Regional Haze Rule Four-Factor Analysis for the International Paper Savannah Mill

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1. INTRODUCTION

The Georgia Department of Natural Resources (DNR) Environmental Protection Division (EPD) is in the process of developing a State Implementation Plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. EPD was required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of visibility impairing pollutants, such as sulfur dioxide (SO_2), for the 2021-2028 period. EPD requested that several facilities within the State submit a Four-Factor Analysis (FFA) to examine the feasibility of additional SO_2 emissions controls for sources shown to contribute to more than one percent to the visibility impairment at Class I Federal areas. EPD submitted an updated SIP to EPA and subsequently submitted a draft regional haze plan on April 22, 2022. EPA responded with comments both on the EPD SIP and the FFA conducted by International Paper (IP) and other permittees.

IP originally submitted this FFA to GA EPD in November 2020. In response to comments from EPA to GA EPD and a request from Anna Aponte, GA EPD, on June 3, 2022[1], IP has updated this report. This report provides the International Paper - Savannah Mill's (Savannah Mill or Savannah) FFA for all significant sources of SO_2 emissions, as requested in EPD's July 10, 2020 letter. Documentation of EPD requests and EPA comments is included in Appendix A. Table 1 of EPD's June 20, 2020 letter indicates that the Savannah Mill is shown to contribute more than one percent of the visibility impairment at the Wolf Island Wilderness, Cape Romain Wilderness, and Okefenokee Wilderness Class I areas.

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available

[1] Email from Anna Aponte, GA EPD, to Emily Henderson, IP on June 3, 2022.

Retrofit Technology (BART). Specifically, the BART provisions required states to conduct an evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the New Source Performance Standards (NSPS) at 40 CFR Part 60. The purpose of the program was to identify older emission units that contributed to haze at Class I areas that could be retrofitted with emissions control technology to reduce emissions and improve visibility in these areas. The BART requirement applied to emission units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;
2. The units are located at facilities in one of 26 NSPS categories; and
3. The units have a total potential-to-emit (PTE) of at least 250 tpy of NO_X, SO_2, and PM_{10} from all BART-era emission units at the same facility.

We note that none of the units covered by this FFA are BART units. MACT standards that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: “Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART.” Sources demonstrating compliance with MACT and BART are already well controlled. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, “there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area."[2] The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas, and sources that are already well-controlled. This FFA focuses on the significant sources of SO_2 emissions at the Savannah Mill as directed by EPD and does not further evaluate other well-controlled sources.

There are four significant SO_2 emissions sources at the Savannah Mill and they include the No. 13 Power Boiler (PB13), No. 15 Recovery Furnace (RF15), No. 15 Recovery Furnace Smelt Dissolving Tank (RF10), and No. 7 Lime Kiln (LK07). This report provides a FFA for SO_2 for the No. 13 Power Boiler and No. 15 Recovery Furnace. Annual SO_2 emissions from the No. 15 Recovery Furnace Smelt Dissolving Tank and the No. 7 Lime Kiln are approximately 6 tons per year total based on past air emissions inventory reports. The No. 15 Recovery Furnace Smelt Dissolving Tank is already equipped with a wet scrubber. The No. 7 Lime Kiln achieves inherent control of SO_2 through absorption of sulfur by the calcium in the kiln. Therefore, as these units are well controlled and low emitting, they are not included in the FFA because no additional SO_2 emissions control measures would be reasonable to apply. A summary of actual annual SO_2 emissions and projected SO_2 emissions are presented in Table 1-1.

Table 1-1
Summary of Annual SO_2 Emissions

Emissions Unit Description	2018 Emissions (TPY)	2019 Emissions (TPY)	Projected 2028 Emissions (TPY)[2]
No. 13 Power Boiler	4,252[1]	3,911	4,082
No. 15 Recovery Furnace	22	20	21
No. 7 Lime Kiln	2	2	2

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

Emissions Unit Description	2018 Emissions (TPY)	2019 Emissions (TPY)	Projected 2028 Emissions (TPY)[2]
No. 15 Recovery Furnace Smelt Dissolving Tank	4	3	4

1. 2018 emissions from PB13 have been updated to use the most recent SO_2 emission factor based on stack test data when firing non-condensable gases.
2. Projected 2028 Emissions are based on the average of 2018 and 2019 actual annual emissions. These emissions are slightly higher and more representative than the 3,945 tpy projection used by Georgia DNR because they are an average of two recent representative production years that are a reasonable approximation of the emission levels that the Mill expects in 2028.

Table 1-2 presents expected average hourly emission rates during normal operation at production capacity compared to the allowable hourly emission rates for each source as listed in Title V Permit No. 2631-051-0007-V-03-0. The hourly emission rates shown are calculated based on the most recent stack test average or published data and the maximum rated capacity of each source. They represent expected hourly emission rates during normal operating conditions and because they are based on averages of stack test data, they do not reflect any operational variability that can occur due to fluctuations in process operating variables or transitory conditions such as startup and shutdown. These hourly emission rates cannot be extrapolated directly to annual emission rates because the Mill does not operate at capacity on a continuous basis and equipment is periodically shutdown for maintenance.

The expected average hourly SO_2 emission rates for the No. 15 Recovery Furnace, No. 7 Lime Kiln, and No. 15 Smelt Dissolving Tank are less than 10% of the allowable emission rates and support the reasonable projection of actual emission levels for 2028. The differences between actual and allowable emission rates are not due to reduced utilization or lack of demand, but are a result of changes in operation of the units over time (e.g., changes in fuel mix) to reduce their emission rates. In addition, the current methods of operation of these sources support that no additional controls or restrictions are necessary in order to maintain low actual emissions (other than removal of certain fuels from the permit as already requested). Actual SO_2 emissions from No. 13 Power Boiler are less than the allowable emission rate because the boiler no longer burns fuel oil or coal. The majority of the SO_2 emissions from No. 13 Power Boiler are a result of combustion of sulfur-containing process gases for compliance with federal air regulations for pulp and paper process units.

The highest hourly SO_2 emissions from a recovery furnace often occur during startup when firing auxiliary fuel. The No. 15 Recovery Furnace no longer burns fuel oil for startup; natural gas is burned during startup and has a much lower SO_2 emission rate than fuel oil. The sodium salt fume in the upper furnace acts to limit SO_2 emissions during normal operations. The highest hourly SO_2 emissions from a lime kiln also often occur when starting up and burning auxiliary fuel. The No. 7 Lime Kiln no longer starts up on fuel oil; natural gas is burned during kiln startup and has a much lower SO_2 emission rate than fuel oil.

As mentioned above, SO_2 emissions during normal operation of the kiln are low due to absorption of any sulfur by the calcium in the kiln. If sulfur-containing pulp mill gases are burned in a lime kiln, breakthrough can occur if the sulfur loading is too high. The No. 7 Lime Kiln serves as a backup control device for combustion of low-volume, high-concentration (LVHC) pulp mill gases. It was designed and permitted as a backup control device for LVHC gases (for compliance with 40 CFR Part 60, Subpart BB) prior to the Mill being required to control its high-volume, low-concentration (HVLC) gases and stripper off-gases (SOG) under 40 CFR Part 63, Subpart S; therefore, the allowable SO_2 limit was put in place assuming the kiln would burn LVHC for a prolonged period of time. However, because HVLC gases and SOG are now also required to be controlled at all times and there is no backup control device for these gases, LVHC gases would only be combusted in the kiln for a short period of time before either the primary control device (No. 13 Power Boiler) was brought back online or the mill was shutdown[3].

[3] The mill has restrictions under 40 CFR 63 Subpart S for not controlling either SOG or HVLC gases. As PB13 is the only control device for these gases, the boiler cannot have prolonged periods of downtime before pulping operations, and therefore the mill must be shutdown.

Table 1-2
Expected Average Hourly Actual SO_2 Emissions During Normal Operation versus Permit Limits

Emissions Unit Description	SO_2 Hourly Permit Limit	Expected Average Hourly Emissions During Normal Operation at Production Capacity	Hourly Emissions Basis
No. 13 Power Boiler	2,822 lb/hr[1]	1,219 lb/hr	Sum of Maximum Capacity of: 140 ADTP/hr and 8.71 lb/ADTP from 2014 Stack Test, 312 MMBtu/hr – Bark and 8.70E-02 lb/MMBtu from TV Condition 6.2.11, and 968 MMBtu/hr – Natural Gas and 5.88E-04 lb/MMBtu from AP-42
No. 15 Recovery Furnace	319 lb/hr	5.8 lb/hr	Maximum Capacity of 168 TBLS/hr and 3.45E-02 lb/TBLS from 2016 Stack Test
No. 7 Lime Kiln	719 lb/hr	1.4 lb/hr	Maximum Capacity of 55.8 TCaO/hr and 2.44E-02 lb/TCaO from 2016 Stack Test
No. 15 Recovery Furnace Smelt Dissolving Tank	11.4 lb/hr	1.0 lb/hr	Maximum Capacity of 168 TBLS/hr and 6.00E-03 lb/TBLS from NCASI TB 884 Update

1. The permit further limits annual emissions from PB13 to 6,578 tpy.

1.1 FOUR-FACTOR ANALYSIS

EPD has requested that the mill address the following four factors specified in the Clean Air Act at Section 169A(g)(1) for technically feasible SO_2 emission control measures:

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

Savannah has addressed these factors for additional control options that could be applied to the power boiler and recovery furnace at the mill using available site-specific data, capital costs of controls from U.S. EPA publications or previous analyses (either company-specific or for similar sources), and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual and U.S. EPA fact sheets. The Savannah Mill has not performed site-specific engineering analyses for this study but has used readily available information to determine if additional emissions controls may be feasible and cost effective. The emissions reduction expected for each control technology evaluated was based on a typical expected control efficiency and projected 2028 actual emissions. Evaluating cost effectiveness based on actual emissions provides a better representation of the true cost of each technology to the mill than an evaluation based on allowable emissions. In addition, actual emissions are more representative of the 2021-2028 planning period than potential emissions. The average of 2018 and 2019 actual emissions are representative of 2028 emissions because they are reflective of anticipated production, fuel, and non-condensable gas (NCG) firing scenarios at the Savannah Mill and emissions were calculated using the most recent site-specific and published emission factors.

An interest rate of 4.75% and 20 year equipment life were used to calculate the capital recovery factor. We selected a 20-year equipment life based on our financial policy of depreciating equipment over 20 years. While equipment may have a longer useful life, financial policy dictates how capital costs are depreciated. In addition, a useful life of 30 years for DSI is not realistic because the abrasive environment will result in a shorter useful life. Although the OAQPS Cost Manual might suggest that 30 years is appropriate, industry experience indicates that equipment will need to be rebuilt before that time. For these reasons, 20 years is the useful life span for both technologies evaluated. The 4.75% interest rate represents the current bank prime interest rate (as of June 17, 2022[4]) as recommended by the OAQPS Cost Manual; however, the prime rate dropped during the COVID-19 pandemic and has varied over the past two years from 3.25% to a high of 5.5% in December 2018. Labor, chemical, and utility costs are primarily based on mill-specific values from finance department records for 2022.

[4] https://www.federalreserve.gov/releases/h15/

1.2 SUMMARY OF SOURCES EVALUATED

Table 1-3 lists the SO_2 emission units included in the FFA with their installation dates, fuels, existing emission control technology, expected 2028 SO_2 emissions, and applicable major air regulations. The boiler and recovery furnace evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants (HAPs) and are already well controlled. Industrial boilers and recovery furnaces are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), which require the use of Maximum Achievable Control Technology (MACT). While the MACT standards are intended to minimize HAP emissions, they also directly reduce acid gas emissions and promote good combustion practices. NSPS Subpart D contains emission limits for SO_2. The fuels fired by the No. 13 Power Boiler are low-sulfur fuels (natural gas and biomass) as the mill has discontinued its use of coal. The majority of the SO_2 emissions from the boiler are from combustion of NCGs that contain sulfur compounds. These gases are combusted to meet the HAP emissions control requirements of 40 CFR 63, Subpart S.

