Compliance Assurance Monitoring (CAM)

The Compliance Assurance Monitoring (CAM) rule is essentially a companion rule to Title V, requiring that control device operating parameters be monitored in order to demonstrate compliance with a specified emission limitation or standard. In order for the CAM Rule to apply to a specific emission unit/pollutant, the following, four criteria must be met:

1) The emission unit must be located at a major source for which a Part 70 or Part 71 permit is required.
2) The emission unit must be subject to an emission limitation or standard.
3) The emission unit must use a control device to achieve compliance.
4) The emission unit must have potential, pre-controlled emissions of the pollutant of at least 100 percent of the major source threshold.

The CAM Rule defines two classes of emission units. These are "large pollutant-specific emissions units" and "other pollutant-specific emissions units". The "large" units are those, "...with the potential to emit...taking into account control devices...the applicable regulated pollutant in an amount greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source..." The "other" units are those that are not "large" units. As such, the primary difference between the two categories is that "large" units are those that are still major (*i.e.,* greater than 100 percent of the major source threshold) after the application of controls, while the "other" units are those that are non-major (*i.e.,* less than or equal to 100 percent of the major source threshold) following the application of controls. For "large" units, the CAM rule, at 40 CFR 64.3(b)(4)(ii), requires that the owner/operator collect four or more data values equally spaced over each hour and average them over the applicable averaging period. As specified at 40 CFR 64.3(b)(4)(iii), for the "other" units, the CAM rule specifies that the data collection can be less frequent, "but the monitoring shall include some data collection at least once per 24-hour period".

The CAM rule contains some exemptions that are applicable for sources at the Palatka Mill. Most notably, at 40 CFR 64.2(b)(1)(i), the rule contains an exemption for sources that are subject to "emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act". Also, in cases where emission units utilize a continuous compliance demonstration method, such as a continuous emission monitor (CEM) or continuous opacity monitor (COM), 40 CFR 64.2(b)(1)(iv) provides an exemption as long as the method, "Provides data either in units of the standard or correlated directly with the compliance limit". Table 1 summarizes the CAM requirements for the "controlled" emission units at the Palatka Mill. For the pollutant-specific emission units that are required to have a CAM Plan, the Plans are provided in subsequent sections of this document.

Table 1. CAM Applicability – Palatka, Florida Mill

Source ID	Source Description	Control Device	Pollutant Controlled	Applicable Requirement(s)	Pre-Control Emissions (tpy)	CAM Threshold (tpy)	CAM Plan Required? (yes or no)
015	No. 5 Power Boiler	ESP	PM	FAC 62-296.405(1)(b) 40 CFR 63, Subpart DDDDD (only initial notification)	49,840[1]	100	**Yes**, normally exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart DDDDD proposed after 11/15/90, but no monitoring requirements
016	No. 4 Combination Boiler	ESP[2]	PM	FAC 62-296.405(1)(b) 40 CFR 63, Subpart DDDDD	40,420[3]	100	**Yes**, normally exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart DDDDD proposed after 11/15/90; Mill will likely comply per the fuel testing allowance and only be required to maintain fuel usage records
017	No. 4 Lime Kiln	Venturi Scrubber	PM	BACT (40 CFR 52.21) BACT (FAC 62-212.400(6)) 40 CFR 63, Subpart MM	16,480[4]	100	**No**, exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart MM proposed after 11/15/90
			SO_2[5]	BACT (40 CFR 52.21) BACT (FAC 62-212.400(6))	80[5]	100	**No**, pre-control emissions less than threshold
018	No. 4 Recovery Boiler	ESP	PM	BACT (40 CFR 52.21) BACT (FAC 62-212.400(6)) 40 CFR 63, Subpart MM	132,440[6]	100	**No**, exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart MM proposed after 11/15/90

Table 1. CAM Applicability – Palatka, Florida Mill (continued)

