FR 19645). This finding of failure to attain reset the attainment date to April 5, 2027.

Section 179(d)(1) of the Clean Air Act states that within one year after the Administrator publishes the notice that an area has not attained the NAAQS (CAA §179(c)(2)), the State must submit a revision to the applicable implementation plan meeting the requirements of CAA§179(d)(2). The revision must meet the requirements of CAA §110 and must include such additional measures as the Administrator may reasonably prescribe, including all measures that can be feasibly implemented in the area in light of technological achievability, costs, and any nonair quality and other air quality-related health and environmental impacts.

Air quality modeling runs developed by Tennessee, indicate that the Kingsport nonattainment area will attain the NAAQS based on: 1) SO_2 emission reductions achieved by Eastman's conversion of the B-253 powerhouse (Boilers 25-29) from coal to natural gas operation, as previously identified in the 2017 submittal; 2) installation of dry sorbent injection (DSI) controls on Boilers 23 and 24 of Eastman's B-83 powerhouse; and 3) adoption of revised emission limits for Eastman's B-83 and B-325 powerhouses.

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1 Tennessee began operation of an ambient SO_2 monitor in the vicinity of Andrew Johnson Elementary School (AQS ID #471636003) on January 1, 2019. This monitor registered SO_2 ambient concentrations of 104 ppb on January 5, 2019, 82 ppb on January 8, 2019, 96 ppb on January 20, 2019, and 90 ppb on January 25, 2019, as well as subsequent exceedances during the first quarter of 2019 (see Attachment). These exceedances were validated by the Division of Air Pollution Control on May 28, 2019.

1.0 INTRODUCTION

In June 2010, EPA promulgated a new one-hour primary SO_2 NAAQS of 75 parts per billion (ppb). This one-hour primary standard is met when the three-year average of the annual (99th percentile) of the daily maximum one-hour average concentrations is less than or equal to 75 ppb, as determined in accordance with Appendix T of 40 CFR 50[2]. EPA revised the air quality standard for SO_2 based on an integrative synthesis of the entire body of evidence on human health effects associated with ambient SO_2 and upon the results of quantitative exposure and risk assessments reflecting this evidence. In considering the entire body of evidence, EPA chose to focus primarily on respiratory morbidity following short-term exposure to SO_2 (5 minutes to 24 hours), for which the Agency's Integrated Science Assessment[3] found a causal relationship[4].

The nonattainment designation for an area initiates a process that requires affected States to develop an implementation plan that includes, among other things, a demonstration showing how it will attain the ambient standard. States are required to submit SIPs to EPA within 18 months of the effective date of the designations[5]. To be approved by the EPA, SIPs must provide for future attainment of the NAAQS as expeditiously as practicable but no later than five years from the effective date of designation (October 4, 2018).

The Kingsport, Tennessee SO_2 nonattainment area includes the portion of Sullivan County encompassing a circle having its center at coordinates 36.5186 N; 82.5350 W (B-253 powerhouse, Eastman Chemical Company), and having a three-kilometer radius (**Figure 1-1**). Between 2008 and 2010, air quality monitoring at one monitor within this region indicated that the one-hour average SO_2 concentrations exceeded the 75 ppb National Ambient Air Quality Standard (NAAQS), and EPA designated the area as nonattainment for the one-hour SO_2 NAAQS, effective October 4, 2013.

2 40 CFR §50.17.

3 National Center for Environmental Assessment (NCEA), *Integrated Science Assessment for Sulfur Oxides-Health Criteria,* September 12, 2008.

4 Federal Register June 22, 2010, page 35524.

5 42 U.S. Code §7514(a).

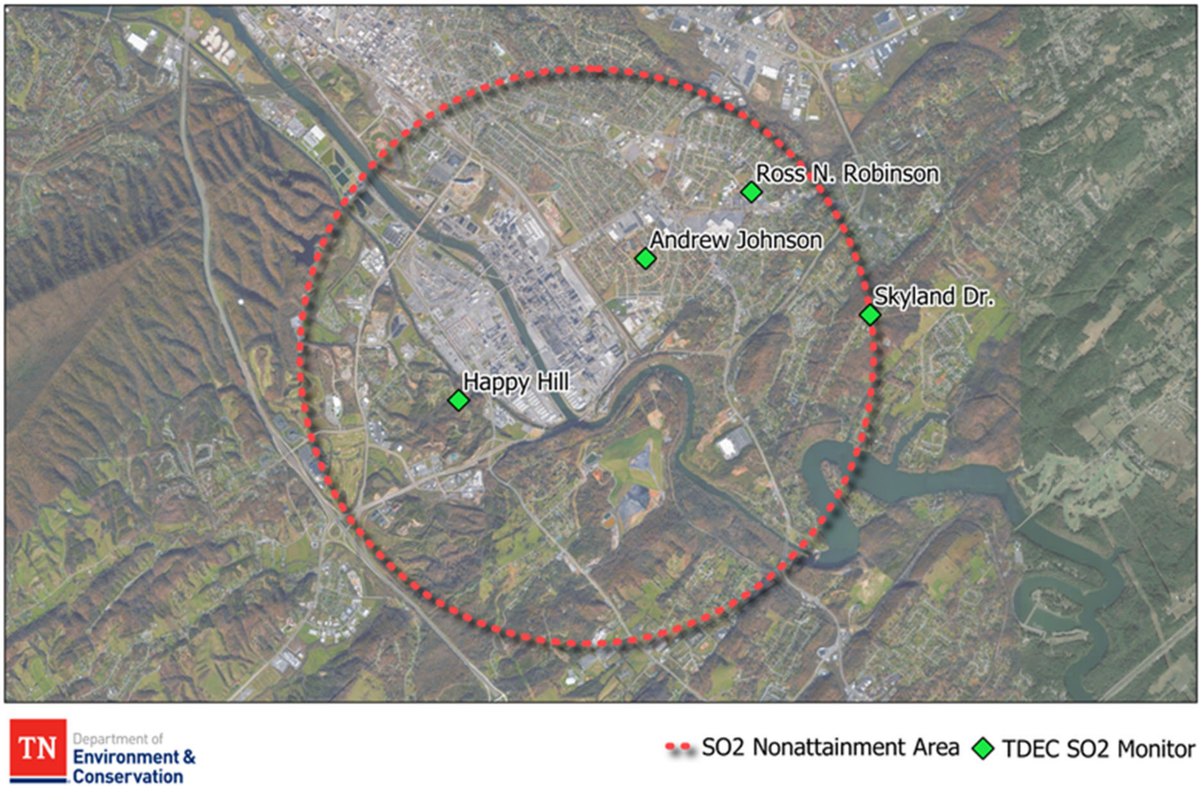

Figure 1-1: Kingsport SO_2 Nonattainment Area

Tennessee submitted an attainment demonstration for Sullivan County to U. S. EPA on May 11, 2017. This attainment demonstration projected that the area would attain the NAAQS no later than five years from the effective date of designation based on (1) the conversion of five boilers from Eastman's B-253 powerhouse from coal to natural gas operation (reduction of B-253 SO_2 emissions from 14,897 tons/year to 10 tons/year) and the adoption of a combined emission limit from Eastman's B-83 and B-325 powerhouses (30-day rolling average emission rate of 1,753 lb/hr)[6]. EPA proposed approval of the SIP on June 29, 2018 (83 FR 30609). On July 9, 2018, Tennessee submitted a revised ambient monitoring network plan to U. S. EPA, which added two ambient SO_2 monitors at Happy Hill Road (AIRS ID: 47-163-6004) and Andrew Johnson Elementary School (AIRS ID: 47-163-6003), and these monitors began operation on October 10, 2018, and January 1, 2019, respectively.

The Andrew Johnson monitor registered SO_2 ambient concentrations of 104 ppb on January 5, 2019, 82 ppb on January 8, 2019, 96 ppb on January 20, 2019, and 90 ppb on January 25, 2019, as well as subsequent exceedances during the first quarter of 2019 (**Table 1-1**). These exceedances were validated by the Division of Air Pollution Control on May 28, 2019. On June 13, 2019, the Division of Air Pollution Control notified Eastman Chemical Company that the reference monitor had registered four validated ambient SO_2 concentrations in excess of the NAAQS during calendar year 2019.

6 Operating permit 070072, issued May 10, 2017.

Table 1-1: 2019 Exceedances, Andrew Johnson Monitor	
Date	**Daily Max. Concentration (ppb)**
1/5/2019	104
1/8/2019	82
1/20/2019	96
1/25/2019	90
2/7/2019	95
2/15/2019	95
3/6/2019	102
3/10/2019	87
3/24/2019	83
4/20/2019	100
4/23/2019	77
5/12/2019	82
5/15/2019	104
5/26/2019	82
5/28/2019	109
10/20/2019	79
12/4/2019	117
12/18/2019	95

The Division's written notification triggered the contingency plan requirements established by permit 070072, as follows:

- Undertake a full system audit of all emissions units subject to control under the SIP and submit a written system audit report within 30 days of notification. Permit 070072 required the system audit report to detail the operating parameters of all emissions units for the 10-day periods up to and including the date upon which the reference monitor registered each exceedance, together with recommended provisional SO_2 emission control strategies for each affected unit (B-83 Boilers 18 through 24 and B-325 Boilers 30 and 31) and evidence that these control strategies have been deployed, as appropriate.

- Upon consultation with the Technical Secretary, develop and implement operational changes, include fuel switching, physical or operational reduction of production capacity, or other changes necessary to prevent future monitored violations of the standard.

Eastman submitted the system audit report on July 17, 2019, and identified a provision control strategy (installation of a portable dry sorbent injection (DSI) system on Boilers 23 and 24 in the B-83 powerhouse). Eastman selected the provisional emission control strategy based on the following factors:

1. Of the remaining coal-fired boilers at Eastman's Kingsport facility, Boilers 23 and 24 (B-83 powerhouse) offered the best opportunity for hourly SO_2 emission reductions for the highest percent of operating time.

2. Boiler 31 (B-325 powerhouse) uses a spray dryer absorber and fabric filter that reduces SO_2 emissions by 90-95%.

3. Boiler 30 (B-325 powerhouse) uses a spray dryer absorber and electrostatic precipitator (ESP) that reduces SO_2 emissions by about 65%.

4. Boilers 18-24 (B-83 powerhouse) were uncontrolled in 2019. Of these, the high-pressure baseload boilers (23 and 24) are operated preferentially over the remaining boilers, which are smaller and operate at lower pressures.

Eastman began working with an equipment supplier to deploy a portable DSI beginning in January 2019. Installation of the DSI system occurred in April 2019[7], and operation on one boiler began on May 2, 2019. After a one-month startup period of intermittent operation, Eastman began near-continuous operation of the DSI system around June 1, 2019. On September 26, 2019, Eastman selected dry sorbent injection as the permanent controls for Boilers 23 and 24 and submitted a proposed schedule for the design and installation of a permanent system, as follows:

- Project Definition: September 26, 2019, through February 28, 2020
- Detailed Engineering: February 1, 2020, through September 30, 2020
- Procurement: May 1, 2020, through February 28, 2021
- Field Construction: January 1, 2020, through September 30, 2021
- Checkout/Startup: October 1, 2021, through November 1, 2021

This attainment demonstration updates the 2017 modeling to include the additional controls. The attainment demonstration also includes updates to include all of the permitted emission sources at Eastman's Kingsport facility and adds new emission limits for Eastman's hazardous waste incineration units.

Eastman Chemical Company – Facility Summary

Eastman Chemical Company is considered a megasource[8] and has been issued 24 major source operating permits (MSOPs) by the Division of Air Pollution Control[9]. The permits cover a variety of

7 , Preparatory work prior to DSI installation included decommissioning of the unit from its previous location, refurbishment of the unit at the supplier's shop, and alterations as needed to utilize the portable system on two boilers at once. Eastman, in parallel, launched a project to prepare the B-83 facility for the portable unit, including electrical, water, and sewer connections and installation of convey lines to deliver the sorbent to the boilers.

8 Each EPA Region, in consultation with affected States/locals, has the flexibility to define and identify megasources as it deems appropriate within the Region. When identifying megasources, EPA Regions consider the number and types of emission units; the volume and character of pollutants emitted; the number and types of control and monitoring systems; the number of applicable regulatory requirements; the availability of monitoring data; the degree of difficulty in determining compliance at individual units and at the entire facility; and the footprint of the facility.

9 Since 2017, the number of major source operating permits has been consolidated from 26 permits to 24. One additional

manufacturing operations (**Table 1-2**) and specify the Federal and State requirements applicable to the facility.

Table 1-2: Eastman Chemical Company Major Operations		
Operation	**MSOPs**	**Description**
Chemical Manufacturing	03, 04, 10, 16, 17, 18, 19, 20, 21, 25	Chemical manufacturing operations produce organic acids, aldehydes, and esters. The products of these operations may be used as intermediates in other Eastman operations (e.g., polymers and cellulose esters). Includes coal gasification operations used to manufacture chemical intermediates from coal (MSOP-03, MSOP-17).
Polymers	09, 24, 31, 34	These operations produce polymers such as polyethylene terephthalate for use in the manufacture of consumer products.
Cellulose Esters/Specialty Plastics, and Acetate Fibers	08, 13, 23, 27, 33	Reaction of cellulose with organic acids to produce cellulose esters, manufacture of synthetic fibers, associated storage and handling operations.
Utilities	02, 11, 26, 32	Includes coal and gas-fired boilers (MSOP-02 and MSOP-26), hazardous waste combustion (MSOP-32), heat transfer systems, and wastewater treatment operations.
Technology	22	Pilot plant and small-scale production.
Miscellaneous support operations	29	Woodworking shop, paint shop, and emergency engines.

source (plastic recycling and methanolysis) is currently under construction and will be permitted as a separate major source.

2.0 SO_2 NONATTAINMENT AREA PLANNING ELEMENTS

Section 172 of the Clean Air Act addresses the general requirements for nonattainment areas. Specific statutory requirements include the requirement for an accurate emissions inventory for all sources of SO_2 within the nonattainment area (point, area, and mobile sources); a New Source Review (NSR) permit program; and an attainment demonstration using an EPA approved air quality dispersion model. The SIP submittal must also provide for: Reasonable Further Progress (RFP); implementation of RACM including RACT, and adequate contingency measures for the affected area. These elements are briefly described below.

2.1. Emissions Inventory

Emissions inventory and source emission rate data serve as the foundation for modeling and other analyses that enable air agencies to: 1) estimate the degree to which different sources within a nonattainment area contribute to violations within the affected area; and 2) assess the expected improvement in air quality within the nonattainment area due to the adoption and implementation of control measures. The air agency should develop a comprehensive, accurate and current inventory of actual emissions from all sources of SO_2 emissions in each nonattainment area, as well as any sources located outside the nonattainment area which may affect attainment in the area (CAA §172(c)(3)). This inventory should be consistent with the EPA's most recent emissions inventory data requirements as codified at 40 CFR 51 Subpart A.

Emission inventories should contain thorough documentation of how the emissions estimates were prepared. States should also submit a projected attainment year inventory that includes estimated emissions for all SO_2 emission sources that are determined to impact the nonattainment area for the year in which the area is expected to attain the standard, consistent with the attainment demonstration for the affected area. This inventory should reflect projected emissions for the attainment year for all SO_2 sources in the nonattainment area, taking into account emission changes that are expected after the base year. Such emissions changes would include any expected emission reductions from existing control measures, from any new measures that may be adopted as part of the local area attainment plan, or from expected source shutdowns, so long as the existing and new control measures and source shutdowns are enforceable; and would include any expected emission increases due to new sources or growth by existing sources (CAA §172(c)(4)). The SIP should also include the best available information on current-year and future year allowable SO_2 emission rates for SO_2 sources in the nonattainment area[10]. Tennessee's emissions inventory was approved by EPA on March 1, 2021 (86 FR 11873).

2.2 New Source Review (NSR)

Part D of title I of the CAA prescribes the procedures and conditions under which a new major stationary source or major modification may obtain a preconstruction permit in an area designated nonattainment for any criteria pollutant. The nonattainment NSR (nonattainment NSR) permitting requirements in section 172(c)(5) and 173 of the CAA are among "the requirements of this part" to be submitted to the EPA as part of a revised SIP. Air agencies that already have a nonattainment NSR

10 Appendix A of EPA's SIP guidance provides a thorough discussion of the emission rate information recommended for the SO_2 modeling analysis.

permitting program applicable to areas previously designated nonattainment on the basis of the previous SO_2 NAAQS (annual, 24-hour or 3-hour averaging periods) may be able to use that existing program to authorize the construction and modification of major stationary sources of SO_2 that would locate in a new 2010 SO_2 nonattainment area. However, because there are very few nonattainment areas designated under the previous SO_2 NAAQS, a few air agencies may not have nonattainment NSR rules that apply when new nonattainment areas for SO_2 are designated. In such cases, within 18 months of designation, such agencies would need to either revise their existing nonattainment NSR programs or develop new ones to enable the permitting of any major stationary source of SO_2 locating in a nonattainment area under the 2010 SO_2 NAAQS. Tennessee's Nonattainment New Source Review program was approved by EPA on March 1, 2021 (86 FR 11873). '

2.3. Attainment Demonstration

Section 172(c) of the Clean Air Act directs States with nonattainment areas to submit an attainment demonstration as a part of the SIP. An attainment demonstration should consist of an air quality modeling analysis and supporting information, which demonstrate that the control strategy will provide sufficient emission reductions for the area to attain the NAAQS. If control measures within the nonattainment area are not sufficient to attain the standard, States may need to adopt control measures on SO_2 sources that may affect attainment in the area but are located outside the nonattainment area. In such cases, the modeling for the attainment demonstration should include explicit modeling of these sources in the modeling domain.

The approvable compliance dates for control measures in the attainment demonstration must be as expeditious as practicable, and attainment plans should require sources to comply with the requirements of the attainment strategy at least one calendar year before the attainment date. SIPs should be able to provide at least one calendar year of air quality monitoring data before the attainment deadline to demonstrate that the plan is providing for attainment.

For a short-term (i.e., 1-hour) NAAQS, dispersion modeling, using allowable emissions, and addressing stationary sources in the affected area (or sources outside the area which may affect attainment) is appropriate for demonstrating attainment. Selection of the modeling domain is based on the number of sources to be modeled, their geographic distribution, and the kind of receptor network needed to show attainment. The modeling domain should encompass the entire nonattainment area and should, as necessary, incorporate sources located outside the nonattainment area which may affect attainment but are not otherwise accounted for in the modeling analysis (i.e., through use of background concentrations or explicit modeling). The modeling domain should also identify sufficient receptors to appropriately characterize changing gradients of air quality concentrations.

EPA recommends that States follow EPA's Guideline on Air Quality Models, 40 CFR part 51 Appendix W and the supplemental modeling guidance in Appendix A of EPA's SIP guidance document. The guidance provides recommendations on modeling techniques and guidance for estimating pollutant concentrations in order to assess control strategies and determine emission limits.

2.4. Control Strategy (Including RACM/RACT)

The SIP must include enforceable emission limitations, and such other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emission rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to provide for attainment of such standard in such area by the applicable attainment date[11].

The SIP should provide for attainment of the standard based on SO_2 emission reductions from permanent and enforceable control measures, and States should consider all Reasonably Available Control Measures (RACM) and Reasonably Available Control Technologies (RACT) that can be implemented in light of the attainment needs for the affected area(s). EPA also promulgated other regulatory requirements that are expected to yield substantial SO_2 reductions, and the implementation of national and regional control measures should ease the process of planning for attainment of the SO_2 NAAQS.

2.5. Reasonable Further Progress (RFP)

Section 171(1) of the CAA defines RFP as "such annual incremental reductions in emissions of the relevant air pollutant as are required by this part (part D) or may reasonably be required by the EPA for the purpose of ensuring attainment of the applicable NAAQS by the applicable attainment date." As the EPA has previously explained, this definition is most appropriate for pollutants that are emitted by numerous and diverse sources, where the relationship between any individual source and the overall air quality is not explicitly quantified, and where the emission reductions necessary to attain the NAAQS are inventory-wide.

2.6. Conformity

General conformity is required by CAA §176(c). This section of the Act requires that actions by federal agencies do not cause new air quality violations, worsen existing violations, or delay timely attainment of the relevant NAAQS or interim reductions and milestones. General conformity applies to any federal action (e.g., funding, licensing, permitting, or approving), other than certain highway and transportation projects, if the action takes place in a nonattainment or maintenance area (i.e., an area which submitted a maintenance plan that meets the requirements of CAA §175A and has been redesignated to attainment) for ozone, PM, NO_X, carbon monoxide, lead or SO_2. As directed by CAA §176(c)(6), general conformity for the revised SO_2 NAAQS will not apply until one year after the effective date of a nonattainment designation for that 2010 NAAQS. EPA's General Conformity Rule (40 CFR §§93.150 to 93 .165) establishes criteria and procedures for determining if a federal action conforms to the SIP. With respect to the 2010 SO_2 NAAQS, federal agencies are expected to continue to estimate emissions for conformity analyses in the same manner as they estimated emissions for conformity analyses under the previous SO_2 NAAQS. EPA's General Conformity Rule includes the basic requirement that a federal agency's general conformity analysis be based on the latest and most accurate emission estimation techniques available (40 CFR §93.159(b)). When updated and improved emissions estimation techniques become available, EPA expects the federal agency to use these techniques.

Transportation conformity is required under CAA §176(c) to ensure that federally supported highway and transit project activities are consistent with ("conform to") the purpose of the SIP. Transportation conformity applies to areas that are designated nonattainment, and those areas redesignated to attainment after 1990 ("maintenance areas" with plans developed under CAA §175A) for

11 CAA §172(c)(6).

transportation-related criteria pollutants.

Due to the relatively small, and decreasing, amounts of sulfur in gasoline and on-road diesel fuel, the EPA's transportation conformity rules provide that they do not apply to SO_2 unless either the EPA Regional Administrator or the director of the state air agency has found that transportation-related emissions of SO_2 as a precursor are a significant contributor to a $PM_{2.5}$ nonattainment problem, or if the SIP has established an approved or adequate budget for such emissions as part of the RFP, attainment or maintenance strategy.

Neither Tennessee nor the EPA Regional Administrator have found that transportation-related emissions of SO_2 as a precursor are a significant contributor to a $PM_{2.5}$ nonattainment problem, and there is no $PM_{2.5}$ nonattainment area that includes Sullivan County. Furthermore, Tennessee is not establishing a motor vehicle emissions budget as part of the RFP, attainment, or maintenance strategy for sulfur dioxide in Sullivan County. Therefore, Tennessee is not required to address transportation conformity as part of this submittal.

2.7. Contingency Measures

Section 172(c)(9) of the Clean Air Act[12] defines contingency measures as such measures in a SIP that are to be implemented in the event that an area fails to make RFP or fails to attain the NAAQS by the applicable attainment date. Contingency measures are to become effective without further action by the state or the EPA, where the area has failed to (1) achieve RFP or, (2) attain the NAAQS by the statutory attainment date for the affected area. These control measures are to consist of other available control measures that are not included in the control strategy for the affected area. However, SO_2 presents special considerations.

- First, for some of the other criteria pollutants, the analytical tools for quantifying the relationship between reductions in precursor emissions and resulting air quality improvements remains subject to significant uncertainties, in contrast with procedures for directly emitted pollutants such as SO_2.

- For SO_2, the analytical tools for quantifying the relationship between emission reductions and air quality improvements are less subject to uncertainties, in contrast with procedures for other criteria pollutants.

- Control efficiencies for SO_2 control measures are well understood and are far less prone to uncertainty than for other criteria pollutants.

For SO_2 programs, EPA has explained that "contingency measures" can mean that the air agency has a comprehensive program to identify sources of violations of the SO_2 NAAQS and to undertake an "aggressive" follow-up for compliance and enforcement, including expedited procedures for establishing enforcement consent agreements pending the adoption of the revised SIP. This approach to contingency measures for SO_2 would not preclude an air agency from requiring additional

12 "Such plan shall provide for the implementation of specific measures to be undertaken if the area fails to make reasonable further progress, or to attain the national primary ambient air quality standard by the attainment date applicable under this part. Such measures shall be included in the plan revision as contingency measures to take effect in any such case without further action by the State or the Administrator."

contingency measures that are enforceable and appropriate for a particular source category. The source might adopt a contingency measure such as switching to low sulfur coal or reducing load until more permanent measures can be put into place to correct the problem. In either case, in order for the EPA to be able to approve the SIP, the contingency measures would need to be a fully adopted provision in the SIP that becomes effective where the area has failed to meet RFP or fails to attain the standard by the statutory attainment date.

3.0 EMISSION INVENTORY

The following emissions inventories are included:

1. Baseline (2017) actual emissions inventory from all SO_2 in the nonattainment area, plus any sources located outside the nonattainment area which may affect attainment in the area. This inventory is consistent with EPA's emissions inventory data requirements codified in 40 CFR 51 Subpart A.

2. Projected attainment year inventory (2027) that includes estimated SO_2 emissions for all sources determined to impact the nonattainment area. This inventory reflects projected emissions for the attainment year for all SO_2 sources in the nonattainment area, taking into account emission changes that are expected after the base year.

3. Current-year and future year allowable SO_2 emission rates for SO_2 sources in the nonattainment area.

3.1 Base Year Inventory

Point Sources – Eastman Chemical Company

The starting point for the 2017 point source emission inventory was the 2017 National Emissions Inventory (NEI). The 2017 data was supplemented with information submitted by the affected facilities.

The largest point source located within the nonattainment area is Eastman Chemical Company's Tennessee Operations facility. The base year actual emissions for this facility are summarized in **Tables 3-1** (coal-fired boilers) **and 3-2** (other emission sources). The base year inventory indicates that that the coal-fired boilers were responsible for nearly all SO_2 emissions from this facility (~98%). Point Source emissions for Eastman are included in Attachment A.

Table 3-1: Eastman Chemical Company 2017 Actual Emissions – Coal-Fired Boilers		
Release Point ID	**Description**	**2017 SO_2 Emissions (tons)**
B-253-1	B-253 Coal-Fired Boilers	4,779[13]
B-83-1	B-83 Coal-Fired Boilers	4,447
B-325-1	B-325 Coal-Fired Boilers	1,340
Subtotal:		**10,566**

13 Includes both coal and natural gas operation.

Table 3-2: Eastman Chemical Company 2017 Actual Emissions – Other Point Sources		
Release Point ID	**Description**	**SO_2 Emissions (tons)**
B-456-1	Emergency Diesel Generator	0.07
RICE-1	Emergency Engines	0.8
B-265B-1	Dowtherm Furnace	0.014
B-232-1	Manufacture of Aromatic Acids	0.028
B-7R-1	Cracking Furnaces 1 Through 24	0.16
B-256-1,2,3	Dowtherm Heaters #5, 6, and 8	0.06
B-351-5	Coal Gasification, Warm and Cold Flares	8.1
B-238-1	Furnaces	0.35
B-248-1	Solid/Liquid Chemical Waste Incinerators	11.7
B-227-2,3	Dowtherm Heaters #3 and 4	0.019
B-227A-1	Parts Cleaning Ovens	0.0002
B-6C-1	Cracking Furnaces 27 and 28	0.8
B-90-7	Production of Miscellaneous Organic Chemicals	0.08
B-338-3	Recovery of Carbonylation Reactor Catalyst	0.44
B-55G-1	Acid Concentration Sludge System	1.1
B-423-1	Gas-Fired Boilers A, B, and C	0.12
B-248-2	Liquid Chemical Waste Incinerator	2.96
B-190-7	Plastics Compounding Facility	0
B-272-1,2,3	Dowtherm Heaters #7, 9, and 10	0.08
B-545-1	Copolyester Monomer Manufacturing	0.048
RICE-3	Emergency Engines	1
RICE-2	Emergency Engines	0.6
B-7RC-1	Cracking Furnaces 25 and 26	0.03
B-334-1	Acid Gas Removal and Sulfur Recovery Plants	18.70
B-334-2	Synthesis Gas Pilot Plant	2.19
OC-BATCH	General Purpose Batch Equipment for Production of Specialty Chemicals	7.05
Fugitive	Fugitive Equipment Leaks	1.37
B-Area A-B7	Crude Acetic Anhydride Manufacture	0.02
PB-1	Portable Boiler	0.002
	Subtotal	**57.89**

Point Sources – Primester GP

Primester GP operates a cellulose acetate manufacturing process at 1801 Warrick Drive (adjacent to Eastman Chemical Company). This facility is regulated by Title V Operating Permit 574994 (issued January 1, 2020). This facility includes one SO_2 emission source (Cellulose Scrap Recovery Process). Reject dope from various points in the acetylation operation is processed for the recovery of cellulose sludge, and recovered materials are distilled for reuse. Once the recoverable materials are removed from the cellulose sludge, it is heated with sulfuric acid in pressurized reactors to degrade the sludge into smaller solids for offsite management. Sulfur dioxide is emitted from the equipment and conveyors at this source, and SO_2 emissions are controlled by a wet scrubber.

Primester is not subject to the annual or triennial air emissions reporting requirements established pursuant to 40 CFR 51 Subpart A. Actual emissions for 2017 were calculated as 0.57 tons based on production data submitted by Primester[14].

Point Sources – EnviraGlass, LLC

EnviraGlass, LLC operated a glass manufacturing facility located at 1450 Lincoln Street (adjacent to Eastman Chemical Company). This facility was regulated by Title V Operating Permit 563047 (issued to AGC Flat Glass North America on April 4, 2012) and was included in the previous attainment demonstration. This permit expired March 31, 2017, and in 2018, the Division of Air Pollution Control determined that the source was no longer in operation. Therefore, this facility was not included in base year or attainment year inventories.

Area Sources

The area source emission inventory was developed using EPA Nonpoint files located on EPA's CHIEF Emission Inventory website for the 2017 NEI and for area sources that have possible point source contribution, subtraction of available activity data to eliminate double counting. County-level emissions were apportioned to the nonattainment area by using a percentage (9.3%) derived from the 2010 Census Bureau Population data for the county and the population for the nonattainment area. Details on the development of area source emissions are contained in Attachment B.

There have been two triennial inventory cycles (2014 and 2017) since the submittal of the previous attainment demonstration, and with any new inventory cycle, changes to approaches are made to improve the process of creating the inventory and the methods for estimating emissions. In the 2014 and 2017 inventory cycles, EPA made changes to pollutant and SCC codes, refined quality assurance checks and features, and created a Nonpoint Survey to assist with data reconciliation for the nonpoint data. In addition to process changes, the 2014 and 2017 NEIs improved emissions estimation methods for all data categories[15,16]. For the 2017 NEI, EPA specifically identified large decreases in SO_2 emissions

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14 Pursuant to Tennessee Code Annotated 68-201-105(b)(2), Primester requested protection of the 2017 production data as confidential business information.

15 U. S. EPA, *2014 National Emissions Inventory, Version 1 Technical Support Document,* December 2016, Chapter 2, page 21. Available online at https://www.epa.gov/sites/default/files/2016-12/documents/nei2014v1_tsd.pdf.

16 U. S. EPA, *2017 National Emissions Inventory: January 2021 Updated Release, Technical Support Document*, Chapter 2, pages 12-15. Available online at https://www.epa.gov/sites/default/files/2021-02/documents/nei2017_tsd_full_jan2021.pdf.

from residential fuel combustion based on decreases in consumption and more significantly, using a lower default sulfur content for distillate fuel oil: 500 ppm in 2017 vs 3% (30,000 ppm) in 2014.

Onroad Mobile Sources

Onroad mobile sources include emissions from motorized vehicles that are normally operated on public roadways. This includes passenger cars, motorcycles, minivans, sport-utility vehicles, light-duty trucks, heavy-duty trucks, and buses. The sector includes emissions generated from parking areas as well as emissions while the vehicles are moving. The sector also includes "hoteling" emissions, which refers to the time spent idling in a diesel long-haul combination truck during federally mandated rest periods of long-haul trips.

The 2017 NEI is comprised of emission estimates calculated based on the MOVES model run with S/L/T-submitted activity data when provided, except for California and tribes, for which the NEI includes submitted emissions. In cases where S/L/T submitted data is not provided, EPA-developed default activity based on data from the Federal Highway Administration. County-level emissions were apportioned to the nonattainment area by using a percentage (9.3%) derived from the 2010 Census Bureau Population data for the county and the population for the nonattainment area. Details on the development of area source emissions are contained in Attachment C.