Table 1-3
Summary of Emissions Sources Evaluated

Emissions Unit Description	Size	Year Installed	Permitted Fuels	Control Technology	Major Regulatory Programs	Projected 2028 Actual SO_2 Emissions[1] (tons)
No. 13 Power Boiler[2]	1,280 MMBTU/hr	1982	Biomass, Natural Gas, (Coal to be removed)	Low-sulfur startup fuel, Electrostatic Precipitator, LVHC sent to a White Liquor Scrubber	NSPS Subpart D MACT Subpart DDDDD	4,082
No. 15 Recovery Furnace	162.2 TBLS/hr	1995	Natural Gas, Black Liquor Solids (No. 6 Fuel Oil to be removed)	Low-sulfur startup fuel, Electrostatic Precipitator	MACT Subpart MM	21

[1] Average of actual emissions from 2018 and 2019.
[2] The No. 13 Power Boiler is permitted to combust HVLC pulp mill gases, LVHC pulp mill gases, and SOG. A portion of the LVHC gases are controlled by the White Liquor Scrubber.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the mill has made emissions reductions for a variety of reasons. The mill is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including the use of clean fuels for startup, and resulted in emissions reductions of both HAPs and SO_2. With the Boiler MACT project, the Savannah Mill ceased firing fuel oil in PB13, added load-bearing natural gas burners, and optimized combustion controls and the combustion air system. The Savannah Mill stopped burning coal in PB13 in 2017 and stopped burning No. 6 fuel oil in RB15 in 2015. The Mill does not intend to burn No. 6 fuel oil in the future and requested removal of coal and No. 6 fuel oil as permitted fuels in the latest Title V renewal application submitted in December 2019. Document Organization
The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the FFA.
- **Section 2 – Four-Factor Analysis for the Boiler:** provides the FFA for PB13.
- **Section 3 – Four-Factor Analysis for the Recovery Furnace:** provides the FFA for RF15.
- **Section 4 – Estimated Visibility Impact:** presents a discussion of the estimated visibility impacts of the Mill and any additional controls.
- **Section 5 – Summary of Findings:** presents a summary of the FFA.
- **Appendix A – EPD Requests and EPA Comments**
- **Appendix B – Control Cost Estimates**
- **Appendix C – Supporting Information**

1.4 RESULTS OF THE FFA

As previously stated, both the No. 13 Power Boiler and No. 15 Recovery Furnace are already well-controlled, the few technically feasibly controls are not cost effective, and the sources are not significantly contributing to visibility impacts at nearby Class I areas[5]. Further control should not be required to reduce emissions for the second planning period of the RHR.

[5] Refer to Section 4 of this report.

2. FOUR-FACTOR ANALYSIS FOR THE BOILER

This section of the report presents the results of the FFA for SO_2 emissions from PB13 at the mill. To evaluate the cost of compliance portion of the FFA, Savannah performed the following steps:

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

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

2.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for industrial boilers was determined based on a review of the RBLC database[6] and knowledge of typical controls used on boilers in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 2-1 summarizes the potentially feasible control technologies for industrial boilers.

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

Table 2-1
Control Technology Summary

Pollutant	Typically Available Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet Scrubbers Dry scrubbing systems

Technically feasible control technologies for industrial boilers were evaluated, taking into account current air pollution controls, fuels fired, and RBLC Database information. Fuel switching from biomass to 100% natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[7] It is not reasonable as part of this analysis to convert an existing biomass boiler at a forest products mill to a natural gas-fired boiler because biomass boilers at forest products mills fire the biomass residuals from the mill processes as a readily available, carbon neutral, and relatively inexpensive source of fuel. U.S. EPA's Regional Haze Guidance states the following on page 29: "A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."

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

2.1.1 Available SO_2 Control Technologies

The potentially feasible control measures for reducing emissions of SO_2 from industrial boilers are discussed in detail in this section.

Low-Sulfur Fuels

Uncontrolled emissions of SO_2 are proportional to the amount of sulfur in the fuel (or process gas) being fired in a boiler. Natural gas and biomass are considered low-sulfur fuels and are fired by PB13. Natural gas and biomass combustion result in negligible SO_2 emissions.

NCG Incineration

As previously stated, the majority of SO_2 emissions from PB13 are a result of burning NCGs. NCG's are collected at various points throughout the pulp and paper process from sources such as the evaporator, digester, and washer systems and burned in PB13. HAP emissions from NCG sources are required to be controlled per 40 CFR 63, Subpart S. Options for control include incineration in a recovery furnace, power boiler, lime kiln, or a thermal oxidizer. Installation of a dedicated thermal oxidizer requires a large capital investment, creates an additional point source of emissions, requires additional water use, and would require installation of a scrubber following the thermal oxidizer for SO_2 control. Additionally, International Paper has operational experience with thermal oxidizers at several mills, and these incinerators have proven to be very unreliable and have had poor compliance performance. Incineration of NCGs in the lime kiln contributes to ring formation which limits kiln capacity and can cause unscheduled shutdowns. A well-operated recovery furnace can have very low SO_2 emissions since one primary purpose of a Kraft recovery furnace is to recover this sulfur and reuse it as fresh cooking chemical for the pulp and the sodium salt fume in the upper furnace acts to limit SO_2 emissions.

Wet Scrubbers

In a wet scrubber, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant and the amount of gas to liquid contact and residence time. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers. Generation of wastewater from the scrubber and its disposition must be considered in any evaluation.

The wet scrubbing process described above results in a visible plume from the stack and would require a new stack and ductwork replacement for acid resistance. Due to the size of the existing stack and because the Savannah Mill is located in close proximity to downtown Savannah, flue gas reheat is considered. With the addition of a flue gas reheat system at the end of the wet scrubbing process, as the gas is reheated before release, the visible plume is significantly reduced or completely mitigated. Other benefits of flue gas reheat are an enhanced plume rise and increased dispersion of residual pollutants.

White Liquor Scrubber for NCGs

Pulp and paper mills install a white liquor scrubber in-line with the NCG collection system to reduce the need for sulfur make-up in the liquor cycle through recovery of sulfur in the NCG streams prior to incineration. Sulfur compounds in the NCGs are converted to SO_2 when incinerated therefore a white liquor scrubber aids to reduce SO_2 generated from combustion by recovering a portion of sulfur back to the liquor cycle prior to incineration. The Savannah Mill already controls certain LVHC gas streams via a white liquor scrubber prior to combustion.

Circulating Dry Scrubber with Pulse Jet Fabric Filter

In a circulating dry scrubber, a dry sorbent (usually lime) is mixed with the flue gas in a dedicated vessel. The pollutant molecules react with the sorbent to form salts and reacted solids are dried completely by heating of the flue gas. These solids are then routed to a fabric filter where they are collected and eventually removed from the system and sorbent is returned to the reaction chamber.

In a pulse jet fabric filter system, the fabric filter is cleaned by a compressor providing a high-pressure burst of air into the open end of the fabric filter resulting in higher amounts of solids being removed over time. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing, which would be especially challenging in Savannah with high humidity levels. It is also noted that the salts created by this control device will be collected in the ash system and change the chemical makeup of the ash and create potential disposal and/or beneficial reuse issues.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream and prior to PM air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. DSI systems are typically used to control SO_2, hydrochloric acid and other acid gases on coal-fired boilers.

The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the same as described for the dry scrubber system. Additionally, a brown visible plume can potentially form when NO_2 concentrations reach about 35 ppm and above. Trona reacts with NO to form NO_2 and at high NOx levels and high trona injection rates, some units have experienced a visible brown/yellowish plume at the stack. This could cause issues with negative public perception, and potentially an increase in citizen complaints due to the proximity of the mill to the downtown Savannah area.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same or similar type of emissions unit under review or is available and applicable to the emissions unit type under review.

Prior to the Boiler MACT project, No. 13 Power Boiler was permitted to burn coal, biomass, fuel oil, and NCGs. After the Boiler MACT project fuel conversion, the boiler was able to burn coal, biomass, natural gas, and NCGs. Since the conversion, the Savannah Mill has eliminated coal use and requested to remove coal as a permitted fuel with the 2019 Title V renewal application. Potassium is generated during biomass combustion which in combination with chlorine can cause boiler corrosion depending on the boiler design; however, corrosion is mitigated when potassium binds with sulfur. Because the boiler was originally designed to burn coal and biomass, the metallurgy of PB13 is different than for a boiler originally designed to burn biomass in combination with a lower sulfur fuel. With coal no longer being a source of sulfur, corrosion is mitigated in PB13 when potassium binds with the sulfur in the NCGs. Therefore, if NCG's were removed from the power boiler, it would experience accelerated superheater corrosion or the final super heater temperature would need to be lowered, derating the boiler.

Other challenges exist with the control options of routing the NCG's to the recovery furnace or further control of NCG's in a white liquor scrubber. Either option would impact the Mill's liquor cycle because sulfur would be recovered back into the liquor cycle through either the white liquor scrubber bottoms or the recycled salt cake from the recovery boiler electrostatic precipitator (ESP). Additionally, sewering spent white liquor to the WWTP would result in air emissions because spent liquor contains hydrogen sulfide and methyl mercaptan that remains in solution at a high pH.

As the high pH spent liquor would be combined with other lower pH process wastewater streams at the WWTP, the pH of the spent liquor stream would decrease. This decrease in pH would then result in hydrogen sulfide and methyl mercaptan being released from solution, resulting in increased emissions and odor.

The basic elements of pulping chemicals are sulfur (S) and sodium (Na) and these chemicals must be maintained in balance to run the pulping process reliably and to maintain the desired pulp quality and yield. If additional sulfur were added to the liquor cycle from the control of additional NCGs, then the Mill would need to either purge sulfur from the liquor cycle or increase make-up chemicals in the form of sodium to maintain that sulfur to sodium balance. Additionally, increasing sulfur content in the liquor cycle would impact International Paper's agreement to accept spent acid from a neighboring facility because this would upset the sulfur balance already established at the Mill. If sulfur needs to be purged from the system, the solution would be to discharge the brine from the neighboring facility to the IP Savannah's WWTS. Therefore, the control options of routing the NCG's to the recovery furnace or control of additional NCG's in a white liquor scrubber are not considered reasonable and were not further evaluated in this report for the Savannah Mill.

The Savannah Mill's Wastewater Treatment Plant (WWTP) is covered by a National Pollutant Discharge Elimination System (NPDES) permit. The current permit, with an effective date of 2019, contains a compliance schedule to meet biologically-based Ultimate Oxygen Demand (UOD) limits that were agreed to in the Savannah River Subcategory 5R plan and represent an approximately 85% reduction in current permit limits[8]. This reduction requires a significant upgrade of the existing wastewater treatment system as well as employment of a Best Management Practices (BMP) program to significantly reduce loading upstream of the treatment system. Wastewater produced from the sewering of NCGs in white liquor, effluents generated from a wet scrubber system and/or the third-party brine contain high loading in the form of high sulfur content

[8] https://epd.georgia.gov/watershed-protection-branch/total-maximum-daily-loadings#_TMDL_Alternatives

and high Chemical Oxygen Demand (COD). In a biological WWTP, wastewater kinetics dictate that the oxygen demand associated with COD must first be satisfied in order for efficient destruction of UOD to occur. High COD demand is further exacerbated by the presence of high sulfur because sulfur is an oxygen scavenger. Even with the significantly upgraded treatment system and use of BMP, biologically-based wastewater treatment systems experience extended periods (on the order of months) of reduced efficiency due to seasonal influences and typical operational upsets. These periods can reduce compliance margins to less than 10%. During these periods, the inclusion of an effluent stream that has a high COD and sulfur content would likely result in non-compliance with our NPDES permit.