Source ID	Source Description	Control Device	Pollutant Controlled	Applicable Requirement(s)	Pre-Control Emissions (tpy)	CAM Threshold (tpy)	CAM Plan Required? (yes or no)
019	No. 4 Smelt Dissolving Tanks (two total)	Venturi Scrubber (one each)	PM	BACT (40 CFR 52.21) BACT (FAC 62-212.400(6)) 40 CFR 63, Subpart MM	2,364 (total); 1,182 (each)[7]	100	**No**, exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart MM proposed after 11/15/90
			TRS	FAC 62-296.404(3)(d)1	67.5 (total as H_2S); 33.8 (each as H_2S)	100	**No**, pre-control emissions less than threshold (FAC rule is expressed as H_2S)
031	Tall Oil Plant	Spray Tower/ Scrubber	TRS	FAC 62-296.404(3)(b)1	<13[8]	100	**No**, pre-control emissions less than threshold
035	Chlorine Dioxide Plant[9]	Packed-gas Adsorption Column[9]	NA	None	NA	NA	**No**, applicable limits not established for this source and exhaust routed to packed-gas adsorption column at No. 3 Bleach Plant
036	No. 3 Bleach Plant	Packed-Gas Adsorption Column	Chlorinated HAPs (excluding chloroform)	40 CFR 63, Subpart S	399.5 (as Cl_2)[10]	10 (HAP) 25 (all HAPs)	**No**, exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart S proposed after 11/15/90
037	Thermal Oxidizer[11]	Scrubber	SO_2	PCP Exclusion	2,744	100	**Yes**
		Candle Mist Eliminators	SAM	None	<23.2[12]	100	**No**, applicable limits not established for this source and pre-control emissions are less than threshold

Table 1. CAM Applicability – Palatka, Florida Mill (continued)

Source ID	Source Description	Control Device	Pollutant Controlled	Applicable Requirement(s)	Pre-Control Emissions (tpy)	CAM Threshold (tpy)	CAM Plan Required? (yes or no)
NA	HVLC DNCGs[13]	No. 5 Power Boiler or No. 4 Combination Boiler	HAPs/VOCs	40 CFR 63, Subpart S	348.9[13] (HAPs) 199.6[13] (VOCs)	10 (HAP) 25 (all HAPs) 100 (VOCs)	**No.** Title V operating permit has not yet been applied for; also, ultimately will be exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart S proposed after 11/15/90
			TRS	Co-benefit of HAP reductions	49.6[13]	100	**No.** Title V operating permit has not yet been applied for; also, ultimately CAM will not be required since pre-control emissions less than threshold
			CO	Co-benefit of HAP reductions	14.5[13]	100	
NA	NCGs/SOGs[14]	Thermal Oxidizer (primary); No. 4 Combination Boiler (back-up)[15]	HAPs/VOCs	40 CFR 63, Subpart S	HAPs > 10/25 VOC> 100	10 (HAP) 25 (all HAPs) 100 (VOCs)	**No**, exempt per 40 CFR 64.2(b)(1)(i) – 40 CFR 63, Subpart S proposed after 11/15/90
			TRS	FAC 62-296.404(3)(f)1 Co-benefit of HAP reductions	2,365 (Thermal Oxidizer); 473.0 (Combination Boiler)	100	**Yes**
NA	No. 3 Paper Machine	Venturi Scrubber	PM	None	Unknown	100	**No**, applicable limits not established for this source
NA	No. 4 Paper Machine	Venturi Scrubber	PM	None	Unknown	100	**No**, applicable limits not established for this source (approve by FDEP as an insignificant source)
NA	Converting Area	Baghouses (2)[16]	PM	None	Unknown	100	**No**, applicable limits not established for these sources

ESP – electrostatic precipitator
H_2S – hydrogen sulfide
Cl_2 – chlorine
HVLC – high volume, low concentration
DNCGs – dilute, non-condensible gases
NCGs – non-condensible gases
SOGs – condensate stripper off-gases
PCP – pollution control project
PM – particulate matter
SO_2 – sulfur dioxide
TRS – total reduced sulfur compounds
HAP(s) – hazardous air pollutant(s)
CO – carbon monoxide
SAM – sulfuric acid mist
NA – not applicable