Nonroad Mobile Sources (Excluding Locomotive/Rail Emissions)

Emission estimates from nonroad mobile sources are based on EPA's MOVES model (version 3.0.4), which includes estimates for growth based on expected future economic conditions and other factors as well as any national controls that apply to these sources in future years. EPA's MOVES model was used for the nonroad portion of the inventory. MOVES was used to generate annual emission estimates for the required pollutants. County-level emissions were apportioned to the nonattainment area by using 2010 Census Bureau Population data for the county and the nonattainment area. Nonroad emissions are contained in Attachment D.

Locomotive/Rail Emissions

Base-year emissions from locomotives were taken from EPA's 2017 National Emissions Inventory (NEI). The 2017 NEI counts locomotive emissions as both point sources and as nonroad mobile sources. EPA's Technical Support Document for the 2017 NEI states that the point source category includes locomotive emissions within railyards. For nonroad mobile sources, the locomotive sector includes railroad locomotives powered by two-stroke or four-stroke diesel-electric engines.

The Technical Support Document states that 2017 rail emissions were developed by the Lake Michigan Air Directors Consortium (LADCO) and the State of Illinois, with support from various other states in a collaborative team called Eastern Regional Technical Advisory Committee (ERTAC). ERTAC used confidential line-haul activity data, in millions of gross ton route miles per link, from the Federal Railroad Administration for 2016. Adjusted rail fuel consumption index values were used to allocate each Class 1 railroad's fuel use to links based on MGT. The Association of American Railroads provided ERTAC Rail with locomotive fleet mix information for 2017 for emission factor application. Since the rail link-based activity was confidential, ERTAC provided county-level emissions summaries to EPA. Locomotive emissions are shown in **Table 3-3** and Attachment D.

Table 3-3: Base-Year SO_2 Emissions From Locomotives		
SCC	**2017 SO_2 Emissions (tons)**	**Nonattainment Area SO_2 Emissions (tons)**
Mobile Sources – Railroad Equipment, Diesel, Line Haul Locomotives: Class I Operations	0.033482	0.003113826
Internal Combustion Engines – Railroad Equipment, Diesel, Yard Locomotives	0.01045717	0.000972517
Total	**0.04393917**	**0.004086343**

Summary of Base-Year Emissions Inventory

The base-year emissions inventory for the Kingsport nonattainment area is summarized in Table 3-3.

Table 3-4: Summary of Base-Year Emissions Inventory	
Description	**SO_2 Emissions (tons)**
Eastman Chemical Company – Boilers	10,567
Eastman Chemical Company – Other Point Sources	180.0
Primester	0.57
Area Sources	3.31
Onroad Mobile Sources	1.70
Nonroad Mobile Sources (Excluding Locomotive/Rail)	0.00656
Locomotive/Rail Emissions	0.00408
Total Emissions	**10,753**

Other Emission Sources

Tennessee identified two point sources located outside the nonattainment area that may affect attainment in the area. Domtar Paper Company's Kingsport Mill is located near the nonattainment area (see Figure 1-1). Base year emissions for this facility are shown in **Table 3-5**.

Table 3-5: Domtar Paper Company 2017 Actual Emissions		
Release Point ID	**Description**	**SO_2 Emissions (tons)**
REC-1	Recovery Area – New Soda Recovery Boiler	3.06
HFB1-1	Biomass Boiler	17.3
LK-1	Lime Kiln	12.1
NCG-1	NCG System	12.7
Total		**45.16**

BAE Systems Ordnance Systems, Inc. operates Holston Army Ammunition Plant's Area A and Area B facilities in Sullivan and Hawkins Counties, respectively. The Area B operations included four coal-fired boilers. These boilers last operated on October 1, 2021, and BAE submitted formal notification of the retirement of these boilers on November 1, 2021. A base-year inventory for this facility is included in **Table 3-6**. Point Source emissions for Domtar and Holston Army Ammunition Plant are included in Attachment A.

Table 3-6: Holston Army Ammunition Plant 2017 Actual Emissions	
Unit Description	**SO_2 Emissions (tons)**
200B-1 BOILERS FOR AREA B STEAM	585.96
200B-1 BOILERS FOR AREA B STEAM	609.66
200B-1 BOILERS FOR AREA B STEAM	243.08
200B-1 BOILERS FOR AREA B STEAM	328.48
B-262 MIURA BOILERS (4 total)	0.075
B-352 ACETIC ANHYDRIDE MANUFACTURE AND REFINING	0.01
B-352 ACETIC ANHYDRIDE MANUFACTURE AND REFINING	0.0033
B-352 ACETIC ANHYDRIDE MANUFACTURE AND REFINING	0.0033
B-352 ACETIC ANHYDRIDE MANUFACTURE AND REFINING	0.0033
B-352 ACETIC ANHYDRIDE MANUFACTURE AND REFINING	0.0033
OPEN BURNING OF EXPLOSIVE WASTE	0.022
OPEN BURNING OF EXPLOSIVE WASTE	0.33
Total	**1,768**

3.2 Current Allowable Emissions

Allowable SO_2 emissions for Eastman Chemical Company are shown in **Tables 3-7** (coal-fired boilers) **and 3-8** (other emission sources).

Table 3-7: Eastman Chemical Company Allowable Emissions – Coal-Fired Boilers			
Boiler ID	**Allowable SO_2 Emission Rate**	**Emission Limit Basis**	**SO_2 Emissions (tons/year)**
B-83 Boilers 18 through 24 and B-325 Boilers 30 and 31	1,753 lb/hr	30-day average	7,678
B-83 Boilers 18 through 24	2.4 lb/MMBtu	24-hour average	23,526[17]
B-325 Boiler 30	317 lb/hr	30 calendar day rolling average	1,389
B-325 Boiler 31	293 lb/hr	30 calendar day rolling average	1,283
Total			**33,876**

17 The 2.4 lb/MMBtu allowable emission rate was not included in the modeled attainment demonstration, because the 30-day rolling average SIP limit is more restrictive.

Table 3-8: Eastman Chemical Company Allowable Emissions – Other Emission Sources							
MSOP	**Source #**	**PES**	**Source Description**	**Permit**	**Condition**	**Vent ID(s)**	**SO_2 Emission Limit**
02	80-0003-01	B-253-1	Boilers 25-29	577389	E5-1	A	2.4 lb/MMBtu (24-hr avg.)[18]
02	80-0003-01	B-253-1	Boilers 25-29	577389	E5-1	B	
02	80-0003-01	B-253-1	Boilers 25-29	577389	E5-1	C	
02	80-0003-01	B-253-1	Boilers 25-29	577389	E5-1	D	
02	80-0003-01	B-253-1	Boilers 25-29	577389	E5-1	E	
03	80-0003-144	B-338-3	catalyst recovery	573862	E6-6	A	1000 ppmvd (one-hour average) and 0.44 tons/year
10	80-0003-120	B-90-7	TBHQ production	573610	E5-8	C	0.13 tons/year
10	80-0003-120	B-90-7	TBHQ production	573610	E5-8	E	
10	80-0003-121	B-90B-1	BHA production	573610	E6-5	A1	0.32 lb/hr
11	80-0003-126	B-227-2, 3	HTM furnaces	573592	E3-3	A	0.19 lb/hr and 0.8 tons/year
11	80-0003-126	B-227-2, 3	HTM furnaces	573592	E3-3	B	
11	80-0003-127	B-256-1,2,3	HTM furnace 5	573592	E4-3	A	0.34 lb/hr and 1.5 tons/year
11	80-0003-127	B-256-1,2,3	HTM furnace 6	573592	E4-3	B	
11	80-0003-127	B-256-1,2,3	HTM furnace 8	573592	E4-3	C	
11	80-0003-128	B-272-1,2,3	HTM furnace 7	573592	E5-3	A	0.34 lb/hr and 1.5 tons/year
11	80-0003-128	B-272-1,2,3	HTM furnace 9	573592	E5-3	B	
11	80-0003-128	B-272-1,2,3	HTM furnace 10	573592	E5-3	C	
11	82-0003-104	RICE-2	B-63 emergency fire pump engine	573592	N/A	A	N/A
11	82-0003-104	RICE-2	B-269 emergency fire pump engine	573592	N/A	B	N/A
16	80-0003-30	B-6C-1	Cracking furnaces 27 and 28	576946	E3-7	A	0.03 lb/hr

18 2.4 lb/MMBtu is the SO_2 allowable established by TAPCR 1200-03-14. PSD construction permit 966859F establishes a fuel usage restriction for Boilers 25 through 29 (only natural gas may be used as fuel), and when fuel use restrictions are taken into account, SO_2 emissions are only 10 tons/year.

<table>
<tr><th colspan="8">Table 3-8: Eastman Chemical Company Allowable Emissions – Other Emission Sources</th></tr>
<tr><th>MSOP</th><th>Source #</th><th>PES</th><th>Source Description</th><th>Permit</th><th>Condition</th><th>Vent ID(s)</th><th>SO_2 Emission Limit</th></tr>
<tr><td>16</td><td>80-0003-30</td><td>B-6C-1</td><td>Cracking furnaces 27 and 28</td><td>576946</td><td>E3-7</td><td>B</td><td></td></tr>
<tr><td>16</td><td>80-0003-164</td><td>B-7R-1</td><td>Cracking Furnaces 5-16 and 9-24</td><td>576946</td><td>E4-4</td><td>A</td><td rowspan="2">0.12 lb/hr</td></tr>
<tr><td>16</td><td>80-0003-164</td><td>B-7R-1</td><td>Cracking Furnaces 5-16 and 9-24</td><td>576946</td><td>E4-4</td><td>B</td></tr>
<tr><td>16</td><td>80-0003-166</td><td>B-7RC-1</td><td>Cracking Furnaces 25 and 26</td><td>576946</td><td>E6-4</td><td>A</td><td rowspan="2">0.02 lb/hr</td></tr>
<tr><td>16</td><td>80-0003-166</td><td>B-7RC-1</td><td>Cracking Furnaces 25 and 26</td><td>576946</td><td>E6-4</td><td>B</td></tr>
<tr><td>16</td><td>80-0003-297</td><td>Area A-B7</td><td>Acetic Anhydride Manufacturing</td><td>576946</td><td>E7-3</td><td>A</td><td rowspan="2">0.03 lb/hr</td></tr>
<tr><td>16</td><td>80-0003-297</td><td>Area A-B7</td><td>Acetic Anhydride Manufacturing</td><td>576946</td><td>E7-3</td><td>B</td></tr>
<tr><td>17</td><td>80-0003-168</td><td>B-334-1</td><td>Acid Gas Removal and Sulfur Recovery</td><td>572407</td><td>E4-7</td><td>B</td><td>21.8 lb/hr</td></tr>
<tr><td>17</td><td>80-0003-168</td><td>B-334-1</td><td>Acid Gas Removal and Sulfur Recovery</td><td>572407</td><td>E4-9</td><td>Equipment Leaks</td><td>1.30 tons/year</td></tr>
<tr><td>17</td><td>80-0003-172</td><td>B-334-2</td><td>Synthesis Gas Pilot Plant</td><td>572407</td><td>E5-1</td><td>A</td><td>0.5 lb/hr</td></tr>
<tr><td>17</td><td>80-0003-172</td><td>B-334-2</td><td>Synthesis Gas Pilot Plant</td><td>572407</td><td>E5-2</td><td>Equipment Leaks</td><td>0.06 tons/year</td></tr>
<tr><td>17</td><td>80-0003-171</td><td>B-351-5</td><td>Cold and Warm Flares</td><td>572407</td><td>E8-1</td><td>C</td><td>47.6 lb/hr</td></tr>
<tr><td>19</td><td>80-0003-185</td><td>B-545-1</td><td>Copolyester Monomer Manufacturing</td><td>575805</td><td>E3-6</td><td>B</td><td rowspan="2">0.13 tons/year</td></tr>
<tr><td>19</td><td>80-0003-185</td><td>B-545-1</td><td>Copolyester Monomer Manufacturing</td><td>575805</td><td>E3-6</td><td>C</td></tr>
<tr><td>19</td><td>80-0003-185</td><td>B-545-1</td><td>Copolyester Monomer Manufacturing</td><td>575805</td><td>E3-6 & E3-19</td><td>Q</td><td>0.06 tons/year</td></tr>
<tr><td>23</td><td>80-0003-224</td><td>B-55-1</td><td>Organic Acids & Anhydrides Manufacturing</td><td>576513</td><td>E3-8 & E3-9</td><td>I</td><td>1000 ppmvd (one-hour average) and 0.97 tons/year</td></tr>
<tr><td>24</td><td>82-0003-247</td><td>B-238-1</td><td>HTM Furnaces</td><td>576162</td><td>E5-4</td><td>F</td><td rowspan="3">0.55 tons/year</td></tr>
<tr><td>24</td><td>82-0003-247</td><td>B-238-1</td><td>HTM Furnaces</td><td>576162</td><td>E5-4</td><td>G</td></tr>
<tr><td>24</td><td>82-0003-247</td><td>B-238-1</td><td>HTM Furnaces</td><td>576162</td><td>E5-4</td><td>K</td></tr>
<tr><td>24</td><td>82-0003-247</td><td>B-238-1</td><td>HTM Furnaces</td><td>576162</td><td>E5-4 & E5-5</td><td>L</td><td>0.26 tons/year</td></tr>
</table>

Table 3-8: Eastman Chemical Company Allowable Emissions – Other Emission Sources							
MSOP	Source #	PES	Source Description	Permit	Condition	Vent ID(s)	SO_2 Emission Limit
24	82-0003-305	H2 Plants	Hydrogen Plants 3, 4, 5, and 6	576162	E8-7	3A	0.96 tons/year
24	82-0003-305	H2 Plants	Hydrogen Plants 3, 4, 5, and 6	576162	E8-7	4A	
24	82-0003-305	H2 Plants	Hydrogen Plants 3, 4, 5, and 6	576162	E8-7	5A	
24	82-0003-305	H2 Plants	Hydrogen Plants 3, 4, 5, and 6	576162	E8-7	6A	
25	82-0003-254	OC-BATCH	Production of Specialty Organic Chemicals	576606	E3-8	7-I	7.05 tons/year
25	82-0003-254	OC-BATCH	Production of Specialty Organic Chemicals	576606	E3-8	A-G	
25	82-0003-254	OC-BATCH	Production of Specialty Organic Chemicals	576606	E3-8	A-L	
26	82-0003-131	B-325-1	Boilers 30 and 31	576501	E3-8	A	317 lb/hr (30-day avg) from Boiler 30
26	82-0003-131	B-325-1	Boilers 30 and 31	576501	E3-9	A	293 lb/hr (30-day avg) from Boiler 31
26	82-0003-132	B-423-1	Gas Boilers A, B, and C	576501	E4-4	A	0.4 lb/hr
26	82-0003-132	B-423-1	Gas Boilers A, B, and C	576501	E4-4	B	
26	82-0003-132	B-423-1	Gas Boilers A, B, and C	576501	E4-4	C	
27	82-0003-303	B-190-1	Plastics Compounding	574985	E5-6 & E5-7	F	1000 ppmvd (one-hour average) and 0.10 tons/year
27	82-0003-303	B-190-1	Plastics Compounding	574985	E5-6 & E5-7	L	
29	82-0003-102	RICE-1	Emergency Engines	574111	E7-3	A	0.90 tons/year
29	82-0003-102	RICE-1	Emergency Engines	574111	E7-3	H	
29	82-0003-102	RICE-1	Emergency Engines	574111	E7-3	I	
29	82-0003-102	RICE-1	Emergency Engines	574111	E7-3	K	
29	82-0003-102	RICE-1	Emergency Engines	574111	E7-3	P	
31	82-0003-276	B-265B-1	HTM furnaces	576485	E3-3	A	0.03 tons/year

Table 3-8: Eastman Chemical Company Allowable Emissions – Other Emission Sources							
MSOP	**Source #**	**PES**	**Source Description**	**Permit**	**Condition**	**Vent ID(s)**	**SO_2 Emission Limit**
31	82-0003-276	B-265B-1	HTM furnaces	576485	E3-3	C	
32	82-0003-282	B-248-1	Solid/liquid incinerators	576926	E3-2, E3-8	D	1,000 ppmvd and 40 tons/year
32	82-0003-282	B-248-1	Solid/liquid incinerators	576926	E3-2, E3-8	E	
32	82-0003-283	B-248-2	Liquid chemical incinerator	576926	E4-2, E4-7	A	1,000 ppmvd and 20 tons/year
32	82-0003-103	RICE-3	Emergency Engine	576926	E8-6	A	1 ton/year
34	82-0003-293	B-232-1	Manufacture of Aromatic Acids	576931	N/A	UA	N/A
34	82-0003-293	B-232-1	Manufacture of Aromatic Acids	576931	N/A	UB	N/A
34	82-0003-293	B-232-1	Manufacture of Aromatic Acids	576931	N/A	UC	N/A
36	82-0003-310	B-655-1	Methanolysis Plant	978695	E4-10	A	0.10 lb/hr
						D	0.15 lb/hr
						E	0.15 lb/hr
02	82-0003-311	B-83-11	New Boilers 32, 33, and 34	979100	S1-3	F	0.15 lb/hr

Current allowable emissions for Domtar are shown in **Table 3-9**. PSD construction permit 978656 was issued to Domtar June 21, 2021, to convert the idled mill from a hardwood bleached soda process to produce containerboard from 100% recycled material. This project included the following changes:

- Optimization of the Bubbling Fluidized Bed (BFB) Biomass Boiler (82-0022-33) for combustion of biomass, including OCC rejects, wastewater treatment plant sludge, bark, and other wood waste, with natural gas and ultra-low sulfur diesel as secondary fuels.

- Conversion of the existing Soda Recovery Furnace (82-0022-34) to disable the furnace's capability to combust black liquor solids. The repowered furnace will be designated as the No. 2 Power Boiler and will combust only natural gas and ULSD.

- The existing lime kiln will be permanently shut down.

Table 3-9: Domtar Paper Company Allowable Emissions

Permitted Emission source	**Allowable SO_2 Emission Rate**	**SO_2 Emissions (tons/year)**
Biomass Boiler	11.43 lb/hr (daily average)	50.06
No. 2 Power Boiler	1.33 lb/hr (daily average)	5.83
Emergency Engines	1.83 lb/hr	0.46 (at 500 hours/year)
Total		**56.35**

Domtar's Kingsport Mill is currently shut down, and these limits will apply upon startup of the modified source. Domtar's allowable emissions, and the changes associated with the conversion of the Kingsport Mill, are not part of the control strategy for the nonattainment area. Tennessee included Domtar's updated allowable emissions in the modeled attainment demonstration to confirm that the facility did not substantially impact the nonattainment area.

3.3 Attainment Year Inventory

As part of the SIP submittal, the air agency should also submit a projected attainment year inventory that includes estimated emissions for all emission sources of SO_2 which are determined to have an impact on the affected nonattainment area for the year in which the area is expected to attain the standard, consistent with the attainment demonstration for the affected area. This inventory should reflect projected emissions for the attainment year for all SO_2 sources in the nonattainment area, taking into account emission changes that are expected after the base year. Such emissions changes would include any expected emission reductions from existing control measures, from any new measures that may be adopted as part of the local area attainment plan, or from expected source shutdowns, so long as the existing and new control measures and source shutdowns are enforceable; and would include any expected emission increases due to new sources or growth by existing sources. *See* CAA section 172(c)(4).

The projected attainment year is 2027. An attainment year inventory was developed by projecting the baseline inventory forward to develop a 2027 inventory. This inventory reflects projected emissions for the attainment year for all SO_2 sources in the nonattainment area, taking into account emission changes that are expected after the base year. Such emissions changes include new control measures, emission reductions from existing control measures, or from expected source shutdowns.

Point Sources

The attainment year inventory for Eastman Chemical Company's coal-fired boilers is shown in **Table 3-10**. This inventory projects 4,012 tons/year of SO_2 emissions following conversion of the remaining B-253 boilers from coal to natural gas operation, installation of DSI controls on B-83 Boilers 23 and 24, and adoption of a revised combined limit for B-83 and B-325. Future year emissions for Eastman's B-83 boilers were estimated from the base year emissions by applying a 60% nominal control efficiency to Boilers 23 and 24. Future emissions for B-325 were estimated from the base year by assuming no changes to future year emissions.

Table 3-10: Eastman Chemical Company Attainment Year Inventory – Boilers		
Release Point ID	**Description**	**SO_2 Emissions (tons/year)**
B-253-1	B-253 Coal-Fired Boilers	10
B-83-1	B-83 Coal-Fired Boilers	2,672
B-325-1	B-325 Coal-Fired Boilers	1,340
Subtotal:		**4,022**

Construction permit 979100 was issued to Eastman Chemical Company on August 3, 2021. This permit allows the construction of three new natural gas-fired boilers (B-83 Boilers 32, 33, and 34) with a nominal heat input of 249 MMBtu/hr each. Condition G18 requires Eastman to permanently cease operation of B-83 Boilers 18, 19, and 20 following the startup of Boilers 32, 33, and 34 (one coal-fired boiler must be shut down for each natural gas-fired boiler that begins operation). A separate permit (operating permit 079592) was issued as part of Tennessee's 2021 Regional Haze SIP (see Appendix G-2g). This permit requires the shutdown of Boilers 18, 19, and 20 no later than December 31, 2028. Boilers 32, 33, and 34 were added to the future year inventory. Although Boilers 18, 19, and 20 may cease operation prior to the attainment year[19], the *required* shutdown date occurs in 2028, and these boilers were included in the future year inventory. Portable boiler PB-1 was included in the base year inventory but removed from the future year inventory. This is a temporary unit that was added in 2017 to provide backup steam generation following an accident at Eastman's Kingsport facility. This boiler was removed from the permit in 2020 (Title V renewal permit 576501) and is no longer onsite. Future year emissions for Eastman's hazardous waste incinerators were estimated using the highest actual emission rate for calendar years 2018 through 2020.

For Holston Army Ammunition Plant, PSD construction permit 974192 (issued October 8, 2018) allows for the construction of four natural gas and No. 2 fuel oil-fired boilers with maximum design heat input capacities of 327 MMBtu/hr each. Condition S1-10 of this permit requires the coal-fired boilers to permanently cease operation following startup of the new boilers and establishes interim emission limits that apply during the shakedown period for the new boilers. On November 1, 2021, BAE Systems Ordnance Systems, Inc. (operating contractor for Holston Army Ammunition Plant) notified

19 As discussed in Section 5.0 (RACT), condition G18 of construction permit 979100 requires Eastman to permanently cease operation of Boilers 18, 19, and 20 upon startup of proposed natural gas boilers 32, 33, and 34.

the Division of Air Pollution Control that the coal-fired boilers have ceased operation. The future year inventory for Holston Army Ammunition Plant removes the coal boilers, adds the gas/oil boilers, and assumes no other changes in SO_2 emissions.

For other SO_2 point sources (Eastman Chemical Company's remaining emission sources and Primester), the future year emission inventory assumes no growth from the remaining sources. The "no growth" assumption was based on Tennessee's Growth Policy (TAPCR 1200-03-09-.01(5))[20], which requires all minor stationary sources and minor modifications proposing to construct in a nonattainment area to utilize best available control technology (BACT)[21], as specified by the Technical Secretary of the Tennessee Air Pollution Control Board. This rule also requires major stationary sources and major modifications to install Lowest Achievable Emission Rate (LAER) control technology, obtain offsetting emissions reductions, and to comply with other nonattainment New Source Review requirements. Point Source emissions for Eastman are included in Attachment A.

Area Sources

Future-year emissions were projected for 2027 using emission data sets and information used by U. S. EPA to develop the 2016v1 and 2016v2 emissions inventories[22,23]. For each source classification code, Tennessee calculated a growth factor as the difference between 2026 and 2016 emissions, as follows:

Growth factor = (2026 emissions – 2016 emissions)/10

For each year between 2017 and 2027, future year emissions were calculated by adding the growth factor to the base year (2016) and to each subsequent year. The final result (2027 emissions) was used for the future-year emission inventory. County-level emissions were apportioned to the nonattainment area by using a percentage (9.3%) derived from the 2010 Census Bureau Population data for the county and the population for the nonattainment area[24]. Area source emissions of SO_2 for 2027 are shown in **Table 3-10**. Future-year area source emissions are included in Attachment B.

20 TAPCR 1200-03-09-.01(5) includes Tennessee's nonattainment New Source Review requirements.

21 TAPCR 1200-03-09-.02(2)(d). This definition of BACT is roughly identical to the PSD BACT definition, except for minor changes in wording.

22 The 2016v1 inventory is available online at https://www.epa.gov/air-emissions-modeling/2016v1-platform.

23 The 2016v2 inventory is available online at https://www.epa.gov/air-emissions-modeling/2016v2-platform.

24 The allocation of nonpoint source emissions by population should not significantly overcount or undercount emissions relative to the county as a whole, because these emissions should vary directly with population (i. e., a population-weighted allocation of emissions from the entire county to the nonattainment area should be representative of the nonattainment area). Tennessee also believes that any overcounting or undercounting should have a negligible impact on the emission inventory as a whole, because these emissions are a small fraction of the overall emissions.

Table 3-11: Future Year Area Source SO_2 Emissions	
Year 2027	**SO_2 (tons/year)**
Sullivan County Nonattainment Area	3.39

Onroad Mobile Sources

Onroad mobile sources as an emissions source category comprises a large number of individual sources. Onroad mobile sources are all vehicles certified for onroad use. These include, for example, cars, motorcycles, pickup trucks, buses, delivery trucks and long-haul trucks (18 wheelers). As a group, onroad vehicles contribute significant amounts of certain air pollutants. Emissions from onroad sources are estimated through the use of locally gathered information on the vehicle population and the miles driven in the area, as well as a number of other inputs, combined with EPA's Motor Vehicle Emissions Simulator (MOVES) model. Details on the development of the onroad emissions are contained in Appendix D.

Federal standards for National Low Emission Vehicles (NLEV) began in 1999 and implemented through 2001 for new light duty cars and trucks. EPA has since implemented further reductions from onroad mobile sources; the Federal Tier 2 and Tier 3 vehicle emission standards. Federal Tier 2 vehicle emission standards require all passenger vehicles in a manufacturer's fleet, including light-duty trucks and Sport Utility Vehicles (SUVs), to meet an average standard of 0.07 grams of oxides of nitrogen (NO_x) per mile in 2007[25]. The Tier 2 standards also cover passenger vehicles over 8,500 pounds gross vehicle weight rating (the larger pickup trucks and SUVs), which are not covered by the Tier 1 regulations. For these vehicles, the standards were phased in beginning in 2008, with full compliance in 2009. The new standards require vehicle emissions to be 77% to 95% cleaner than those manufactured to meet Tier 1 standards. The Tier 2 rule also reduced the sulfur content of gasoline to 30 parts-per-million (ppm) starting in January of 2006. Most gasoline sold in Tennessee prior to January 2006 had a sulfur content of up to 300 ppm. Sulfur occurs naturally in gasoline but interferes with the operation of catalytic converters on vehicles resulting in higher NO_x emissions. The combination of lower-sulfur gasoline and the Tier 2 engine emissions standards are necessary to achieve the Tier 2 vehicle emission standards.

EPA has promulgated a Tier 3 rule designed to further reduce air pollution from new passenger cars and trucks. The Tier 3 vehicle standards reduce both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles. Beginning in 2017, Tier 3 emissions standards will lower the sulfur content of gasoline and lower the emissions from light duty passenger cars and trucks even further[26]. The Tier 3 gasoline sulfur standard will make emission control systems more effective for both existing and new vehicles. Removing sulfur allows the vehicle's catalyst to work more efficiently. Lower sulfur gasoline also facilitates the development of some lower-cost technologies to improve fuel economy and reduce greenhouse gas (GHG) emissions, which reduces gasoline consumption and saves consumers money.

New EPA standards designed to reduce NO_x and VOC emissions from heavy-duty gasoline and diesel

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25Environmental Protection Agency, *Federal Register*, Vol. 65, No. 28, February 10, 2000.
26Environmental Protection Agency, *Control of Air Pollution From Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards; Final Rule. Federal Register,* Vol. 79, No. 81, April 28, 2014.

highway vehicles began to take effect in 2004. A second phase of standards and testing procedures, beginning in 2007, will reduce particulate matter from heavy-duty highway engines, and will also reduce highway diesel fuel sulfur content to 15 ppm, allowing for additional emission control devices. The total program, when fully implemented, is expected to achieve a 90% reduction in particulate matter (PM) emissions and a 95% reduction in NO_x emissions for these new engines using ultra low sulfur diesel, compared to existing engines using higher sulfur content diesel[27].

As older, more polluting vehicles leave the fleet, and are replaced by newer, lower emitting cars and trucks, emissions from vehicles subject to EPA's Federal Motor Vehicle Control Programs are expected to decrease significantly. EPA's Tier 3 motor vehicle emissions control program are expected to contribute to even further emissions reductions from the onroad mobile source sector.

Effective in 2005, the Tennessee Air Pollution Control Board promulgated a statewide motor vehicle anti-tampering rule. This rule, defined in Chapter 1200-3-36, Motor Vehicle Tampering, was promulgated to reduce the air pollution caused by tampering with a motor vehicle's emissions control system. The area of applicability for this rule is statewide. Chapter 1200-3-36 defines tampering as modifying, removing, or rendering inoperative any air pollution emission control device, which results in an increase in emissions beyond established federal motor vehicle standards. Additionally, the rule identifies what is specifically prohibited, for example, removing a catalytic converter.

Tennessee has promulgated rules for Stage I Gasoline Vapor Recovery for several counties throughout Tennessee, including Anderson, Blount, Jefferson, Knox, Loudon, and Sevier Counties in the greater Knoxville area, and Washington and Sullivan Counties in the Tri-Cities area. Gasoline dispensing stations in these counties that were existing sources on December 29, 2004, were required to comply with this rule by May 1, 2006.

Parts of the emissions inventory for onroad sources were developed in conjunction with the Kingsport Metropolitan Planning Organization (MPO) and TDOT. Development of the onroad emission inventory followed EPA's Technical Guidance on the use of MOVES for SIP inventory development[28]. Onroad emissions are developed through the use of locally gathered data applied to EPA's Motor Vehicle Emissions Simulator (MOVES) model. Some of the locally developed data includes vehicles miles travelled (VMT) and vehicle population. **Tables 3-12 and 3-13** summarize the Annual VMT and vehicle population in Sullivan County in 2027.

Table 3-12: Sullivan County 2027 Annual Vehicle Miles Traveled

County	2027 Annual Vehicle Miles Traveled (VMT)
Sullivan	1,550,435,137

27Environmental Protection Agency, *Federal Register*, Vol. 66, No. 12, January 18, 2001.
28*MOVES3 Technical Guidance: Using MOVES to Prepare Emissions Inventories for State Implementation Plans and Transportation Conformity*. US EPA. EPA-420-B-20-052, November 2020.

Table 3-13: 2027 Vehicle Population in Sullivan County		
Source Type ID	**Source Type**	**2027**
11	Motorcycle	4,850
21	Passenger Car	88,417
31	Passenger Truck	61,270
32	Light Commercial Truck	3,325
41	Other Bus	64
42	Transit Bus	15
43	School Bus	493
51	Refuse Truck	16
52	Single Unit Short-haul Truck	3,754
53	Single Unit Long-haul Truck	169
54	Motor Home	555
61	Combination Short-haul Truck	168
62	Combination Long-haul Truck	232

EPA's MOVES model, version 3.0.3, was used to estimate emissions from onroad mobile sources in Sullivan County for 2027. The January 2022 release of the MOVES3 database was used for this analysis. The county-level emissions were apportioned to the nonattainment area by using U. S. Census Bureau Population data for 2010 in the nonattainment area as compared to the population of the entire county. Onroad emissions of SO_2 for 2027 are shown in **Table 3-14**. Future-year onroad emissions are included in Attachment C.