Additionally, the Savannah Mill is covered by a groundwater withdrawal permit that contains a compliance schedule to reduce groundwater consumption by 1.3 MGD by 2025 and requires additional capital investment to offset current groundwater usage. The freshwater demand for a wet scrubber system represents 10% of that required reduction and implementing a wet scrubber system would jeopardize compliance with our future groundwater permit limits.

Therefore, the control options of a white liquor scrubber, wet scrubber system or controlling NCGs in the No. 15 Recovery Furnace were not considered reasonable and were not further evaluated in this report for the Savannah Mill.

2.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

Installing a circulating dry scrubber with a pulse jet fabric filter and DSI in the form of trona injection prior to the No. 13 Power Boiler's ESP were considered technically feasible and were evaluated.

2.4 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

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

The SO_2 control technologies evaluated for cost effectiveness for No. 13 Power Boiler are summarized in Table 2-2. Capital, operating, and total annual cost estimates for each feasible pollution control technique are presented in Appendix B. These are screening level cost estimates and are not based on detailed site-specific engineering studies.

Table 2-2
Control Technologies Evaluated for PB13

Pollutant	Additional Controls Evaluated on PB13
SO_2	Circulating dry scrubber with pulse jet fabric filter system Dry sorbent injection

U.S. EPA indicates that a retrofit factor is appropriate when estimating the cost to install a control system on an existing facility, in order to address the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the cost of correcting design errors. A retrofit factor can be used to reflect additional difficulty associated with installing auxiliary equipment, special care in placing equipment, additional insulation and painting of piping and ductwork, additional site preparation, extra engineering or supervision during installation, and unanticipated delays that cause lost production costs. The OAQPS Cost Manual, Section 1, Chapter 2 states that at the study cost level, a retrofit factor of as much as 50 % is justified, and even at the detailed cost level, a retrofit factor is often added. A retrofit factor of 1.5 was applied to the total capital cost of each control technology evaluated as an engineering study has not been performed, space constraints exist, and production could be lost due to an extended Mill outage or unexpected delays.

2.4.1 SO_2 Economic Impacts – Circulating Dry Scrubber with Pulse Jet Fabric Filter

The circulating dry scrubber with a pulse jet fabric filter system capital cost was estimated using the spray dryer absorber (SDA) cost methodologies presented on EPA's Retrofit Cost Analyzer page[9] (based on a January 2017 Sargent and Lundy report prepared under a U.S. EPA contract) and scaled from 2016 to 2021 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Although Black & Veatch evaluated HCl controls for Boiler MACT compliance in 2014, the boiler's fuel and emissions profile have changed since that time and the controls were not sized or evaluated for SO_2 control; therefore, the U.S. EPA cost estimating methodology for dry scrubbers was utilized.

Capital cost for an onsite landfill expansion was also included because the mill is currently restricted on the amount of lime product that can be sent to the offsite landfill being used. The landfill expansion cost is based on a 2007 study by URS Corporation, with the cost scaled to 2021 dollars. Operating costs were estimated using site specific utility, labor, and chemical costs. The estimated emissions reduction is based on 90% control, although a site-specific evaluation of this technology for SO_2 control on PB13 as it is currently operated has not been performed. Table 2-3 summarizes the estimated cost effectiveness of implementing this control technology for the No. 13 Power Boiler.

2.4.2 SO_2 Economic Impacts – DSI System

The capital cost for a DSI system to inject trona prior to the ESP on the No. 13 Power Boiler was estimated using the EPA's Retrofit Cost Analyzer (based on an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract) and was scaled from 2016 to 2021 dollars using the

[9] https://www.epa.gov/airmarkets/retrofit-cost-analyzer

CEPCI. Although Black & Veatch evaluated HCl controls for Boiler MACT compliance in 2014, the boiler's fuel and emissions profile have changed since that time and the controls were not sized or evaluated for SO_2 control; therefore, the U.S. EPA cost estimating methodology for dry sorbent injection was utilized.

Capital cost for an onsite landfill expansion was also included because the mill is currently restricted on the amount of lime product that can be sent to the offsite landfill being used. The landfill expansion cost is based on a 2007 study by URS Corporation, with the cost scaled to 2021 dollars. Site-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system. While the Sargent and Lundy report indicates that 50% SO_2 control can be achieved when injecting trona prior to an ESP without increasing PM emissions, IP selected a control efficiency of 65% based on the EPA calculator guidance[10]. Table 2-3 summarizes the estimated cost effectiveness of implementing this control technology for the No. 13 Power Boiler.

2.4.3 Summary of SO_2 Economic Impacts

Table 2-3 summarizes the estimated capital cost which include the construction of a landfill - discussed further below, annual cost, and cost effectiveness of implementing each SO_2 control technology for the No. 13 Power Boiler, based on operating data and the projected 2028 actual SO_2 emissions.

[10] The PB13 ESP is oversized based on current fuel mix. The original ESP design was for a boiler burning coal and biomass rather than the current configuration of biomass and natural gas.

Table 2-3
PB13 Cost Summary

Control Technology	Capital Cost ($)	Annual Cost ($/yr)	Controlled SO_2 Emissions (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Dry Scrubber	$208,846,066	$20,441,000	3,674	$5,564
DSI	$63,153,860	$16,571,000	2,653	$6,245

IP does not consider implementation of either of these two technologies to be cost effective given the high capital cost and the high cost per ton.

2.4.4 Energy and Non-Air Related Impacts

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

Both the dry scrubber and DSI system options would utilize additional energy and generate additional solid waste. There is no additional disposal capacity in the existing mill-owned landfill, and waste management requirements of the privately owned landfill where the majority of the Mill's waste is disposed strictly controls the amount of lime and sulfur containing wastes the privately owned landfill will accept making the privately owned landfill an unreliable outlet for disposal. Therefore, both the dry scrubber and DSI options would require an expansion of the existing mill-owned landfill. Savannah would need time to obtain corporate approvals for capital funding and would have to undergo substantial expansion design to once again begin fully utilizing the existing landfill. Design, procurement, construction, and staffing up for expanded operations would easily consume three years. Savannah would also need to execute landfill permit modifications that may need to go to public comment. These permit modifications are often time-consuming and have an indeterminate timeline and endpoint. All of this would need to occur in parallel with the complex project associated with the boiler retrofit.

2.5 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls after the effective date of the final standard. If controls are ultimately required to meet RHR requirements, the Mill would need at least three years to implement them after final EPA approval of the RHR SIP. Savannah would need time to obtain corporate approvals for capital funding and would have to undergo substantial re-engineering to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. Savannah would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. Savannah would also need to execute air permit modifications, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate mill systems, the availability of contractors, and the like. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

2.6 REMAINING USEFUL LIFE OF EXISTING SOURCES

The No. 13 Power Boiler has an estimated remaining useful life of twenty years or more.

3. FOUR-FACTOR ANALYSIS FOR THE RECOVERY FURNACE

This section of the report presents the results of the FFA for SO_2 emissions from the recovery furnace at the Savannah Mill. To evaluate the cost of compliance portion of the FFA, Savannah performed the following steps:

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

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

3.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for recovery furnaces was determined based on a review of the RBLC database and knowledge of typical controls used on recovery furnaces in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 3-1 summarizes the potentially feasible control technologies for recovery furnaces.

Table 3-1
Control Technology Summary

Pollutant	Typically Available Controls on Recovery Furnaces
SO_2	Good operating practices Wet Scrubbers Low-sulfur startup fuel

Technically feasible control technologies for recovery furnaces were evaluated, considering current air pollution controls and RBLC Database information. Note that we have not included dry scrubbing as an available SO_2 control for recovery furnaces because all of the particulate collected in a recovery furnace ESP is recycled back into the process and it cannot be contaminated with sorbent.

3.1.1 Available SO_2 Control Technologies

Good Operating Practices

Per NCASI Technical Bulletin 884, Section 4.11.2, most of the sulfur introduced to a recovery furnace leaves the recovery furnace in the smelt while under one percent of sulfur is released into the air. One of the primary purposes of a Kraft recovery furnace is to recover this sulfur and reuse it as fresh cooking chemical for making pulp. Factors that influence SO_2 levels include liquor sulfidity, liquor solids content, stack oxygen content, boiler load, auxiliary fuel use, and boiler design. The sodium salt fume in the upper boiler also acts to limit SO_2 emissions. A well-operated recovery furnace can have very low SO_2 emissions.

Low-Sulfur Startup Fuel

Fossil fuel is used to start up a recovery furnace prior to introducing black liquor. Emissions of SO_2 during a cold startup are proportional to the amount of sulfur in the fossil fuel being fired. Natural gas and ULSD are considered low sulfur fossil fuels and produce negligible SO_2 emissions when combusted.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO2 control, the absorption process is chemical-based and uses an alkali solution (i.e., sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers. Generation of wastewater from the scrubber and its disposition must be considered in any evaluation.

3.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same or similar type of emissions unit under review or is available and applicable to the emissions unit type under review.

The No. 15 Recovery Furnace is not equipped with add-on SO_2 control technology. Good combustion practices and low-sulfur startup fuels are already utilized to minimize SO_2 emissions. Actual emissions from the No. 15 Recovery Furnace are quite low. A wet scrubber is not considered technically feasible for the same reasons set out in Section 2.2. The Mill cannot implement a control technology that increases loading to the WWTP or freshwater demand. Absent those technical considerations, application of capital-intensive add-on controls to this unit would not be cost effective, given the low actual emissions and the expectation that the emissions will continue to be low because high-sulfur fuels are no longer utilized.

3.3 TIME NECESSARY FOR COMPLIANCE

There is no required compliance time because the mill is already using the reasonable and available control measures: good operating practices and low-sulfur startup fuel.

3.4 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The No. 15 Recovery Furnace is assumed to have an estimated remaining useful life of twenty years or more.

4. ESTIMATED VISIBILITY IMPACT

The goal of the RHR is to improve the visibility in Class I areas. Accordingly, when evaluating whether additional emissions controls are reasonable, it is appropriate to consider the degree to which individual control projects might contribute towards that goal. Although states have a statutory requirement to consider the four factors addressed in this report, EPA's guidance[11] also allows inclusion of a fifth factor that considers visibility impacts of controls. On pages 36 and 37 of the August 2019 guidance, the EPA states:

> *"Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal." . . .*
> *". . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."*

EPA's 2019 Regional Haze Rule guidance does not specifically state what would constitute an insignificant visibility impact, but the preamble to the 1999 Regional Haze Rule (64 FR 35730) does specify a "no degradation" visibility change if the impact is less than 0.1 deciview. This amount of visibility change (for the worst 20% haze days) is less than 1% of the 2028 glidepath target, so it constitutes a very low value.

[11] US EPA; "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"[11] in August 2019. Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

The impact to Class I area visibility of current Mill emissions of SO_2 and NOx can be determined by analyzing the results of visibility modeling conducted by the VISTAS / SESARM[12] Regional Planning Organization, of which Georgia is a member. The VISTAS modeling was conducted by Alpine Geophysics and utilized advanced CAMx photochemical grid modeling including modeling particulate matter simulations and source apportionment studies. Determinations of the haze contributions of specified large sources was accomplished by "tagging" the selected sources for determining their contribution to impairment at each Class I area of interest. The IP Savannah Mill was one of the specific sources tagged in the CAMx modeling, so those modeling results can be used directly to determine the visibility impact of the current Mill emissions, as well as the impact of any further controls that would reduce the Mill's emissions.

Visibility impairment is commonly expressed using two parameters to characterize the visibility impairment:

- **Light Extinction (b_{ext})** is the reduction in light due to scattering and absorption as it passes through the atmosphere. Light extinction is directly proportional to pollutant particulate and aerosol concentrations in the air and is expressed in units of inverse megameters or Mm^{-1}.

- **Deciview (DV)** is a unitless metric of haze which is proportional to the logarithm of the light extinction. Deciview correlates to a person's perception of a visibility change, with a change of 1 deciview being barely perceptible. The "no degradation" value of 0.1 DV included in the 1999 Regional Haze Rule is only 10% of this perceptibility threshold.