[1] Pre-controlled emissions estimated based on controlled emissions of 249.2 tpy and an assumed control efficiency of 99.5%.
[2] ESP is preceded by mechanical cyclones. These cyclones are considered to be inherent process equipment, as opposed to control devices. Also, Combination Boiler is preceded by a pre-scrubber to remove sulfur compounds, thus reducing the formation of sulfur dioxide – per 40 CFR 64.1, passive control measures that act to prevent pollutants from forming are not considered to be “control devices”.
[3] Pre-controlled emissions estimated based on controlled emissions of 202.1 tpy and an assumed control efficiency of 99.5%.
[4] Pre-controlled emissions estimated based on controlled emissions of 164.8 tpy and an assumed control efficiency of 99%.
[5] Due to the presence of alkaline material in a lime kiln, the majority of sulfur dioxide capture occurs in the lime kiln itself. NCASI test data has shown very little difference in sulfur dioxide emissions for a lime kiln equipped with a scrubber vs. a lime kiln equipped with an ESP, indicating that a majority of the sulfur dioxide control is occurring in the kiln itself; assumed 50% control and 40 tpy controlled emissions of sulfur dioxide from scrubber.
[6] Pre-controlled emissions estimated based on controlled emissions of 331.1 tpy and an assumed control efficiency of 99.75%.
[7] Uncontrolled emissions based on AP-42 emission factor (Table 10.2-1, September 1990, reformatted January 1995).
[8] Pre-controlled emissions estimated based on controlled emissions of 0.5 tpy and an assumed control efficiency of 96%.
[9] Exhaust gases from the chlorine dioxide recovery system and the gases from the chlorine dioxide storage and process vessels are routed to the Bleach Plant (036) Scrubber.
[10] Uncontrolled emissions based on controlled emissions of 3.99 tons per year and an assumed control efficiency of 99%.
[11] Thermal Oxidizer is preceded by a two pre-scrubbers to remove sulfur compounds, thus preventing the formation of sulfur dioxide – per 40 CFR 64.1, passive control measures that act to prevent pollutants from forming are not considered to be “control devices”.
[12] Post-control emissions information provided by vendor in terms of an outlet concentration as opposed to a control efficiency; uncontrolled value estimated based on highest test value (5.3 lbs/hour) prior to addition of candle mist filter (5.3 lbs/hour x 8760 hours/year = 23.2 tons/year).
[13] Includes gases from the new brownstock washers, oxygen delignification system, bleach plant pre-washer, and various process tanks; maximum uncontrolled HAP emissions estimated at 348.9 tpy (34.9 tpy - brownstock washers, 289.3 tpy - oxygen delignification, 21.1 tpy - bleach plant pre-washer, 3.6 tpy - process tanks); maximum uncontrolled VOC emissions estimated at 199.6 tpy (43.9 - brownstock washers, 104.4 tpy - oxygen delignification, 20.6 tpy - bleach plant pre-washer, 30.7 tpy - process tanks); maximum uncontrolled TRS emissions estimated at 49.6 tpy (22.0 - brownstock washers, 2.7 tpy - oxygen delignification, 14.9 tpy - bleach plant pre-washer, 10.0 tpy - process tanks); maximum uncontrolled CO emissions estimated at 14.5 tpy from the oxygen delignification system; this modification is currently only covered by a construction permit – a CAM plan will not be required for this equipment until the Title V permit is modified.
[14] Includes gases from the batch digester system, Nos. 1 through 4 multiple effect evaporators, the turpentine system, and the condensate stripper.
[15] Two pre-scrubbers are in place for sulfur removal prior to destruction in the thermal oxidizer. Per 40 CFR 64.1, these are considered to be passive control measures that reduce the generation of sulfur dioxide. The CAM rule does not apply to passive control measures.
[16] There are two baghouses located in the converting area – one is rated at 20,000 actual cubic feet per minute (acfm) and the second is rated at 200,000 acfm; typical operation for the 20,000-acfm unit is to vent indoors; typical operation for the 200,000-acfm unit is to vent indoors half of the year and vent outdoors during the remaining time.

As shown in Table 1, the following pollutant-specific emission units are required to have a CAM Plan as part of this Title V renewal application:

- No. 5 Power Boiler (Emission Unit 015) for PM from the ESP
- No 4 Combination Boiler (Emission Unit 016) for PM from the ESP
- Thermal Oxidizer (Emission Unit 037) for SO_2 from the Scrubber
- Thermal Oxidizer (Emission Unit 037) for TRS destruction
- No. 4 Combination Boiler (Emission Unit 016) for TRS destruction

The CAM Plans for these are presented in the following five sections.

CAM Plan
No. 5 Power Boiler (Emission Unit 015)
Electrostatic Precipitator

Source Information:	Combustion source fires fuel oil, used oil, and natural gas (start-up fuel); also, this Boiler will function as a control device for the dilute non-condensible gases (DNCGs)
Control Device(s):	Electrostatic precipitator for particulate matter (PM) control
Applicable Limits:	0.1 lb/MMBTU and 56.89 lbs/hour (steady state) (Rule 62-296.405(1)(b)) 0.3 lb/MMBTU and 170.7 lbs/hour (soot blowing/load change) (Rule 62-210.700(3)) The unit is also subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD) promulgated September 13, 2004; however, there are no applicable standards/limitations in the rule for existing, large gaseous and liquid fuel-fired units; the only requirement for this unit is the filing of an initial notification
Current Monitoring:	Annual stack test for PM

The proposed CAM Plan for the ESP on the No. 5 Power Boiler is provided in Table 2.