Table 3-14: Nonattainment Area Onroad SO_2 Emissions	
Year 2027	**SO_2 (tons/year)**
Sullivan County Nonattainment Area	0.41

Nonroad Mobile Sources (Excluding Locomotive/Rail)

Future-year emissions were projected for 2027 using EPA's MOVES model. Aircraft, commercial marine and rail future-year emissions were projected for 2027 using emission data sets and information used by U. S. EPA to develop the 2016v1 and 2016v2 emissions inventories[29,30]. For each source classification code, Tennessee calculated a growth factor as the difference between 2026 and 2016 emissions, as follows:

Growth factor = (2026 emissions – 2016 emissions)/10

For each year between 2017 and 2027, future year emissions were calculated by adding the growth factor to the base year (2016) and to each subsequent year. The final result (2027 emissions) was used for the future-year emission inventory. County-level emissions were apportioned to the

29 See footnote 22.
30 See footnote 23.

nonattainment area by using 2010 Census Bureau Population data for the county and the nonattainment area. Nonroad emissions of SO_2 for 2027 are shown in **Table 3-15**. Future-year nonroad emissions are included in Attachment D.

Table 3-15: Nonattainment Area Nonroad SO_2 Emissions	
Year 2027	**SO_2 (tons/year)**
Sullivan County Nonattainment Area	0.0405

Locomotive/Rail Emissions

Future-year locomotive/rail emissions were estimated from base-year emissions by assuming a 50% increase in emissions between 2017 and 2027. The 50% adjustment was based on a review of other nonroad categories and determining the highest calculated emissions increase for all nonroad categories (43.3% for several types of compressed natural gas-burning equipment). Future-year locomotive emissions are shown in **Table 3-16** and in Attachment D.

Table 3-16: Future-Year SO_2 Emissions From Locomotives		
SCC	**2027 SO_2 Emissions (tons)**	**Nonattainment Area SO_2 Emissions (tons)**
Mobile Sources – Railroad Equipment, Diesel, Line Haul Locomotives: Class I Operations	0.050223	0.004670739
Internal Combustion Engines – Railroad Equipment, Diesel, Yard Locomotives	0.015685755	0.001458775
Total	**0.065908755**	**0.006129514**

Domtar and Holston Army Ammunition Plant

Future year emissions were not quantified for Domtar or Holston Army Ammunition Plant. Both facilities are located outside of the nonattainment area. Domtar's allowable emissions were included in the modeled attainment demonstration and did not significantly impact the nonattainment area. Holston Army Ammunition Plant retired their coal-fired boilers in 2021, and SO_2 emissions from other sources at this facility are negligible.

Summary

The future year inventory is summarized in **Table 3-17**.

Table 3-17: Summary of Future-Year Emissions Inventory	
Description	**SO_2 Emissions (tons)**
Eastman Chemical Company – Boilers	4,022
Eastman Chemical Company – Other Point Sources	55.64
Area Sources	0.363
Onroad Mobile Sources	0.41
Nonroad Mobile Sources	0.057

Table 3-17: Summary of Future-Year Emissions Inventory	
Description	**SO_2 Emissions (tons)**
Locomotive/Rail	0.006
Total	**4,069**

4.0 CONTROL MEASURES

The SIP must include enforceable emission limitations, and such other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emission rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to provide for attainment of such standard in such area by the applicable attainment date.

The SIP should provide for attainment of the standard based on SO_2 emission reductions from permanent and enforceable control measures, and States should consider all Reasonably Available Control Measures (RACM) and Reasonably Available Control Technologies (RACT) that can be implemented in light of the attainment needs for the affected area(s). EPA also promulgated other regulatory requirements that are expected to yield substantial SO_2 reductions, and the implementation of national and regional control measures should ease the process of planning for attainment of the SO_2 NAAQS.

4.1 Repowering of Boilers 25-29

Tennessee adopted a Regional Haze SIP on March 31, 2008[31], which covers the period from 2008-2018 and establishes the State's plan for a return to natural visibility conditions at Class I areas in Tennessee and Class I areas affected by Tennessee sources. The 2008 Regional Haze SIP implements the requirement for affected sources to install Best Available Retrofit Technology (BART) for SO_2 and other visibility-impairing pollutants[32].

Tennessee identified a number of BART-eligible sources within the state, including Boilers 25-29 at Eastman Chemical Company's B-253 Powerhouse in Kingsport. The 2008 Regional Haze SIP required these boilers to comply with an SO_2 limit of 0.20 lb/MMBtu, or to reduce uncontrolled SO_2 emissions by 92%, no later than five years after approval of Tennessee's SIP. These emission limits became enforceable with the issuance of BART permit 061873H on March 31, 2008[33].

Tennessee amended the 2008 Regional Haze SIP on May 9, 2012, and submitted the amendment to EPA on May 14, 2012, as revised on May 25, 2012.The amended SIP allowed Eastman to implement BART no later than April 30, 2017, or an Alternative BART option (repowering of the boilers from coal to natural gas) by December 31, 2018. The Alternative BART option became Federally enforceable with the issuance of BART permit 066116H on May 9, 2012, and the issuance of an amended BART permit on May 22, 2012 (BART permit 066116H was submitted to EPA on May 14, 2012, as revised on May 25, 2012). A PSD construction permit (966859F), which authorized construction for the boiler

31 This SIP was submitted to U. S. EPA on April 4, 2008. EPA issued a limited disapproval of Tennessee's regional haze plan on June 7, 2012 (77 FR 33642) due to the plan's reliance on the Clean Air Interstate Rule (CAIR). In conjunction with the limited disapproval, EPA promulgated a FIP replacing reliance on CAIR with reliance on CSAPR to address the deficiency in the SIP. On September 24, 2018 (83 FR 48237), EPA converted the limited approval/limited disapproval of Tennessee 2008 Regional Haze SIP to a full approval.

32 A BART-eligible source is an emission source that has the potential to emit 250 tons or more of a visibility-impairing pollutant, was constructed between August 7, 1962, and August 7, 1977, and whose operations fall within one or more of 26 listed source categories. The Clean Air Act requires BART for any BART-eligible source that a State determines "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area."

33 Approved by EPA November 27, 2012 (77 FR 70689).

repowering, was issued June 5, 2013. Condition 6 of PSD construction permit 966859F states that on and after the startup date of each modified boiler in the B-253 fuel-burning installation, only natural gas shall be used as fuel for each modified boiler. The repowered boilers began operation on the dates shown in **Table 4-1**, and conversion of the five B-253 boilers from coal to natural gas operation reduced SO_2 emissions from B-253 by >99.9% (from 14,897 tons/year to 10 tons/year). Tennessee proposes to adopt a fuel usage restriction for Boilers 25 through 29 (only natural gas may be used as fuel for this source) into the SIP[34].

Table 4-1: Startup Dates of Modified B-253 Boilers

Boiler	Startup Date
25	April 23, 2014
27	April 23, 2016
28	October 2, 2016
29	March 30, 2018
26	October 4, 2018

4.2 Emission Limits for B-83 Powerhouse (Boilers 18-24) and B-325 Powerhouse (Boilers 30-31)

To assure that emissions from the B-83 and B-325 boilers do not endanger future attainment, the following SO_2 emission limit is established (**Table 4-2**). This emission limit was established from AERMOD runs as discussed in Section 7.0. Modeled values were converted to a single 30-day rolling average emission limit using the procedure discussed in EPA's SO_2 SIP guidance. Compliance with these limits will be demonstrated through the use of continuous emissions monitoring systems (CEMS) on all boilers[35].

Table 4-2: B-83 and B-325 Combined Emission Limit

Boilers	SO_2 Emission Limits (lb/hr), 30-operating day rolling average
B-83 Boilers 18-24 (MSOP-02)	1,248 (combined limit for all boilers)
B-325 Boilers 30-31 (MSOP-26)	

Compliance with these limits is based upon the operation of existing controls for B-325 (spray dryer absorbers with PM control devices) and new controls for B-83 Boilers 23 and 24 (dry sorbent injection)[36]. Boilers 30 and 31 (powerhouse B-325) are also subject to existing limits of 317 lb/hr for

34 See Condition 6 of PSD Construction Permit 966859F. Compliance with this restriction is based on design and construction of the modified source (i. e., separate natural gas lines and burners have been installed in the boilers, and the associated coal handling equipment has been removed or abandoned in place). The separate natural gas lines and burners physically restrict the boilers' ability to combust other fuels, including coal and fuel oil.

35 All boilers are equipped with CEMS, but emissions from the larger boilers (23, 24, 30, and 31) are calculated differently from Boilers 18 through 22. Boilers 23, 24, 30, and 31 are subject to the NO_X SIP Call and are required by 40 CFR 75 to install and operate in-stack flow monitors. Because Boilers 18 through 22 are not equipped with flow monitors, SO_2 emissions are calculated in lb/MMBtu using 40 CFR 60 Appendix A, Method 19 and the heat input is calculated from the energy rise of steam across the boiler.

36 See Section 5.1 for a description.

Boiler 30 and 293 lb/hr for Boiler 31[37]. Both limits are based on a 30-calendar day rolling average. All 30-day rolling averages must be calculated as specified in 40 CFR §63.10021(b) (**Equation 4-1**), where Her_i is the hourly emissions rate for hour i (combined total emissions for all boilers) and n is the number of hourly emissions rate values collected over 30 boiler operating days[38].

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad \textbf{Equation 4-1}$$

Permit 080222 requires each CEMS to be fully operational for at least 95% of the operational time of the monitored boiler during any calendar quarter, and missing data must be addressed by substituting the higher value of: (1) the last valid hourly emission rate before, or (2) the first valid hourly emission rate after, the period of missing data.

4.3 Emission Limits for B-248 Hazardous Waste Incinerators

Eastman operates two identical solid/liquid chemical waste incinerators (B-248-1) for combustion of solid and liquid hazardous waste and a liquid chemical incinerator (B-248-2). All three units are subject to an SO_2 emission limit of 1,000 parts per million by volume, dry basis (one-hour average). The solid/liquid chemical waste incinerators and liquid chemical waste incinerator are also subject to annual emission limits of 40 tons/year and 20 tons/year SO_2, respectively. When these units are modeled at the allowable emission rate (1,000 ppmv), the model indicates that these units cause or contribute to exceedances of the SO_2 NAAQS. To assure that emissions from the incinerators do not endanger future attainment, the following SO_2 emission limits are established (**Table 4-3**):

Table 4-3: Hazardous Waste Incinerators Emission Limits

Emission Source	SO_2 Emission Limits (lb/hr), 30- operating day rolling average
B-248-1 Solid/Liquid Chemical Waste Incinerators (MSOP-32)	15.2 (combined total for both incinerators)
B-248-2 Liquid Chemical Waste Incinerator (MSOP-32)	2.0

SO_2 emissions from the incinerators are calculated from the sulfur feed rate and rod scrubber underflow pH using the simulation results of a commercially available software package (ASPEN®)[39]. Permit 080222 requires the SO_2 monitoring system to be fully operational for at least 95% of the operational time of each incinerator during each semiannual reporting period.

4.4 Emission Limits for Tail Gas Incinerator

37 See PSD permit 955272F, Condition 4.

38 "Boiler operating day" means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in any of the boilers. It is not necessary for the fuel to be combusted the entire 24-hour period.

39 Computer simulations were conducted at varying sulfur loading conditions and correlation curves relating pH and scrubber control efficiency were derived. The correlation curve for the highest sulfur feed modeled was used to develop the relationship programmed into the DCS.

Eastman's coal gasification operations (PES B-334-1) include an afterburner to control emissions from the acid gas removal and sulfur recovery operations. The incinerator is subject to an existing SO_2 emission limit of 21.8 pounds per hour, with compliance based on a daily average.

SO_2 emissions are indirectly monitored by an extractive sampling system or equivalent monitor, which continuously measures the H_2S composition in the Shell Claus Off-gas Treatment (SCOT) process overhead stream entering the tail gas incinerator. The distributed control system uses the H_2S composition and the flow rate to calculate the hourly and 24-hour block average (midnight of each day to midnight of the following day) SO_2 emission rates in lb/hr.

Permit 080222 requires the SO_2 monitoring system to be fully operational for at least 95% of the operational time of each incinerator during each semiannual reporting period. Process operational time does not include periods of sulfur recovery plant outages. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks, zero and span adjustments, shall not be included in the data averages. In the event of an analyzer outage or Claus unit upset requiring direct venting to the incinerator, engineering evaluation and calculations are used to determine the SO_2 emissions using actual operational data from the Claus and SCOT units.

4.5 Emission Limits for Cold and Warm Flares

Eastman's cold and warm flares (PES B-351-5) control emissions of hydrogen sulfide, carbon monoxide, and other pollutants from Eastman's coal gasification operations. The flare is subject to existing SO_2 emission limits of 47.6 pounds per hour (24-hour block average) and 8.1 tons during any period of twelve consecutive months. The SIP establishes a new limit of 16.28 lb/hr (one-hour average), which may not be exceeded for more than 88 hours during any calendar year. SO_2 emissions are calculated from the gas flow rates and known plant gas stream compositions assuming 100% conversion of H_2S to SO_2 via combustion in the flare. Permit 080222 requires the SO_2 monitoring system to be fully operational for at least 95% of the operational time of each incinerator during each semiannual reporting period.

4.6 Emission Limits for Primester

Condition E5-1 of Title V Operating Permit 574994 limits SO_2 emissions from Primester's cellulose scrap recovery process (82-0510-03, B-441-2, Vent C) to 1,000 parts per million by volume, dry basis (one hour average) and 0.25 pounds per hour (three-hour average). Compliance is based upon parametric monitoring of the minimum scrubber flow rate (three-hour moving average of 1.0 gallons/minute) and minimum scrubber pH (24-hour block average value of 6.0). Condition E2-11 of Title V Operating Permit 574994 requires all monitoring methods to have at least a 95% operational availability during each semiannual reporting period.

4.7 Adoption of Control Measures into the SIP

Tennessee requests that EPA approve the following requirements (**Table 4-4**) into the SIP. Copies of all permits are included in Attachment I.

Table 4-4: Summary of Emission Limits Included in the SIP				
Permit	**Condition(s)**	**Affected Source**	**Limit/Control Measure**	**Associated Monitoring**
PSD Construction Permit 966859F	6	B-253-1 Boilers 25 through 29	Only natural gas shall be used as fuel	None specified. Compliance with the fuel usage restriction is based on the design and construction of the boiler (natural gas feed lines and burners physically restrict the source's ability to burn other fuels).
SIP Operating Permit 080222	1 through 6 and Attachments A, B, C, and D	B-83 Boilers 18 through 24 and B-325 Boilers 30 and 31	1,248 lb/hr (30-day average, combined limit for all boilers) and associated monitoring	Calculate hourly emissions SO_2 emissions from CEMS data and flow monitoring (B-83 Boilers 23 and 24 and B-325 Boilers 30 and 31) or from CEMS data and calculated heat input (B-83 Boilers 18 through 22).
		B-248-1 Solid/Liquid Chemical Waste Incinerators	15.2 lb/hr (30-day average, combined limit for both rotary kilns) and associated monitoring	Calculate hourly emissions from sulfur feed rate and scrubber pH using established algorithm. Continuously monitor scrubber pH and determine the waste stream sulfur concentrations from analysis or process knowledge.
		B-248-2 Liquid Chemical Waste Incinerator (MSOP-32)	2.0 lb/hr (30-day average) and associated monitoring	
		B-334-1, incinerator for acid gas removal and sulfur recovery plant (MSOP-17)	21.8 lb/hr (24-hour block average) and associated monitoring	Continuously measure the H_2S composition and gas flow rate in the SCOT process overhead stream entering the tail gas incinerator and use the monitored parameters to calculate the SO_2 emission rate.
		B-351-5 cold and warm flares (MSOP-17)	16.28 lb/hr, not to be exceeded for more than 88 hours per calendar year, and associated monitoring	Calculate hourly SO_2 emissions from feed gas composition, valve position, valve upstream pressure, and flow meter readings.
			47.6 lb/hr (24-hour block avg.) and associated monitoring	
		B-55-1, Organic Acids & Anhydrides Manufacturing, Vents B, C, E, I, and K (82-0003-224, MSOP-23)	6.74 lb/hr (average for each batch cycle)	None specified. Allowable emission rate is based on maximum uncontrolled emission rate for each batch[40].
PSD permit 955272F	4	PES B-325-1, Boiler 30	317 lb/hr (30 calendar day rolling average basis) and associated monitoring.	Calculate hourly emissions SO_2 emissions from CEMS data and flow monitoring, as required by permit 080222.
		PES B-325-1, Boiler 31	293 lb/hr (30 calendar day rolling average basis) and associated monitoring.	
Title V Operating Permit 574994 (Primester)	E5-1	82-0510-03, B-441-2, Vent C	1,000 parts per million by volume, dry basis (one hour average) and 0.25 pounds per hour (three-hour average)	Compliance is based upon parametric monitoring of the minimum scrubber flow rate (three-hour moving average of 1.0 gallons/minute) and minimum scrubber pH (24-hour block average value of 6.0).

40 Eastman staff have indicated that additional controls are under consideration for B-55-1, but these plans have not been finalized.

4.8 New Source Review (NSR)

Title I of the Clean Air Act prescribes the conditions under which a new major stationary source or major modification may obtain a preconstruction permit in an area designated nonattainment for any criteria pollutant. The nonattainment NSR permitting requirements in CAA §§172(c)(5) and 173 are among the requirements to be submitted as part of a revised SIP for a nonattainment area. Beginning on the effective date of any nonattainment designation for the 2010 SO_2 NAAQS, proposed major stationary sources and major modifications of SO_2 are under CAA §173 to obtain a nonattainment NSR permit.

Air agencies that have an existing nonattainment NSR program based on previous SO_2 NAAQS (annual, 24-hour, or 3-hour averaging periods) may be able to use the existing program to authorize the construction and modification of major stationary sources of SO_2 that would locate in a new 2010 SO_2 nonattainment area. States that do not have nonattainment NSR rules that apply to new nonattainment areas for SO_2 must, within 18 months of designation, revise their existing nonattainment NSR programs or develop new programs to enable the permitting of any major stationary source of SO_2 locating in a nonattainment area under the 2010 SO_2 NAAQS.

In general, the nonattainment NSR program should ensure that the construction and modification of major stationary sources of SO_2 will not interfere with reasonable further progress toward the attainment of the 2010 SO_2 NAAQS. More specifically, the applicable statutory requirements include:

- The installation of Lowest Achievable Emissions Rate (LAER) control technology;
- The acquisition of emissions reductions to offset new emissions of nonattainment pollutant(s);
- Certification that all major sources owned and operated in the state by the same owner are in compliance with all applicable requirements of the Clean Air Act;
- A demonstration via an analysis of alternative sites, sizes, production process, and environmental control techniques shows that the benefits of a proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification; and
- An opportunity for a public hearing and written comment on the proposed permit.

The nonattainment NSR requirements apply on a pollutant-specific basis with respect to each nonattainment pollutant for which a source has the potential to emit in amounts greater than the applicable major source threshold for the pollutant. For new sources in SO_2 nonattainment areas, a major stationary source is defined as 100 tons/year or more of SO_2. Similarly, nonattainment NSR requirements apply to any existing major stationary source of SO_2 that proposes a modification (physical change or change in the method of operation) that results in a significant net emissions increase (40 tons/year or more) of SO_2.

Tennessee has an existing nonattainment New Source Review program (TAPCR 1200-03-09-.01(5)) that meets the requirements listed above. Tennessee's nonattainment New Source Review program will apply to SO_2 emissions from major stationary sources and major modifications in the Kingsport nonattainment area. The most recent revisions to Tennessee's New Source Review program were approved by EPA on September 24, 2018[41]. On March 1, 2021, EPA approved the Nonattainment New Source Review portion of Tennessee's 2017 SIP submittal[42]. EPA determined that this portion of Tennessee's 2017 submittal met the applicable requirements of sections 110 and 172 of the Clean Air Act and the applicable regulatory requirements at 40 CFR part 51. There have been no changes to the SIP-approved NNSR permit program since EPA's March 1, 2021 approval that that would require the State to request subsequent EPA approval with respect to the nonattainment planning requirements of 172(c)(6).

41 83 FR 48245.

42 86 FR 11873 (March 1, 2021).

5.0 RACT/RACM ANALYSIS

Section 172(c) of the Clean Air Act requires SIPs to provide for reasonably available control measures (RACM), reasonably available control technology (RACT), and reasonable further progress (RFP), as necessary to demonstrate attainment. States must demonstrate that they have adopted all reasonably available control measures (including RACT for stationary sources) necessary to demonstrate attainment as expeditiously as practicable. The SIP revision must contain the list of control measures considered by the State, and information and analysis sufficient to support the State's judgment that it has adopted all RACM, including RACT.

RACT is generally defined as an emission limit that represents the lowest emission limitation that a particular emissions unit is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT may include emission standards; design, equipment, work practice, or operational standards; or any combination thereof.

5.1 RACT Analysis for Eastman Sources

As indicated in Section 3.0, the three fuel-burning installations at Eastman Chemical Company's Kingsport facility were responsible for more than 99% of SO_2 emissions in the nonattainment area in 2011. RACT analyses were performed on the following emission sources:

1. B-253 coal-fired boilers (25-29).
2. B-83 coal-fired boilers (18-24).
3. B-325 coal-fired boilers (30 and 31).
4. B-248-1 Solid / Liquid Chemical Waste Incinerators.
5. B-248-2 Liquid Chemical Waste Incinerator.

The following measures were evaluated as potential RACT/RACM:

<u>B-253 Boilers</u>

The control measures discussed in Section 4.0 (repowering of boilers 25-29 from coal to natural gas operation) are adopted as RACT. As discussed in that section, conversion of these boilers to natural gas operation will reduce SO_2 emissions by >99.9% (from 14,897 tons/year to 10 tons/year). The gas conversion is the lowest emission rate achievable at B-253. The cost-effectiveness of this option was estimated in 2017 as $3,300 per ton of SO_2.

<u>Dry Sorbent Injection (DSI)[43] for B-83 Boilers 23 and 24</u>

On June 13, 2019, Tennessee provided a written notification to Eastman Chemical Company that a reference monitor for the nonattainment area had registered four validated ambient SO_2 concentrations in excess of the NAAQS. The written notification triggered the contingency plan

43 Dry sorbent injection is a pollution control technology that removes acid gases in two steps. First, a powdered sorbent (typically an alkaline reagent such as trona (sodium sesquicarbonate), sodium bicarbonate, or hydrated lime, is injected into the flue gas. Acid gases such as sulfur dioxide react with the sorbent to form a solid compound (i. e., particulate matter), which is removed by the downstream control device, such as an electrostatic precipitator or fabric filter.

requirements established by permit 070072, including the requirement to develop and implement operational changes as necessary to prevent future monitored violations of the standard. Eastman submitted a written response on July 17, 2019, which stated that in response to the monitored exceedances, Eastman began deployment of a contingency plan to install dry sorbent injection (DSI) using sodium bicarbonate as the reagent on Boilers 23 and 24. The letter stated that Eastman selected this provisional emission control strategy for the following reasons:

1. Of Eastman's remaining nine coal-fired boilers at its Kingsport, Tennessee site, Boilers 23 and 24 offer the best opportunity for hourly SO_2 emission reductions for the highest percent of operating time.

2. Boiler 31 already has a highly efficient spray dryer absorber and fabric filter system that reduce SO_2 by 90-95%.

3. Boiler 30 has a spray dryer absorber and electrostatic precipitator (ESP) that reduce SO2 by about 65%.

4. Boilers 18-24 have no SO2 control equipment. Of these, Boilers 23 and 24 are high pressure base loaded boilers that are operated preferentially over the remaining smaller and lower pressure Boilers 18 -22.

Eastman deployed a portable system to reduce SO_2 emissions from Boilers 23 and 24 and selected DSI as the permanent system to be installed, as follows:

- Project Definition: September 2019 – February 28, 2020
- Detailed Engineering: February 1, 2020 – September 30, 2020
- Procurement: May 1, 2020 – February 28, 2021
- Field Construction: January 1, 2020 – September 30, 2021
- Checkout/Startup: October 1, 2021 – November 1, 2021

On August 13, 2020, Eastman submitted a four-factor analysis for Boilers 23 and 24[44], which stated that the permanent DSI for Boilers 23 and 24 would operate with an overall average removal efficiency of 60%[45]. The control measures discussed in Section 4.0 (installation of DSI on Boilers 23 and 24) are adopted as RACT.

44 The four-factor analysis was submitted pursuant to Tennessee's May 15, 2020, request, which was developed as part of the Tennessee's long-term strategy Regional Haze.

45 The nominal control efficiency of the permanent DSI is higher than the efficiency of the portable system that was operated between 2019 and 2021. The four-factor analysis noted that the rental system consisted of a single train serving two boilers, whereas the permanent system consists of one train for each boiler plus a spare train. The permanent DSI will also have a dehumidifier on each train which will reduce plugging incidents.

Low-Sulfur Coal for B-83 and B-325 Boilers

In the November 13, 2014, letter to Eastman, Tennessee asked Eastman to provide the sulfur content of the existing coal supply and to evaluate the technical and economic feasibility of low sulfur (e. g., subbituminous)[46] coal combustion in the B-83 and B-325 boilers.

Eastman's response dated December 15, 2014, indicated that the coal supply comes from mines in Southwest Virginia and Eastern Kentucky (Central Appalachian Coal). The sulfur content of this coal averages about 0.8 – 0.9% sulfur with a normal range from 0.7 – 1.1%[47]. Regarding the technical and economic feasibility of subbituminous coal combustion, Eastman raised the following concerns:

1. **Safety**: Eastman indicated a significant fire concern when subbituminous coal sits in a silo or bunker for an extended time. The letter states that Eastman has found that the last 20% of coal will not freely fall from the silos, and about 2,500 tons of coal per silo will remain idle. Over a sufficient time period, this coal has a high potential to spontaneously combust[48].

2. **Storage capacity**: The letter states that subbituminous coal typically has a heating value of 8,500 Btu/lb, which is about 33% less than coal from Central Appalachia. This means that a boiler would have to burn about 33% more coal to produce the same amount of energy. Since Eastman utilizes silos which only hold a limited number of tons, the effective storage capacity

46 Subbituminous coal deposits are found in Wyoming, Montana, Colorado, Utah, and New Mexico. Subbituminous coals are desirable for SO_2 control due to their lower sulfur content (often less than 1%) compared to bituminous coal. See Babcock & Wilcox. *Steam – Its Generation and Use*, 40th edition, 1992. Chapter 8, pages 4-6.

47 Eastman's 2014 letter states that the coal burned at their facility "is very low sulfur content for Central Appalachian Coal." Review of available data suggests that the reported sulfur content is within the low range for bituminous coals, as indicated in the following table.

Coal Class	Group	Description	State	County	Sulfur content
II	1	Low-volatile bituminous	WV	McDowell	0.74
II	1	Low-volatile bituminous	PA	Cambria	1.68
II	2	Medium-volatile bituminous	PA	Somerset	1.68
II	2	High-volatile bituminous A	PA	Indiana	2.20
II	3	High-volatile bituminous A	PA	Westmoreland	1.82
II	3	High-volatile bituminous A	KY	Pike	0.70
II	3	High-volatile bituminous A	OH	Belmont	4.00
Source: Babcock & Wilcox. *Steam – Its Generation and Use*, 40th edition, 1992. Chapter 8, page 6.					

48 See Babcock & Wilcox. *Steam – Its Generation and Use*, 40th edition, 1992. Chapter 8, page 6. Regarding the likelihood of spontaneous combustion in coal, subbituminous is stated to have higher moisture content, higher volatile matter content, and a tendency for spontaneous combustion when drying, compared to bituminous coal.

Another source (*Propensity of Coal to Self-Heat*, International Energy Agency, December 2010) states that coal will self-heat as it oxidizes. The self-heating will continue with a continuous air supply and inadequate heat dissipation. The propensity of coal to self-heat and lead to spontaneous combustion is increased with lower grades of coal. (lignite, subbituminous). The self-heating raises the temperature to a plateau until moisture is vaporized, then the temperature rises rapidly. Conversely, dry coal can ignite following sorption of water. Thus, wet and dry coal should be stored separately. Long term storage in silos provides conditions for accelerated self-heating through air movement. Ventilation at the top of a silo is essential to remove the volatile gases emitted by the coal. Sealing the silo to prevent air flow will help prevent self-heating. Flooding the upper parts of a silo with inert gas is another prevention method.

(measured in days) would be decreased by 33%. Therefore, the second concern is a reliability concern to meet steam load demand[49].

3. **De-rating of boiler capacity**: The letter states that due to limitations on feeders and ash handling systems[50], combustion of subbituminous coal would result in a de-rating of the boilers' capacities such that the plant production needs could not be reliably met with adequate reserve. The net effect is that Eastman would have to install additional gas fired boilers to make up the lost capacity.

Tennessee rejected this option as RACT based on our review of the information submitted by Eastman. After considering the potential safety and reliability impacts, Tennessee concluded that combustion of low-sulfur coal would not be feasible for B-83 and B-325.

B-325 coal-fired boilers (30 and 31)

This fuel burning installation consists of two pulverized coal-fired boilers with a nominal heat input capacity of 780 MMBtu/hr (Boiler 30) and 880 MMBtu/hr (Boiler 31). SO_2 emissions from these boilers are controlled by a spray dryer absorber (SDA) associated with each boiler. Flue gas is routed to the spray dryer absorbers, and a rotary atomizer sprays a lime and recycle ash slurry into the absorber chambers. The lime reacts with sulfur dioxide and the slurry water is evaporated. Reaction products, fly ash, and flue gas are routed out of the chamber to a downstream electrostatic precipitator (ESP) for Boiler 30 or a fabric filter baghouse for Boiler 31.

Boiler 31 has a higher SO_2 control efficiency than Boiler 30 because a baghouse is used as the final

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49 The exact increase in required storage capacity depends on the specific coal ranks that are compared, but Babcock & Wilcox data (*Steam – Its Generation and Use*, Chapter 8) indicate that changing from bituminous to subbituminous coal requires increased coal combustion at constant heat input.

Rank	% Change in Coal Combustion at Constant Heat Input
II-1 Low-volatile bituminous	95.1%
II-3 High-volatile bituminous	100.0%
III-1 Subbituminous A	121.7%
III-2 Subbituminous B	145.0%
III-3 Subbituminous C	162.9%

50 Coal handling requirements would increase, as indicated in the previous note. Babcock & Wilcox data (*Steam – Its Generation and Use*, Chapter 8) indicates that ash generation would decrease for some subbituminous coal ranks.

Rank	% Change in Ash Generation at Constant Heat Input
II-1 Low-volatile bituminous	93.0%
II-3 High-volatile bituminous	100.0%
III-1 Subbituminous A	108.3%
III-2 Subbituminous B	68.2%
III-3 Subbituminous C	99.4%

control device. Although spray dryer absorbers are used in each boiler for SO_2 control, Boiler 30 uses an ESP for particulate control, and there is no further reaction with the SO_2 in the flue gas. In the Boiler 31 baghouse, the lime builds up into a filter cake, and additional control results from the reaction of SO_2 with the filter cake (i. e., a portion of the SO_2 that passes through the SDA can be absorbed inside the baghouse).

For Boiler 31, the spray dryer absorber/fabric filter combination constitutes RACT, and no further analysis is required. In 2017, Tennessee asked Eastman to evaluate the technical and economic feasibility of control device upgrades for Boiler 30 (e. g., upgrade the existing ESP to a baghouse). The RACT analysis was updated based on information provided by Eastman in 2020 for Tennessee's 2021 Regional Haze SIP.

Upgrade ESP to Fabric Filter for B-325 Boiler 30: The only feasible control technology Eastman identified to add to the effectiveness of the current spray dryer absorber and electrostatic precipitator (ESP) to control SO_2 on Boiler 30 would be replacement of the existing ESP with a fabric filter. This could conceivably increase the control effectiveness from 70% to 92% due to increased reaction time on the filter bags. Eastman estimated the cost-effectiveness of this control technology at $7,834 per ton of SO_2 reduction ($7,415 per ton based on Tennessee's review of Eastman's calculations). This estimate was based on a baseline emission rate of 1,136 tons/year[51], a removal efficiency of 92%, and an incremental SO_2 reduction of 833 tons/year (**Table 5-1**).