Both metrics are helpful in understanding changes to visibility impairment, but while the deciview is the best parameter to relate the significance of a perceived visibility change, modeling produces results in the form of light extinction using the new IMPROVE equation that converts particulate concentrations to visibility impairment.

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12 "VISTAS" is an acronym for Visibility Improvement -State and Tribal Association of the Southeast and "SESARM" stands for Southeastern States Air Resource Managers, Inc. Their web site for Regional Haze Rule modeling results is https://www.metro4-sesarm.org/content/vistas-regional-haze-program.

VISTAS modeled 2028 projected actual emissions for a large set of point sources (3,945 tons of SO_2 were modeled for IP Savannah) and confirmed that sulfate is the primary contributor to visibility impairment in the Southeast. According to the slide presentation used in the May 20, 2020 VISTAS Regional Haze Project Update Stakeholder Briefing by Jim Boylan, the modeled impacts from the IP Savannah Mill SO_2 emissions were 0.14 Mm^{-1} at Okefenokee Wilderness Area, 0.20 Mm^{-1} at Wolf Island Wilderness Area, and 0.18 Mm^{-1} at Cape Romain Wilderness Area (the three closest Class I areas to the Mill). The impacts in Mm^{-1} are typically two times to an order of magnitude higher than the deciview impact. Therefore, the impact from a reduction in mill SO_2 emissions would be less than the "no degradation" threshold of 0.1 deciview and would not be reasonable to require.

5. SUMMARY OF FINDINGS

The emission sources at the IP Savannah Mill evaluated in this report are already subject to various stringent emission limits and emissions reductions have already been made at the Mill to comply with Boiler MACT requirements and the 1-hour SO_2 National Ambient Air Quality Standard (NAAQS). However, in response to a request from EPD, Savannah evaluated whether additional emissions controls for SO_2 are feasible for the No. 13 Power Boiler and No. 15 Recovery Furnace.

As part of the FFA, the following information was reviewed: site-specific emissions and control information, site-specific cost data, publicly available cost data, the U.S. EPA RBLC database, and U.S. EPA's OAQPS Control Cost Manual. The best information available in the time allotted to perform the analyses was used. We also considered the other three statutory factors: energy and non-air impacts, time necessary for compliance, and remaining useful life of the emission units. The energy and non-air impacts analyses show that implementing the technically feasible additional control measures would increase energy usage, solid waste generation, and could potentially cause a smaller compliance margin against non-air permit limits. All of the emission units are presumed to have a remaining useful life exceeding 20 years and the time necessary to implement any of the control measures would be at least four years.

Given the results of the four factor analysis, and the fact that Georgia is below their glidepath for the 2021-2028 period as shown in Figures 5-1 and 5-2[13], **requiring additional SO_2 control measures on the sources at the IP Savannah Mill is not reasonable for purposes of making further progress in reducing regional haze**. Note that a figure was not included for Wolf Island Wilderness and it is noted that this specific location does not have an IMPROVE monitor.

[13] https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf

Figure 5-1

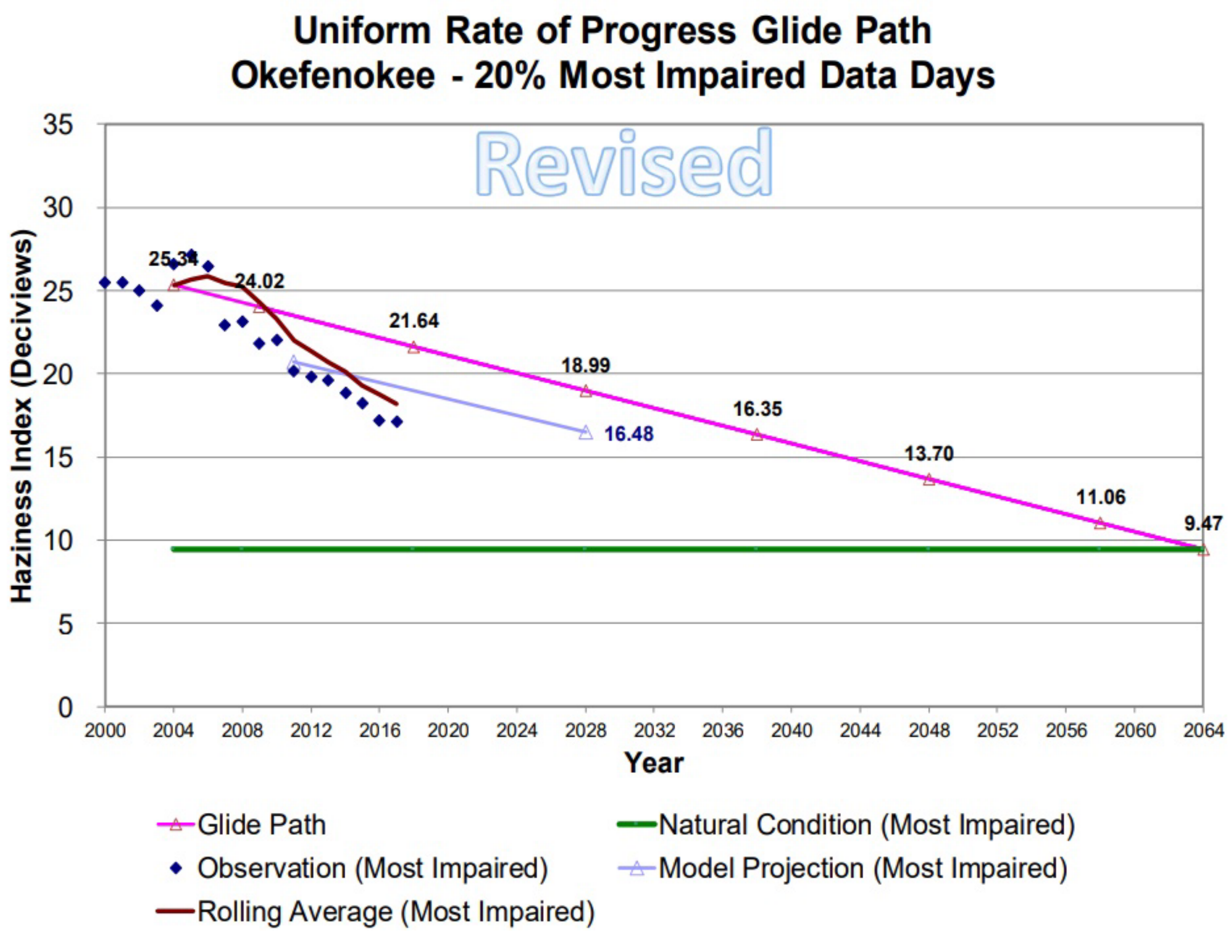
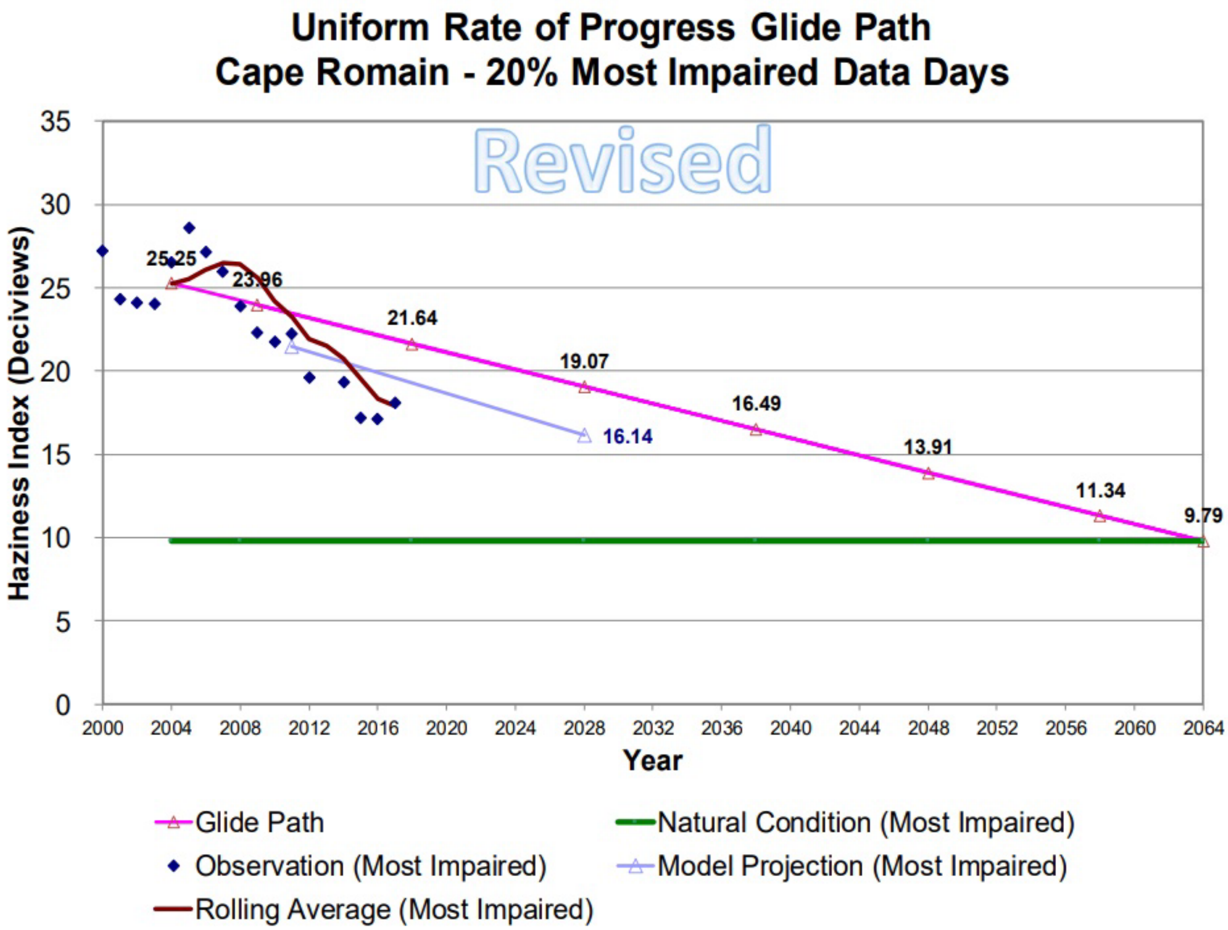

Uniform Rate of Progress Glide Path
Okefenokee - 20% Most Impaired Data Days
Revised
Haziness Index (Deciviews)
Year
25.34
24.02
21.64
18.99
16.48
16.35
13.70
11.06
9.47
Glide Path
Natural Condition (Most Impaired)
Observation (Most Impaired)
Model Projection (Most Impaired)
Rolling Average (Most Impaired)

Figure 5-2


Uniform Rate of Progress Glide Path
Cape Romain - 20% Most Impaired Data Days
Revised
Haziness Index (Deciviews)
Year
25.25
23.96
21.64
19.07
16.49
13.91
11.34
9.79
16.14
Glide Path
Natural Condition (Most Impaired)
Observation (Most Impaired)
Model Projection (Most Impaired)
Rolling Average (Most Impaired)

Any determination that additional controls are reasonable would need to be justified based on a more detailed evaluation that fully considers site-specific factors and the visibility improvements that would result from the installation of such controls. In addition, it is important to note the following points:

- The estimated visibility improvement at nearby Class I areas from installing controls would be negligible because it is estimated to be less than 0.1 deciview.
- Very few additional controls are technically feasible, and those that may be technically feasible are not cost effective and could have a negative impact on non-air permits and requirements (e.g., solid waste generation).
- The No. 15 Recovery Furnace utilizes good combustion practices and low-sulfur startup fuels to minimize SO_2 emissions.
- The No. 13 Power Boiler is subject to Boiler MACT emission limits and work practices that became effective in 2013 with a 2016 compliance date. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the boiler only starts up on clean fuel.
- The Mill has reduced SO_2 emissions by discontinuing coal firing in PB13 and fuel oil firing in RB15 and has requested removal of coal and fuel oil as permitted fuels in the latest Title V renewal application submitted in December 2019.
- U.S. EPA will continue the required process to evaluate acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology review for NESHAP Subpart DDDDD sources.
- The No. 13 Power Boiler is subject to NSPS Subpart D which contains emission limits for SO_2.
- Mill SO_2 emissions demonstrate compliance with the 1-hour SO_2 NAAQS.