Table 2. Proposed Monitoring Plan for ESP on the No. 5 Power Boiler

	Indicator No. 1	Indicator No. 2
Indicator	Secondary Voltage (kV) (for each field)	Secondary Current (mA) (for each field)
Monitoring Approach	Voltmeter – continuous measurement; to be used in conjunction with readings for “current” in calculating total power	Ammeter – continuous measurement; to be used in conjunction with readings for “voltage” in calculating total power
Indicator Range	8,800 Watts (minimum value for total power)	8,800 Watts (minimum value for total power)
QIP Threshold	> 5% excursions at FDEP discretion and request	> 5% excursions at FDEP discretion and request
	Performance Criteria	
Data Representativeness	The voltage will be measured using standard instrumentation provided for this purpose	The current will be measured using standard instrumentation provided for this purpose
Verification of Operational Status	N/A	N/A
QA/QC Practices and Criteria	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer’s recommendation	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer’s recommendation
Monitoring Frequency	Measured continuously; records should not be required to be kept when the Boiler is not in operation, nor should the minimum value apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)	Measured continuously; records should not be required to be kept when the Boiler is not in operation, nor should the minimum value apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)
Data Collection Procedure	Recorded as a 15-minute average; these values will be used in conjunction with the readings for current in calculating a total power value for the unit	Recorded as a 15-minute average; these values will be used in conjunction with the readings for voltage in calculating a total power value for the unit
Averaging Period	1-hour block (average of the calculated 15-minute values for total power collected during the 1-hour period)	1-hour block (average of the recorded 15-minute values for total power collected during the 1-hour period)

Monitoring Approach Justification

Rationale for Selection of Performance Indicators

ESPs use electrical energy to remove particulate matter from exhaust gas streams. Electrical fields are established by applying a direct-current voltage across a pair of electrodes – a discharge electrode and a collection electrode. The primary components of an ESP include the shell or housing, discharge electrodes, collection electrodes, high voltage equipment (*e.g.,* transformer, rectifier, and meters), rapping system, and collection hopper(s). Particulate matter, suspended in the gas stream, is electrically charged by passing through the electrical field around each discharge electrode (negatively charged electrode). The negatively charged particles then migrate toward the positively charged collection electrodes or "collection plates". The particulate matter is separated from the gas stream by retention on the collection electrodes. The particulate matter is then removed from the collection plates and collected in a hopper.

Voltage and current are considered two of the primary indicators of ESP performance. For the purposes of this CAM Plan, the Palatka Mill is proposing to utilize secondary voltage and secondary current for each field in calculating the total power for the unit. Secondary voltage is a measure of the voltage applied to the discharge electrodes and is a partial indicator of the energy or power consumed by the ESP. A decrease in voltage indicates lower particle charging. This parameter can also be an indicator of which fields are operating properly. Secondary current is a measure of the current supplied to the discharge electrodes and it is also a partial indicator of the energy or power consumed by the ESP. A drop in current may indicate a loss of power.

According to ESP manufacturers, voltage monitoring is more relevant than amperage monitoring for the purposes of verifying compliance. The measure of current is an indicator of the free electrons that are available for charging the dust particles. The precise amount of current is really not important, as long as there is enough to charge all of the dust present in the gas stream.

Dust collection by ESPs is affected by particle properties. The properties include mean particle size, size distribution, cohesion, adhesion, particle surface resistivity, density, and shape. All of these characteristics have an effect on the ESP's operation. Secondary voltage and current are also affected by these particle properties.