Table 5-1: Cost Estimate – Upgrade ESP to Fabric Filter for B-325 Boiler 30

Category	Cost	Basis
Total Direct Capital Cost	$14,495,000	Vendor/engineering study estimate
Total Indirect Capital Cost	$17,181,753	Includes construction indirect costs, engineering, construction coordination, Eastman labor and travel, contingency, and escalation
Total Capital Investment (TCI)	$31,676,753	Total direct plus indirect capital costs
Total Direct Annual Cost (TDAC)	$855,802	No additional operating or supervisory labor. Maintenance costs were estimated as 3.0% of TCI. Reagent savings are based on Boiler 31 costs.
Indirect Annualized Costs	$3,804,896	Total Capital Investment multiplied by a capital recovery factor (CRF) of CRF = i/[1-(1+i)^-n] Where i = 8.5% and n = 15 CRF = 0.120
Total Indirect Annual Cost (TIAC)	$5,321,540	Indirect annual costs plus overhead and administrative costs
Total Annual Cost	$6,177,341	TDAC + TIAC
Cost-Effectiveness ($/ton)	$7,415	

51 Controlled SO_2 emissions with spray dryer and electrostatic precipitator, nominal control efficiency of 60%.

As part of the 2021 Regional Haze SIP development, Tennessee consulted with the National Park Service (NPS) and with U. S. EPA, and those agencies identified two potential areas of concern: (1) the 15-year equipment life used by Eastman to develop the DSI/fabric filter cost estimates; and (2) the use of an 8.5% real interest rate in lieu of a nominal interest rate.

- Eastman used a 15-year equipment life to develop the DSI/fabric filter cost estimates, and NPS recommended a 20-year equipment life. For fabric filters, EPA's *Air Pollution Control Cost Control Manual* states that the system lifetime varies from 5 to 40 years, with 20 years being typical. Although Eastman's equipment life is within the range recognized by EPA, Tennessee adjusted Eastman's estimate by increasing the fabric filter equipment life from 15 years to 20 years.

- EPA and NPS stated that the 8.5% interest rate used in the calculations should be replaced with the bank prime interest rate (currently 3.25%) or with a firm-specific rate that is justified by the source. Tennessee reviewed Eastman's costs by recalculating the cost effectiveness at 3.25%[52].

The adjusted costs for this option are shown in **Table 5-2**.

Table 5-2: Adjustments of Eastman Control Costs Based on EPA and NPS Recommendations

Adjustment	Cost Effectiveness ($/ton)
Adjust Interest Rate to 3.25%	$6,083
Adjust Interest Rate to 3.25% and change baghouse equipment life from 15 years to 20 years	$5,475

Tennessee rejected the addition of a baghouse to Boiler 30 as RACT based on the cost effectiveness of the option and the attainment needs of the area. The addition of a baghouse to Boiler 30 would not attain the NAAQS in the absence of the ongoing reductions from B-83 and would not advance the attainment date.

<u>Control Device Upgrade for B-83 Boilers 23 and 24</u>

In addition to the proposed RACT identified above (dry sorbent injection), Eastman identified replacement of the existing electrostatic precipitators (ESPs) with fabric filters as an additional SO_2 control technology for Boilers 23 and 24. This upgrade could increase the nominal control efficiency to 90% due to increased reaction time on the filter bags. This option may be technically feasible but is complicated by several site-specific factors at the B-83 powerhouse.

- There is limited space at B-83, and the only practical option is to convert the existing ESPs to fabric filters, preserving only the ash hoppers.

52 Eastman staff noted in follow-up discussions that use of the nominal interest rate was established per EPA's guidance but was not required by law or regulation. The Division took no position on whether a real, as opposed to nominal, interest rate was appropriate for the Regional Haze SIP.

- The Building 83 complex and surrounding area are fully developed, and there are no open areas to establish fabrication facilities, laydown, or parking. These areas must be established remote to the project site, and all material and manpower transported to the construction footprint. This would significantly increase the construction cost.

- Eastman states that this option was assessed by a vendor who specializes in fabric filters and has experience with ESP-to-fabric filter conversions. The vendor concluded that it is unknown if the conversion is technically feasible without a flow model study to determine if the "box" footprint of the ESP is large enough to accommodate a fabric filter of sufficient size to meet the applicable particulate matter and opacity emission standards.

- The vendor also indicated that it is unknown if the existing induced draft fans on the outlet of the ESPs are large enough to handle the increased pressure drop caused by the fabric filters. A new higher horsepower fan could result in the need to stiffen the boiler walls. While replacement of the ID fan would not render the option technically infeasible, it would drive the cost of the option up significantly.

Notwithstanding the technical feasibility of this option is currently unknown, Eastman estimated the cost-effectiveness assuming it is technically feasible. Eastman provided a cost estimate of $9,004 per ton SO_2 reduced ($8,989 per ton based on Tennessee's review of Eastman's calculations) to upgrade the ESP on B-83 Boilers 23 and 24 to a fabric filter (**Table 5-3**). Eastman's costs are based on site-specific vendor estimates. The four-factor analysis states that the upgrade could increase the control effectiveness from 60% (DSI plus existing ESP) to 90% due to increased reaction time on the filter bags. However, the four-factor analysis identifies several factors that complicate this option.

- There is limited space at the B-83 powerhouse, and the four-factor analysis states that the only practical option is to convert the existing ESPs to fabric filters, preserving only the ash hoppers.

- The B-83 complex and surrounding area are fully developed, and there are no open areas to establish fabrication facilities, laydown, or parking. These areas must be established remote to the project site, and all material and manpower transported to the construction footprint.

- The four-factor analysis states that this option has been assessed by a vendor who specializes in fabric filters and has experience with ESP-to-fabric filter conversions. The vendor concluded that the technical feasibility of this option is unknown without a flow model study to determine whether the "box" footprint of the ESP is large enough to accommodate a fabric filter that would perform well enough to meet the applicable particulate matter and opacity emission standards.

- The four-factor analysis states that it is unknown if the existing induced draft fans on the outlet of the ESPs are large enough to handle the increased pressure drop caused by the fabric filters. A new higher horsepower fan could result in the need to stiffen the boiler walls. While replacement of the ID fan would not render the option technically infeasible, it would drive the cost of the option up significantly (Eastman estimates an order of magnitude cost estimate range of $4-6 million per boiler for larger ID fans).

The four factor analysis states that the costs for this option were based on the cost estimate for Boiler 30 (upgrade ESP to fabric filter) using the 0.6 scaling factor rule[53] and increased by 25% to account for the increased complexity of this project. The Division considered the specific factors identified above in the review of Eastman's estimate.

Table 5-3: Cost Summary – Upgrade ESP to Fabric Filter for B-83 Boilers 23 & 24		
Category	**Cost**	**Basis**
Total Direct Capital Cost	$27,904,472	Includes major equipment items, demolition, civil/structural, mechanical (piping, valves, etc.), electrical equipment, instrumentation & controls, and painting.
Total Indirect Capital Cost	$32,895,214	Includes construction indirect costs, engineering, construction coordination, Eastman labor and travel, contingency, and escalation
Total Capital Investment (TCI)	$60,799,686	Total direct plus indirect capital costs
Total Direct Annual Cost (TDAC)	$685,991	No additional operating or supervisory labor. Maintenance costs were estimated as 3.0% of TCI.
Indirect Annualized Costs	$7,303,082	Total Capital Investment multiplied by a capital recovery factor (CRF) of CRF = i/[1-(1+i)^-n] Where i = 8.5% and n = 15 CRF = 0.120
Total Indirect Annual Cost (TIAC)	$10,216,872	Indirect annual costs plus overhead and administrative costs
Total Annual Cost	$11,533,898	TDAC + TIAC
Cost Effectiveness ($/ton)	$9,004	Based on 1,281 tons/year SO_2 reduction

As stated previously, Tennessee consulted with the National Park Service (NPS) and with U. S. EPA, and those agencies identified two potential areas of concern: (1) the 15-year equipment life used by Eastman to develop the DSI/fabric filter cost estimates; and (2) the use of an 8.5% real interest rate in lieu of a nominal interest rate. The adjusted costs for this option are shown in Table 5-4.

53 The 0.6 scaling factor rule and complexity factor are represented as shown below:

Boilers 23 & 24 capital cost = 2 x [(Boiler 30 capital cost)(1.25)(501 MMBtu/hr/780 MMBtu/hr)$^{0.6}$]

Table 5-4: Adjustment of Eastman Control Costs Based on EPA and NPS Recommendations	
Adjustment	**Cost Effectiveness ($/ton)**
Baseline	$9,003
Adjust Interest Rate to 3.25% and change baghouse equipment life from 15 years to 20 years	$6,728

Tennessee rejected the addition of a baghouse to Boilers 23 and 24 as RACT based on the cost effectiveness of the option and the attainment needs of the area. Tennessee rejected this option as RACT because the addition of a baghouse to Boilers 23 and 24 would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 (i. e., from installation of DSI on boilers 23 and 24) and would not advance the attainment date.

Additional Controls for B-83 Boilers 21 and 22

Boilers 21 and 22 are currently uncontrolled for SO_2. Eastman identified the following control options:

- Spray dryer absorber/fabric filter
- Wet scrubber
- Installation of DSI similar to Boilers 23 and 24
- Installation of DSI along with conversion of the existing ESPs to fabric filters

Spray dryer absorber/fabric filter or wet scrubber: The four-factor analysis states that there is no space available for installation of large add-on control devices such as spray dryer absorbers or wet scrubbers and their associated ancillary equipment, so these two options were eliminated as technically infeasible.

Dry sorbent injection (no fabric filter upgrade): A DSI system may be technically feasible for Boilers 21 and 22, since there is a reagent injection location available in the ducts downstream of the economizers with adequate residence time in the duct prior to the ESPs. However, the existing ESPs may be unable to handle the increased particulate matter loading that will result from the DSI system. Total ash loading would be expected to increase by approximately 60 percent. No field tests have been conducted on these boilers to determine the impact on the performance of the ESPs. As compared to the ESPs on Boilers 23 and 24, the ratio of collection area to gas flow (specific collection area (SCA)) is about 40 percent less (117 sf/kcfm vs 209 sf/kcfm). All the ESPs on Boilers 21 – 24 are considered to have "small" SCAs, so their capacity to handle increased particulate matter loading is marginal. Given that the DSI system tends to challenge the ESPs on Boilers 23 and 24, at times causing increased opacity, Eastman can only assume the smaller (relative) ESPs on Boilers 21 and 22 will not be adequate to handle the increased particulate loading while remaining in compliance with applicable particulate matter and opacity emission limits. Therefore, any analysis of cost-effectiveness should assume improved particulate matter controls are required and installed.

DSI and fabric filter upgrade: Eastman provided a cost estimate of $8,725[54] per ton SO_2 reduced for DSI/fabric filter installation on B-83 Boilers 21 and 22 (**Table 5-5**) based on site-specific vendor estimates for B-83 Boilers 23 and 24. The four-factor analysis states that compared to the ESPs on

54 Tennessee's estimate (Table 5-5) is lower than Eastman's because Tennessee's calculation corrects an error in maintenance labor and materials (from 4% to 3%)

Boilers 23 and 24, the ratio of collection area to gas flow (specific collection area (SCA)) is about 40% less (117 sf/kcfm vs 209 sf/kcfm). All the ESPs on Boilers 21 – 24 are considered to have “small” SCAs, so their capacity to handle increased particulate matter loading is marginal. Given that the DSI system tends to challenge the ESPs on Boilers 23 and 24, at times causing increased opacity, Eastman assumes the smaller ESPs on Boilers 21 and 22 will not be adequate to handle the increased particulate loading, and any analysis of cost-effectiveness should assume improved particulate matter controls are required and installed. Eastman’s four-factor analysis states that the cost-effectiveness of the technology applied to these boilers would be substantially higher than for Boilers 23 and 24, as follows:

- Boilers 21 and 22 are low pressure boilers and their capacity factors are significantly lower than Boilers 23 and 24 (Boilers 23 and 24 high pressure boilers used to meet the plant’s baseload steam and electricity demands). For the past nine years, the capacity factor for Boilers 23 and 24 has averaged 0.56 whereas the capacity factor for Boilers 21 and 22 has averaged 0.37.

- An engineering study was not conducted for Boilers 21 and 22 (costs are based on Boilers 23 and 24), but the fixed capital costs of a DSI are expected to be at least as much as the $10 million cost for the Boiler 23/24 DSI. Because these boilers operate at about half the rated capacity of Boilers 23 and 24, there will be a decreased economy of scale.

- Several factors are likely to increase the capital cost for Boilers 21 and 22. The four-factor analysis states that the location for the injection lances would be on the high roof of the powerhouse (instead of inside the building). An access platform and roof structure would need to be installed from which to mount and access the injection lances.

- Adequate space for the silos and injection systems will also be a challenge and will inevitably drive up the costs. The four-factor analysis states that Eastman has not identified a practical location to install this equipment.

Table 5-5: Cost Estimate – Install DSI/FF for B-83 Boilers 21 & 22		
Category	**Costs**	**Basis**
Total Capital Investment (TCI)	$50,112,833	DSI was assumed to be the same cost as the ongoing project for Boilers 23 and 24. The fabric filter cost was scaled from the estimate for Boilers 23 and 24.
Total Direct Annual Cost (TDAC)	$2,366,800	No additional operating or supervisory labor. Maintenance labor and materials were estimated as 3.0% of TCI[55].

55 Eastman’s 3% estimate of maintenance labor and materials is based upon a study provided by Black and Veatch, which assessed the cost of different control options for Boiler MACT compliance. Section 6.2.6 of this study states, “The annual maintenance materials and labor costs are typically estimated as a percentage of the total equipment costs of the system. Based on typical electrical utility industry experience, maintenance materials are estimated to be between 1 and 5 percent of the total direct capital costs according to the retrofit technology. Some initial recommended spare parts are included in the

Table 5-5: Cost Estimate – Install DSI/FF for B-83 Boilers 21 & 22		
Category	**Costs**	**Basis**
		Reagent costs were estimated from Boilers 23 and 24 usage assuming 33% less usage.
Indirect Annualized Costs	$6,034,610	TCI x CRF CRF = i/[1-(1+i)^-n] Where I = 8.5% and n = 15 CRF = 0.120
Total Indirect Annual Cost (TIAC)	$6,679,468	Indirect annual costs plus overhead and administrative costs[56]
Total Annual Cost	$9,046,268	TDAC + TIAC
Cost-Effectiveness ($/ton)	$8,339	Based on 1,296 tons/year SO_2 reduction.

As stated previously, Tennessee consulted with the National Park Service (NPS) and with U. S. EPA, and those agencies identified two potential areas of concern: (1) the 15-year equipment life used by Eastman to develop the DSI/fabric filter cost estimates; and (2) the use of an 8.5% real interest rate in lieu of a nominal interest rate. The adjusted costs for this option are shown in **Table 5-6**.

Table 5-6: Adjustment of Eastman Control Costs Based on EPA and NPS Recommendations	
Adjustment	**Cost Effectiveness ($/ton)**
Baseline	$8,339
Change baghouse equipment life from 15 years to 20 years	$6,342

Tennessee rejected the addition of a DSI and fabric filter to Boilers 21 and 22 as RACT based on the cost effectiveness of the option and the attainment needs of the area. Tennessee rejected this option as RACT because the addition of a DSI and baghouse to Boilers 21 and 22 would not attain the NAAQS in the absence of the reductions from B-253 and the reductions from B-83 (i. e., from installation of DSI on boilers 23 and 24) and would not advance the attainment date.

Wet Scrubber for B-83 Boilers 18 through 24: Eastman considered the addition of wet SO_2 scrubbers on Boiler 24 in 2006 during the initial investigation of required BART controls. Eastman

capital costs. An annual maintenance value of 3 percent of the total direct capital costs was used as the basis for the yearly maintenance materials and labor cost. For technologies that replace a similar existing technology in the current plant site, a determination of the additional maintenance requirements is performed. If the required maintenance materials and labor are similar to the existing technology, no additional maintenances costs are credited for the new control technology."

56 Section 2.5.5.8 of the Cost Control Manual (Property Taxes, Insurance, and Administrative Charges) states, "These three indirect operating costs are factored from the system total capital investment, at 1, 1, and 2%, respectively." Property taxes are not typically included in control cost calculations, since no additional land purchase is required for installation of a control device, and insurance and administrative costs are calculated as 3% of TCI.

subsequently rejected wet scrubber technology due to concerns over space limitations and high dissolved salt loadings on the South Fork Holston River[57]. Tennessee reviewed this option again for both the 2017 attainment demonstration and the 2021 Regional Haze SIP and concluded that this option is technically infeasible.

Shutdown of B-83 Boilers 18 through 20: In its four-factor analysis for Tennessee's 2021 Regional Haze SIP, Eastman included a commitment to cease operation of Boilers 18, 19, and 20 no later than December 31, 2028 (see condition 2 of Regional Haze SIP permit 079592). Eastman subsequently applied for a construction permit (permit 979100, issued August 3, 2021, and amended October 5, 2021) to construct three new natural gas boilers (Boilers 32, 33, and 34) to replace the steam generating capacity lost by shutdown of the coal units. Condition G18 of this permit requires Eastman to permanently cease operation of Boilers 18, 19, and 20 as follows:

- Boiler 19 must cease operation on or before the startup date of Boiler 32.
- Boiler 18 must cease operation on or before the startup date of Boiler 33.
- Boiler 20 must cease operation on or before the startup date of Boiler 34.

The permit requires Eastman to notify the Technical Secretary in writing of the shutdown date of each boiler no later than 30 days after the date of each shutdown. The cost effectiveness of this option was not submitted with the four-factor analysis because Eastman planned to adopt the option by the end of the second planning period for the 2021 Regional Haze SIP. Tennessee considered whether an earlier shutdown date should be required for the attainment demonstration and rejected an earlier shutdown date as RACT. Tennessee rejected an earlier shutdown date because shutdown of Boilers 18, 19, and 20 prior to December 31, 2028, would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 (i. e., from installation of DSI on boilers 23 and 24) and would not advance the attainment date.

<u>RACT Summary Table for Eastman Boilers</u>

RACT options for the B-83, B-253, and B-325 boilers are summarized in **Table 5-7**.

Table 5-7: RACT Summary for Eastman Boilers

Emission Source	RACT Option	Annualized Cost ($/ton)	Comments
B-253, Boilers 25-29	Convert to natural gas	$3,300	This option is adopted as RACT for Boilers 25 through 29. Cost effectiveness is based on the information submitted with the 2017 SO_2 attainment demonstration.
B-83 Boilers 23 and 24	Dry sorbent injection (DSI)	Not provided	This option is adopted as RACT for Boilers 23 and 24. Installation of DSI was adopted as a permanent control strategy following implementation of the 2017 contingency plan.

57 Under Tennessee Division of Water Resources (DWR) Rule 0400-40-03-.03(1)(d) (Criteria for Water Uses), total dissolved solids (TDS) may not exceed 500 mg/L in areas designated for use of Domestic Water Supply. Likewise, under Rule 0400-40-03-.03(3)(d), impacts to Fish and Aquatic Life are monitored for oversaturation of dissolved solids. This concentration limit is applied to contributions from all sources discharging to the waterway in question as well as waterways downstream. The addition of a wet scrubber discharging to the South Fork Holston River would require testing of TDS in order to ensure compliance with the general permissible limits set forth by DWR and the Clear Water Act. Eastman's permit (#TN0002640) does not stipulate a specific maximum discharge of TDS for the outfall as it is currently written.

Table 5-7: RACT Summary for Eastman Boilers			
Emission Source	**RACT Option**	**Annualized Cost ($/ton)**	**Comments**
B-83 Boilers 23 and 24	Upgrade DSI and (ESP) combination to DSI with fabric filter (FF)	$6,728 - $9,003	Tennessee rejected this option as RACT after considering the cost of this option in light of the area's attainment needs (this option would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 and would not advance the attainment date). Tennessee also considered the technical feasibility issues identified by Eastman in the four-factor analysis.
B-83 Boilers 21 and 22	Spray dryer absorber (SDA) and FF	Infeasible	Technically infeasible based on space limitations.
B-83 Boilers 21 and 22	Wet scrubber	Infeasible	Technically infeasible based on space limitations.
B-83 Boilers 21 and 22	DSI/ESP	Infeasible	Tennessee rejected this option as technically infeasible based on the size of the ESPs and increased PM loading.
B-83 Boilers 21 and 22	DSI/FF	$6,342 - $8,339	Tennessee rejected this option as RACT after considering the cost of this option in light of the area's attainment needs (this option would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 and would not advance the attainment date). Tennessee also considered the technical feasibility issues identified by Eastman in the four-factor analysis.
B-83 and B-325, all boilers	Low-sulfur coal (e.g., subbituminous)	Infeasible	Tennessee rejected this option as RACT after considering safety, capacity, and transportation issues.
B-325, Boiler 30	Upgrade ESP to FF	$5,475 - $7,415	Tennessee rejected this option as RACT after considering the cost of this option in light of the area's attainment needs (this option would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 and would not advance the attainment date).
B-83 Boilers 18-20	Shutdown and replace with new natural gas boilers	Not reported	Eastman is subject to enforceable requirements to cease operation of Boilers 18, 19, and 20 no later than December 31, 2028, or the startup dates of new natural gas-fired Boilers 32, 33, and 34 (whichever is earlier). Tennessee rejected an earlier shutdown date as RACT based on the area's attainment needs (this option would not attain the NAAQS in the absence of the reductions from B-253 and the pending reductions from B-83 and would not advance the attainment date).

<u>B-248-1 Solid/Liquid Chemical Waste Incinerators and B-248-2 Liquid Chemical Waste Incinerator</u>

Eastman's B-248 complex includes three hazardous waste combustors: two rotary kilns that may burn either solid or liquid chemical waste (designated as PES B-248-1, Vents D and E) and one liquid chemical waste incinerator (designated as PES B-248-2, Vent A) . All three sources are subject to SO_2 emission limits of 1,000 ppmv, dry basis (one-hour average) as well as annual emission limits (40 tons/year from B-248-1 and 20 tons/year from B-248-2). Because all three emission units utilize SO_2 control devices (multi-rod scrubber for each vent) and pre-control emissions exceeded major source thresholds, these units are subject to the requirements of 40 CFR 64 (Compliance Assurance

Monitoring [CAM]). The CAM plan for these sources requires Eastman to monitor sulfur feed rates[58] and scrubber pH[59], and to calculate SO_2 emissions using a commercially available software package[60]. Based on modeling of these emission sources, Tennessee established SO_2 emission limits of 15.2 lb/hr (30-day rolling average) for PES B-248-1 and 2.0 lb/hr (30-day rolling average) for PES B-248-2. These emission limits are adopted as RACT for the hazardous waste incinerators. Full emissions data for this source are included in Attachment F.

Acid Gas Removal and Sulfur Recovery Plants (Tail Gas Incinerator)

Eastman's coal gasification operations (**Figure 5-1**) include an afterburner to control emissions from the acid gas removal and sulfur recovery operations. This afterburner was included in the modeled attainment demonstration based on an allowable emission rate of 21.8 pounds per hour of SO_2. Eastman submitted 2018-2021 actual emissions for this source (**Table 5-8**), which indicated that total emissions from the afterburner vent ranged from 13.1 tons/year to 17.7 tons/year. Tennessee also calculated an average (2.6 lb/hr) and 99th percentile (10.6 lb/hr) hourly emission rate for the afterburner. Compared to boiler emissions, emissions from the afterburner are negligible, no additional controls are required as RACT. Full emissions data for this source are included in Attachment G.

Table 5-8: Tail Gas Incinerator SO_2 Emissions

Year	SO_2 Emissions (tons)	99th Percentile Emission Rate (lb/hr)
2018	17.7	11.6
2019	18.7	5.5
2020	13.1	5.6

58 Waste stream sulfur concentrations are determined either from process knowledge or from analysis using ASTM method D4239 or equivalent and are entered into the Environmental Management Information System (EMIS). EMIS provides information to the DCS regulating the feed of waste. As waste streams are burned, sulfur feed rates are calculated by the DCS using waste and fuel mass flow sensors that are required by 40 CFR 60 Subpart EEE.

59 A pH sensor and transmitter are installed in either the rod scrubber underflow line or the sump (which receives the rod scrubber underflow) before any caustic or additional water is added in the recycle loop. The distributed control system (DCS) receives pH values from the transmitter, and a data archival system records the pH reading four or more times equally spaced over the hour.

60 A series of computer simulations using a commercially available software package (ASPEN®) have been conducted to establish the rod scrubber underflow pH as the key process variable that indicates sulfur dioxide control efficiency. Computer simulations were conducted at varying sulfur loading conditions and correlation curves relating pH and scrubber control efficiency were derived. The correlation curve for the highest sulfur feed modeled was used to develop the relationship programmed into the DCS as a series of straight lines plotted between the following points:

Point	Rod Scrubber Underflow pH	SO_2 Removal Efficiency (%)
1	0.00	0.0
2	4.13	0.0
3	4.20	67.2
4	4.42	82.8
5	4.74	90.6
6	5.64	98.1
7	14.00	98.1

Table 5-8: Tail Gas Incinerator SO_2 Emissions		
Year	**SO_2 Emissions (tons)**	**99th Percentile Emission Rate (lb/hr)**
2021 (January 1 through September 30)	8.5	6.8

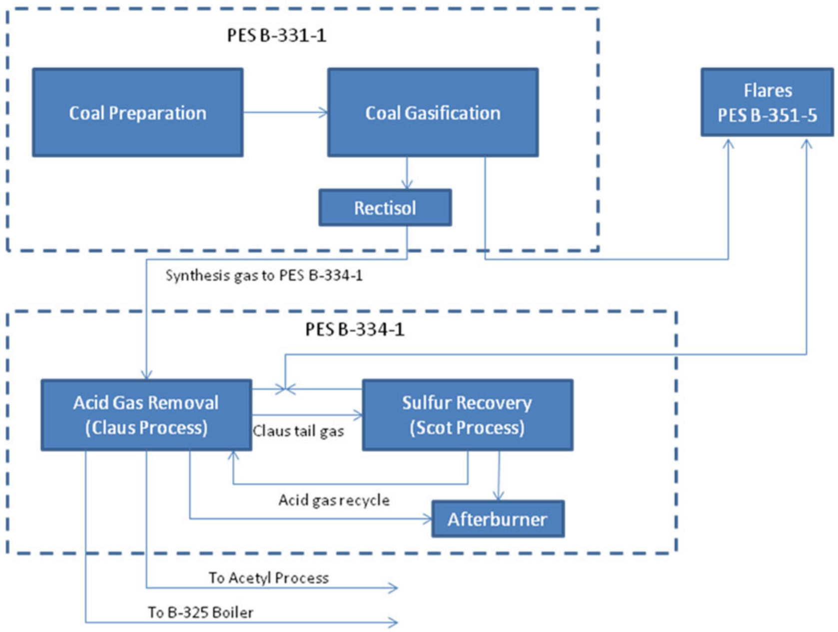

Figure 5-1: Coal Gasification Operations

5.2 RACT Analysis for Primester GP

Primester includes one SO_2 emission source (Cellulose Scrap Recovery Process). A wet scrubber is used to control SO_2 emissions from the process, and the Title V application dated September 20, 2018, states that the control efficiency of this scrubber is 95% for SO_2. Condition E5-1 of Title V Operating Permit 574994 limits SO_2 emissions to 1,000 ppmv (one-hour average) and 0.25 lb/hr (3-hour average), and the permit specifies parametric monitoring (3-hour average minimum flow rate of 1.0 gpm and 24-hour average minimum effluent pH of 6.0) to ensure proper operation of the scrubber. Because SO_2 emissions from this source are well-controlled and are low relative to the emissions from Eastman's coal-fired boilers, no additional RACT options were considered for this facility.

5.3 RACT Analysis for Area Sources

As indicated in Section 3.0, area sources were responsible for less than 0.03% of total SO_2 emissions within the nonattainment area in 2017. Because the fraction of SO_2 emissions from area sources is negligible compared to emissions from large point sources, this category was eliminated from consideration as potential RACT.

5.4 RACT Options for Sources Adjacent to the Nonattainment Area – Domtar Paper Company

Domtar Paper Company, LLC's Kingsport Mill is located adjacent to the nonattainment area, and Tennessee considered whether additional RACT controls are necessary for this facility. The only significant emission sources from this facility are the biomass boiler, which has an emission limit of 11.43 lb/hr (daily average) and the No. 2 Power Boiler, with an emission limit of 1.33 lb/hr (daily average).

Condition S1-1.B of PSD construction permit 978656 states that only biomass, natural gas, and ultra-low sulfur diesel (ULSD) may be used as fuels for the biomass boiler, and that the boiler is only capable of burning these fuels. Natural gas and ULSD contain negligible sulfur, and the permit defines "biomass" as bark, other wood waste, corrugated cardboard rejects, and wastewater treatment plant sludge. The PSD final determination for this permit also notes that Condition E6-3 Title V Operating Permit 573622 establishes a potential SO_2 emission rate of 0.0151 lb/MMBtu for biomass combustion[61] (8.2 lb/hr at a maximum heat input capacity of 544 MMBtu/hr). Condition S1-4.B of permit 978656 limits SO_2 emissions from this source to 11.43 lb/hr (daily average). For the No. 2 Power Boiler, condition S2-1.B of PSD construction permit 978656 states that only natural gas and ULSD (maximum sulfur content of 15 ppm) may be used as fuels. Condition S2-4.B of permit 978656 limits SO_2 emissions from this source to 1.33 lb/hr (daily average).

Because SO_2 emissions from this facility are low relative to the emissions from Eastman's coal-fired boilers, and because SO_2 emissions are limited by the fuel usage restrictions identified in permit 978656, no additional RACT options were considered for this facility.

5.5 RACT Options for Sources Adjacent to the Nonattainment Area – Holston Army Ammunition Plant

As noted in Section 3.0, Holston Army Ammunition Plant's Area B boilers were retired November 1, 2021. Because there are no other significant sources of SO_2 emissions, no additional RACT options were considered for this facility.

61 Table B-7 of Domtar's December 15, 2017, Title V application states that the SO_2 emission factor was based on a 2003 stack test.

6.0 REASONABLE FURTHER PROGRESS

Section 171(1) of the Clean Air Act defines Reasonable Further Progress (RFP) as "such annual incremental reductions in emissions of the relevant air pollutant as are required by this part (part D) or may reasonably be required by the EPA for the purpose of ensuring attainment of the applicable NAAQS by the applicable attainment date." As EPA has previously explained, this definition is most appropriate for pollutants that are emitted by numerous and diverse sources, where the relationship between any individual source and the overall air quality is not explicitly quantified, and where the emission reductions necessary to attain the NAAQS are inventory-wide.

EPA's SIP guidance states that since "SO_2 concentrations are often dominated by emissions from a limited number of sources, and emissions controls often yield swift and dramatic air quality improvement," "adherence to an ambitious compliance schedule" would constitute RFP for SO_2. This means that the air agency needs to ensure that affected sources implement appropriate control measures as expeditiously as practicable to assure attainment of the standard.

EPA's SIP guidance states that the approvable compliance dates for control measures must be as expeditious as practicable, and attainment plans should require sources to comply with the requirements of the attainment strategy at least one calendar year before the attainment date. EPA's SIP guidance notes that the Agency may exercise judgment concerning the approval of SIPs with varying compliance dates for emission reductions, but States should be aware that EPA would not be able to make a determination of attainment for areas with monitors, if monitoring data do not yield a design value that meets the NAAQS prior to the attainment date.

The repowered B-253 boilers began operation between April 23, 2014, and October 4, 2018, as previously indicated in Table 4-1, interim DSI controls were installed on B-83 Boilers 23 and 24 in June 2019, and installation of the permanent DSI controls on B-83 Boilers 23 and 24 was completed in November of 2021. The incremental change in emission rates is shown in **Table 6-1**. For other emission sources (hazardous waste incinerators, flares, sulfur recovery plant incinerator), allowable emissions were updated as necessary to demonstrate attainment, but there was no change in actual emission rates. All required controls will be in place and will be federally enforceable following issuance of operating permit 080222[62].

Table 6-1: Projected Change in Actual Emissions*, 2017-2028

Source	Average SO_2 Emission Rate (lb/hr)			
	2017	**2019**	**2020**	**2028 Projection**
B-83, 18-24	1,012	711	354	397
B-253-26	683	0.46	0.46	0.46
B-253-29	681	0.46	0.46	0.46
B-325, 30-31	300	308	291	300
Total	**2,676**	**1,019**	**646**	**699**

62 The emission limits and other requirements specified in permit 080222 will become enforceable on and after the first day of the calendar month that is at least 180 days following approval of the SIP by the Tennessee Air Pollution Control Board and issuance of the permit.