APPENDIX A -
EPD REQUESTS AND EPA COMMENTS

GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Richard E. Dunn, Director

Air Protection Branch
4244 International Parkway
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Atlanta, Georgia 30354
404-363-7000

July 10, 2020

Emily Henderson
International Paper Company
1201 W. Lathrop Ave.
Savannah, GA 31415

Subject: Regional Haze 4-Factor Analysis
International Paper - Savannah, Chatham County, Georgia

Dear Ms. Henderson:

On July 1, 1999, the United States Environmental Protection Agency (EPA) published the final Regional Haze Regulations in the Federal Register[1]. Section 51.308 of the Regional Haze Regulations requires each state to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." Georgia submitted its initial regional haze plan on February 11, 2010. The plan was supplemented on November 19, 2010 and updated on July 26, 2017 to change reliance from the Clean Air Interstate Rule (CAIR) to the Cross-State Air Pollution Rule (CSAPR) for certain regional haze requirements. U.S. EPA fully approved the Georgia regional haze plan on May 4, 2018 (83 FR 19637). Paragraph 40 CFR 51.308(f) of the Regional Haze Regulation requires that states submit a regional haze implementation plan revision by July 31, 2021. As part of the plan revision, the State of Georgia must establish a reasonable progress goal (expressed in deciviews) that provides for reasonable progress towards achieving natural visibility conditions in the Cohutta Wilderness Area, Okefenokee Wilderness Area, and Wolf Island Wilderness. The goal "must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period."

The State of Georgia must also submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas.

In establishing reasonable progress goals, the State must consider the four factors specified in section 169A of the federal Clean Air Act and in paragraph 51.308(f)(2)(i) of the Regional Haze

[1] The Regional Haze regulations were amended on July 6, 2005, October 13, 2006, June 7, 2012, and January 10, 2017.

Regulations: (1) the cost of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources.

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

The Georgia Environmental Protection Division (EPD) has worked with Visibility Improvement State and Tribal Association of the Southeast (VISTAS), of which Georgia is a member, to identify facilities that significantly impact visibility impairment for Class I Federal areas within and outside of Georgia consistent with the Regional Haze statutory and regulatory requirements and EPA guidance. VISTAS initially utilized an Area of Influence (AoI) analysis to help identify the areas and sources most likely contributing to poor visibility in Class I Federal areas. This AoI analysis involved running a backward trajectory model to determine the origin of the air parcels affecting visibility. This information was then spatially combined with emissions data to determine the pollutants, sectors, and individual sources that were most likely contributing to the visibility impairment at each Class I Federal area. Georgia first used this information to determine that the pollutant and sector with the largest impact on visibility impairment was sulfur dioxide from point sources. Georgia then used the results of the AoI analysis to identify sources to "tag" for PM (Particulate Matter) Source Apportionment Technology (PSAT) modeling. PSAT modeling uses "reactive tracers" to apportion particulate matter among different sources, source categories, and regions. PSAT was implemented with the CAMx (Comprehensive Air Quality Model with extensions) photochemical model to determine visibility impairment due to individual facilities. Georgia identified sources shown to have an impact on one or more Class I Federal areas that is greater than or equal to one percent ($\geq$1.00%) of the total sulfate and nitrate visibility impairment from EGU and non-EGU point sources on the most impaired days for that Class I Federal area. These sources are being considered for additional analysis.

Based on analyses conducted by Georgia EPD and VISTAS, sulfur dioxide emissions from International Paper - Savannah have been shown to contribute to more than one percent to the visibility impairment at three mandatory Class I Federal area (Table 1). In order to meet the requirements of Section 51.308(d)(1)(i)(A) of the Regional Haze Rule, we must consider each of the four factors listed above for your facilities. Actual 2028 sulfur dioxide emissions have been projected to be 3,945.38 tons per year for International Paper - Savannah based on historical operations and emissions and any changes that are expected to occur. Please review this information to determine if these estimates reasonably project actual 2028 emissions. Should you have a significantly different estimate for projected 2028 sulfur dioxide emissions, please provide that estimate along with the justification and methodology for the revised estimate.

Georgia EPD is requesting that you conduct a four-factor analysis on emission sources at your facility. Specifically, the analysis should include all significant sources of SO_2 emissions at International Paper - Savannah.

Table 1. International Paper – Savannah (13051-3679811)
Modeled SO_2 = 3,945.38 tpy, Modeled NOx = 1,560.73 tpy

Impacted VISTAS Class I Areas	Sulfate PSAT (Mm^{-1})	Nitrate PSAT (Mm^{-1})	Total EGU & non-EGU Sulfate + Nitrate (Mm^{-1})	Sulfate PSAT % Impact	Nitrate PSAT % Impact
Wolf Island Wilderness (GA)	0.200	0.012	12.957	1.54%	0.09%
Cape Romain Wilderness (SC)	0.180	0.009	14.028	1.28%	0.06%
Okefenokee Wilderness Area (GA)	0.140	0.008	13.400	1.04%	0.06%

EPA's August 20, 2019, memorandum provides guidance on how the four statutory factors can be characterized. In order to identify control measures with the highest level of control effectiveness that are both technically feasible and cost effective using the minimal amount of effort, Georgia EPD also requests that the analyses be conducted using a "top-down" approach as follows:

Step 1: Identify all control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Rank remaining control technologies by control effectiveness;
Step 4: Application of the four statutory factors (cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, remaining useful life of existing source) to control technologies identified in Step 3 and document the results; and
Step 5: Select control technology

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

You should submit the requested four-factor analyses by no later than November 30, 2020. Should you have a different estimate for projected 2028 sulfur dioxide emission than that presented in this letter, please submit that information by not later than August 10, 2020. Should you have any questions concerning this request, please contact Dr. James Boylan at (404) 363-7014 or via email at James.Boylan@dnr.ga.gov.

Sincerely,

Karen Hays

Karen Hays, P.E
Chief
Air Protection Branch

Attachment

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

Determining Which Emission Control Measures to Consider

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

Characterizing the Cost of Compliance (Statutory Factor 1)

Estimate the cost of compliance starting with the control measure with the highest level of control effectiveness. The cost of compliance should be in terms of cost/ton of sulfur dioxide reduced. The cost used as the numerator in the cost/ton metric should be the annualized cost of implementing the control measure and should be determined using methods consistent with U.S. EPA's Air Pollution Cost Control Manual[2]. Should you use a method that deviates from the Cost Control Manual, you should include that methodology, including all calculations and assumptions, and you should justify why the method used is more appropriate than methods specified in the Cost Control Manual. The emission reduction used as the denominator for the cost/ton metric should be the annual tons of reduction from implementation of the control measure. If your analysis indicates that the control measure should be included as part of Georgia's long-term strategy for the second implementation period, further analysis is not necessary. If your analysis indicates that the control measure is not cost effective, you should estimate the cost of compliance for the control measure with the next highest level of control effectiveness. This process should be repeated until you have identified a control measure that should be included in Georgia's long-term strategy or until all of the control measures have been analyzed.

Characterizing the Time Necessary for Compliance (Statutory Factor 2)

Provide an estimate of the time needed to comply with the control measure(s) identified using statutory factor 1. Specify the source-specific factors used to estimate the time to install the control measure and provide a justification as to why the estimated time is reasonable.

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

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

Characterizing Remaining Useful Life of the Source (Statutory Factor 4)

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

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

From: Aponte, Anna <Anna.Aponte1@dnr.ga.gov>
Sent: Friday, June 3, 2022 3:08 PM
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Subject: [External] :Updates to your Regional Haze 4 Factor Analysis based on EPA comments

Emily,

To continue our conversation from last week, we have come up with a list of items that we need your help addressing from the EPA Region 4 comments on our pre-draft SIP.

1) From our meeting with IP on May 19, Updated cost analysis for dry and wet scrubber, especially looking at the other costs like impact on water permits, disposal of waste in landfill. This is also to include an update to the prime interest rate from 3.25% to 4.00%.
2) Key Comment 1.b - Evaluate emissions of Recovery Furnace No. 15. EPA identified this unit as being uncontrolled and it doesn't have any Monitoring, Recordkeeping or Reporting Requirements (MRR).
3) Key Comment 2 - Please clarify the compliance schedule for Power Boiler No. 13.
4) General Comment 8.b.i - IP-Savannah used 80% for the control efficiency in a dry scrubber for SO2 which was based on an older EPA document. EPA suggests IP to use between 85-95% as defined in the EPA's Air Pollution Control Cost Manual.
5) General Comment 8.b.ii - EPA showed in a table, differences in the allowable emissions and the actual emissions for the No. 15 Recovery Furnace and the No. 13 Power Boiler. We need your help in reconciliation of these numbers. If IP can help provide a discussion on this or as EPA is calling "Gap analysis" that would greatly help our SIP submittal.
6) General Comment 8.b.iii - In the 4FA, IP presented SO2 emissions as annual emissions. EPA asked that emissions data be put on a shorter timescale as well, such as lb/hr as to help with comparisons to existing permit limits at the facility.
7) General Comment 8.b.iv – EPA asked specifically about the Lime Kiln permitted emissions. Stating that based on permit condition 3.3.1c the unit could emit up to 3,149 tpy but based on the 4FA submitted, that listed 2 tpy. EPD would like your help in closing that gap specifically on any facility constraints or limits on the lime kiln that EPD wouldn't otherwise be aware of that would reduce the emissions.

Since several cost analysis items are being updated, it would be best if you can update your 4 Factor Analysis and we would appreciate your response by June 17th . This is to avoid confusion with different versions of the cost numbers in the main 4 Factor Analysis versus a supplement. Of course, if you have any questions, feel free to reach out to me.

Anna Aponte

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GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

The U.S. Environmental Protection Agency (EPA) Partial, Preliminary Draft Key & General Comments regarding Georgia's April 22, 2022, Draft Regional Haze State Implementation Plan (SIP)

Thank you for your e-mail on April 22, 2022, indicating that Georgia's draft regional haze plan for the second implementation period had been submitted for the EPA's review. Below are the EPA's partial, preliminary draft key and general comments which the EPA and the State will discuss on an upcoming call to be arranged separately. This first set of expedited comments is focused on identifying significant approvability issues and also includes additional comments identified as time allowed. Additional EPA feedback will be provided at a later date.

Note: All page numbers referenced refer to the page numbers of the SIP narrative file unless otherwise specified.

Key Comments

1. **Emissions Limits in the SIP:**
    a. The State must adopt emissions limits and supporting monitoring, recordkeeping, and reporting (MRR) conditions into the regulatory portion of the SIP for measures necessary for reasonable progress.[1] Region 4 understands that the State is in the process of incorporating proposed permit conditions[2] into final State permits which will be submitted as a supplemental SIP revision.

    b. The existing measures (emissions limits) for IP-Savannah No. 15 Recovery Furnace (RF15) and GP-Brunswick's No. 5 Recovery Furnace (R401) and No. 6 Recovery Furnace (R407) appear to be considered necessary for reasonable progress and therefore sulfur dioxide (SO_2) emissions limits and the associated MRR would be needed to reflect existing emissions limits for these units. In the alternative, the State can demonstrate that these measures are not necessary for reasonable progress for these units. The EPA will work with the State to address this comment.