The ESP for the No. 5 Boiler has two "fields" or "transformer rectifier" (T/R) sets. Total power is determined by summing the values from each field as follows:

$$P_t = V_1 I_1 + V_2 I_2$$

Where: P_t = total ESP power (watts)
V_1 = secondary voltage (kV), ESP field 1
I_1 = secondary current (mA), ESP field 1
V_2 = secondary voltage (kV), ESP field 2
I_2 = secondary current (mA), ESP field 2

Rationale for Selection of Indicator Ranges

Secondary voltage and current readings were taken during recent particulate matter stack tests performed in January 2003 and January 2004. The results of the tests, along with the recorded voltage and current levels, are summarized in Table 3. Operations staff at the Mill believe that there were problems with the instrumentation during the 2003 tests. Also, during those tests, a single reading was made for the parameters for each 4-hour period. For the 2004 tests, readings were taken approximately every 15 minutes. For these reasons, only the 2004 readings are used in setting minimum values for the CAM Plan.

Table 3. Monitored Parameters During 2003 and 2004 Tests – No. 5 Power Boiler

Test Date	Run	PM Limit (lb/MMBTU)	Test Result (lb/MMBTU)	Field No. 1		Field No. 2	
				Secondary Voltage (kV)	Secondary Current (mA)	Secondary Voltage (kV)	Secondary Current (mA)
January 2004	1	0.1	0.08	23 - 32	10 – 30	42 - 47	260 – 280
	2	0.1	0.08	19 - 35	10 – 20	40 - 47	250 – 280
	3	0.1	0.09	25 - 31	20 – 50	45 - 50	250 – 330
	4[1]	0.3[1]	0.17	26 - 29	20 - 30	45 - 50	290 – 330
January 2003[2]	1[1]	0.3[1]	0.20	32	50	18	30
	2[1]	0.3[1]	0.18	35	20	20	40
	3[1]	0.3[1]	0.17	35	20	20	40
	1	0.1	0.04	37	20	19	30
	2	0.1	0.07	37	20	15	20
	3	0.1	0.09	37	20	15	20

[1] Soot-blowing conditions.
[2] Mill operations staff have reported possible instrumentation problems during the 2003 tests; also, a single reading was recorded for each 4-hour period; for these reasons, these data are not considered in establishing acceptable parametric values for the CAM Plan.

An analysis of the 2004 readings is provided in Table 4.

Table 4. Analysis of 2004 Parametric Values from Testing – No. 5 Power Boiler

Run	Field No. 1		Field No. 2		Minimum Power (Watts)
	Secondary Voltage (kV)	Secondary Current (mA)	Secondary Voltage (kV)	Secondary Current (mA)	
1	23	10	42	260	11,150
2	19	10	40	250	10,190
3	25	20	45	250	11,750
4	26	20	45	290	13,570
Minimum Power (Watts)					10,190
Average Power (Watts)					11,665
Standard Deviation (Watts)					1,423
Average - 2 Standard Deviations (95% Confidence) (Watts)					8,800

Based on an analysis of this data, the Palatka Mill proposes a minimum value for power of 8,800 watts.

Implementation/Compliance Plan

The necessary instrumentation is not currently in place. Furthermore, the Mill will not have feedback regarding FDEP's acceptance of the monitoring protocol until the permit it issued. As required by 40 CFR 64.4 (e), the necessary monitoring equipment will be installed, tested, and operational no later than 180 days following issuance of the final Title V permit.

CAM Plan
No. 4 Combination Boiler (Emission Unit 016)
Electrostatic Precipitator

Source Information: Combustion source fires wood/bark, fuel oil, used oil, and natural gas (start-up fuel); also, this Boiler functions as the back-up control device for non-condensible and stripper off-gases (NCGs and SOGs); in the future, the Boiler will also function as a control device for the DNCGs

Control Device(s): Centrifugal collector followed by an electrostatic precipitator for PM control

Applicable Limits: 0.1 lb/MMBTU and 41.9 lbs/hour (fuel oil firing) (Rule 62-296.410(1)(b)2)
0.3 lb/MMBTU and 125.6 lbs/hour (wood/bark firing) (Rule 62-296.410(1)(b)2)

The unit is also subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD) promulgated September 13, 2004; as an existing, large solid fuel-fired unit, this Boiler will have to be in compliance with the rule requirements no later than September 13, 2007.

Current Monitoring: Annual stack test for PM

The proposed CAM Plan for the ESP on the No. 4 Combination Boiler is provided in Table 5.