Table 6-1: Projected Change in Actual Emissions*, 2017-2028				
	Average SO_2 Emission Rate (lb/hr)			
Source	2017	2019	2020	2028 Projection
B-83 and B-325 actual emissions are from CEMS data reported by Eastman. Actual and projected emissions for B-253-1 were taken from Table 6-2 of Tennessee's 2017 SO_2 attainment demonstration. B-325 Boilers 30 and 31 would also be subject to existing emission limits of 317 lb/hr (Boiler 30) and 293 lb/hr (Boiler 31), based on a 30 calendar day rolling average. The B-83 and B-325 boilers would be subject to a combined 30-day rolling average allowable emission rate of 1,248 lb/hr. 2028 projected emissions for B-83 and B-325 are based on the period of July 1, 2019, through December 31, 2020.				

7.0 MODELED ATTAINMENT DEMONSTRATION

This section summarizes the development of a modeled attainment test following application of the control strategy. Supporting documentation for the modeled attainment demonstration is included in Attachment H.

7.1 Introduction

EPA finalized major updates to the existing AERMOD platform on January 17, 2017. The modeling demonstration uses the most current version of AERMOD (version 22112) and relying on the urban turbulence related to the heat island effect for the source urban location. AERMOD is considered appropriate for SIP development because SO_2 concentrations resulting from direct source emissions are projected to be close to the source in near field ambient assessment. Concentrations are highest relatively close to sources and are much lower at greater distances due to dispersion (i.e., a strong concentration gradient). The AERMOD modeling system includes several components. The main regulatory components are:

- AERMOD: the dispersion model (U.S. EPA, v22112, 04-22-2022)
- AERMAP: the terrain processor for AERMOD (U.S. EPA, v18081, 03-22-2018)
- AERMET: the meteorological data processor for AERMOD (U.S. EPA, v22112, 04-22-2022)

Additional regulatory processing and screening tools are:

- AERSURFACE: the surface characteristics processor for AERMET (U.S. EPA, v20060, 02-29-2020)
- AERSCREEN: a recently released screening version of AERMOD (U.S. EPA, v22112, 04-22-2022)
- BPIPPRIME: the building input processor (U.S. EPA, v04274, 09-30-2004)
- AERMINUTE, a preprocessor to AERMET that calculate 1-hourly averaged winds from 1-minute ASOS winds (U.S. EPA, v15272, 09-29-2015)

7.2 Modeling Domain

The modeling domain should at a minimum encompass the nonattainment area and include the sources thought most likely to cause or contribute to NAAQS violations in and around the nonattainment area. The guidance notes that in the modeling exercise, all modeled receptors should exhibit modeled attainment of the NAAQS. Given the variability of meteorology (e. g., wind speed and direction) and the short-term nature of the NAAQS, comparison of modeled design values at only one receptor, such as the location of the monitor, would not yield results that are sufficiently robust to demonstrate attainment.

Tennessee used the portion of Sullivan County encompassing a circle having its center at coordinates 36.5186 N; 82.5350 W (B-253 powerhouse, Eastman Chemical Company), and having a three-kilometer radius (i. e., the portion of Sullivan County designated as nonattainment) as the modeling domain.

7.3 Receptor grid

The model receptor grid depends on the size of the modeling domain, the number of modeled sources, and complexity of the terrain. Receptor placement should be of sufficient density to provide the resolution needed to detect significant concentration gradients with receptors placed closer together near the source to detect local gradients and placed farther apart away from the source. Additional receptors should be placed at key locations such as fence lines (which define the ambient air boundary for a particular source) or monitor locations (for comparison to monitored concentrations for model evaluation purposes). If complex terrain is included in the model calculations, AERMOD requires that receptor elevations be included in the model inputs. In those cases, the AERMAP terrain processor (U.S. EPA, v18081, 03-22-2018) should be used to generate the receptor elevations and hill heights.

Model receptors were placed at 50-meter intervals along and near the fenceline, public access roads, and riverbanks. Receptors were not placed in the interior of Eastman's facility, since access to the property is controlled via fences, gates, and other restrictions (e. g., parking lots are patrolled by Eastman security to limit public access). Receptors were placed in a 100-meter grid throughout the remainder of the nonattainment area. Terrain elevations were developed from the National Elevation Dataset (NED) acquired from USGS, using EPA's terrain processor (AERMAP version 18081).

7.4 Meteorological Data

Meteorological data should be spatially and climatologically representative, based on: 1) the proximity of the meteorological monitoring site to the area under consideration, 2) the complexity of terrain, 3) the exposure of the meteorological site, and 4) the period of time during which data are collected. Sources of meteorological data include NWS stations, site-specific or onsite data, and other sources.

The Sullivan County nonattainment area features valleys and complex terrain ridges oriented west-southwest to east-northeast. In anticipation of the need to conduct a refined dispersion modeling analysis of their facility's SO_2 emissions, Eastman initiated a comprehensive meteorological and air quality monitoring study in 2012. The meteorological program, conducted from April 1, 2012, through March 31, 2013, involved a site-specific installation and operation of a 100-meter tower and Doppler SODAR system to provide profiles of meteorological data as AERMOD inputs. The modeled attainment demonstration used this site-specific meteorological data.

In the 2017 AD submittal, Eastman onsite meteorological data used the 1992 NLCD and applied the adjustment to the horizontal friction velocity (ADJ_U*) and without the application of turbulence (sigma-theta and sigma-w) turbulence parameters in the Eastman SO2 modeling.

In the Summer of 2020, EPA has indicated concerns over the use of (ADJ_U*) Beta option and turbulence issues, so the onsite met data was revised to remove the adjustment to the horizontal friction velocity and keeping the application of turbulence.

Subsequently, in August of 2020, EPA has indicated concerns over the inclusion of turbulence measurements at all in the onsite meteorological data when using the urban dispersion option with the associated heat island effect because of the double counting of the turbulence effect from the measurements and the urban option based on the 2018 and 2021 EPA's AERMOD implementation guidance[63], which indicates that sigma-theta and/or sigma-w should not be used when running AERMOD in urban mode as stated below in Section 3.3 of the guidance:

> "The use of site-specific meteorological data obtained from an urban setting may require some special processing if the measurement site is located within the influence of the urban heat island and site-specific turbulence measurements are available (*e.g.*, σθ and/or σw). As discussed in Section 5.4, the urban algorithms in AERMOD are designed to enhance the turbulence levels relative to the nearby rural setting during nighttime stable conditions to account for the urban heat island effect. Since the site-specific turbulence measurements will reflect the enhanced turbulence associated with the heat island, site-specific turbulence measurements should not be used when applying AERMOD's urban option, in order to avoid double counting the effects of enhanced turbulence due to the urban heat island."

Accordingly, the 1992 NLCD onsite met data was revised by the removal of the ADJ_U* in the AERMET surface met data file and by also removing the measured turbulence during stable conditions (i.e., nighttime) by assigning missing values for sigma-theta and sigma-w in the AERMET profile met data file.

Finally, in September 2022, and in response to the EPA R4 comments regarding the 2/2022 draft AD submittal, TDEC has updated the Eastman onsite met with the 2011 NLCD and with the application of the latest version of AERMET (version 22112). This final meteorological set consists of using the 2011 NLCD and the removal of the adjustment to the horizontal friction velocity (ADJ_U*) and the removal of turbulence (by assigning sigma-theta and sigma-w missing values) during stable hours only, which is processed through AERMOD (NOTURBST) as it is now an available option with the latest version of AERMOD (version 22112).

7.5 Background Concentration

When completing a cumulative NAAQS analysis, modeled impacts from the facility are combined with background concentrations, which represent the air quality concentrations due to sources that are not explicitly modeled (e.g., mobile sources, small but local stationary sources, non-regulated fugitive sources, and large but distant sources). A cumulative analysis will be performed for this project and for SO2. Therefore, an ambient background monitor for this pollutant was selected.

Section 8.2.2 of Appendix W gives guidance on background concentrations for isolated single sources and is also applicable for multi-source areas. Background concentrations may be determined from the use air quality data in the vicinity of the source for the averaging times of concern.

Selection of the existing monitoring station data that is "representative" of the ambient air quality in the area surrounding the proposed facility is determined based on the following three criteria: 1) monitor location, 2) data quality, and 3) data correctness. Key considerations based on the monitor location criteria include proximity to the non-attainment area of the facility, similarity of emission sources impacting the monitor to the emission sources impacting the airshed surrounding the facility,

63 AERMOD Implementation Guide, EPA-454/B-21-006, July 2021. Sigma-theta is the standard deviation of the horizontal wind direction fluctuations. Sigma-w is the standard deviation of the vertical wind speed fluctuations.

and the similarity of the land use and land cover (LULC) surrounding the monitor and the facility. The data quality criteria refers to the monitor being an approved State and Local Air Monitor (SLAM) or similar monitor type subject to the quality assurance requirements in 40 CFR Part 58 Appendix A. Data correctness refers to the fact that the most recent three complete years of quality assured data are generally preferred.

7.5.1 SO_2 Background Monitors

Since basically all the Eastman sources in addition to nearby sources (Domtar facility and Cardinal Glass facility) are accounted for in the SIP modeling for a total of 80 sources and in order to exclude double counting the SO_2 emissions contributions from the Eastman sources, a total of three monitoring sites were considered as representative background concentrations for the Eastman AD project and are shown in **Figure 7-1** and listed below:

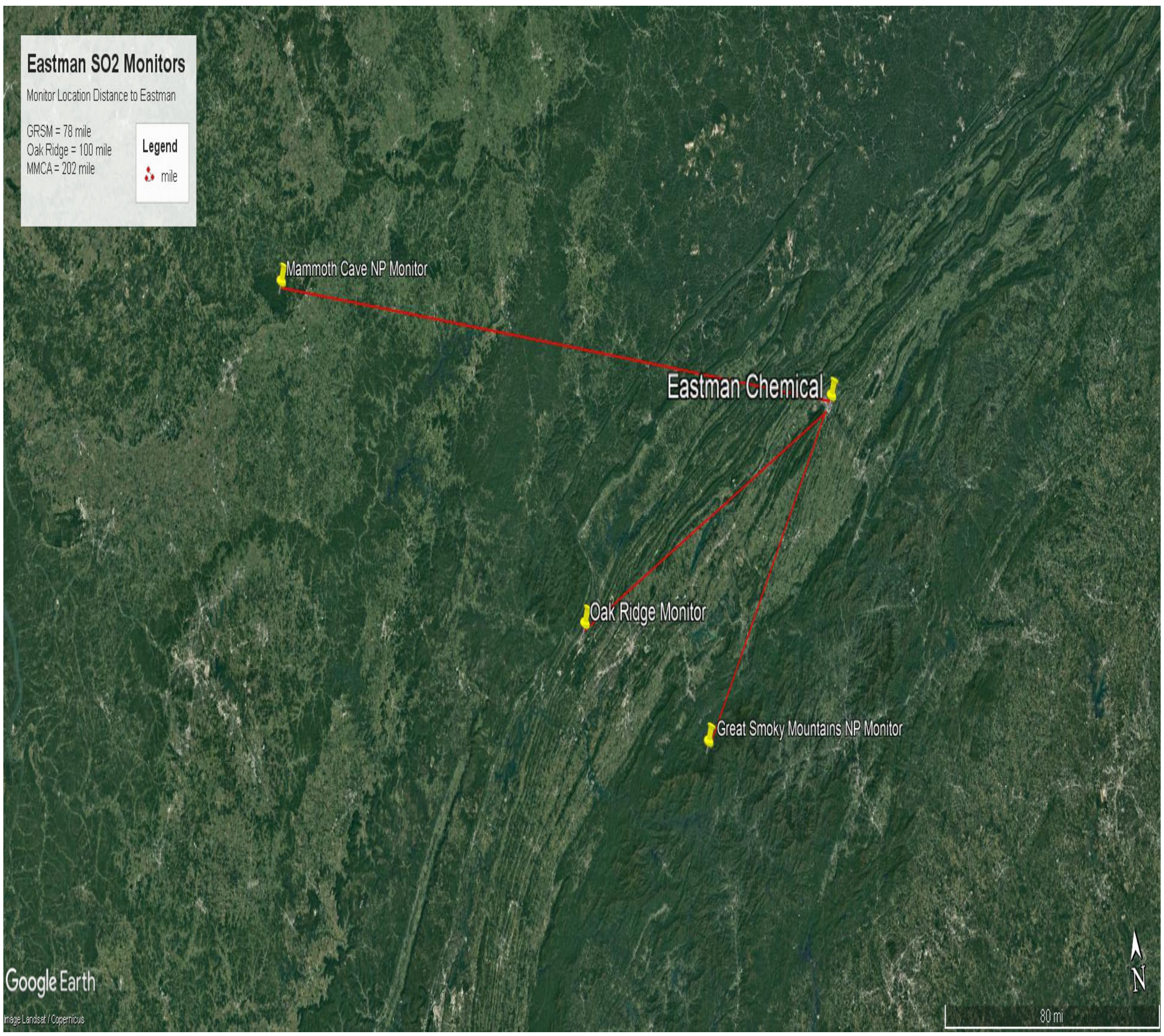

Figure 7-1: SO_2 Monitor Locations

Oak Ridge National Lab Reservation Monitoring site in TN, Site ID 47-001-0101
Great Smoky Mountains (GRSM) NP site in TN, Site ID 47-009-0101

Mammoth Cave (MMCA) NP site in KY, Site ID 21-061-0501

The Oak Ridge in (Oak Ridge, TN) and the GRSM site in the Park are the closest to the Eastman facility. However, the Oak Ridge monitoring site did not report any data in 2020. The most recent 3-year, 2019-2021, design values (DVs) for the GRSM and MMCA sites are 1 ppb and 2.3 ppb respectively.

Tennessee has elected to use the ambient SO_2 concentrations from the monitor located at MMCA site in Kentucky (AQS ID 21-061-0501) that is deemed representative of the Eastman facility location based on the terrain similarity, the monitor location relative to the influences of nearby industrial sources and the completeness of the monitoring record, to develop "seasonal by hour of the day" background concentrations. Hourly background concentrations by season are shown in **Table 7-1**.

Table 7-1: Background Concentration (ppb) Lookup Table for Each Season by Hour of Day Mammoth Cave, (2019-2021)

Hour	Winter	Spring	Summer	Fall
1	1.2	1.0	0.7	1.2
2	1.2	1.0	0.7	1.0
3	1.5	0.9	1.0	0.8
4	2.0	0.8	1.0	0.7
5	2.5	0.9	0.8	0.4
6	1.7	0.7	0.5	0.4
7	1.6	1.8	0.7	0.5
8	2.7	2.1	1.0	0.9
9	2.2	1.7	1.3	1.6
10	2.1	2.0	1.8	1.6
11	1.6	1.6	1.7	1.5
12	1.2	1.6	1.5	0.7
13	1.2	1.5	1.7	0.8
14	1.1	1.3	1.4	0.8
15	1.4	1.6	1.0	0.6
16	1.0	1.3	0.7	1.1
17	1.2	0.8	0.7	1.1
18	1.1	0.8	0.8	1.0
19	1.6	1.1	0.8	1.3
20	2.0	1.0	0.8	0.7
21	1.9	1.1	0.6	0.8
22	1.6	1.2	0.5	1.9
23	2.4	1.6	0.4	1.7
24	1.3	1.0	0.4	1.6

7.6 Urban/Rural Determination

Section 7.2.3 of 40 CFR 51, Appendix W, states that steady-state Gaussian plume models used in most applications should employ dispersion coefficients consistent with those contained in the preferred models. Factors such as averaging time, urban/rural surroundings, and type of source may dictate the selection of specific coefficients. A key feature of AERMOD's formulation is the use of directly observed variables of the boundary layer to parameterize dispersion.

The selection of either rural or urban dispersion coefficients in a specific application should follow one of the procedures described in Section 7.2.3(c)-(f) of Appendix W. These include a land use classification procedure or a population-based procedure to determine whether the character of an area is primarily urban or rural.

- **Land Use Procedure:** Classify the land use within the area circumscribed by a 3-km radius circle about the source (A_0) using the meteorological land use typing scheme proposed by Auer. If land use types I1, I2, C1, R2, and R3 account for 50% or more of the total area, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

- **Population Density Procedure**: Compute the average population density per square kilometer with A_0 as defined above. If the population density is greater than 750 people/km^2, use urban dispersion coefficients; otherwise use appropriate rural dispersion coefficients.

Of the two methods, the land use procedure is considered more definitive. Appendix W states that population density should not be applied to highly industrialized areas where the urban land use criteria are satisfied but the population density indicates a rural classification.

The urban/rural determination for the nonattainment area was developed by Eastman and AECOM in 2016 and is documented in Attachment H1. Based on 52.4% urban land usage, modeling with urban dispersion coefficients is appropriate.

7.7 Effective Population

AERMOD requires the input of urban population when utilizing the urban option. The Eastman facility is located at the edge of a small city (population of about 50,000), but the population does not account for the fugitive heat release from the facility. Tennessee used the methodology used by Eastman and AECOM in 2016, which estimated an urban-rural temperature difference of about 9° C based on calculated anthropogenic heat releases from the facility and an effective urban population of about 200,000 (see Attachment H1). Similarly, Tennessee estimated a temperature difference of about 8-10° C based on a review of satellite data (**Figure 7-2**). From the presentation given by Robert J. Paine at the 2014 EPA Modeling Workshop on urban industrial effects (Attachment H2), this temperature difference also indicates an effective population of about 200,000[64].

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64 *Source-Related Modeling Issues for the Iron and Steel Industry*. AISI Presentation at EPA's 2014 Modeling Workshop, May 20, 2014. The effective population is calculated from the urban-rural temperature difference using the equation below:

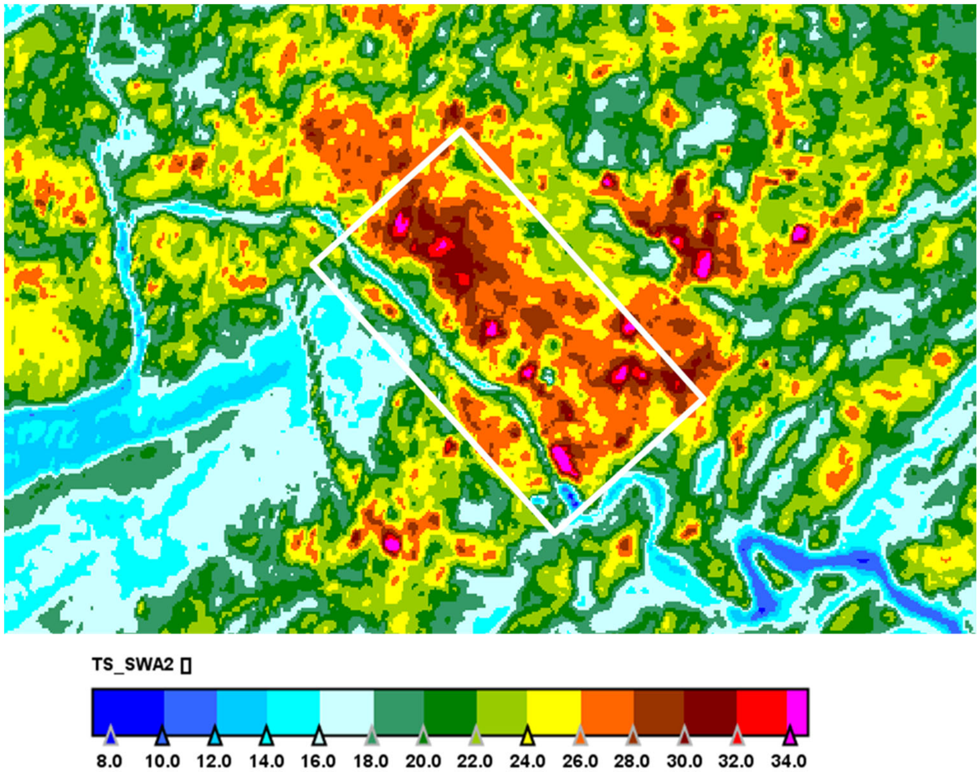

Figure 7-2: 100-m Resolution L8 TIR Estimate of LST using SWA Method
Scene: April 26, 2013, 4:07 PM
(Approximate Plant Boundary inside White Rectangle)

7.8 Building Downwash Analysis

Good engineering practice (GEP) stack height is defined as the stack height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes or eddy effects created by the source, nearby structures or terrain features.

A GEP stack height analysis was performed for the boiler stacks in accordance with EPA's stack height guidelines (EPA, 1985). Per the guidelines, the physical GEP height, (HGEP), is determined from the

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$$P = P_0 e^{\left(\frac{\Delta T_{U-R} - \Delta T_{Max}}{0.1\Delta T_{Max}}\right)}$$

Where P = effective population; P_0 = 2,000,000; ΔT_{U-R} = measured urban-rural temperature difference, and ΔT_{Max} = 12° C. An observed temperature difference of 8-10° C produces the following results:

ΔT_{U-R}	8	10
ΔT_{max}	12	12
P_0	2,000,000	2,000,000
P	71,348	377,751
Average P:	**224,550**	

dimensions of all buildings which are within the region of influence using the following equation:

HGEP = HB + 1.5L

where:
HB = height of the structure within 5L of the stack which maximizes HGEP, and

L = lesser dimension (height or projected width) of the structure.

For a squat structure, i.e., height less than projected width, the formula reduces to: HGEP = 2.5HB

In the absence of influencing structures, a "default" GEP stack height is credited up to 65 meters.

A summary of the GEP stack height analyses is presented **Table 7-2**. The GEP formula stack heights for all the sources are higher than their respective stack heights. Therefore, emissions are potentially subject to building downwash and wind direction-specific building dimensions developed with the EPA's Building Profile Input Processor (BPIP-PRIME) were input to AERMOD. The BPIP input and output files are provided in the modeling archive. The locations (**Figure 7-3**) and dimensions of the 24 buildings/structures relative to the exhaust stacks are also provided in the modeling archive.

Table 7-2: Summary of GEP Analysis

Stack Name	Emission Source	Stack Height (m)	Stack-Bldg. Elev. Diff. (m)	HGEP-EQN1 (m)	GEP Stack Height Value (m)
83_1824	B-83 Powerhouse Boilers 23-24	70.104	0.25	79.75	79.75
253_25	B-253 Powerhouse Boiler 25	76.2	-0.1	180.96	180.96
253_26	B-253 Powerhouse Boiler 26	76.2	-0.01	180.87	180.87
253_27	B-253 Powerhouse Boiler 27	76.2	-0.14	181	181
253_28	B-253 Powerhouse Boiler 28	76.2	-0.15	181.01	181.01
253_29	B-253 Powerhouse Boiler 29	76.2	-0.13	180.99	180.99
325_3031	B-325 Powerhouse Boilers 30-31	114.3	2.58	150	150
DOMTR_BB	DOMTAR Biomass Boiler	60.35	N/A	0	65
TAIL_GAS	Tail Gas Incinerator	38.1	1.08	56.3	65
H24A	H2 Plants	33.528	N/A	0	65
H25A	H2 Plants	22.86	N/A	0	65
H26A	H2 Plants	22.86	N/A	0	65
OCB7I	Batch Specialty Chemical Operation - Intermittent Batch Operation	22.86	3.9	172.09	172.09
OCBAG	Batch Specialty Chemical Operation - Intermittent Batch Operation	22.86	3.9	172.09	172.09
OCBAL	Batch Specialty Chemical Operation - Intermittent Batch Operation	19.9644	3.9	172.09	172.09
B4231A	NG-Fired Boiler, 226 MMBtu/hr	21.0312	N/A	0	65

Table 7-2: Summary of GEP Analysis					
Stack Name	**Emission Source**	**Stack Height (m)**	**Stack-Bldg. Elev. Diff. (m)**	**HGEP-EQN1 (m)**	**GEP Stack Height Value (m)**
B4231B	NG-Fired Boiler, 226 MMBtu/hr	21.0312	N/A	0	65
B4231C	NG-Fired Boiler, 226 MMBtu/hr	21.0312	N/A	0	65
B1901F	NG-Fired Parts Cleaning Oven	23.4696	N/A	0	65
B1901L	NG-Fired Parts Cleaning Oven	28.6512	N/A	0	65
RICE1A	Diesel-Fired Emergency Engine	3.6576	N/A	0	65
RICE1H	Diesel-Fired Emergency Engine	3.048	N/A	0	65
RICE1I	Diesel-Fired Emergency Engine	3.048	N/A	0	65
RICE1K	Diesel-Fired Emergency Engine	3.6576	-0.68	111.18	111.18
RICE1P	Diesel-Fired Emergency Engine	1.524	N/A	0	65
B265B1A	NG-Fired Heat Transfer Furnace	10.668	-1.13	181.98	181.98
B265B1C	NG-Fired Heat Transfer Furnace	12.192	-1.13	181.98	181.98
RK	Rotary Kilns1&2 Solid/Liquid Chemical Incinerator B2481D and B2481E	36.576	-6.7	30.85	65
LCD	Liquid Chemical Incinerator B2482A	15.24	0.5	60.98	65
RICE3A	Diesel-Fired Emergency Engine	3.3528	N/A	0	65
RICE2B63	B-63 Emergency Fire Pump Engine	3.66	-5.41	115.91	115.91
RIC2B269	B-269 Emergency Fire Pump Engine	4.27	N/A	0	65
DOMTR_SR	Domtar No. 2 Power Boiler	84.1248	N/A	0	65
DOMTR_LK	Domtar Lime Kiln	38.1	N/A	0	65
PRMSTER	Cellulous Acetate Process	12.192	2.84	164.81	164.81
B6551	Methanolysis Plant	46.02	-3.75	129.1	129.1
B8311_32	New Gas Boiler 32	50.9	0.03	110.47	110.47
B8311_33	New Gas Boiler 33	50.9	0.03	110.47	110.47
B8311_34	New Gas Boiler 34	50.9	0.03	110.47	110.47
B383_3	Catalyst Recovery	27.43	3.02	145.41	145.41
B90_7_1	TBHQ Production	1.52	N/A	0	65
B90_7_2	TBHQ Production	22.86	N/A	0	65
B90B_1	BHA Production	22.86	N/A	0	65
B22723_1	HTM Furnaces	19.51	-2.83	163.13	163.13
B22723_2	HTM Furnaces	19.51	-2.83	163.13	163.13
B6C1_27	Crack Furnace 27 and 28	39.62	N/A	0	65
B6C1_28	Crack Furnace 27 and 28	39.62	N/A	0	65
B7R_1	Crack Furnace 5-16 and 9-24	29.26	N/A	0	65
B7R_2	Crack Furnace 5-16 and 9-24	30.48	N/A	0	65
B7RC_1	Crack Furnace 25 and 26	20.73	N/A	0	65
B7RC_2	Crack Furnace 25 and 26	20.73	N/A	0	65

Table 7-2: Summary of GEP Analysis					
Stack Name	**Emission Source**	**Stack Height (m)**	**Stack-Bldg. Elev. Diff. (m)**	**HGEP-EQN1 (m)**	**GEP Stack Height Value (m)**
AB7_1	Acetic Anhydride Manufacturing	33.53	N/A	0	65
AB7_2	Acetic Anhydride manufacturing	9.14	N/A	0	65
B334_2	Synthetic Gas Pilot Plant	9.14	-0.24	116.82	116.82
B351_5	Cold and Warm Flares	80.55	N/A	0	65
B545_1	Copplyester Monomer Manufacturing	45.72	N/A	0	65
B545_2	Copplyester Monomer Manufacturing	58.52	N/A	0	65
B545_3	Copplyester Monomer Manufacturing	47.24	N/A	0	65
B238_1	HTM Furnaces	22.25	N/A	0	65
B238_2	HTM Furnaces	22.25	N/A	0	65
B238_3	HTM Furnaces	32	N/A	0	65
B238_4	HTM Furnaces	45.72	N/A	0	65
H2_2_6	Hydrogen Plants 3-6	33.53	N/A	0	65
B232_1	Aromatic Acid Manufacturing	17.68	N/A	0	65
B232_2	Aromatic Acid Manufacturing	11.28	N/A	0	65
B232_3	Aromatic Acid Manufacturing	17.68	N/A	0	65
B256_5	HTM Furnace 5	22.86	-2.7	165.64	165.64
B256_6	HTM Furnace 6	22.86	-2.7	165.64	165.64
B256_7	HTM Furnace 7	22.86	-2.7	165.64	165.64
B256_8	HTM Furnace 8	22.86	-2.7	165.64	165.64
B256_9	HTM Furnace 9	22.86	-2.7	165.64	165.64
B256_10	HTM Furnace 10	22.86	-2.7	165.64	165.64
CARGLAS1	Cardinal Glass Gas Melting Furnace 1	65.6844	N/A	0	65
CARGLAS2	Cardinal Glass Gas Melting Furnace 2	32.004	N/A	0	65
B55_1B	Organic Acids & Anhydrides Manufacturing	21.34	N/A	0	65
B55_1C	Organic Acids & Anhydrides Manufacturing	16.76	N/A	0	65
B55_1E	Organic Acids & Anhydrides Manufacturing	39.62	N/A	0	65
B55_1I	Organic Acids & Anhydrides Manufacturing	18.29	N/A	0	65
B55_1K	Organic Acids & Anhydrides Manufacturing	10.67	N/A	0	65

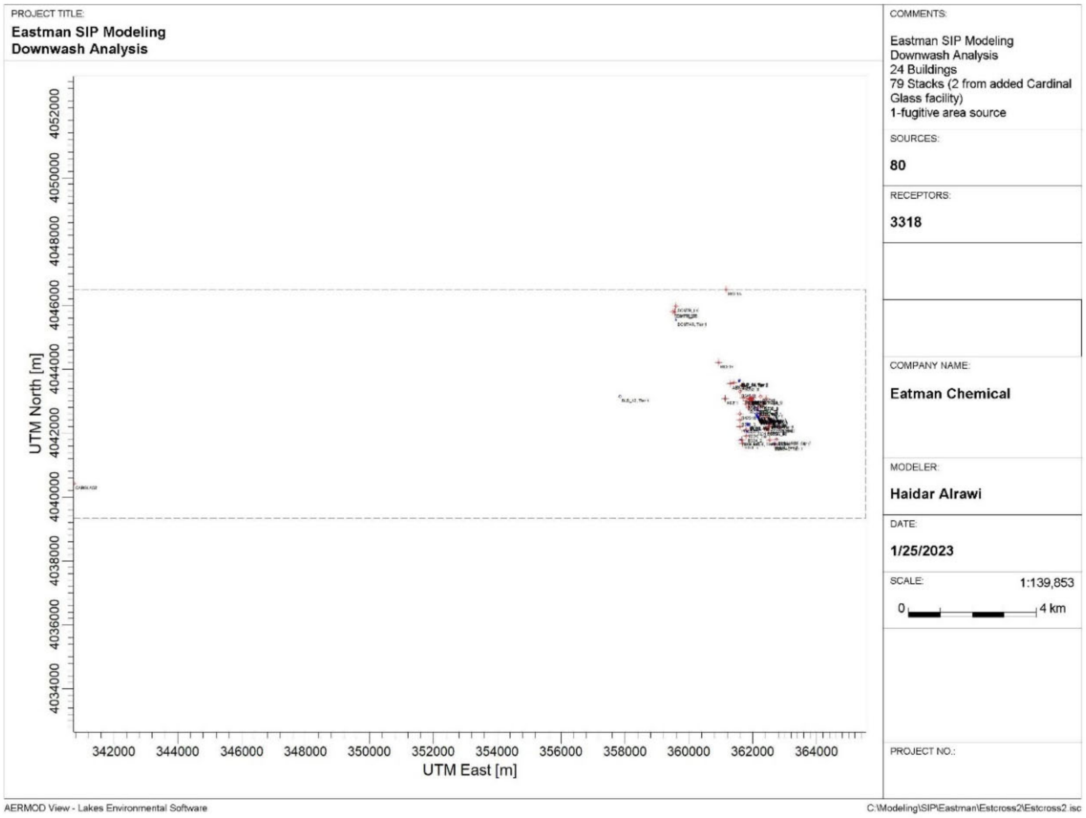

Figure 7-3: GEP Building Downwash for Eastman Chemical

7.9 Selection of Sources to Model

Appendix W states that all sources expected to cause a significant concentration gradient in the vicinity of the source of interest should be explicitly modeled and that the number of such sources is expected to be small except in unusual cases. Other sources, which do not cause significant concentration gradients in the vicinity of the primary source, should be included in the modeling via monitored background concentrations. Except as noted below (batch chemical manufacturing), model runs were performed for all Eastman sources and all nearby sources affecting the nonattainment area.