2. **Compliance Schedules:** Please clarify what the compliance schedules are for Power Boiler 13 at IP-Savannah and Units 1-4 at Plant Bowen pursuant to 40 CFR 51.308(f)(2).

3. **Prehearing Reminders:** The Clean Air Act (CAA) section 169(A)(d) requires that the plan "…shall include a summary of the conclusions and recommendations of the Federal land managers in the notice to the public." The State could address this requirement in the prehearing submission by referencing in the public notice the location of the full set of Federal Land Manager (FLM) comments regarding the April 22, 2022, draft plan and associated materials.

[1] In the alternative, the State can demonstrate that the measures are not necessary for reasonable progress. See Section 4.1 of the EPA's July 8, 2021, Memorandum, *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period* (2021 Memo).

[2] The narrative includes proposed permit conditions for certain emissions units at Georgia Power – Plant Bowen (Plant Bowen); International Paper – Savannah Mill (IP-Savannah); and Georgia Pacific - Brunswick Cellulose (GP-Brunswick).

4. **Final Plan Reminders:** Once FLM consultations have concluded, please include a description of how the State addressed any comments provided by the FLMs pursuant to 40 CFR 51.308(i)(3).

General Comments

1. **Transmittal Letter:** Please clarify in the transmittal letter for the prehearing and final SIP any materials to be adopted into the regulatory portion of the SIP at 40 CFR 52.570. Also, please list any materials provided for reference only that are not to be adopted into the SIP.

2. **Pollutants Evaluated:** The EPA recommends the State more fully explain why it is not evaluating nitrogen oxides (NOx) emissions controls in the four-factor analyses (FFAs) for sources contributing to visibility impairment at Class I areas affected by the State's sources and for sources/emissions units demonstrating that they are effectively controlled. The EPA will work with the State to address this comment.

3. **Environmental Justice:** The EPA encourages states to consider equity and environmental justice as part of their technical analyses when developing regional haze strategies for the second period to the extent possible.[3] The EPA will work with the State to consider this comment.

4. **Gap Analysis:** For the emissions units listed in Key Comment 1.b. above and for Units 1-4 at Plant Bowen, the EPA recommends: a) providing a comparison of recent, past actual emissions/emissions rates versus permitted allowable emissions/emissions rates and b) assessing whether the compliance margin is reasonable in each case.[4] To the extent there is a significant discrepancy between the recent actual emissions/rates and the permitted emissions/rates, the State should consider adopting a more stringent SO_2 emission limit for the source or explain why it is declining to do so. The EPA will work with the State to address this comment.

5. **Emission Inventories:**
   a. Page 42 of the narrative states that "Georgia used a combination of 2023en and 2028el data for projected 2028 EGU emissions." The EPA recommends describing, with specificity, which electric generating units' (EGUs) emissions were projected using 2023en data and, separately, which EGUs' emissions were projected using 2028el data. One way this could be accomplished would be to include, as an additional attachment or appendix, a spreadsheet of the underlying data that formed the basis of the Georgia-specific information contained in Table 4-1 to the Eastern Research Group, Inc. (ERG)'s Task 2A report in Appendix B-1a.

   b. The EPA additionally recommends providing further justification and explanation regarding the use of 2028el data for projected EGU emissions in light of statements in both the narrative and in Appendix B-1a that "the EPA 2028el projected emissions for EGU emissions are not reflective of probable emissions for 2028."

   c. Table 4-2 to ERG's Task 2A report contained in Appendix B-1a indicates that for non-EGU facilities, Georgia asked ERG to "[a]djust state-provided facility-level 2028 emissions for all pollutants to the

[3] See Section 5.6, page 16, of the 2021 Memo.
[4] See also General Comment 6.b.ii related to a gap analysis for IP-Savannah.

process-level using process-level emission proportions from EPA 2023." Page 113 of the narrative states that "Georgia used 2016 emissions (or 2014 emissions if 2016 was not available) to represent 2028 emissions for the 33 non-EGU facilities with over 100 tons per year (tpy) of SO_2 in 2011, exclusive of Hartsfield-Jackson Atlanta International Airport." The EPA recommends that Georgia further clarify in the narrative whether the adjustments described in Table 4-2 to ERG's Task 2A report are the same adjustments referenced more generally on page 113 of the narrative.

d. Page 48 of the narrative states that "[f]or the most part, the modeling analysis approach for regional haze followed EPA's 2011el-based air quality modeling platform, which includes emissions…" The EPA recommends clarifying this language to more fully explain if 2011el emissions data was used for any sources in light of the adjustments outlined in Tables 4-1 and 4-2 of Appendix B-1a. Additionally, page 112 of the narrative states that "the VISTAS 2028 emissions inventory is based on 2028el emissions." This statement seems to conflict with the above-referenced statement on Page 48. The EPA recommends clarifying this language.

e. Table 4-1, Page 45: The EPA recommends explaining discrepancies for non-point source emissions between the 2011 emissions inventory for Georgia in Table 4-1 and the 2011 National Emissions Inventory version 2 (NEIv2). Please provide an explanation of how the emissions were calculated for the non-point and point ("EGU" and "Non-EGU Point") source emissions in Table 4-1 and if any emission sectors were excluded. The EPA will work with the State to address this comment.

6. **Source Selection:**
   a. The EPA recommends augmenting the justification for the Area of Influence (AoI) and Particulate Matter Source Apportionment Technology (PSAT) thresholds and noting where these can be found as noted on page 188.

   b. The EPA encourages the State to provide more explanation as to why the State's source selection approach "captures a reasonable set of sources of emissions to assess for determining what measures are necessary to make reasonable progress." The EPA will work with the State to address this comment.

   c. The EPA recommends explaining how the selection of sources within the State for a FFA captures a meaningful portion of the State's total contribution to visibility impairment to Class I areas.[5] The EPA will work with the State to address this comment.

   d. The EPA suggests adding a statement explaining the reason for the significant difference between Plant Wansley's projected 2028 SO_2 emissions of 4,856.0 tpy and the 2017-2019 SO_2 emissions of 2,720.78 tpy (2017), 2,134.03 tpy (2018), and 1,656.01 tpy (2019), with an average over the 2017-2019 period of 2,170.27 tpy. In particular, it would be helpful to identify if there are new emissions limitations and/or controls that are contributing to the 2017-2019 lower emissions resulting in SO_2 emissions much lower than the projected 2028 emissions and whether they are state enforceable.

[5] See Section 2.1, page 3, of the 2021 Memo.

e. The State did not select certain sources listed on page 196 (Mohawk Industries, Inc.; Southern States Phosphate & Fertilizer; Savannah Sugar Refinery) for a FFA based on application of an AoI scaling factor. The State downscaled the AoI contribution for these three sources in Georgia by a factor of three on the basis that "…the AoI results are almost always at least three times higher than the PSAT results…" as noted on page 188. The EPA recommends that Georgia provide a more robust justification for why the State is not selecting these sources for a FFA. The EPA will work with the State to address this comment.

7. FFAs (General):

a. **Prior Comments:** The EPA did not include the Agency's prior draft comments regarding the FFAs for the State's sources unless there were additional issues to discuss. See the attached June 7, 2021, e-mail (IP-Savannah, GP-Brunswick) and the August 31, 2021, e-mail for a copy of those comments for reference.

b. **Generic Recommendations:**

i. The EPA recommends providing additional cost-related information in the SIP narrative for each emissions control option evaluated, including the interest rate, equipment life, and control efficiency.[6]

ii. The EPA recommends that the State identify any deviations from the EPA Air Pollution Control Cost Manual's principles and factors and explain how any alternative approaches are appropriate.[7] For example, if the State is relying on cost analyses that use an interest rate other than the current bank prime interest rate[8] (default) or, in the alternative, a firm-specific interest rate with justification, please explain how the State's use of an alternate interest rate is appropriate in this instance.

iii. **Cost-effectiveness Threshold:**[9] Please explain what, if any, cost-effectiveness threshold the State is using in assessing the reasonableness of requiring additional controls for reasonable progress[10] and justify why such a threshold is appropriate and consistent with the requirement to make reasonable progress.[11]

8. FFAs (Specific Sources):

a. GP-Brunswick FFA: Please explain how the cost-effectiveness of the replacement of No. 6 fuel oil with one percent fuel oil for the fourth and sixth control options in Table 7-40 factored into the decision

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[6] Other optional additions may include annualized cost and tons reduced.
[7] See page 31 of the 2019 Guidance.
[8] To identify the current bank prime interest rate, go to: https://www.federalreserve.gov/releases/h15/ (go to "bank prime loan" rate in the table).
[9] For the second period, states are not required to establish cost-effectiveness thresholds.
[10] States are not required to set cost-effectiveness thresholds.
[11] Given the iterative nature of the regional haze program, a state may not automatically rely on the same cost-effectiveness threshold in the second period as in the first period.

in the Summary on page 218 to not require these control options given that the cost-effectiveness values were \$4,221/ton and \$4,154/ton of sulfur dioxide (SO_2) removed in 2020 dollars.[12]

b. IP-Savannah FFA:

i. On page 42 of Appendix G-2, the IP-Savannah FFA uses an 80 percent SO_2 control efficiency for the dry scrubber with justification.[13] The EPA's *Air Pollution Control Cost Manual* (Cost Manual) suggests 85-95 percent for dry scrubbers in Table 1.1 on page 1-4. The EPA recommends that the State bolster this justification for use of an 80 percent SO_2 control efficiency for the dry scrubber control option to explain why this deviation from the Cost Manual is appropriate in this instance.

ii. Based on a comparison of allowable emissions in IP-Savannah's current title V permit with its stated actual annual emissions in its FFA, it appears that allowable emissions for the No. 15 Recovery Furnace and the No. 13 Power Boiler significantly exceed recent actual emissions. The EPA recommends including more detailed discussion regarding whether the actual emissions for these units are representative of projected 2028 emissions in light of the differences between actual emissions and allowable emissions for these units. Additionally, as noted in Section 2.3 of the 2021 Memo, "if a source can achieve, or is achieving, a lower emission rate using its existing measures than the rate assumed for the 'effective control,' a state should further analyze the lower emission rate(s) as a potential control option." The EPA recommends that the State consider developing a gap analysis for these two units. Actual emissions and projected emissions are discussed in more detail in the table below.

Emission Unit	**Hourly SO_2 Permit Limit (pounds/hour (lb/hr))**	**Annual SO_2 Limit (calculated from hourly permit limit)**	**Actual annual SO_2 emissions as described in the FFA**
No. 15 Recovery Furnace	319 lb/hr	1,397 tpy	21 tpy
No. 13 Power Boiler	2,822 lb/hr	12,360 tpy	4,082 tpy

iii. The IP-Savannah FFA presents SO_2 emissions (actual, projected, and controlled) as annual emissions. While this annual information is useful for summary purposes, the EPA recommends including emissions data on a shorter timescale as well (e.g., lb/hr, which is the timescale used for the existing SO_2 limits for the units at this facility). This information is important for the gap analysis described in the comment above.

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[12] The fourth control option affects No. 4 Power Boiler, No. 5 Recovery Furnace, and No. 5 Lime Kiln and the sixth control option affects the No. 4 Power Boiler and No. 5 Recovery Furnace.