Table 5. Proposed Monitoring Plan for ESP on the No. 4 Combination Boiler

	Indicator No. 1	Indicator No. 2
Indicator	Secondary Voltage (kV) (for each field)	Secondary Current (mA) (for each field)
Monitoring Approach	Voltmeter – continuous measurement; to be used in conjunction with readings for "current" in calculating total power	Ammeter – continuous measurement; to be used in conjunction with readings for "voltage" in calculating total power
Indicator Range	14,530 Watts (minimum value for total power)	14,530 Watts (minimum value for total power)
QIP Threshold	> 5% excursions at FDEP discretion and request	> 5% excursions at FDEP discretion and request
	Performance Criteria	
Data Representativeness	The voltage will be measured using standard instrumentation provided for this purpose	The current will be measured using standard instrumentation provided for this purpose
Verification of Operational Status	N/A	N/A
QA/QC Practices and Criteria	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer's recommendation	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer's recommendation
Monitoring Frequency	Measured continuously; records should not be required to be kept when the Boiler is not in operation, nor should the minimum value apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)	Measured continuously; records should not be required to be kept when the Boiler is not in operation, nor should the minimum value apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)
Data Collection Procedure	Recorded as a 15-minute average; these values will be used in conjunction with the readings for current in calculating a total power value for the unit	Recorded as a 15-minute average; these values will be used in conjunction with the readings for voltage in calculating a total power value for the unit
Averaging Period	1-hour block (average of the calculated 15-minute values for total power collected during the 1-hour period)	1-hour block (average of the recorded 15-minute values for total power collected during the 1-hour period)

Monitoring Approach Justification

Rationale for Selection of Performance Indicators

ESPs use electrical energy to remove particulate matter from exhaust gas streams. Electrical fields are established by applying a direct-current voltage across a pair of electrodes – a discharge electrode and a collection electrode. The primary components of an ESP include the shell or housing, discharge electrodes, collection electrodes, high voltage equipment (*e.g.,* transformer, rectifier, and meters), rapping system, and collection hopper(s). Particulate matter, suspended in the gas stream, is electrically charged by passing through the electrical field around each discharge electrode (negatively charged electrode). The negatively charged particles then migrate toward the positively charged collection electrodes or "collection plates". The particulate matter is separated from the gas stream by retention on the collection electrodes. The particulate matter is then removed from the collection plates and collected in a hopper.

Voltage and current are considered two of the primary indicators of ESP performance. For the purposes of this CAM Plan, the Palatka Mill is proposing to utilize secondary voltage and secondary current for each field in calculating the total power for the unit. Secondary voltage is a measure of the voltage applied to the discharge electrodes and is a partial indicator of the energy or power consumed by the ESP. A decrease in voltage indicates lower particle charging. This parameter can also be an indicator of which fields are operating properly. Secondary current is a measure of the current supplied to the discharge electrodes and it is also a partial indicator of the energy or power consumed by the ESP. A drop in current may indicate a loss of power.

According to ESP manufacturers, voltage monitoring is more relevant than amperage monitoring for the purposes of verifying compliance. The measure of current is an indicator of the free electrons that are available for charging the dust particles. The precise amount of current is really not important, as long as there is enough to charge all of the dust present in the gas stream.

Dust collection by ESPs is affected by particle properties. The properties include mean particle size, size distribution, cohesion, adhesion, particle surface resistivity, density, and shape. All of these characteristics have an effect on the ESP's operation. Secondary voltage and current are also affected by these particle properties.

The ESP for the No. 4 Combination Boiler has three "fields" or "transformer rectifier" (T/R) sets. Total power is determined by summing the values from each field as follows:

$$P_t = V_1 I_1 + V_2 I_2 + V_3 I_3$$

Where:
P_t = total ESP power (watts)
V_1 = secondary voltage (kV), ESP field 1
I_1 = secondary current (mA), ESP field 1
V_2 = secondary voltage (kV), ESP field 2
I_2 = secondary current (mA), ESP field 2
V_3 = secondary voltage (kV), ESP field 3
I_3 = secondary current (mA), ESP field 3

Rationale for Selection of Indicator Ranges

Secondary voltage and current readings were taken during recent particulate matter stack tests performed in January 2003 and January 2004. The results of the tests, along with the recorded voltage and current levels, are summarized in Tables 6 (Fields 1 and 2) and 7 (Field 3). For the 2003 tests, a single reading was made for the parameters for each 4-hour period. For the 2004 tests, readings were taken approximately every 15 minutes. For this reason, only the 2004 readings are used in setting minimum values for the CAM Plan.