EPA's March 1, 2011, modeling guidance for the one-hour NO_2 NAAQS identified challenges in the modeling of intermittent operations because EPA's modeling guidance (Appendix W to 40 CFR Part 51) generally recommends the modeling of maximum allowable emissions at continuous operation. However, modeling of an intermittent source as if it operated continuously can result in significantly higher modeled impacts than would realistically be observed for intermittent sources. The overestimation results from an implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions on specific hours and days associated with the modeled design value based. In fact, the guidance notes, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact of outliers in the emissions distribution[65]. The guidance expressed concern that given the implications of the probabilistic form of the 1-hour NO_2 NAAQS, EPA is concerned that assuming continuous operations for intermittent emissions would effectively impose a level of stringency beyond that intended by the level of the standard itself. The guidance stated that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO_2 standard under these circumstances. Tennessee used EPA's 2011 NO_2 guidance and considered the following criteria to determine whether certain intermittent sources may be excluded from modeling and/or incorporation of the sources' allowable emissions into the SIP:

- **Randomness of operating hours:** An intermittent source that operates on a random schedule that cannot be controlled would be appropriate to consider under the guidance. On the other hand, an intermittent source that operates on a regular schedule (e. g., one hour every day) would be less suitable for application of the guidance, since the single hour of emissions from each day could contribute significantly to the modeled design value based on the annual distribution of daily maximum concentrations.

- **Frequency of operating hours**: The 2011 guidance notes that the frequency of startup/shutdown events varies by facility type. For example, a large baseload power plant may experience startup/shutdown events on a relatively infrequent basis, but a peaking unit may go through much more frequent startup/shutdown cycles. It may be appropriate to apply this guidance in the former case, but not the latter.

- **Flexibility of scheduling:** Certain emissions scenarios can be scheduled with some degree of flexibility, while others cannot be scheduled. For example, emergency generator emissions from regular use can be scheduled, while emergency use typically cannot be scheduled.

The following sources were not modeled based on infrequent and irregular operation and on the variation in operating hours from month to month and year to year.

Production of Specialty Organic Chemicals (MSOP-25, PES OC-BATCH): This source consists of equipment for the batch production of specialty organic chemicals. Conditions E3-8 and E3-9 of Title V permit 576606 limit SO_2 emissions from this source to 1,000 ppmvd (one-hour average) and 7.05 tons/year. The Title V application for this process states that SO_2 emissions from the batch processes are calculated for each operating step, and the total emissions for each step are added to calculate an emission factor for each product (lb/batch). These emission factors are multiplied by the number of batches produced to calculate total emissions from the production of each specific product during a specified time period (e. g., 12-month rolling totals).

The batch chemical manufacturing process produces multiple products, and because SO_2 is not emitted from all processes, Tennessee requested additional information on SO_2 emissions from this source. Eastman responded[66] that only one process in B-267 (benzimidazole) generates SO_2 emissions and provided the following information.

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65 The one-hour NO_2 and SO_2 standards are based on the same format, except that the NO_2 standard is based on the 98th percentile of the daily maximum one-hour average concentration, and the SO_2 standard is based on the 99th percentile.

66 E-mail from Steve Moore (Eastman Chemical Company) to Travis Blake (TDEC-APC) September 8, 2022. This information

- Emissions are estimated at 28.2 lb/batch and is based on conversion of a sulfur-containing additive to SO_2.
- Emissions occur during one distinct step in the process, and that step typically requires about one hour to complete.
- Benzimidazole is a campaigned product, and only one to two batches per year are required to meet customer demand.
- Emissions are routed to the #12 Caustic Scrubber, Vent ID A-L in PES OC-BACTH in MSOP-25.

Table 7-3 summarizes the times the SO_2 generating step occurred since January of 2017.

Table 7-3: SO_2 Emissions from Batch Chemical Manufacturing (MSOP-25, PES OC-BATCH)				
Year	**Start Time**	**Stop Time**	**Total Time (hr)**	**Total SO_2 Generated (lb)**
2017	12/11/2017 2:41	12/11/2017 7:41	5.0	28.2
	12/14/2017 16:33	12/14/2017 17:40	1.1	28.2
2018	No batches were produced			
2019	2/24/2019 9:20	2/24/2019 10:25	1.1	28.2
	2/27/2019 2:41	2/27/2019 2:54	0.2	28.2
2020	No batches were produced			
2021	4/29/2021 0:18	4/29/2021 1:04	0.8	28.2

The batch process does not operate randomly, and Tennessee assumes that benzimidazole production can be scheduled with some degree of flexibility, but Table 7-3 indicates that the batch process operated in SO_2 service for less than 0.07% of the total hours during each calendar year between 2017 and 2021. The operating hours are so infrequent that the frequency of operation outweighs the other factors, and the batch chemical manufacturing operation may be considered as an intermittent SO_2 source. Therefore, this source was excluded from the modeling.

7.10 SO_2 Emissions from Eastman Boiler Complexes

Figure 7-4 shows the location of each of Eastman's major powerhouses.

updated a previous e-mail dated January 21, 2022, which indicated more frequent operation of the source. The original data were based on caustic scrubber usage rather than the operation of the specific batch process that generates SO_2 emissions, and the technician who pulled the data did not understand what specific information was sought. The caustic scrubber is required by 40 CFR 63 Subpart FFFF to control halogenated HAP emissions, so the scrubber operating time is not representative of SO_2 emissions from the source (follow-up phone call between Travis Blake (TDEC-APC), Chelsea Materi (TDEC-APC), and Steve Moore (Eastman Chemical Company), October 4, 2022.

Figure 7-4: Eastman Powerhouses

The five stacks at the 253 Powerhouse serve identical boilers (Boilers 25 – 29) which provide steam and electricity to Eastman's Kingsport facility. These boilers, installed during the 1960s and 1970s, were designed as coal-fired boilers and are equipped with electrostatic precipitators for particulate matter control. Between 2013 and 2017, Eastman reduced SO_2 emissions from the B-253 boilers by repowering all boilers from coal to natural gas operation, and this change reduced total plant SO_2 emissions to about one third of 2011 levels.

The stack at the 325 Powerhouse serves two coal-fired boilers, Boiler 30 and Boiler 31, and is modeled as a single emission source. Boiler 31 is equipped with a spray dryer absorber and fabric filter to control particulate matter and acid gases. Boiler 30 is equipped with a spray dryer absorber and electrostatic precipitator to control particulate matter and acid gases.

Stack C at the 83 Powerhouse serves seven coal-fired boilers (Boilers 18 – 24). The combination of boilers and boiler operating loads at any given time depends on manufacturing demands along with availability of boilers as each boiler has annual scheduled shutdowns. All of the B-83 boilers are equipped with electrostatic precipitators for particulate matter control. In 2019 Eastman installed a temporary dry sorbent injection (DSI) system as an interim control strategy on B-83 Boilers 23 and 24. The interim strategy reduced emissions from those boilers by about 50%, and in November 2021, Eastman replaced the portable system with a permanent DSI with a nominal control efficiency of 60%.

7.11 Modeling of Boiler SO_2 Emissions

Because two different boiler stacks are modeled, multiple combinations of critical values may result in a design concentration that attains the NAAQS. In addition, the facility load can shift among the 18-22, 23-24, and 30-31 units so that the units do not simultaneously emit at peak rates. Tennessee determined a range of operational cases to model at a maximum emission rate (combined total for both stacks) of 1,600 lb/hr[67]. Future SO_2 emissions for B-83 and B-325 were based on hourly SO_2 emission rates occurring between July 1, 2019, and December 31, 2020 (Attachment E). Tennessee considers these data to be representative of facility operations based on the amount of data and the range of operating conditions addressed by the dataset (e. g., periods with high and low heat inputs, maintenance outages, etc.).

Modeled Emission Rates for Boilers 18-22: Emission rates for each model run were calculated by dispatching the boilers in the following order: 22, 21, 20, 19, 18 (Boilers 21 and 22 are newer and have higher heat inputs, so these boilers were assumed to be dispatched first). When more than one boiler was dispatched, the heat input was divided evenly between all boilers (since the regression lines are slightly different for each boiler, dividing the heat input evenly avoids biasing the stack data toward an individual boiler).

Modeled Emission Rates for Boilers 23-24: Boilers 23 and 24 were modeled at 762 lb/hr, based on the design heat input, five-year maximum SO_2 emission rate before control, pre-control emission rate, and an estimated control efficiency of 60% for the permanent DSI.

Modeled Emission Rates for Boilers 30-31: Boilers 30 and 31 were modeled as shown in **Table 7-4**.

Table 7-4: B-325 Modeled Emission Rates[68]

Run	Boiler(s)	B-325 SO_2 Emissions (lb/hr)	Basis for Emissions
2023-0120-5	20, 21, 22, 23, 24, 30	317	Boiler 31 down, Boiler 30 at permitted emission rate
2023-0120-6	20, 21, 22, 23, 24, 30	366.4	Boiler 31 down, Boiler 30 at permitted emission rate divided by compliance ratio
2023-0120-7	21, 22, 23, 24, 31	497.6	Boiler 30 down, Boiler 31 at permitted emission rate divided by compliance ratio[69]
2023-0120-9	18, 19, 20, 21, 22, 30, 31	585.8	This is an adjusted version of an old run at the combine NSPS allowable for Boilers 30 and 31 (610 lb/hr) adjusted downward to maintain emissions at 1,600 lb/hr.
2023-0120-12	18, 19, 20, 21, 22, 30, 31	754	Combined NSPS allowable for Boilers 30 and 31 divided by the compliance ratio for B-325

67 The modeled emission rate was established through preliminary runs as the *critical emission value* (i. e., the highest hourly emission rate at which the model predicts attainment of the SO_2 NAAQS throughout the nonattainment area).

68 Model run ID numbers are not sequential because Tennessee developed multiple runs but later eliminated some runs as redundant. Model run IDs were updated to reflect the most recent runs performed in response to EPA comments.

69 Although Boiler 31 has lower emissions than Boiler 30, dividing the allowable emission rate by the compliance ratio inflates the SO2 emissions for this run (i. e., Boiler 31 has a lower compliance ratio than Boiler 30).

The highest modeled emission rate for Boilers 30 and 31 (754 lb/hr) was calculated by dividing the combined allowable emission rate for Boilers 30 and 31 (610 lb/hr) by the compliance ratio (ratio of 99th percentile hourly and 99th percentile 30-day rolling average emission rates) as described in Section 7.14 (**Table 7-5**).

Table 7-5: Calculation Modeled Emission Rate from 30-Day Rolling Average Emission Limit, B-325 Boilers	
Period of representative emissions	July 1, 2019, through December 31, 2020
99th percentile hourly emission rate (combined total for both boilers)	433.6 lb/hr
99th percentile 30-day rolling average emission rate (combined total for both boilers)	350.8 lb/hr
Compliance ratio	0.809
Allowable emission rate (combined total for both boilers)	610 lb/hr, 30-day rolling average
Modeled emission rate (combined total for both boilers)	754 lb/hr

These calculations are included in Attachment H.

Calculation of Stack Parameters for Boilers 18-22: Stack parameters for Boilers 18-22 were calculated by linear regression of emissions plotted against stack flow and temperature for all hours of nonzero emissions between July 1, 2019, and December 31, 2020. A typical plot for Boiler 18 is shown in **Figure 7-5.** Data and plots for all boilers are included in Attachment H.

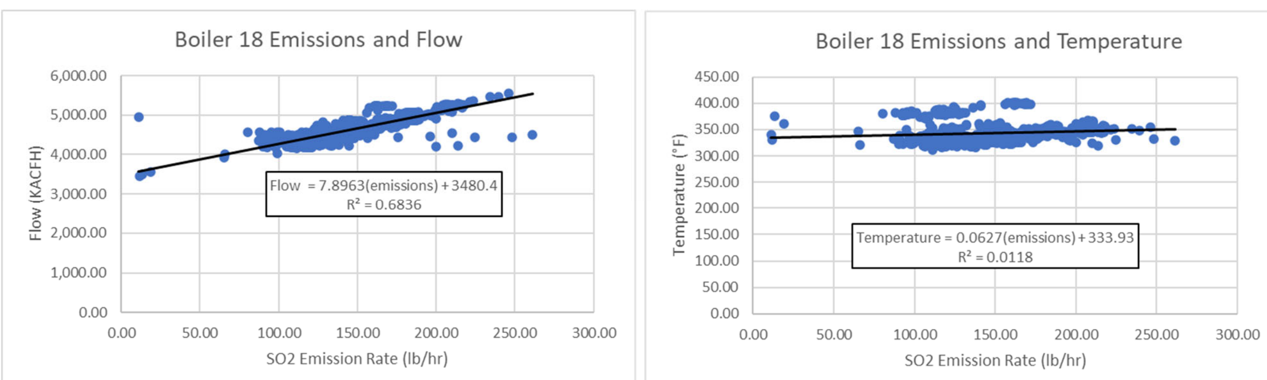

Figure 7-5: Typical Plots for Stack Flow and Temperature, Boiler 18

Calculation of Stack Parameters for Boilers 23 and 24: The methodology described above for Boilers 18-22 could not be used to calculate stack parameters for Boilers 23 and 24 because stack data at the modeled emission rate represented to nonoperation of the DSI or poor DSI efficiency, rather than high load. Eastman provided a three-level flow RATA for Boiler 23 (**Table 7-7**), and the stack flows at full load were extrapolated from the RATA based on the known heat input (calculated from steam output and heat to load ratios identified in the RATA). The stack temperature for Boilers 23 and 24 was based on the temperatures provided in Eastman's RATA calculations (**Table 7-6**).

Table 7-6: Stack Parameter Calculation for Boilers 23 and 24		
Parameter	**Value**	**Comments**
Heat Input (MMBtu/hr)	1,002	Total for Boilers 23 and 24
Uncontrolled Emission Rate (lb/MMBtu)	1.9	
Applied Control Efficiency	60%	DSI nominal control efficiency
Total SO_2 Emissions (lb/hr)	762	
Total Flow (KACFH)	26,425	Flow at nameplate capacity of Boilers 23 and 24, extrapolated from Boiler 23 RATA at high load
Stack Temperature (°F)	336	Value from Eastman RATA at high load
Stack Diameter (ft)	14	
Stack Velocity (ft/s)	47.68	Calculated from stack diameter and flow

Calculation of Stack Parameters for Boilers 30 and 31: Stack parameters for Boilers 30 and 31 were calculated as the 98th percentile value of all hours of operation between July 1, 2019, and December 31, 2020. Emissions and stack parameter data for Boilers 30 and 31 are included in Attachments E and H.

Conversion of Units: All stack parameters were converted to metric units as follows:

SO_2 Emissions (g/s) = (lb/hr)(453.59 g/lb)/(3,600 s/hr) **Equation 7-1**
Stack Velocity (m/s) = (ft/s)(0.3048 m/ft) **Equation 7-2**
Temperature (K) = ((°F-32)/1.8)+273 **Equation 7-3**

Summary: Boiler emission rates for the model runs are summarized in **Table 7-8**.

7.12 Other SO_2 Emission Sources

Stack parameters and emission rates for other modeled emission sources (Eastman sources and nearby sources) are provided in **Table 7-9**. Table 7-9 compares the modeled emission rates to potential SO_2 emissions. Maximum uncontrolled hourly emissions for all natural gas-fired sources (e. g., process heaters, ovens, control devices) were calculated from the design heat input specified in the permit application, an AP-42 emission factor of 0.6 lb SO_2 per million standard cubic feet of natural gas burned, and a heating value of 1,020 MMBtu/MMscf. Some natural gas-fired sources list "process gas" or "chemical fuel" as an alternate fuel, and the permit applications for these sources were reviewed to confirm that alternate fuels either contain no sulfur or contain the same amount of sulfur as natural gas. One source identified "tar" as an alternate fuel, and Tennessee contacted Eastman staff to confirm that the alternate fuel contains no sulfur[70]. For No. 2 fuel oil combustion, maximum

70 See footnote **Error! Bookmark not defined.**.

uncontrolled hourly emissions were calculated from the design heat input and a maximum sulfur content of 15 parts per million by weight. Emissions from process emission sources were calculated as the maximum hourly uncontrolled emission rate at the design capacity.

Flare: In Eastman's coal gasification plant (see Figure 5-1 for flow diagram), pulverized coal is treated with oxygen and steam to produce synthesis gas (CO + H_2, **Equation 7-1**), and the Rectisol process removes unwanted synthesis gas components (H_2S, CO_2, COS, HCN, NH_3, nickel and iron carbonyls, other sulfur compounds) using a refrigerated methanol solvent (~ -40°F), followed by desorption and stripping. Synthesis gas undergoes additional treatment in the acid gas removal and sulfur recovery processes (see Section 8.6 for additional discussion of these process units), and the final product is routed to Eastman's North Coal Gas facility for use in the manufacturing of organic alcohols, acids, and anhydrides.

$$C + O_2 + H_2O \longrightarrow CO + H_2 + CO_2 \qquad \textbf{Equation 7-1}$$

The flares in B-351-5 function as control devices during startup, shutdown, or malfunction of the gasifiers and sulfur recovery operations to reduce emissions of carbon monoxide, hydrogen sulfide, and other gaseous pollutants (e. g., carbonyl sulfide, HCN, ammonia, nickel and iron carbonyls, other sulfur compounds). Flaring of the gas is the only realistic control strategy for hydrogen sulfide and other pollutants due to the process safety concerns associated with the presence of hydrogen gas (i. e., the use of an alternate control device such as a boiler or process heater is likely infeasible).

Condition E8-1 of Title V permit 572407 limits SO_2 emissions from the flares to 47.6 lb/hr (24-hour block average) and 8.1 tons during any period of twelve consecutive months[71]. Sulfur dioxide emissions are calculated from the known plant gas stream compositions, assuming 100% conversion of H_2S to SO_2, and gas flow rates. Flow rates through all but two safety relief valves are calculated using the upstream operating pressure and position of each valve (percentage open), using each valve's fixed flow characteristic and continuous monitored by the plant's Distributed Control System (DCS). Flow meters, which are continuously monitored by the DCS, are used to calculate the flow rate (in KSCFH) through the remaining two safety valves.

Eastman submitted hourly SO_2 emissions data for the period of January 1, 2019 through December 31, 2021, and the 99th percentile emission rate was determined from the hourly data. Tennessee reviewed the 99th percentile emission rate and determined that for the three-year period reviewed, there were 25,823 total hours. The 99th percentile value was determined to be 6.21 lb/hr, and during the three-year period, there were 480 hours in which SO_2 emissions were above the 99th percentile value (1.86% of total operating hours). When individual years were considered, the worst-case 99th percentile emission rate was 16.28 lb/hr in 2020, and Tennessee elected to model this emission rate. At this value, the total hours exceeding the modeled emission rate are (88 hours in 2020) did not exceed 1% of the total operating hours. Supporting data and calculations for the flare are presented in Attachment H9.

71 Condition E8-1 applies to both vents in the flare complex, but the Cold Gas Flare system (Vent B) and the Warm Gas Flare system (Vent C) collect gases from different safety valves. The use of non-overlapping safety systems prevents thermal shock due to mingling of gas streams with different temperatures, and only the warm flare emits SO_2 in appreciable quantity.

Organic Acids & Anhydrides Manufacturing (MSOP-23): Eastman's organic acids and anhydrides manufacturing operation (82-0003-224, PES B-55-1) recovers cellulose scrap from reject dope (cellulose ester with acetate, propionate, or butyrate). The sludge process in B-55 uses sulfuric acid digestion to reclaim the acetic, propionic, and butyric acids from the cellulose ester rejects. The sulfuric digestion is a batch process that takes place in four glass-lined tanks that contain cellulose ester, acetic acid, propionic acid, butyric acid, water, and sulfuric acid. Each batch is heated to a temperature setpoint and held for a designated time period. Emissions from the glass-lined tanks are routed to a common vent header and scrubber (Vent B). When a batch is complete, the resulting sludge is transferred to a hold tank and emissions from the hold tank are routed to a vent header and scrubber (Vent K). The hold tank feeds the sludge belt filter, where vacuum is applied to separate the liquid from the solids, and the solids are washed with water to remove residual acids for recovery. The vapors from the vacuum system are routed to a scrubber (Vent C), and a hood over the Sludge Belt Filter routes fumes from the belt to a scrubber (Vent I). Solids fall off the end of the sludge belt and are carried with a water stream to the facility's on-site wastewater treatment plant. Condition E3-9 of Title V permit 576513 limits SO_2 emissions from this source to 0.96 tons/year.

The Title V application for this source stated that SO_2 was emitted from Vent I (wet scrubber for belt filter), but prior to modeling of the emission source, Eastman provided an update that stated that SO_2 is emitted primarily from Vent B (wet scrubber for glass-lined tanks), and the stack parameters for Vent B were used for dispersion modeling. Eastman also stated that uncontrolled SO_2 emissions from the glass-lined tanks were 4 lb/batch. Four batch reactors (glass-lined tanks) vent to Vent B, and the average batch time is between three and five hours. The worst-case scenario assumed that all four batches are charged at the same time so that SO_2 emissions (which are typically worst in the last hour of the batch cycle). Using the information provided by Eastman, average SO_2 emissions for the batch cycle were recalculated as indicated in **Equation 7-2**.

$$\frac{(4 \text{ lb } SO_2/\text{batch})(4 \text{ batches})}{3 \text{ hr}} = 5.33 \text{ lb/hr } SO_2 \qquad \textbf{Equation 7-2}$$

Eastman sampled other vents in B-55, found that small amounts of SO_2 were emitted from other vents in the sludge recovery process, as indicated in **Table 7-10**, and updated the stack parameters (**Table 7-11**)[72] and coordinates (**Table 7-12**)[73] for these vents. Tennessee applied these stack parameters into a revised model run as indicated in **Table 7-13**.

72 October 26, 2022 e-mail from Steve Moore (Eastman Chemical Company) to Travis Blake (TDEC-APC). On October 31, 2022, Eastman applied for a minor modification to Title V Operating Permit 576513 (MSOP-23) to incorporate these changes into the Title V permit.

73 October 20, 2022 e-mail from Steve Moore (Eastman Chemical Company) to Travis Blake (TDEC-APC).

Table 7-7: Boiler 23 Flow Data from Eastman RATA						
Load Range	**Steam Load (Kpph)**	**Heat to Load Ratio (MMBtu/1,000 lb steam)**	**Heat Input (MMBtu/hr)**	**CEMS Flow Average (kSCFH)**	**Stack Temp (°F)**	**Stack Flow (KACFH)**
Low	168	1.671	280.7	5,781	330	8,649
Mid	233	1.645	383.3	7,356	338	11,118
high	292	1.597	466.3	8,232	336	12,410
Rated Load	330	1.597	527.0	9,087	336	13,700
Nameplate	314	1.597	501	8,764	336	13,212

Table 7-8: Boiler Model Runs										
		Boilers 18-24				**Boilers 30-31**				
Run	**Boiler(s)**	**SO_2 Emissions (lb/hr)**	**SO_2 Emissions (g/s)**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**SO_2 Emissions (lb/hr)**	**SO_2 Emissions (g/s)**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**Total SO_2 Emissions (lb/hr)**
2023-0120-1[74]	18, 19, 20, 21, 22	1,600.0	201.60	16.48	447.92					1,600
2023-0120-5	20, 21, 22, 23, 24, 30	1,283.0	161.65	22.63	439.34	317	39.94	18.97	383.50	1,600
2023-0120-6	20, 21, 22, 23, 24, 30	1,233.6	155.43	22.42	438.80	366.4	46.17	18.97	383.50	1,600
2023-0120-7	21, 22, 23, 24, 31	1,102.0	138.85	19.96	438.21	497.6	62.70	18.22	397.28	1,600
2023-0120-9	18, 19, 20, 21, 22, 30, 31	1,014.2	127.79	14.01	441.90	585.8	73.81	37.19	390.25	1,600
2023-0120-12	18, 19, 20, 21, 22, 30, 31	846.0	127.79	14.01	441.90	754	95.00	37.19	390.25	1,600

74 Model run ID numbers are not sequential because Tennessee developed multiple runs but later eliminated some runs as redundant. Model run IDs were updated to reflect the most recent runs performed in response to EPA comments.

Table 7-9: Other Modeled SO_2 Emission Sources					
ID	**Description**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**SO_2 Emission Rate (g/s)**	**Basis**
DOMTR_BB	Domtar Biomass Boiler	15.39	449.70	1.44	Allowable emissions from PSD permit 978656 (11.43 lb/hr, daily average). Maximum uncontrolled hourly emissions are 6.13 lb/hr.
TAIL_GAS	Tail Gas Incinerator	21.34	644.26	2.75	Allowable emission rate (21.8 lb/hr).
FUGITIVE	Fugitive			1.72E-08[75]	SO_2 emissions from equipment leaks are estimated from equipment counts (i. e., number of pumps, valves, flanges, connectors, etc.) and emission factors plus nontraditional fugitive emissions[76] (estimated as 10% of equipment leaks). There are no numeric emission limits for equipment leaks, and compliance is based on work practice standards (quarterly or annual inspection using audible, visual, or olfactory methods). Fugitive SO_2 emissions are estimated as 1.45 tons/year.
H2_2_6	Hydrogen Plants 3-6 (Hydrogen Plant #3)	15.54	533.00	3.78E-03	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable)[77].
H24A	H2 Plants (Hydrogen Plant #4)	15.54	533.00	4.31E-03	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable).
H25A	H2 Plants (Hydrogen Plant #5)	26.52	494.67	9.49E-03	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable).
H26A	H2 Plants (Hydrogen Plant #6)	26.52	494.67	9.49E-03	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable)[78].
B4231A	NG-Fired Boiler, 226 MMBtu/hr	15.15	471.89	1.68E-02	Modeled emission rate was based on the allowable emission rate for the fuel burning installation (0.4 lb/hr) divided among three boilers. Maximum uncontrolled hourly emissions are equal to the permitted allowable (0.4 lb/hr total for all boilers at the design heat input).
B4231B	NG-Fired Boiler, 226 MMBtu/hr	15.15	471.89	1.68E-02	
B4231C	NG-Fired Boiler, 226 MMBtu/hr	15.15	471.89	1.68E-02	
B1901F	NG-Fired Parts Cleaning Oven	2.23	386.33	1.44E-03	Allowable emission rate of 0.10 tons/year divided evenly between both furnaces and converted to

75 Fugitive emissions are modeled in g/s*m^2, where the fugitive area is 2,425,384 m^2 (1353.3 m x 1792.2 m).
76 Fugitive emissions from equipment closures including manways, body flanges, and blind flanges
77 During review of EPA's comments, Tennessee noted a small discrepancy between the modeled emission rate (0.03 lb/hr) and the calculated maximum hourly emission rate (0.034 lb/hr). We believe that this difference is a rounding error with no significance to the model output.
78 During review of EPA's comments, Tennessee noted a small discrepancy between the modeled emission rate (0.075 lb/hr) and the calculated maximum hourly emission rate (0.076 lb/hr). We believe that this difference is a rounding error with no significance to the model output.

Table 7-9: Other Modeled SO_2 Emission Sources					
ID	Description	Stack Velocity (m/s)	Stack Temperature (K)	SO_2 Emission Rate (g/s)	Basis
B1901L	NG-Fired Parts Cleaning Oven	7.62	302.44	1.44E-03	equivalent lb/hr emissions (0.011lb/hr each furnace). Maximum uncontrolled hourly SO_2 emissions from each furnace are 2.1 x 10^{-4} lb/hr.
RICE1A	Diesel-Fired Emergency Engine	78.9432	750.77778	7.47E-04	Allowable emissions for PES RICE-1 (total for all engines) are 0.90 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
RICE1I	Diesel-Fired Emergency Engine	71.628	785.77778	2.33E-04	Allowable emissions for PES RICE-1 (total for all engines) are 0.90 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
RICE1H	Diesel-Fired Emergency Engine	21.0312	745.22222	1.77E-05	Allowable emissions for PES RICE-1 (total for all engines) are 0.90 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
RICE1K	Diesel-Fired Emergency Engine	61.2648	658	4.36E-04	Allowable emissions for PES RICE-1 (total for all engines) are 0.90 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
RICE1P	Diesel-Fired Emergency Engine	99.6696	710.22222	1.08E-04	Allowable emissions for PES RICE-1 (total for all engines) are 0.90 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
B265B1A	NG-Fired Heat Transfer Furnace	5.79	605.22	3.63E-04	Allowable emission rate is 0.03 tons/year. Maximum uncontrolled hourly emissions were calculated as 0.0029 lb/hr for Vent A and 0.0037 lb/hr for Vent C.
B265B1C	NG-Fired Heat Transfer Furnace	2.74	616.33	4.60E-04	
RK	Solid/Liquid Chemical Incinerators, B-248-1 Vents D and E	17.07	319.11	2.52E+00	CEV of 20 lb/hr
LCD	Liquid Chemical Incinerator B-248-2, Vent A	15.85	319.11	1.26E+00	CEV of 10 lb/hr
RICE3A	Diesel-Fired Emergency Engine	41.7576	713.55556	5.50E-04	Allowable emissions for PES RICE-3 are 1.0 tons/year. Modeled emission rate is uncontrolled potential to emit.
RICE2B63	B-63 Emergency Fire Pump Engine	53.64	727.4	3.51E-04	Allowable emissions for PES RICE-2 are 1.24 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
RIC2B269	B-269 Emergency Fire Pump Engine	45.72	788	2.56E-04	Allowable emissions for PES RICE-2 are 1.24 tons/year. Modeled emission rate is maximum uncontrolled hourly emission rate.
DOMTR_SR	Domtar No. 2 Power Boiler	14.54	429.26	1.70E-01	1.33 lb/hr allowable (daily average) from PSD permit 978656. Maximum uncontrolled hourly emissions are 1.33 lb/hr.
DOMTR_LK	Domtar Lime Kiln	6.46	516.48	4.91E-01	3.9 lb/hr allowable (daily average) from Title V permit 573622. Emissions will be zero following startup of the modified source (the facility will no longer produce soda pulp, and the lime kiln will not be needed). The allowable emission rate was retained in the model because there is no enforceable shutdown requirement for the lime kiln.