[13] The IP-Savannah FFA includes the following justification: "*SO_2 control efficiency from Mill quote in 2014 was 80% and aligns with the EPA fact sheet for 'Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers.'*" The EPA fact sheet was published in 2001 and includes the following language on the first page: "*…the highest removal efficiencies are achieved by wet scrubbers, greater than 90% and the lowest by dry scrubbers, typically less than 80%. New dry scrubber designs are capable of higher control efficiencies, on the order of 90%.*" See the EPA's Air Pollution Control Technology Fact Sheet at https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf.

iv. The No. 7 Lime Kiln is permitted to emit up to 3,149 tpy of SO_2 based on condition 3.3.1c in IP-Savannah's current title V permit, which contains an SO_2 limit of 719 lb/hr. However, the IP-Savannah FFA indicates that this source's actual SO_2 emissions are two tpy. The EPA recommends that the State include further explanation regarding this large differential between actual and allowable emission at this emissions unit, including whether these low actual SO_2 emissions are due to reduced utilization of this emission unit during 2018 and 2019. *See* 2021 Memo, page 12.

v. The footnote to Table 1-1 of the IP-Savannah FFA states that current emissions were calculated based upon an average of 2018 and 2019 actual emissions, and that these emissions were used as a surrogate to project 2028 emissions. While it may be appropriate to use current emissions to develop the baseline emission scenario, the EPA recommends providing additional justification and explanation as to why 2018 and 2019 actual emissions are representative of current actual emissions. *See Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, p. 29, August 20, 2019 ("2019 Guidance").

vi. It appears that these averaged 2018 and 2019 actual emissions differ from the State's 2028 emission projections for IP-Savannah. The EPA recommends that the State explain, on a per emissions unit basis, any differences between the State's 2028 emissions projections and those used in the FFA.

c. Plant Bowen FFA:

i. The FFA for Plant Bowen indicates that the State sent a letter to Georgia Power requesting a FFA for this facility on July 10, 2020. The EPA suggests that this letter be included as part of Appendix G-1.

ii. Page 8 of Plant Bowen's FFA indicates that 2019 actual annual emissions were used as a surrogate for Plant Bowen's projected 2028 emissions for use in the FFA. Page 8 also notes that these 2019 actual emissions are "below Georgia EPD's 2028 projection of 10,453 tpy." The EPA recommends that the State include additional information in the FFA regarding the basis for the State's 2028 projection of 10,453 tpy of SO_2 year along with additional discussion regarding whether the State agrees with Georgia Power's use of 2019 projections as a replacement for the State's 2028 projections. This discussion should include analysis of whether 2019 actual emissions are representative of current emissions. *See* 40 CFR 51.308(f)(2)(iii); 2019 Guidance, p. 29. This information should be discussed in the FFA. Additionally, as noted elsewhere in these comments, the EPA recommends that all emissions be quantified separately for each boiler.

iii. The FFA for Plant Bowen focuses on controls for the entire plant in the aggregate. The EPA recommends that the FFA be supplemented to include analysis for each individual boiler unit at Plant Bowen, including cost per ton of SO_2 reduction quantifications for each boiler. *See* 40 CFR 51.308(f)(2)(iii) (requiring documentation of the technical basis underlying an FFA). This analysis is recommended because each boiler can operate independently from the other boilers. The EPA additionally recommends that these analyses be completed under the assumption that Units 1 and 2 will continue to operate and, separately, under the assumption that Units 1 and 2 will be decommissioned no later than December 31, 2027, as formally requested by Georgia Power in

Georgia PSC Docket #44160. *See* 40 CFR 51.308(f)(2)(iv)(C) (requiring consideration of "[s]ource retirement and replacement schedules").

iv. The FFA for Plant Bowen discusses switching from Illinois Basin coal to either Powder River Basin (PRB) coal or Central Appalachian (CAPP) coal as SO_2 control options that are feasible. For PRB coal, the FFA describes potential physical limitations in coal handling that may make it more difficult to fully switch to PRB coal at Plant Bowen. It is unclear if these limitations are identical for all four boilers. The EPA recommends that the FFA describe any such physical limitations for each individual boiler rather than for the plant in the aggregate.

v. Regarding switching to either PRB coal or CAPP coal as an SO_2 control option, the EPA recommends that coal blending be considered as a potential control option for inclusion in the FFA (e.g., blending Illinois Basin coal with PRB coal at various percentages). *See* 2019 Guidance, p. 30 (discussing adjustments to a source's fuel mix as a potential control option). The EPA recommends that any discussion of coal blending as a control option include whether blending different types of coal could mitigate any physical limitations associated with coal handling that might otherwise result in a facility derate.

9. Consultation – Interstate:

a. **Table 10-2, text on p.234:**

i. Two Florida sources, Buckeye Florida, Limited Partnership, and Rock Tenn could not be found under those names in the October 8, 2021, Florida regional haze plan narrative.

ii. The EPA generally recommends listing the page numbers and files in the Florida, South Carolina, and Tennessee regional haze plans referenced in Table 10-2 and/or in the text related to interstate consultation decisions on FFAs. (See General Comment 9.a.iii. for suggestions as to where these FFA conclusions may be found in the Florida, South Carolina, and Tennessee regional haze plans.) If available, consider adding website links to the cited final plans for Florida, South Carolina, and Tennessee. Another option would be for the State to summarize the FFA outcomes similar to what was done for the Indiana, Ohio, and Pennsylvania sources listed in this section.

iii. In support of General Comment 9.a.ii, below are suggestions indicating where information may be found in the Florida, South Carolina, and Tennessee regional haze plans to support Table 10-2:

- The White Springs, Florida source is listed as 'Nutrien White Springs Ag Chem (12047-769711)' on page 254 of the October 8, 2021, Florida haze plan narrative as effectively controlled for sulfuric acid plants C, D, E, and F, which is further discussed on page 256. The provisions to be adopted into the Florida SIP are in the file named: "Final SIP 2021-01 Regional Haze.pdf" on pages 13-14.

- JEA Northside in Florida is discussed as Units 1 and 2 together and, separately, Unit 3.
  - Units 1 and 2 are determined to be effectively controlled with SO_2 limits more stringent than the alternative Mercury and Air Toxics Standard (MATS) 0.2 pounds (lb) SO_2/million British

Thermal Units (MMBtu) limit (see p.254 Florida haze plan narrative, Appendix G-3c-1, and p.12 of the "Final SIP 2021-01" file).
    - JEA Northside Unit 3's FFA is discussed in section 7.8.1 on pages 264-269 with the conclusions in Section 7.8.1.1.5 on page 264 of the Florida narrative, Appendix G-3c-2, and on page 13 of the "Final SIP 2021-01" file.[14]

- Santee Cooper Cross Generating Station in South Carolina is discussed in the May 3, 2022, South Carolina Regional Haze Plan narrative on pages 181-184 in Section 7.8.4[15] and, at a later date, Appendix G.

- Alumax of South Carolina (now Century Aluminum of South Carolina) is discussed in the May 3, 2022, South Carolina Regional Haze Plan narrative in section 7.8.1[16] on pages 162-168 and Appendix G. The units affected are listed in Table 7-21 as Potlines 02, 03, 04, 05, and Bake Oven 01.

- Eastman Chemical Company (Eastman) in Tennessee is discussed in the February 23, 2022, narrative in section 7.8.1 on pages 205-206 and Appendix G-2 where Appendix G-2f contains Tennessee's analysis and conclusions.[17]

[14] See Florida's conclusions for JEA Unit 3 on page 269 of the SIP narrative that: "…the Department has determined that switching to lower sulfur No. 6 fuel oil is necessary for reasonable progress…. Thus, the Department will require JEA to either begin firing only fuel oil with sulfur content less than or equal to 1% in 2026, or shut down the unit by the end of 2028."

[15] See South Carolina's conclusions for Units 1-4 that: 'Units 1-4 are well controlled, and additional controls are not needed for the purpose of remedying any existing anthropogenic visibility impairment at Cape Romain….the Department is proposing that existing SO_2 control measures for Cross based on the MATS rule be adopted into the regulatory portion of the SIP as required by Section 169A(b)(2) of the CAA.'

[16] See South Carolina's conclusions that: '…the units at Century are well controlled for SO_2, and additional controls are not needed for the purpose of remedying any existing anthropogenic visibility impairment at Cape Romain.… the Department is proposing that existing measures in Department-issued permits be adopted into the SIP as required by Section 169A(b)(2) of the CAA.'

[17] See Tennessee conclusions in Appendix G-2f: 'TDEC-APC…concluded that reasonable progress for Eastman Chemical Company the permanent shutdown of B-83 Boilers 18, 19, and 20 and the installation of permanent dry sorbent injection (without upgrading the existing ESPs) on Boilers 23 and 24.'

APPENDIX B -
CONTROL COST ESTIMATES

Table B-1

IP Savannah - No. 13 Power Boiler

Capital and Annual Costs Associated with Spray Dryer Absorber Retrofit

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
EPC Project?			☐ FALSE	
Unit Size	A	(MW)	**124**	<--- User Input (Greater than 50 MW); 1280 MMBtu/hr, assumes 33% efficiency to convert to equivalent MW output
Retrofit Factor	B		**1.5**	<--- User Input (An "average" retrofit has a factor = 1.0); A 1.5 retrofit factor is applied to the total capital investment as an engineering study has not been performed, space constraints exist, equipment must be hardened to resist hurricanes, and production could be lost due to an extended Mill outage or unexpected delays. The retrofit factor was not applied to the landfill development cost.
Heat Rate	C	(Btu/kWh)	**10348**	<--- User Input; 1280 MMBtu/hr /A*1000
SO2 Rate	D	(lb/MMBtu)	**1.24**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		Bituminous **3**	<--- User Input; Coal not fired at IP Savannah - EPA tool set to Bituminous so that Coal Factor equals 1 and therefore does not increase cost when multiplied by other inputs.
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		1.035	C/10000
Heat Input	H	(Btu/hr)	1.28E+09	A*C*1000
Capacity Factor	I	(%)	**58.55**	<--- User Input
Operating SO2 Removal	J	(%)	**90**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	1.1	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	2.6	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	M	(%)	1.35	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	7	(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**260**	<--- User Input 2022 cost
Waste Disposal Cost	Q	($/ton)	**40**	<--- User Input Onsite disposal in landfill expansion
Aux Power Cost	R	($/kWh)	**0.037**	<--- User Input 2022 cost
Makeup Water Cost	S	($/kgal)	**0.272**	<--- User Input 2022 cost
Operating Labor Rate	T	($/hr)	**50.74**	<--- User Input (2022 Labor cost including all benefits)

Costs are all based on 2016 dollars, scaled to 2021 dollars using CEPCI

Capital Cost Calcuation	**Example**	**Comments**
Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.		
BMR ($) = if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 30,352,000	Base module absorber island cost
BMF ($) = if (A>600 then (A*52000) else 338000*(A^0.716))*B*(G*D)^0.2	$ 16,780,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) = if (A>600 then (A*138000) else 899000*(A^0.716))*B*(G*F)^0.4	$ 43,044,000	Base balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc...
BM ($) = BMR + BMF + BMB	$ 90,176,000	Total base module cost including retrofit factor
BM ($/kW) =	729	Base cost per kW
Total Project Cost		
A1 = 10% of BM	$ 9,018,000	Engineering and Construction Management costs
A2= 10% of BM	$ 9,018,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$ 9,018,000	Contractor profit and fees
CECC ($) = BM + A1 + A2 + A3	**$ 117,230,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =	**948**	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	$ 5,862,000	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)

TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**123,092,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs		**995**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$	12,309,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	$	-	EPC fees of 15%
Cost to expand onsite landfill for solid waste disposal	$	31,877,434	2007 URS Corporation cost to expand landfill: $1,218,750/acre times 19.41 acres, scaled from 2007 (525.4) to 2021 (708) dollars using the Chemical Engineering Plant Cost Index (CEPCI).
TPC ($) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1	**$**	**208,846,066**	Total project cost; Scaled from 2016 (541.7) to 2021 (708.0) using the CEPCI. Includes landfill capital cost.
TPC ($/kW) = Includes Owner's Costs and AFUDC		**1688**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (8 operators)*2080*T/(A*1000)	$	6.83	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	7.29	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.29	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**14.41**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	2.25	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.78	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	$	0.50	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.02	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**3.55**	Total Variable O&M costs

Annual Capacity Factor =	**59%**	
Annual MWhs =	634,460	
Annual Heat Input MMBtu =	6,565,620	
Annual Tons SO2 Created =	**4,082**	Projected Actual SO2 emissions from Power Boiler 13.
Annual Tons SO2 Removed =	**3,674**	at removal efficiency = 90%
Annual Tons SO2 Emission =	408	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.124	Value is AT or ABOVE a 0.06 floor rate
Annual Capital Recovery Factor =	**0.0786**	Based on 4.75% interest rate, 20 year life
Annual Capital Cost (Including AFUDC), $ =	16,405,000	
Annual FOM Cost, $ =	1,782,000	
Annual VOM Cost, $ =	2,254,000	
Total Annual Cost, $ =	20,441,000	
Capital Cost, $/MWh =	25.86	
FOM Cost, $/MWh =	2.81	
VOM Cost, $/MWh =	3.55	
Total Cost, $/MWh =	32.22	
Capital Cost, $/ton =	4,465	
FOM Cost, $/ton =	485	
VOM Cost, $/ton =	614	
Total Cost, $/ton =	**5,564**	

Table B-2
IP Savannah - No. 13 Power Boiler
Capital and Annual Costs Associated with Dry Sorbent Injection Retrofit

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
EPC Project?			☐ FALSE	
Capacity Factor			**58.55**	
Unit Size	A	(MW)	**124**	<--- User Input (Greater than 50 MW); 1280 MMBtu/hr, assumes 33% efficiency to convert to equivalent MW output
Retrofit Factor	B		**1.50**	<--- User Input (An "average" retrofit has a factor = 1.0); A 1.5 retrofit factor is applied to the total capital investment as an engineering study has not been performed, space constraints exist, equipment must be hardened to resist hurricanes, and production could be lost due to an extended Mill outage or unexpected delays. The retrofit factor was not applied to the landfill development cost.
Heat Rate	C	(Btu/kWh)	**10348**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**1.24**	<--- User Input
Type of Coal	E		Bituminous	<--- User Input; Coal not fired at IP Savannah - EPA tool set to Bituminous so that Coal Factor equals 1 and therefore does not increase cost when multiplied by other inputs.
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Unmilled Trona	<--- User Input
Removal Target	H	(%)	**65**	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	1.28E+09	A*C*1000
NSR	K	(Btu/hr)	3.31	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	6.32	Trona = (1.2011x10^-06)*K*A*C*D Hydrated Lime =(6.055*(10^-7))*K*A*C*D
Estimated HCL Removal	V	(%)	96	Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MMBtu Milled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MMBtu Unmilled Trona with an BGH = 0.005*H+97.574, or 0.002 lb/MMBtu Milled Trona with an BGH = 0.005*H+97.574, or 0.002 lb/MMBtu Hydrated Lime with an ESP = 54.92*H^0.197, or 0.002 lb/MMBtu Hydrated Lime with a BGH = 0.0085*H+99.12, or 0.002 lb/MMBtu
Sorbent Waste Rate	N	(ton/hr)	4.90	For Trona (0.7387+0.00185*H/K)*M, Lime = (1.00 + 0.00777*H/K)*M. Waste product adjusted for a maximum of 5% inert in the Trona sorbent and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	5.59	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power **Include in VOM?** ☑	Q	(%)	0.92	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	**274.5**	<--- User Input. In example, unmilled trona = $225, 2016 cost - escalated using 1.22 per BLS Consumer Price Index
Waste Disposal Cost	S	($/ton)	**40**	<--- User Input - onsite disposal in expanded landfill
Aux Power Cost	T	($/kWh)	**0.037**	<--- User Input 2022 data
Operating Labor Rate	U	($/hr)	**50.74**	<--- User Input (2022 Labor cost including all benefits)

Table B-2
IP Savannah - No. 13 Power Boiler
Capital and Annual Costs Associated with Dry Sorbent Injection Retrofit

Costs are all based on 2016 dollars, scaled to 2021 dollars using CEPCI

Capital Cost Calcuation	**Example**	**Comments**
Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.		
Unmilled Trona or hydrated lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)		Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM ($) =	$ 18,991,000	
BM ($/kW) =	154	Base cost per kW
Total Project Cost		
A1 = 10% of BM	$ 1,899,000	Engineering and Construction Management costs
A2= 5% of BM	$ 950,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM	$ 950,000	Contractor profit and fees
CECC ($) = BM + A1 + A2 + A3	**$ 22,790,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) = Excludes Owner's Costs =	**184**	Capital, engineering and construction cost subtotal per kW
B1 = 2% of CECC if EPC TRUE, else 5% of CECC	$ 1,140,000	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$ 23,930,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs	**193**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	$ -	EPC fees of 15%
Cost to expand onsite landfill for solid waste disposal	$ 31,877,434	2007 URS Corporation cost to expand landfill: $1,218,750/acre times 19.41 acres, scaled to 2021 dollars using the CEPCI.
TPC ($) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1	**$ 63,153,860**	Total project cost; Scaled from 2016 (541.7) to 2021 (708.0) using the CEPCI. Includes landfill capital cost.
TPC ($/kW) = Includes Owner's Costs and AFUDC	**511**	Total project cost per kW
Fixed O&M Cost		
FOMO ($/kW yr) = (2 additional operators)*2080*U/(A*1000)	$ 1.71	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.01)/(B*A*1000)	$ 1.02	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$ 0.06	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$ 2.79**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh) = M*R/A	$ 14.02	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	$ 3.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) = Q*T*10	$ 0.34	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$ 17.75**	Total Variable O&M costs

Table B-2

IP Savannah - No. 13 Power Boiler

Capital and Annual Costs Associated with Dry Sorbent Injection Retrofit

Annual Capacity Factor =	**59%**	
Annual MWhs =	634,460	
Annual Heat Input MMBtu =	6,565,620	
Annual Tons SO2 Created =	**4,082**	Projected Actual SO2 emissions from Power Boiler 13.
Annual Tons SO2 Removed =	**2,653**	at removal efficiency = 65%
Annual Tons SO2 Emission =	1,429	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.435	Value is AT or ABOVE a 0.1 floor rate
Trona MMtpy per 1.0 MMtpy SO2 Reduction =	12.22	
Annual Capital Recovery Factor =	**0.0786**	Based on 4.75% interest rate, 20 year life
Annual Capital Cost (Including AFUDC), $ =		4,961,000
Annual FOM Cost, $ =		346,000
Annual VOM Cost, $ =		11,264,000
Total Annual Cost, $ =		**16,571,000**
Capital Cost, $/MWh =		7.82
FOM Cost, $/MWh =		0.55
VOM Cost, $/MWh =		17.75
Total Cost, $/MWh =		26.12
Capital Cost, $/ton =		1,870
FOM Cost, $/ton =		130
VOM Cost, $/ton =		4,245
Total Cost, $/ton =		**6,245**

IP Savannah Mill Site Specific Data

Electricity cost, $/KWh	0.0370	2022 finance department records
Water cost, $/gal	0.27	2022 finance department records
solid waste disposal cost, $/ton	50	2022 Updated - Based on $37/ton tipping + hauling
Caustic Cost, $/gal	2.33	2022 finance department records
Operator Hourly Rate, $/hr	50.74	2022 finance department records
Supervisor Hourly Rate, $/hr	54.72	2022 finance department records
Maintenance Labor Hourly Rate, $/hr	50.52	2022 finance department records

APPENDIX C - SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

Final

January 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

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

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

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DSI Cost Methodology

Purpose of Cost Algorithms for the IPM Model

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

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

Technology Description

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

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

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

DSI Cost Methodology

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

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

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

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

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

DSI Cost Methodology

Establishment of the Cost Basis

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

Methodology

Inputs

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

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

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

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

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

DSI Cost Methodology

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

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

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

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

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

Outputs

Total Project Costs (TPC)

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

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

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

DSI Cost Methodology

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

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

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

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

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

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

Fixed O&M (FOM)

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

The following factors and assumptions underlie calculations of the FOM:

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

DSI Cost Methodology

Variable O&M (VOM)

Variable O&M is a function of the following:

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

The following factors and assumptions underlie calculations of the VOM:

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

DSI Cost Methodology

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

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

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

LEGAL NOTICE

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SDA FGD Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

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

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

Establishment of the Cost Basis

Cost data for the SDA FGD systems based on actual installations were more limited than those for the wet FGD systems until 2012. However, since 2012 the market trend has shifted toward the installation of dry FGD/CDS technology. Even with the new data, a similar trend of capital cost with generating capacity (MW size) is generally seen between the wet and SDA system. The same least-square curve fit power relationship for capital costs as a function of generating capacity, up to 600 MW, was used for the wet and SDA cost estimation with the constant multiplier adjusted to ensure that the curve represented the data available.

The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB;

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- Project Execution = Multiple lump-sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

A dry FGD system designed to treat 100% of the flue gas is capable of meeting Mercury Air Toxics Standards (MATS) limits for HCl of 0.002 lb/MBtu. Dry FGDs can remove up to 99% HCl in the flue gas.

Based on the recently acquired data and recently completed projects, it appears the overall capital cost has increased by only 6% over the costs published in 2013. Analysis of the data indicates that the lack of a large number of FGD projects has resulted in competitive pressure to absorb any significant increase in the cost.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for small units would be accomplished by treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering or converting to natural gas firing, using dry sorbent injection, and/or reducing operating hours. Capital costs of approximately $1,000/kW may be used for units below 50 MW under the premise that these units will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu, and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu. Typically, both SDA and circulating dry scrubber (CDS) technologies have been applied to low sulfur fuel (lower than 2 lb/MMBtu).

The alternate dry technology, CDS, can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu. Recent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in last four years.

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Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Retrofit difficulty.

The base modules are:

BMR =	Base absorber island cost that includes an absorber and a baghouse
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plant costs including: ID or booster fans, piping, ductwork and reinforcement, electrical, etc…
BM =	BMR + BMF + BMB

The total base module installed cost (BM) is then increased by:

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

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

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

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

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

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

Fixed O&M (FOM)

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

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 8 additional operators are required for an SDA FGD system. The FOMO was based on the number of additional operations staff required.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 1.5% of the BM. Cost of bags and cages are included in the fixed O&M cost with the assumption that bag replacement is carried out once every 3 years and cage replacement is carried out once every 9 years.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. While the capital costs are based on a 95% sulfur removal design, the operating sulfur removal percentage can be adjusted to reflect actual variable operating costs.
- In addition to sulfur removal efficiency, the estimated reagent usage was based on a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F.
- The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet.
- The basis for the lime purity was 90% CaO with the balance being inert material.
- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation

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estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

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

- Lime cost in $/ton. No escalation is observed in pebble lime cost. However, the cost could significantly vary with the location.
- Waste disposal costs in $/ton. The site-specific cost could be significantly different.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Makeup water costs in $/1000 gallon.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for lime reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet for an SDA FGD.

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Table 1. Example of a Complete Cost Estimate for an SDA FGD

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**500**	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		**1**	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	**9800**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**2**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	**95**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**125**	<--- User Input
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMR ($) =	if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 55,086,000	Base module absorber island cost
BMF ($) =	if (A>600 then (A*52000) else 338000*(A^0.716))*B*(D*G)^0.2	$ 33,100,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if (A>600 then (A*138000) else 899000*(A^0.716))*B*(F*G)^0.4	$ 77,837,000	Base module balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$ 166,023,000	Total Base module cost including retrofit factor
BM ($/KW) =		332	Base module cost per kW

Total Project Cost	**Example**	**Comments**
A1 = 10% of BM	$ 16,602,000	Engineering and Construction Management costs
A2 = 10% of BM	$ 16,602,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$ 16,602,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$ 215,829,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =	**432**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$ 10,791,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$ 226,620,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =	**453**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$ 22,662,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of (CECC + B1)	$ -	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**$ 249,282,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =	**499**	Total project cost per kW

SDA FGD Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	125	<--- User Input
Waste Disposal Cost	Q	($/ton)	30	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Makeup Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	2.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	4.98	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**7.10**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A*J/95	$	1.81	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A*J/95	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**3.64**	