Table 7-9: Other Modeled SO_2 Emission Sources					
ID	**Description**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**SO_2 Emission Rate (g/s)**	**Basis**
PRMSTER	Cellulose Acetate Process	3.63	306.48	3.15E-02	Controlled emission rate (0.25 lb/hr).
B6551	Methanolysis Plant	4.88	449.70	1.26E-02	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable).
B8311_32	New Gas Boiler 32	17.07	455.20	1.89E-02	Maximum uncontrolled hourly emissions at the design heat input of each boiler (equivalent to the permitted allowable).
B8311_33	New Gas Boiler 33	17.07	455.20	1.89E-02	
B8311_34	New Gas Boiler 34	17.07	455.20	1.89E-02	
B338_3	Catalyst Recovery	21.95	310.80	1.26E-02	Allowable emission rate (0.44 tons/year) converted to an equivalent lb/hr emission rate (0.1 lb/hr). Maximum uncontrolled hourly emissions from this source are only 0.002 lb/hr)
B90_7_1	TBHQ Production	43.28	298.00	1.15E-03	0.01 lb/hr. Vent E is an uncontrolled process vent, and SO_2 is used as a reagent in the process. Emissions from this vent are negligible because SO_2 is added below its solubility limit of in water.
B90_7_2	TBHQ Production	0.09	298.00	2.59E-03	0.02 lb/hr. Vent C is an uncontrolled process vent, and SO_2 is used as a reagent in the process. Emissions from this vent are negligible because SO_2 is added below its solubility limit of in water. The application also states that there is adequate mixing and reaction time such that no excess SO_2 remains in solution.
B90B_1	BHA Production	6.10	294.10	4.03E-02	0.31 lb/hr. SO_2 emissions from this source are the maximum uncontrolled hourly emission rate.
B22723_1	HTM Furnaces	2.01	449.70	9.58E-03	Allowable emission rate of 0.19 lb/hr allocated to each furnace by heat input (0.08 lb/hr to Vent A and 0.11 lb/hr to Vent B). Maximum uncontrolled hourly emissions are 0.013 lb/hr from Vent A and 0.008 lb/hr from Vent B.
B22723_2	HTM Furnaces	4.02	449.70	1.44E-02	
B6C1_27	Crack Furnace 27 and 28	12.10	644.10	1.89E-03	Allowable emission rate of 0.03 lb/hr divided evenly among furnaces 27 and 28. Maximum uncontrolled hourly emissions from each furnace are equal to the permitted allowable.
B6C1_28	Crack Furnace 27 and 28	12.10	644.10	1.89E-03	
B7R_1	Crack Furnace 5-16 and 9-24	6.68	644.10	7.56E-03	The cracking furnaces, collectively, may vent through one of two common stacks. Modeled emissions are based on the combined allowable emission rate (0.12 lb/hr for all furnaces) allocated equally between each stack. Maximum uncontrolled hourly emissions are equal to the permitted allowable.
B7R_2	Crack Furnace 5-16 and 9-24	6.68	644.10	7.56E-03	
B7RC_1	Crack Furnace 25 and 26	5.46	644.10	1.26E-03	

Table 7-9: Other Modeled SO_2 Emission Sources					
ID	**Description**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**SO_2 Emission Rate (g/s)**	**Basis**
B7RC_2	Crack Furnace 25 and 26	5.46	644.10	1.26E-03	Modeled emissions are based on the combined allowable emission rate (0.02 lb/hr) allocated equally between each furnace. Maximum uncontrolled hourly emissions are equal to the permitted allowable.
AB7_1	Acetic Anhydride Manufacturing	1.58	505.20	3.02E-03	Allowable emissions of 0.03 lb/hr were allocated between the ketene furnaces (Vent A, 0.024 lb/hr) and thermal oxidizer (Vent B, 0.006 lb/hr). Maximum uncontrolled hourly emissions from Vent A are equal to the modeled allowable. Maximum uncontrolled hourly emissions from Vent B (0.004 lb/hr) are slightly less than the allowable.
AB7_2	Acetic Anhydride manufacturing	3.14	1,144.10	7.56E-04	
B351_5	Cold and Warm Flares	20	1273	2.0513	Modeled at 2020 99th percentile emission rate of 16.28 lb/hr.
B545_1	Copolyester Monomer Manufacturing	17.22	681.90	1.76E-03	Allowable emissions for Vent Q (0.06 tons/year) were subtracted from the source-wide allowable emissions. The difference was divided evenly between Vents B and C and converted to lb/hr (0.008 lb/hr each vent). Maximum uncontrolled hourly emissions are 0.014 lb/hr each for Vents B and C.
B545_2	Copolyester Monomer Manufacturing	2.36	1,088.60	1.76E-03	
B545_3	Copolyester Monomer Manufacturing	10.00	681.30	1.76E-03	Allowable emissions of 0.06 tons/year for Vent Q were converted to a lb/hr equivalent (0.014 lb/hr). Maximum uncontrolled hourly emissions are equal to the permitted allowable.
B55_1B	Organic Acids & Anhydrides Manufacturing	2.66	294.6	0.756	Uncontrolled emission rate of 5.33 lb/hr (batch average).
B55_1C	Organic Acids & Anhydrides Manufacturing	17.70	299.7	0.0857	Uncontrolled emission rate of 0.68 lb/hr. Emissions for this vent were previously believed to be zero, but bag sampling confirmed the presence of small amounts of SO_2.
B55_1E	Organic Acids & Anhydrides Manufacturing	0.12	299.7	0	Emissions for this vent were confirmed to be zero.
B55_1I	Organic Acids & Anhydrides Manufacturing	2.99	299.7	0.0744	Uncontrolled emission rate of 0.59 lb/hr. Emissions for this vent were previously believed to be zero, but bag sampling confirmed the presence of small amounts of SO_2.
B55_1K	Organic Acids & Anhydrides Manufacturing	3.33	307.2	0.0176	Uncontrolled emission rate of 0.14 lb/hr.
B238_1	HTM Furnaces	3.81	477.40	1.26E-03	Maximum uncontrolled hourly emissions at the design heat input (equivalent to the permitted allowable)[79].
B238_2	HTM Furnaces	3.81	477.40	1.26E-03	
B238_3	HTM Furnaces	9.81	471.90	5.04E-03	

79 During review of EPA's comments, Tennessee noted a small discrepancy between the modeled emission rate (0.010 lb/hr each for B-238-1 and B-238-2 and 0.40 lb/hr for B-238-3) and the

Table 7-9: Other Modeled SO_2 Emission Sources					
ID	**Description**	**Stack Velocity (m/s)**	**Stack Temperature (K)**	**SO_2 Emission Rate (g/s)**	**Basis**
B238_4	HTM Furnaces	6.10	258.30	7.56E-03	
B232_1	Aromatic Acid Manufacturing	7.32	323.00	2.88E-04	Emissions listed in the application (0.01 tons/year) were converted to an equivalent lb/hr value (0.0023 lb/hr). Maximum uncontrolled hourly emissions from this vent are 0.0023 lb/hr.
B232_2	Aromatic Acid Manufacturing	32.93	336.90	1.15E-03	Emissions listed in the application (0.04 tons/year) were converted to an equivalent lb/hr value (0.0091 lb/hr). Maximum uncontrolled hourly emissions from this vent are 0.0080 lb/hr.
B232_3	Aromatic Acid Manufacturing	7.01	323.00	2.88E-04	Emissions listed in the application (0.01 tons/year) were converted to an equivalent lb/hr value (0.0023 lb/hr). Maximum uncontrolled hourly emissions from this vent are 0.0023 lb/hr.
B256_5	HTM Furnace 5	4.02	449.70	1.00E-02	Permitted allowable for furnaces 5, 6, and 8 (0.04 lb/hr) were divided evenly among all three furnaces (0.0133 lb/hr). Maximum uncontrolled hourly emissions from each furnace are 0.01 lb/hr.
B256_6	HTM Furnace 6	4.02	449.70	1.00E-02	
B256_8	HTM Furnace 8	4.02	449.70	1.00E-02	
B272_7	HTM Furnace 7	4.02	449.70	1.00E-02	Permitted allowable for furnaces 5, 6, and 8 (0.04 lb/hr) were divided evenly among all three furnaces (0.0133 lb/hr). Maximum uncontrolled hourly emissions from each furnace are 0.01 lb/hr.
B272_9	HTM Furnace 9	4.02	449.70	1.00E-02	
B272_10	HTM Furnace 10	4.02	449.70	1.00E-02	

calculated maximum hourly emission rate (0.012 lb/hr each for B-238-1 and B-238-2 and 0.44 lb/hr for B-238-3). We believe that this difference is a rounding error with no significance to the model output.

Table 7-10: Updated SO_2 Emissions for PES B-55-1	
Vent	**Max. Uncontrolled SO_2 emissions (lb/hr)**
B	5.33
C	0.68
E	Negligible
I	0.59
K	0.14

Table 7-11: Updated Stack Parameters for PES B-55-1					
Vent ID	**Height (ft)**	**Diameter (ft)**	**Velocity (ft/s)**	**Temperature (°F)**	**Orientation**
B	70	0.7	8.74	70.8	Horizontal (South)
C	55	0.33	58.06	80	Horizontal (West)
E	130	0.13	0.38	80	Not Specified
I	60	1.856	9.81	80	Horizontal (East)
K	35	0.854	10.91	93.5	Vertical

Table 7-12: Stack Coordinates for PES B-55-1		
Vent ID	**X**	**Y**
B	361904.27	4043070.28
C	361903.90	4043073.06
E	361929.30	4043089.68
I	361906.88	4043073.05
K	361953.55	4043048.51
StackPoints WGS 1984 UTM Zone 17N from GIS		

Table 7-13: Revised Model Inputs, PES B-55-1						
ID	**Base Elevation (m)**	**Height (m)**	**Diameter (m)**	**Exit Velocity (m/s)**	**Exit Temperature (K)**	**SO_2 Emission Rate (g/s)**
B55_1B	369.19	21.34	0.213	2.66	294.6	0.756
B55_1C	369.19	16.76	0.101	17.70	299.7	0.0857
B55_1E	369.19	39.62	0.040	0.12	299.7	0.000
B55_1I	369.19	18.29	0.566	2.99	299.7	0.0744
B55_1K	369.19	10.67	0.260	3.33	307.2	0.0176

7.13 Results of Model Runs

The results of the model runs are shown in **Table 7-14.** Table 7-10 shows the maximum overall impact for each run (modeled highest-fourth-high concentration) and demonstrates that at the critical emission value of 1,600 lb/hr, there are no violations of the SO_2 NAAQS within the nonattainment area. The worst-case model run is 2022-0928-1 (Boilers 23, 24, 30, and 31 down, Boilers 18 through 22 operating at 1,600 lb/hr).

Table 7-14: Summary of Model Results

Model Run	Receptor Coordinates		Maximum Impact (ppb)
	X	Y	
2023-0120-1	364174	4043033	74.82
2023-0120-5	360974	4041333	66.45
2023-0120-6	360974	4041333	67.17
2023-0120-7	363974	4043233	72.36
2023-0120-9	363874	4042933	69.97
2023-0120-12	363074	4043033	68.98

8.0 SIP EMISSION LIMITS

8.1 Overview

Section 172(c)(6) of the Clean Air Act states that State Implementation Plans for nonattainment areas shall include enforceable emission limitations, and such other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emission rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to provide for attainment of such standard in such area by the applicable attainment date.

EPA's December 12, 2022, comment letter states that where an attainment demonstration relies upon modeling of permitted SO_2 emission limits, such limits need to be made permanent in the SIP. However, one credible approach to excluding small SO_2 sources from the SIP is to model the units in question at their maximum uncontrolled hourly emission levels (i.e., the unrestricted maximum physical and operational capacity to emit, without restriction by any permit term or limit). In other words, the modeling approach would determine whether, even without enforceable restrictions on some sources, the nonattainment area could attain the NAAQS if those respective emission sources emitted at their maximum uncontrolled hourly emission rates. Tennessee reviewed the modeled emission sources at Eastman to determine which emission limits were necessary or appropriate to demonstrate attainment of the NAAQS. We used a hybrid approach based on both the maximum uncontrolled hourly emission rate and modeled contributions to determine which emission limits are necessary to demonstrate attainment of the NAAQS.

8.2 Modeled Impacts

Tennessee reviewed all modeled receptors for the two worst-case model runs (2022-0928-1 and 2022-0928-7)[80] to assess the modeled impact of the SO_2 emission sources. For each dataset, Tennessee considered the following metrics:

1. The highest overall contribution of each source in $\mu g/m^3$.

2. The highest overall contribution as a percentage of the NAAQS (196.5 $\mu g/m^3$).

3. The highest contribution of each source as a percentage of the modeled highest-fourth-high concentration. The contribution of each source was calculated by dividing the modeled concentration of each receptor by the contribution of each source to that receptor.

The contributions of each modeled source are summarized in **Table 8-1**.

80 Model run 2022-0928-1 is the worst-case model run overall, but 2022-0928-7 is more representative of actual plant operations.

Table 8-1: Modeled Impacts of Individual Emission Sources							
Source Description	Model Tag	Modeled Emission Rate (lb/hr)	Max. Uncontrolled Hourly Emission Rate Modeled?	Highest Modeled Impacts			
				Model Run	Overall (ppb)	% of NAAQS	% of Modeled H4H
82-0003-01, B-83-1 Boilers 18 through 24 (MSOP-02)	CONT B83_1824	1,600	No	2023-0120-1	64.34	85.79%	86.00%
82-0003-01, B-253-1 Boilers 25 through 29 (MSOP-02)	CONT B253	2.3	Yes	2023-0120-1	0.12	0.17%	0.17%
82-0003-131, B-325-1 Boilers 30 and 31 (MSOP-26)	CONT B325	0	No	2023-0120-12	30.68	40.90%	44.47%
82-0003-297, B-Area A-B7, Crude Acetic Anhydride Manufacturing (MSOP-16)	CONT ACETIC	0.03	Yes	2023-0120-12	0.0015	0.002%	0.00231%
82-0003-303, PES B-190-1, Parts Cleaning Oven (MSOP-27)	CONT NG_OVENS	0.0228	Yes	2023-0120-12	0.00023	0.0003%	0.0003%
82-0003-247, B-238-1, HTM Furnaces (MSOP-24)	CONT HTM_FURN	0.12	Yes	2023-0120-9	0.06	0.09%	0.09%
82-0003-293, PES B-232-1. Manufacture of Aromatic Acids (MSOP-34) Vents UA, UB, and UC	CONT AROMATIC	0.014	Yes	2023-0120-5	0.00057	0.001%	0.001%
82-0003-276, HTM furnaces (MSOP-31, PES B-265B-1)	CONT NG_HTF	0.006	Yes	2023-0120-12	0.00097	0.001%	0.0014%
82-0003-172, B-334-2 Synthesis Gas Pilot Plant (MSOP-17)	CONT SYN_GAS	N/A (removed from service)	N/A (removed from service)	N/A	N/A	N/A	N/A
82-0003-171, B-351-5 Flares for South Production Area (MSOP-17)	CONT FLARE	16.28	No	2023-0120-1	0.57	0.76%	0.76%
82-0003-144, PES B-338-3, Recovery of Carbonylation Reactor Catalyst (MSOP-03)	CONT CATALYST	0.1	Yes	2023-0120-12	0.0099	0.01%	0.0144%
82-0003-132, PES B-423-1, Gas Boilers A, B, and C (MSOP-26)	CONT NGBOILER	0.4	Yes	2023-0120-9	0.30	0.40%	0.42%
82-0003-185, PESB-545-1, Copolyester Monomer Manufacturing (MSOP-19)	CONT COPLYSTR	0.042	Yes	2023-0120-6	0.001	0.002%	0.002%

Table 8-1: Modeled Impacts of Individual Emission Sources							
Source Description	**Model Tag**	**Modeled Emission Rate (lb/hr)**	**Max. Uncontrolled Hourly Emission Rate Modeled?**	**Highest Modeled Impacts**			
				Model Run	**Overall (ppb)**	**% of NAAQS**	**% of Modeled H4H**
82-0003-224, PES B-55-1, Organic Acids & Anhydrides Manufacturing (MSOP-23), Vent B	CONT ORGANICB	5.33	Yes	2023-0120-9	0.052	0.07%	0.07%
82-0003-224, PES B-55-1, Organic Acids & Anhydrides Manufacturing (MSOP-23), Vents C, I, and K	CONT ORGANICS	1.41	Yes	2023-0120-9	0.066	0.09%	0.09%
82-0003-310, PES B-655-1, Methanolysis Plant (MSOP-36)	CONT METHANOL	0.1	Yes	2023-0120-7	0.01	0.01%	0.02%
82-0003-30, PES B-6C-1, Cracking furnaces 27 and 28; 82-0003-164, PES B-7R-1, Cracking Furnaces 5-16 and 9-24; 82-0003-166, PES B-7RC-1, Cracking Furnaces 25 and 26 (MSOP-16)	CONT CRK_FURN	0.17	Yes	2023-0120-5	0.01	0.01%	0.0124%
82-0003-311, B-83-11 Boilers 32, 33, and 34 (MSOP-02)	CONT NEW_BOIL	0.45	Yes	2023-0120-7	0.03	0.04%	0.05%
82-0003-121, PES B-90B-1, BHA production (MSOP-10)	CONT BHA_PROD	0.32	Yes	2023-0120-12	0.0028	0.004%	0.004%
82-0003-120, B-90-7 TBHQ production, Vents C and E (MSOP-10)	CONT TBHQ_PRD	0.03	Yes	2023-0120-7	0.00027	0.0004%	0.0002%
82-0022-33, Biomass Boiler; and 82-0022-34, No. 2 Power Boiler	CONT DOMTAR	11.43	Yes	2023-0120-12	0.025	0.033%	0.036%
82-0003-168, PESB-334-1, Fugitive Equipment Leaks from Acid Gas Removal and Sulfur Recovery (MSOP-17)	CONT FUGITIVE	1.36×10^{-7}	Yes	2023-0120-7	0.19	0.25%	0.26%
82-0003-305, PES H2 Plants. Hydrogen Plants 3, 4, and 5 (MSOP-24), Vents 3A, 4A, and 5A	CONT H2_PLANT	0.18	Yes	2023-0120-6	0.0022	0.003%	0.003%

Table 8-1: Modeled Impacts of Individual Emission Sources							
Source Description	Model Tag	Modeled Emission Rate (lb/hr)	Max. Uncontrolled Hourly Emission Rate Modeled?	Highest Modeled Impacts			
				Model Run	Overall (ppb)	% of NAAQS	% of Modeled H4H
82-0003-305, PES H2 Plants. Hydrogen Plant 6 (MSOP-24), Vent 6A	CONT HYDROGEN	0.03	Yes	2023-0120-6	0.0022	0.003%	0.003%
82-0003-282, B-248-1 Solid/Liquid Chemical Waste Incinerators, Two Rotary Kilns (MSOP-32). 82-0003-283 B-248-2 Liquid Chemical Waste Incinerator (MSOP-32).	CONT HWI	30	No	2023-0120-7	9.93	13.24%	13.72%
82-0003-254, OC-BATCH Production of Specialty Organic Chemicals (MSOP-25)	CONT BATCH	N/A (intermittent source)	N/A (intermittent source)	N/A	N/A	N/A	N/A
82-0510-03, Primester B-441-2 Cellulose Scrap Recovery	CONT PRMSTER	0.25	No	2023-0120-12	0.0081	0.011%	0.012%
82-0003-104, RICE-2 Fire Pump Engines (MSOP-11)	CONT FIREPUMP	0.005	Yes	2023-0120-7	0.001	0.001%	0.001%
82-0003-102, RICE-1 Emergency Engines (MSOP-29)	CONT EMG_ENG	0.017	Yes	2023-0120-12	0.00050	0.0007%	0.0007%
82-0003-168, B-334-1 Acid Gas Removal and Sulfur Recovery Plants (MSOP-17)	CONT TAIL_GAS	21.8	No	2023-0120-6	0.59	0.79%	0.88%

8.2 Emission Sources Included in the SIP

The following sources were included in the SIP (**Table 8-2**):

Table 8-2: Emission Limits Included in the SIP		
Emission Source	**Description**	**Emission Limits**
82-0003-01	B-83 Boilers 18 through 24	1,248 lb/hr, 30-day rolling average, combined limit for all boilers. Install DSI on B-83 Boilers 23 and 24.
82-0003-131	B-325 Boilers 30 and 31	
82-0003-131	B-325 Boiler 30	317 lb/hr, 30-day rolling average
82-0003-131	B-325 Boiler 31	293 lb/hr, 30-day rolling average
82-0003-282	B-248-1 solid/liquid chemical waste incinerators	15.2 lb/hr, 30-day rolling average, combined limit for both units
82-0003-283	B-248-2 liquid chemical waste incinerator	2.0 lb/hr, 30-day rolling average
82-0003-01	B-253 Boilers 25 through 29	A numeric SO_2 emission limit was not established, but the requirement to burn only natural gas (condition 6 of PSD construction permit 966859F was adopted into the SIP.
82-0003-168	B-334-1, tail gas incinerator for acid gas removal and sulfur recovery plant	21.8 lb/hr, 24-hr block average
82-0003-171	B-351-5 cold and warm flares	16.28 lb/hr (one-hour average), not to be exceeded for more than 88 hours during each calendar year
82-0510-03	Primester Cellulose Scrap Recovery	6.74 lb/hr (average for each batch cycle)

8.2 Determination of Long-Term Emission Limits

EPA's SIP guidance states that adjustment of modeled hourly emissions to a longer-term average of up to 30 days is an appropriate control strategy. The 30-day rolling average is calculated from a representative baseline of hourly emission rates and the modeled emission rate, as shown in **Equation 8-1**:

$$\text{30-day rolling average} = (\text{modeled emission rate})\left(\frac{(99^{th}\text{ percentile 30-day rolling average emission rate})}{(99^{th}\text{ percentile hourly emission rate})}\right) \qquad \textbf{Equation 8-1}$$

Boilers (B-83-1 and B-325-1): The ratio of 99^{th} percentile hourly and 30-day rolling average emission rates is the "compliance ratio." The 30-day rolling average allowable emission rate was calculated as follows (**Table 8-3**, Attachment H).

Table 8-3: Calculation of 30-Day Rolling Average Emission Limit, B-83 and B-325 Boilers	
Period of representative emissions	July 1, 2019, through December 31, 2020
99th percentile hourly emission rate (all boilers)	1,252 lb/hr
99th percentile 30-day rolling average emission rate (all boilers)	976 lb/hr
Compliance ratio	0.78
Modeled emission rate	1,600 lb/hr
Allowable emission rate	1,248 lb/hr, 30-day rolling average

Tennessee established a single emission limit for B-83 and B-325 in lieu of separate emission limits for individual stacks. The model runs demonstrate attainment of the NAAQS under worst-case combinations, and a single emission limit will allow for the necessary variability in boiler operations.

Hazardous Waste Incinerators (B-248-1 and B-248-2): The same methodology was applied to Eastman's rotary kilns (MSOP-32, PES B-248-1) and liquid chemical incinerator (MSOP-32, PES B-248-2) as indicated in **Tables 8-4 and 8-5**, respectively. These emission limits demonstrate attainment of the NAAQS while allowing for variability in incinerator operations.

Table 8-4: Calculation of 30-Day Rolling Average Emission Limit, B-248-1 Hazardous Waste Incinerators (Rotary Kilns)	
Period of representative emissions	January 1, 2019, through December 31, 2020
99th percentile hourly emission rate (both kilns)	0.5 lb/hr
99th percentile 30-day rolling average emission rate (both kilns)	0.3 lb/hr
Compliance ratio	0.76
Modeled emission rate	20 lb/hr
Allowable emission rate	15.2 lb/hr, 30-day rolling average

Table 8-5: Calculation of 30-Day Rolling Average Emission Limit, B-248-2 Hazardous Waste Incinerator (Liquid Chemical Incinerator)	
Period of representative emissions	January 1, 2019, through December 31, 2020
99th percentile hourly emission rate	7.5 lb/hr
99th percentile 30-day rolling average emission rate	1.5 lb/hr
Compliance ratio	0.2
Modeled emission rate	10 lb/hr
Allowable emission rate	2.0 lb/hr, 30-day rolling average

Tail gas incinerator (B-334-1): Tennessee modeled the existing SO_2 emission limit for Eastman's tail gas incinerator (21.8 lb/hr, 24-hour average)[81], and the existing limit will be included in the SIP. Tennessee reviewed the emissions data for 2019 through 2021, and we calculated a compliance ratio using Equation 8-1 (**Table 8-6**).

81 Condition E4-7 of Title V Operating Permit 572407 (MSOP-17).

Table 8-6 indicates that both hourly and 24-hour rolling average emissions from the tail gas incinerator are substantially lower than the permitted allowable. When we calculated the compliance ratio, the result was greater than 1.0, and this result indicates a familiar pattern of low emissions with periodic spikes in the emission rate (i. e., the incinerator operates with low emissions during normal operation, and spikes in the emission rate during process upsets). Tennessee also compared the tail gas incinerator's hourly emissions to the modeled emission rate (**Table 8-7**). Actual emissions from the incinerator exceeded the modeled emission rate for only 51 hours between January 1, 2019, and December 31, 2021 (0.20%). Based on this review, Tennessee determined that the existing limit is protective of the SO_2 NAAQS, and no revisions to the existing limit are needed.

Table 8-6: Calculation of 30-Day Rolling Average Emission Limit, B-334-1 Tail Gas Incinerator	
Period of representative emissions	January 1, 2019, through December 31, 2021
99th percentile hourly emission rate	5.8 lb/hr
99th percentile 24-hr rolling average emission rate	7.9 lb/hr
Compliance ratio	1.38
Modeled emission rate	21.8 lb/hr
Allowable emission rate	21.8 lb/hr, 24-hour block average (existing limit)

Table 8-7: Review of Existing Limit, B-334-1 Tail Gas Incinerator	
Period of representative emissions	January 1, 2019, through December 31, 2021
Total Hours	25,790[82]
Hours > 21.8 lb/hr	51
% of Total Hours > 21.8 lb/hr	0.20%

Cold and Warm Flares (B-351-5): The 99th percentile modeled emission rate (16.28 lb/hr, one-hour average) was added to the SIP permit as a limit not to be exceeded for more than 88 hours per calendar year (approximately 1% of the maximum operating hours during each calendar year). Tennessee was unable to establish a long-term average using the method specified in EPA's SIP guidance, but the proposed limit is consistent with EPA's guidance, in that the limit is based on the underlying principles established by EPA. The SIP guidance allows states to develop control strategies that account for variability in one-hour emissions rates, including rare occurrences of hourly emissions above the critical emission value are a rare occurrence at a source, which would be unlikely to significantly impact air quality (i. e., hourly emission rates above the CEV would be unlikely to occur repeatedly at the times when the meteorology is conducive for high ambient concentrations of SO_2). This option reflects an appropriate balance between assuring attainment and maintenance of the NAAQS while allowing for the necessary variability in source operations and the impairment to source operations that could occur under an unnecessarily restrictive approach. Tennessee also requested adoption of the existing SO_2 limit (47.6 lb/hr, 24-hour block average) into the SIP as a backstop for the 88 hours/year during which the new allowable may be exceeded.

82 Includes 477 hours of incinerator shutdown between June 7, 2021, and June 26, 2021.

8.4 Emission Sources Excluded from the SIP

The following emission sources were excluded from the SIP based upon negligible modeled impacts at the source's maximum uncontrolled hourly emission rate. Tennessee's modeling demonstrates that the area will attain the NAAQS even if these sources emitted at their maximum uncontrolled hourly emission rates. These sources are not expected to be modified in any manner that increase their maximum hourly uncontrolled emissions, and all emission sources will be required to operate in accordance with Eastman's Title V permits to ensure that they do not cause or contribute to a violation of the SO_2 NAAQS.

BHA Production (MSOP-10, PES B-90B-1): Eastman's BHA production (MSOP-10, 82-0003-121, PES B-90B-1) consists of miscellaneous chemical processing equipment used for the batch production of butylated hydroxyanisole (BHA). BHA is typically produced from the reaction of t-butylhydroxyquinone (TBHQ) with dimethyl sulfate ($(CH_3O)_2SO_2$), and trace amounts of sulfur dioxide are emitted, presumably via thermal decomposition of sulfuric acid.

Natural Gas Boilers A, B, and C (MSOP-26): Eastman operates three natural gas-fired boilers (82-0003-132, PES B-423-1) with design heat input capacities of 226 MMBtu/hr each for backup steam generation (i. e., these boilers are designed as backup units in the event of an unplanned outage at another powerhouse).

Fugitive Equipment Leaks from Acid Gas Removal and Sulfur Recovery (MSOP-17, PES B-334-1): Eastman's coal gasification plant includes two process units to remove sulfur from synthesis gas. The Claus process (acid gas removal) oxidizes hydrogen sulfide to sulfur dioxide by substoichiometric combustion in air, and the mixture of hydrogen sulfide and sulfur dioxide is catalytically reacted to produce elemental sulfur. The SCOT process is used to improve Claus process efficiency by reduction of other sulfur compounds to H_2S (sulfur compounds are catalytically reacted with hydrogen at an elevated temperature) and concentration of the sulfur by absorption of the gas stream in an amine absorber. The sulfur-rich overhead gas is returned to the Claus process, and the off-gas is routed to an incinerator. Collectively, these units are permitted as the acid gas and sulfur recovery plants (82-0003-168, PESB-334-1) in Title V permit 572407.

Condition E4-9 of permit 572407 requires an annual leak inspection of all equipment in sulfur dioxide service (contains or contacts a process fluid that is at least 10% sulfur by weight and is not in heavy liquid service or vacuum service). This is a work practice standard that requires an AVO (audible, visual, olfactory) inspection of piping, pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flanges. Condition E4-9 includes a numeric estimate of fugitive emissions for fee payment and NSR baselining (1.45 tons/year), but the estimate is not an emission limit.

Domtar (82-0022): Domtar Paper Company, LLC is located outside of the nonattainment area, but emissions from this source have the potential to impact the nonattainment area based on the proximity of the facility. PSD construction permit 978656 was issued to Domtar June 21, 2021, to convert the idled mill from a hardwood bleached soda process to produce containerboard from 100% recycled material. This project included the following changes:

- Optimization of the Bubbling Fluidized Bed (BFB) Biomass Boiler (82-0022-33) for combustion of biomass, including OCC rejects, wastewater treatment plant sludge, bark, and other wood waste, with natural gas and ultra-low sulfur diesel as secondary fuels.

- Conversion of the existing Soda Recovery Furnace (82-0022-34) to disable the furnace's capability to combust black liquor solids. The repowered furnace will be designated as the No. 2 Power Boiler and will combust only natural gas and ULSD.

- The existing lime kiln will be permanently shut down.

New B-83 Boilers 32, 33, and 34 (MSOP-02, PES B-83-11): Natural gas-fired Boilers 32, 33, and 34 commenced construction during the week of June 6, 2022[83] and were included in the attainment year model.

82-0003-120, B-90-7 TBHQ production, Vents C and E (MSOP-10): The TBHQ production process synthesizes tert-butyl hydroquinone (TBHQ) from hydroquinone and one or more components identified as confidential business information in Eastman's Title V application. Eastman's process includes the addition of a stoichiometric amount (no excess) of SO_2 to the process. Eastman's application states that the addition of SO_2 is below the solubility limit of SO_2 in water to provide sufficient time and mixing for the SO_2 to react completely so that no excess SO_2 is left in the reaction mixture.

Recovery of Carbonylation Reactor Catalyst (MSOP-03): Eastman's coal gasification facility includes unit operations that produce various organic compounds (alcohols, esters, and anhydrides) from synthesis gas, and includes a process for recovery of a carbonylation reactor catalyst (82-0003-144, PES B-338-3).

Methanolysis Plant (MSOP-36): Construction permit 978695 was issued on February 16, 2021, for the construction of a methanolysis plant (82-0003-310, PES B-655-1), which produces monomers from recycled plastics. This permit was subsequently modified with the issuance of construction permit 979538 on December 10, 2021[84]. This source will include a natural gas-fired heat transfer media furnace with a design input capacity of 169 MMBtu/hr of natural gas plus 0.75 MMBtu/hr of process gas, and there will be no other SO_2 emission sources at this process unit. Startup of this source has not occurred as of October, 2022.

Cracking Furnaces (MSOP-16): Title V permit 576946 includes the following cracking furnaces (**Table 8-8**):

Table 8-8: MSOP-16 Cracking Furnaces, Description and Allowable Emissions

Source ID	Description	Heat Input (MMBtu/hr)	SO_2 Allowable Emissions
82-0003-30, PES B-6C-1	Cracking Furnace 27	25	Entire source limit of 0.03 lb/hr and 0.13 tons/year
	Cracking Furnace 28	25	

83 E-mail from Eastman Chemical Company dated June 10, 2022 (NSPS Db notification of start of construction).
84 The modification was issued to allow the installation of a recovery scrubber but does not affect the SO_2 emission limit established in the previous permit.

Table 8-8: MSOP-16 Cracking Furnaces, Description and Allowable Emissions			
Source ID	**Description**	**Heat Input (MMBtu/hr)**	**SO_2 Allowable Emissions**
			(Condition E3-7)
82-0003-164, PES B-7R-1	Cracking Furnace 5	9.9	Entire source limit of 0.12 lb/hr and 0.49 tons/year (Condition E3-7)
	Cracking Furnace 6	9.9	
	Cracking Furnace 7	9.9	
	Cracking Furnace 8	9.9	
	Cracking Furnace 9	9.9	
	Cracking Furnace 10	9.9	
	Cracking Furnace 11	9.9	
	Cracking Furnace 12	9.9	
	Cracking Furnace 13	9.9	
	Cracking Furnace 14	9.9	
	Cracking Furnace 15	9.9	
	Cracking Furnace 16	9.9	
	Cracking Furnace 17	9.9	
	Cracking Furnace 18	9.9	
	Cracking Furnace 19	9.9	
	Cracking Furnace 20	9.9	
	Cracking Furnace 21	13.3	
	Cracking Furnace 22	13.3	
	Cracking Furnace 23	13.3	
	Cracking Furnace 24	13.3	
82-0003-166, PES B-7RC-1	Cracking Furnace 25	17	Entire source limit of 0.02 lb/hr and 0.06 tons/year (Condition E6-4)
	Cracking Furnace 26	13.5	

82-0003-305, PES H2 Plants. Hydrogen Plants 3, 4, 5, and 6 (MSOP-24), Vents 3A, 4A, 5A, and 6A: Hydrogen Plants 3, 4, 5, and 6 produce elemental hydrogen by steam reforming of natural gas. Natural gas is reacted with steam at high pressure to produce elemental hydrogen and carbon monoxide via the following equilibrium reaction:

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2$$

Copolyester Monomer Manufacturing (MSOP-19): Eastman's copolyester monomer manufacturing operation (82-0003-185, PESB-545-1) includes two natural gas-fired process heaters (Vents B and Q) and a natural gas-fired vapor incinerator (Vent C). Condition E3-6 of Title V permit 575805 limits SO_2 emissions (entire source) to 0.13 tons/year. Condition E3-19 of Title V permit 575805 limits SO_2 emissions from Vent Q to 0.06 tons/year. There are no other SO_2 emissions from this source.

Manufacture of Aromatic Acids (MSOP-34, PES B-232-1): Vents UA, UB, and UC are natural gas-fired catalytic or thermal oxidizers used to control VOC and organic HAP emissions from the manufacture of terephthalic acid and isophthalic acid.

Crude Acetic Anhydride Manufacturing (MSOP-16, PES Area A-B7): Eastman's crude acetic anhydride manufacturing operation consists of 10 ketene furnaces and associated equipment used in the manufacture of crude acetic anhydride.

Parts Cleaning Oven (MSOP-27, PES B-190-1): Eastman's cellulose esters and specialty plastics manufacturing operation includes a parts cleaning oven (Vents F and L[85]).

HTM furnaces (MSOP-31, PES B-265B-1): Eastman operates two natural gas-fired heat transfer media (HTM) furnaces as part of its specialty polymer manufacturing and polyester production operations.

HTM Furnaces (MSOP-24, PES B-238-1): Eastman operates four natural gas and fuel gas-fired heat transfer media (HTM) furnaces (82-0003-247, PES B-238-1) for its ester production facility. All sulfur dioxide emissions result from natural gas combustion (there is no sulfur in the fuel gas).

Emergency Engines: Eastman's Title V Operating Permits include sixteen emergency engines, which are operated for emergency services only (**Table 8-9**). The annual operating hours for each engine were provided by Eastman Chemical Company for calendar years 2019, 2020, and 2021[86], and Table 7-2 indicates that all but one engine operated well under 1% of the total hours during each calendar year. The remaining source (Bays Mountain emergency engine) operated for 119 hours in 2019 but for less than 88 hours in 2020 and 2021. This engine is also expected to have a negligible impact on the nonattainment area based on its fuel type (propane). In general, operation of emergency engines would occur randomly, and there would be no flexibility in scheduling[87].

85 Eastman states (April 22, 2022 e-mail from Steve Moore, Eastman Chemical Company, to Travis Blake, TDEC-APC) that the header that sends vapor Vent L receives emissions from the following sources: #24 extruder feeders and die exhaust, 3rd floor feed hoppers, and a Berringer parts cleaning oven. The SO_2 emissions from this vent are due to the combustion of natural gas in the parts cleaning oven. Natural gas is used to heat the oven to normal operating temperatures during cleaning activities.

86 E-mail from Steve Moore, Eastman Chemical Company, to Travis Blake, TDEC-APC, September 6, 2022.

87 Maintenance and readiness checks may be scheduled at nonrandom intervals, but nonemergency operation is limited by federal regulations (40 CFR 60 Subparts IIII and JJJJ and 40 CFR 63 Subpart ZZZZ).

Table 8-9: Emergency Engines Operated by Eastman Chemical Company								
MSOP	**PES**	**Vent ID**	**Description**	**Fuel**	**Heat Input (MMBtu/hr)**	**2019 Operating Hours**	**2020 Operating Hours**	**2021 Operating Hours**
11	RICE-2	A	B-63 Fire Pump	Diesel	1.78	30.9	26.0	22.6
11	RICE-2	B	B-269 Fire Pump	Diesel	1.3	24.1	42.5	43.1
29	RICE-1	A	B-456 Emergency Engine	Diesel	3.79	34.7	32.4	33.1
29	RICE-1	C	B-284 Emergency Engine	Propane	0.18	28.4	35.6	31.6
29	RICE-1	D	Bays Mountain Emergency Engine	Propane	0.18	119.3	40.9	24.6
29	RICE-1	E	B-431 Emergency Engine	Propane	0.1	28.2	34.2	31.9
29	RICE-1	F	B-432 Emergency Engine	Propane	0.1	26.3	31.9	28.3
29	RICE-1	G	B-433 Emergency Engine	Propane	0.13	23.1	29.7	22.2
29	RICE-1	H	B-310 Emergency Engine	Diesel	1.18	28.1	36.2	31.2
29	RICE-1	I	B-300 Emergency Engine	Diesel	0.09	28.4	32.5	31.2
29	RICE-1	J	B-551 Emergency Engine	Propane	0.15	29.3	34.1	37.0
29	RICE-1	K	B-54D Emergency Engine	Diesel	2.21	22.1	0.0	42.5
29	RICE-1	M	CBC Emergency Engine	Natural Gas	0.4	40.6	51.0	50.5
29	RICE-1	N	B-631 Emergency Engine	Propane	0.4	40.9	25.3	22.6
29	RICE-1	P	B-280 Emergency Engine	Diesel	0.55	26.7	32.0	27.9
32	RICE-3	A	B-427 Emergency Engine	Diesel	2.79	54.1	57.2	51.8

9.0 CONTINGENCY MEASURES

Section 172(c)(9) of the CAA defines contingency measures as such measures in a SIP that are to be implemented in the event that an area fails to make RFP, or fails to attain the NAAQS, by the applicable attainment date. Contingency measures are to become effective without further action by the state or the EPA, where the area has failed to (1) achieve RFP or, (2) attain the NAAQS by the statutory attainment date for the affected area. These control measures are to consist of other available control measures that are not included in the control strategy for the NAA SIP for the affected area. EPA's SO_2 SIP guidance states that contingency measures need to be a fully adopted provision in the SIP that becomes effective if the area fails to meet RFP or attain the standard by the statutory attainment date. EPA's SO_2 SIP guidance states that "contingency measures" can mean that the air agency has a comprehensive program to identify sources of violations of the SO_2 NAAQS and to undertake an "aggressive" follow-up for compliance and enforcement.

Upon notification by Tennessee that a reference monitor for the area has registered four validated daily maximum one-hour ambient SO_2 concentrations in excess of the standard during calendar years 2024, 2025, 2026, or 2027, or that a monitored SO_2 violation based on the design value occurred during or after calendar year 2028, Eastman will, without any further action by Tennessee or EPA, undertake a full system audit of all emissions units subject to control under this plan and of all modeled emission units excluded from adoption into the SIP. Eastman will submit a written system audit report to Tennessee within 30 days of the notification. The system audit report must detail the operating parameters of all emissions units, including modeled emission units that were excluded from the SIP, for four 10-day periods up to and including the date upon which the reference monitor registered each exceedance, together with recommended provisional SO_2 emission control strategies for each affected unit and evidence that these control strategies have been deployed, as appropriate.

Upon receipt of the system audit report, Tennessee will immediately begin a 30-day evaluation period to diagnose the cause of the monitored exceedance. This evaluation will be followed by a 30-day consultation period with Eastman to develop and implement operational changes necessary to prevent future monitored violations of the standard. These changes may include fuel switching to reduce or eliminate the use of sulfur-containing fuels, physical or operational reduction of production capacity, or other changes as appropriate. If a permit modification is deemed necessary, Tennessee would issue a final permit within the statutory timeframes required in Tennessee Air Pollution Control Regulations 1200-03-09, and any new emissions limits required by such a permit would be submitted to EPA as a SIP revision. If an emission source is found to be noncompliant with a SIP emission limit, the Technical Secretary will, in addition to conducting enforcement proceedings to bring the source into compliance with its SIP limit, determine whether additional limits must be added to the SIP to meet the requirements of section 172(c)(9) of the Clean Air Act.

10.0 CONCLUSION

Tennessee requests that EPA approve the specified SO_2 pollution controls and emission limits into Tennessee's SIP. As demonstrated above, these measures will provide for attainment and maintenance of the revised SO_2 NAAQS in the Sullivan County nonattainment area.

Department of Environment & Conservation

MEMO

To: Tennessee Air Pollution Control Board
From: Travis Blake
Date: January 30, 2023
Subject: Final copy of SO_2 Attainment Demonstration

Tennessee is submitting a SIP revision to the Air Pollution Control Board to address the portion of Sullivan County designated as nonattainment for the one-hour sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS). The final SIP demonstrates that the Sullivan County nonattainment area will attain the SO_2 NAAQS based on air quality modeling results, emissions inventories, and other evidence.

The full SIP (narrative plus attachments) is too large to transmit via e-mail or hard copy. Copies of the SIP narrative and attachments are available for review at the following link: https://tncloud.tn.gov/owncloud/index.php/s/rcWY9FuIzL0N1Rp. Use the password **TN SIP** (case-sensitive) to access the files.

Division of Air Pollution Control • William R. Snodgrass Tennessee Tower, 15th Floor • 312 Rosa L. Parks Avenue• Nashville, TN 37214 • Tel: (615) 532-0554 • Fax: (615) 532-0614• http://www.tn.gov/environment/

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243

OPERATING PERMIT Issued Pursuant to Tennessee Air Quality Act

Issue Date: March 1, 2023

Permit Number:
080222

Issued To:
Eastman Chemical Company
Tennessee Operations
(MSOP-02, MSOP-17, MSOP-26, MSOP-32)

Installation Address:
South Eastman Road
Kingsport

Installation Description:
See Condition 1 for a list of affected sources.

Emission Source Reference No.
See Condition 1

The holder of this permit shall comply with the conditions contained in this permit as well as all applicable provisions of the Tennessee Air Pollution Control Regulations.

CONDITIONS:

1. On and after September 1, 2023, sulfur dioxide (SO_2) emissions from the emission sources listed in this permit shall not exceed the following limits:

Emission Source	**SO_2 Emission Limits**
B-83 Boilers 18-24 (82-0003-01, MSOP-02)	1,248 lb/hr (combined limit for all boilers), 30-day rolling average
B-325 Boilers 30-31 (82-0003-131, MSOP-26)	
B-248-1 Solid/Liquid Chemical Waste Incinerators (82-0003-282, MSOP-32)	15.2 lb/hr, 30-day rolling average (combined limit for both rotary kilns)
B-248-2 Liquid Chemical Waste Incinerator (82-0003-283, MSOP-32)	2.0 lb/hr, 30-day rolling average
B-334-1 Tail Gas Incinerator (82-0003-168, MSOP-17)	21.8 lb/hr, 24-hour block average
B-351-5 Cold and Warm Flares (82-0003-171, MSOP-17)	16.28 lb/hr (one-hour average), not to be exceeded for more than 88 hours during each calendar year
	47.6 lb/hr (24-hour block average)
B-55-1, Organic Acids & Anhydrides Manufacturing, Vents B, C, E, I, and K (82-0003-224, MSOP-23)	6.74 lb/hr (average for each batch cycle)

40 CFR §§51.110 – 51.112, Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-09-.03(8)

(conditions continued on next page)

TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

NON-TRANSFERABLE **POST AT INSTALLATION ADDRESS**

2. On and after the issue date of this permit, the permittee shall operate and maintain a dry sorbent injection (DSI) system to reduce SO_2 emissions from B-83 Boilers 23 and 24. The permittee shall operate, maintain and repair the control device as required to maintain and assure compliance with the specified emission limits. All periods of nonoperation of the DSI and records of all repair and maintenance activities shall be recorded in a suitable permanent form and kept available for inspection by the Technical Secretary or an authorized representative. These records must be retained for a period of not less than five years. Periods of nonoperation of the DSI and the date each maintenance and repair activity began shall be entered in the log no later than seven days following the start of the period of nonoperation or maintenance and repair maintenance activity, and the completion date shall be entered in the log no later than seven days after activity completion.

   TAPCR 1200-03-09-.03(8)

3. On and after September 1, 2023, the permittee shall comply with the monitoring and reporting requirements specified in Attachments A, B, C, and D of this permit, as shown below. These monitoring plans are incorporated by reference into this permit as fully enforceable conditions.

Emission Source	SO_2 Emission Limits	Monitoring Requirements
B-83 Boilers 18-24 (82-0003-01, MSOP-02)	1,248 lb/hr (combined limit for all boilers), 30-day rolling average	Comply with the monitoring and reporting requirements specified in Attachment A of this permit.
B-325 Boilers 30-31 (82-0003-131, MSOP-26)		
B-248-1 Solid/Liquid Chemical Waste Incinerators (82-0003-282, MSOP-32)	15.2 lb/hr, 30-day rolling average (combined limit for both rotary kilns)	Comply with the monitoring and reporting requirements specified in Attachment B of this permit.
B-248-2 Liquid Chemical Waste Incinerator (82-0003-283, MSOP-32)	2.0 lb/hr, 30-day rolling average	
B-334-1 Tail Gas Incinerator (82-0003-168, MSOP-17)	21.8 lb/hr, 24-hour block average	Comply with the monitoring and reporting requirements specified in Attachment C of this permit.
B-351-5 Cold and Warm Flares (82-0003-171, MSOP-17)	16.28 lb/hr (one-hour average), not to be exceeded for more than 88 hours during each calendar year	Comply with the monitoring and reporting requirements specified in Attachment D of this permit.
	47.6 lb/hr (24-hour block average)	
B-55-1, Organic Acids & Anhydrides Manufacturing, Vents B, C, E, I, and K (82-0003-224, MSOP-23)	6.74 lb/hr (average for each batch cycle)	Periodic monitoring was not required because this emission limit was based on the maximum hourly uncontrolled emission rate for the source. The permittee may not modify this source in any way that increases SO_2 emissions above the permitted allowable.

TAPCR 1200-03-10-.02(1)(a), 1200-03-10-.02(2)(a)

4. Upon notification by the Technical Secretary that a reference monitor for the area has registered four validated ambient SO_2 concentrations in excess of the standard (75 parts per billion, 99^{th} percentile of daily maximum one-hour average concentrations determined in accordance with 40 CFR 50, Appendix T) during calendar years 2024, 2025, 2026, or 2027, or that a monitored SO_2 violation based on the design value occurred during or after calendar year 2028, the permittee shall undertake a full system audit of all emissions units subject to control under this plan. The permittee must submit a written system audit report within 30 days of the notification. The system audit report must detail the operating parameters of all emissions units, including modeled emission units that were excluded from the SIP, for four 10-day periods up to and including the date upon which the reference monitor registered each exceedance, together with recommended provisional SO_2 emission control strategies for each affected unit and evidence that these control strategies have been deployed, as appropriate. Upon consultation with the Technical Secretary, the permittee shall develop and implement operational changes as necessary to prevent future monitored violations of the standard. These changes may include fuel switching, physical or operational reduction of production capacity, or other changes as appropriate. If a permit modification is deemed necessary, any changes to existing permit conditions shall follow the applicable procedures of TAPCR 1200-03-09. If an emission source is found to be noncompliant with a SIP emission limit, the Technical Secretary will, in addition to conducting enforcement proceedings to bring the source into compliance with its SIP limit, determine whether additional limits must be added to the SIP to meet the requirements of section 172(c)(9) of the Clean Air Act.
TAPCR 1200-03-09-.03(8)

5. This permit supersedes the provisions of operating permit 070072. TAPCR 1200-03-09-.03(8)

6. This permit contains requirements that Eastman Chemical Company must meet in addition to the requirements of Title V Operating Permits 572407, 576501, 576513, 576926, and 577389. TAPCR 1200-03-09-.03(8)

(end of conditions)

Attachment A: B-83 and B-325 SO_2 Monitoring and Reporting	
Stack or Flow Diagram Points	PES B-83-1, Boilers 18 through 24 PES B-325-1, Boilers 30 and 31
Pollutants	SO_2 (combined total emissions for all boilers)
Description of Monitoring Protocol	The source owner or operator shall install, maintain, operate, and submit reports of sulfur dioxide emissions from continuous in-stack monitoring systems for sulfur dioxide (SO_2) and either oxygen (O_2) or carbon dioxide as the diluent gas. The sensors of these monitoring systems shall be located in representative areas of the effluent gas stream of the boiler. Electronic signal combining systems shall be installed to convert the output of the pollutant monitors into units of the applicable emission standards. The in-stack sulfur dioxide monitoring systems shall meet all the requirements of 40 CFR Part 60 Appendix B Performance Specification 2 or 40 CFR Part 75 Appendix A. SO_2 emission rates in lb/hr shall be calculated as follows: **Boilers 23-24 and 30-31**: The source owner or operator shall install, certify, operate, and maintain a SO_2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO_2 concentration (in parts per million), volumetric gas flow (in standard cubic feet per hour), and SO_2 mass emissions (in lb/hr) discharged to the atmosphere. The in-stack flow monitoring systems shall meet all the requirements of 40 CFR Part 60 Appendix B Performance Specification 6 or 40 CFR Part 75 Appendix A. **Boilers 18-22:** 40 CFR 60 Appendix A, Method 19 shall be used to determine hourly average emissions of sulfur dioxide expressed as pounds per million Btu heat input. Hourly average emissions of sulfur dioxide expressed as pounds per hour shall be determined by multiplying each hourly average sulfur dioxide emission rate expressed as pounds per million Btu by the respective hourly average heat input. The heat input for Boilers 18-22 will be computed by determining the energy rise of the steam across the individual boiler. The energy rise will be calculated as the difference in the energy of the output steam and the energy of the feedwater input. Boiler outlet pressure, temperature and flow along with the inlet feedwater temperature and flow will be used to determine the total energy change across the boiler. The energy of the outlet steam will be approximated by multiplying the boiler outlet steam flow by steam enthalpy. Enthalpy for the outlet steam conditions shall be determined using the ASME International Steam Tables for Industrial Use at the steam outlet pressure and temperature. Boiler outlet energy will be adjusted for an assumed boiler efficiency of 85%. The feedwater energy will be calculated by multiplying the inlet feedwater flow by the inlet feedwater enthalpy. The feedwater enthalpy will be determined using the enthalpy of saturated water from the ASME Steam Tables at the boiler economizer inlet feedwater temperature. The boiler heat will be determined by subtracting the boiler inlet energy form the boiler outlet energy. This heat input will be transmitted to the SO_2 CEMS data acquisition and control system (DAHS) to use for computation of the sulfur dioxide mass emission rate in pounds per hour. Missing emissions data shall be addressed as follows: Data is considered missing if there are fewer than two valid 15-minute averages during the hour. Data shall be substituted for the duration of each missing data period by using the higher value of: 1) the last valid hourly emission rate before, or 2) the first valid hourly emission rate after, the period of missing data.

Attachment A: B-83 and B-325 SO_2 Monitoring and Reporting	
Calculation of 30-day rolling average	Compliance will be determined on a 30 boiler operating day rolling average basis. All 30-day rolling averages shall be calculated as specified in 40 CFR §63.10021(b) and Equation 8: $$\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq. 8)$$ Where Her_i is the hourly emissions rate for hour i (combined total emissions for all boilers) and n is the number of hourly emissions rate values collected over 30 boiler operating days. **Note**: "Boiler operating day" means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in any of the boilers. It is not necessary for the fuel to be combusted the entire 24-hour period.
Operational requirements for Sulfur Dioxide (SO_2) Monitoring Systems	For each boiler to demonstrate continual compliance with the applicable sulfur dioxide emissions limitations, the in-stack sulfur dioxide monitoring systems shall be fully operational for at least 95% of the operational time of the monitored boiler during any calendar quarter. An operational availability of less than this amount may be considered the basis for declaring the source to be in noncompliance with the applicable monitoring requirements, unless the reasons for the failure to maintain this level of operational availability are accepted by this division as being legitimate malfunctions of the instruments.
Reporting Requirements	The owner or operator shall submit excess emission reports and CEMS downtime reports in accordance with Rule 1200-03-10-.02(2). If there are no excess emissions or CEMS downtime during the reporting period, the owner or operator shall submit a report to that effect. The reports shall be included with the semiannual reports required by the applicable Title V operating permits.

Attachment B: B-248-1 and B-248-2 Monitoring and Reporting

Stack or Flow Diagram Points	PES B-248-1: Vents D (Rotary Kiln #1) and E (Rotary Kiln #2) PES B-248-2: Vent A (Liquid Chemical Incinerator)
Pollutants	SO_2
Control Equipment	SO_2 emissions from the solid/liquid chemical waste incinerators (82-0003-282, PES-B-248-1) and liquid chemical waste incinerator (82-0003-283, PES B-248-2) shall be continuously controlled by wet scrubbers (Croll-Reynolds Clean Air Technologies multi-rod scrubber for each emission point).
Description of Monitoring Protocol	See below

Description of Monitoring Protocol

1. Continuous Monitoring of Rod Scrubber Underflow pH

A pH sensor and transmitter are installed in either the rod scrubber underflow line or the sump (which receives the rod scrubber underflow) before any caustic or additional water is added in the recycle loop. The distributed control system (DCS) will receive pH values from the transmitter, and a data archival system shall record the pH reading four or more times equally spaced over the hour. The permittee shall operate and maintain continuous monitoring systems (CMS) for scrubbing liquid pH and shall operate all CMS to document compliance with the applicable operating parameter limits under this section as follows:

(a) The permittee shall install and operate the CMS in compliance with the manufacturer's written specifications or recommendations for installation, operation, and calibration.

(b) The CMS must sample the regulated parameter without interruption, and evaluate the detector response at least once each 15 seconds, and compute and record the average values at least every 60 seconds.

(c) The span of the CMS detector shall not be exceeded.

(d) Each parameter shall be monitored, and the permittee shall calculate SO_2 emissions from the sulfur feed rate and rod scrubber underflow pH.

(e) The permittee shall perform inspections and maintenance of the scrubbers as recommended by the manufacturer.

2. Determination of Sulfur Dioxide Removal Efficiency

A series of computer simulations using a commercially available software package (ASPEN®) have been conducted to establish the rod scrubber underflow pH as the key process variable that indicates sulfur dioxide control efficiency. Computer simulations were conducted at varying sulfur loading conditions and correlation curves relating pH and scrubber control efficiency were derived. The correlation curve for the highest sulfur feed modeled was used to develop the relationship programmed into the DCS. The DCS relationship is programmed as a series of straight lines plotted between the following points:

Point	Rod Scrubber Underflow pH	Sulfur Dioxide Removal Efficiency (%)
1	0.00	0.0
2	4.13	0.0
3	4.20	67.2
4	4.42	82.8
5	4.74	90.6
6	5.64	98.1
7	14.00	98.1

3. Determination of Sulfur Feed Rates

Waste stream sulfur concentrations are determined either from process knowledge or from analysis using ASTM method D4239 or equivalent and are entered into the Environmental Management Information System (EMIS). EMIS provides information to the DCS regulating the feed of waste. As waste streams are burned, sulfur feed rates are calculated by the DCS using waste and fuel mass flow sensors that are required by 40 CFR 60 Subpart EEE.

Attachment B: B-248-1 and B-248-2 Monitoring and Reporting

Description of Monitoring Protocol (Continued)	4. Calculation of Stack Gas SO_2 Concentration At a minimum of four equally spaced intervals in each hour, the DCS shall calculate the SO_2 emissions concentration using the stack gas flow rate (obtained from sensors required by 40 CFR 63 Subpart EEE), assuming all sulfur from Step #3 is converted to SO_2 and using the SO_2 control efficiency determined in Step #2. The hourly SO_2 concentration and annual emission rate are calculated using the following assumptions and equations: Assumptions: 1. Standard conditions are 68° F and 1 atm; 2. Mole weights: sulfur (S) = 32.06, sulfur dioxide (SO_2) = 64.06; 3. SO_2 removal is based on the relationship established in Step #2; 4. All sulfur feeds react completely to SO_2; 5. Density of SO_2 gas at standard conditions = 0.1662 lb/ft^3. **SO_2 emission rate (lb/hr)** = sulfur feed rate (lb/hr) x (64.06 lb SO_2/32.06 lb S) x (1-SO_2 removal) 30-day rolling average SO_2 emission rates will be calculated from hourly emission rates.
Averaging	One-hour averages shall be calculated from four or more equally spaced data averages over each one-hour period, except during periods of monitoring system breakdown, monitoring system repairs, and periods of non-operation of the source. During these periods, a valid one-hour average shall consist of at least two 15-minute averages. Data collected during periods of monitoring system breakdown, monitoring system repairs, required quality assurance or control periods, and periods of non-operation of the source shall not be included in the data averages. Compliance will be based on a 30-day rolling average basis. 30-day rolling averages shall be calculated as the arithmetic average of all valid one-hour averages over each 30-day period, beginning on midnight of the first day and ending at midnight on the 30th day. For a given 30-day averaging period, a valid average must include at least 75% percent of the measured values within the averaging period.
Monitoring Downtime Incidents	During periods of pH monitoring downtime, the sulfur dioxide removal efficiency shall be assumed to be zero in Step #2 above. Therefore, and pH monitoring system downtime incidents do not need to be reported as required by 40 CFR §64.9(a)(2)(ii). Any monitoring downtime incidents shall be reported in the semiannual reports, unless, in the case of a feed rate flow sensor, the feed line block valve is closed during the incident.
Minimum Data Availability	The SO_2 monitoring system shall be fully operational for at least 95% of the operational time of the incinerator during each semiannual reporting period.
QA/QC Practices	The pH sensors shall be calibrated once per month.
Reference	Operating Plan in the Title V application dated May 24, 2019, PES B-248-1, pages 25 and 26. Operating Plan in the Title V application dated September 28, 2017, PES B-248-2, pages 12 and 13.

Attachment C: PES B-334-1 Monitoring and Reporting	
Stack or Flow Diagram Points	Tail Gas Incinerator (Vent B)
Description of Monitoring Protocol	An extractive sampling system or equivalent monitor shall continuously measure the H_2S composition in the Shell Claus Off-gas Treatment (SCOT) process overhead stream entering the Tail Gas Incinerator. The gas flow rate into the incinerator shall be continuously monitored, and the distributed control system shall use the H_2S composition and the flow rate (differential pressure or equivalent device) to calculate the SO_2 emission rate in lb/hr for a 24-hour block average. Process operational time does not include periods of Sulfur Recovery Plant outages. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks, zero and span adjustments, shall not be included in the data averages. In the event of an analyzer outage or Claus unit upset requiring direct venting to the incinerator, engineering evaluation and calculations will determine the lb/hr SO_2 emissions using actual operational data from the Claus and SCOT units.
Equipment and Installation	Hydrogen sulfide analyzer and flow meter located at the inlet to the tail gas incinerator.
Measurement Frequency	Continuous (at least once every 15 minutes)
Minimum Data Availability	The SO_2 monitoring system shall be fully operational for at least 95% of the operational time of the incinerator during each semiannual reporting period.
QA/QC Practices	Calibrate and maintain all monitoring equipment in accordance with manufacturer's specifications.

Attachment D: PES B-351-5 Monitoring and Reporting	
Stack or Flow Diagram Points	Cold Flare (Vent B) and Warm Flare (Vent C)
Description of Monitoring Protocol	Calculate hourly and 24-hour block average SO_2 emissions using the following parameters: 1. Valve operating positions (percentage valve open); 2. Valve upstream pressures; 3. Flow meter readings for valves. Excess gas from the coal gasification process is relieved based on system pressures to one of two vent systems and combusted in a flare. Flow rates through all but two safety relief valves are calculated using the upstream operating pressure and position of each valve. Flow rates through two safety relief valves are directly measured using flow meters. SO_2 emissions are calculated from the gas flow rates are converted into sulfur flow rates using known plant gas stream compositions assuming 100% conversion of H_2S to SO_2 via combustion in the flare.
Equipment and Installation	Control valve, pressure transmitter, and flow meter located upstream of each flare.
Measurement Frequency	Continuous (at least once every 15 minutes)
Minimum Data Availability	The SO_2 monitoring system shall be fully operational for at least 95% of the operational time of the incinerator during each semiannual reporting period.
QA/QC Practices	**Valve operating positions**: An annual field review will be completed for each control valve. Each flare valve will be verified either during process-related opening or by conducting a manual valve calibration check. Either (1) the process-related verification is completed by verifying the DCS-indicated percent open matches the field-observed percent open; or (2) a manual verification is completed by isolating the selected valve using manual valves as available (the isolated control valve will be given a DCS command to open to a set percentage, and a field operator will visually verify that the correct valve position is achieved). **Valve upstream pressures**: the pressure transmitters are used as input parameters to critical process control loops. Normal and ongoing operations, in conjunction with operators' experience, will ensure proper operation of the pressure transmitters. Any abnormal function in these devices would require corrective action as part of normal plant operations. **Flow meters**: Flow meters shall be calibrated annually.

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED STATE IMPLEMENTAITON PLAN	)	ORDER NO. 23-002
ATTAINMENT DEMONSTRATION	)	
FOR THE SULLIVAN COUNTY ONE-HOUR SO_2	)	
NONATTAINMENT AREA	)	

BOARD ORDER

The Sullivan County, Tennessee SO_2 nonattainment area includes the portion of Sullivan County encompassing a circle having its center at coordinates 36.5186 N; 82.5350 W (B-253 powerhouse, Eastman Chemical Company), and having a three-kilometer radius. Between 2008 and 2010, air quality monitoring at one monitor within this region indicated that the annual average SO_2 concentrations exceeded the 75 ppb National Ambient Air Quality Standard (NAAQS), and EPA designated the area as nonattainment for the one-hour SO_2 NAAQS, effective October 4, 2013.

Air quality modeling runs modeling runs performed by the Division of Air Pollution Control indicate that the Kingsport nonattainment area will attain the NAAQS based on: 1) SO_2 emission reductions achieved by Eastman's conversion of the B-253 powerhouse (Boilers 25-29) from coal to natural gas operation; 2) installation of dry sorbent injection on Eastman's B-83 powerhouse (Boilers 23 and 24); and 3) adoption of new emission limits for Eastman's B-83 and B-325 powerhouses, hazardous waste incinerators, coal gasification operations, and organic acids recovery operations, and Primester's sludge recovery operation..

The Tennessee Air Pollution Control Board finds that the Attainment Demonstration for the Sullivan County, Tennessee SO_2 Nonattainment Area projects that the area will attain the SO_2 National Ambient Air Quality Standard and approves the submittal of the Attainment Demonstration to U. S. EPA for adoption into Tennessee's State Implementation Plan.

Approved on February 8, 2023, by the members of the Tennessee Air Pollution Control Board as follows:

______________________	______________________
______________________	______________________
______________________	______________________
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TN Department of Environment & Conservation

NESHAP Rules Incorporation by Reference

Mark A. Reynolds, Environmental Consultant

NESHAP Rules

- Federal NESHAP Rules
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- 40 CFR Part 61
- 40 CFR Part 63

NESHAP Rules

- Federal NESHAP rules are incorporated by reference in state rules at 0400-30-38
- Board approved this rule in June 2022
- Became state effective on December 28, 2022
- Adopted the July 1, 2020, version of 40 CFR Parts 61 and 63

NESHAP Rules

- This current rule will adopt the July 1, 2022, version of 40 CFR 61 and 63
- By keeping the CFR date current, the Board will be able to keep the state regulations in line with the federal regulations and will be able to enforce the federal regulations directly

NESHAP Rules

- This current rule will also make minor amendments to the Asbestos NESHAP
  - Allow for electronic submissions instead of paper submissions
  - Use of state form for reporting
  - Clarifies some requirements

Two related projects

- Working on a similar rule to adopt by reference all federal NSPS (New Source Performance Standards) rules. Board briefing in October 2022.
- Working with EPA to change TDEC delegation of authority from “automatic” to “adopt by reference” for NESHAP and NSPS rules

Questions

Mark A. Reynolds

Environmental Consultant

Tennessee Department of Environment and Conservation

Division of Air Pollution Control

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