Table 6. Monitored Parameters During 2003 and 2004 Tests – ESP Fields 1 and 2 – No. 4 Combination Boiler

Test Date	Run	PM Limit (lb/MMBTU)	Test Result (lb/MMBTU)	Field No. 1		Field No. 2	
				Secondary Voltage (kV)	Secondary Current (mA)	Secondary Voltage (kV)	Secondary Current (mA)
January 2004	1[1]	0.26[3]	0.13	37.5 - 40	50 – 100	26 - 29	50 – 80
	2[1]	0.26[3]	0.10	34 - 38	80 – 100	25 - 28	40 – 50
	3[1]	0.26[3]	0.04	37 - 38	50 – 130	26 - 28	40 – 60
	4[2]	0.1	0.03	35 - 37	170 – 190	25 - 28	60 – 100
January 2003	1[2]	0.1	0.04	41	40	25	80
	2[2]	0.1	0.02	39	80	34	100
	3[2]	0.1	0.04	39	80	34	100
	1[1]	0.26[3]	0.04	37 - 39	80 – 100	33 - 34	80 – 100
	2[1]	0.26[3]	0.07	37	100	33	80
	3[1]	0.26[3]	0.07	37	100	33	80

[1] Combination of bark and fuel oil fired in unit.
[2] Unit firing 100% fuel oil.
[3] PM limit is a weighted average based on the fuel/heat input ratio – 0.1 lb/MMBTU (oil) and 0.3 lb/MMBTU (bark/wood) depending on the quantity of each fuel being fired.

Table 7. Monitored Parameters During 2003 and 2004 Tests – ESP Field 3 – No. 4 Combination Boiler

Test Date	Run	PM Limit (lb/MMBTU)	Test Result (lb/MMBTU)	Field No. 3	
				Secondary Voltage (kV)	Secondary Current (mA)
January 2004	1[1]	0.26[3]	0.13	38 – 41	420 – 470
	2[1]	0.26[3]	0.10	40 – 42	380 – 450
	3[1]	0.26[3]	0.04	39 – 41	340 – 450
	4[2]	0.1	0.03	38 – 39	460 – 470
January 2003	1[2]	0.1	0.04	45	400
	2[2]	0.1	0.02	44	430
	3[2]	0.1	0.04	44	430
	1[1]	0.26[3]	0.04	44	430
	2[1]	0.26[3]	0.07	44	430
	3[1]	0.26[3]	0.07	44	430

[1] Combination of bark and fuel oil fired in unit.
[2] Unit firing 100% fuel oil.
[3] PM limit is a weighted average based on the fuel/heat input ratio – 0.1 lb/MMBTU (oil) and 0.3 lb/MMBTU (bark/wood) depending on the quantity of each fuel being fired.

An analysis of the 2004 readings is provided in Table 8.

Table 8. Analysis of 2004 Parametric Values from Testing – No. 4 Combination Boiler

Run	Field No. 1		Field No. 2		Field No. 3		Minimum Power (Watts)
	Secondary Voltage (kV)	Secondary Current (mA)	Secondary Voltage (kV)	Secondary Current (mA)	Secondary Voltage (kV)	Secondary Current (mA)	
1	37.5	50	26	50	38	420	19,135
2	34	80	25	40	40	380	18,920
3	37	50	26	40	39	340	16,150
4	35	170	25	60	38	460	24,930
Minimum Power (Watts)							16,150
Average Power (Watts)							19,784
Standard Deviation (Watts)							3,690
90% of Minimum (used this value due to high standard deviation value) (Watts)							14,530

Based on an analysis of this data, the Palatka Mill proposes a minimum value for power of 14,530 watts.

Implementation/Compliance Plan

The necessary instrumentation is not currently in place. Furthermore, the Mill will not have feedback regarding FDEP's acceptance of the monitoring protocol until the permit it issued. As required by 40 CFR 64.4 (e), the necessary monitoring equipment will be installed, tested, and operational no later than 180 days following issuance of the final Title V permit.

CAM Plan
Thermal Oxidizer (Emission Unit 037)
Wet Scrubber

Source Information: Source functions as a control device for the NCGs and SOGs; sulfur dioxide is generated as a result of the combustion of the total reduced sulfur compounds contained in the NCGs and SOGs

Control Device(s): Wet scrubber for sulfur dioxide (SO_2) control

Applicable Limits: 31.3 lbs/hour and 137.2 tons/year (Condition N.6 of the Title V permit)

Current Monitoring: Annual stack test for SO_2
Continuous monitoring of recirculation flow rate
Continuous monitoring of scrubber medium effluent pH

The proposed CAM Plan for the Scrubber on the Thermal Oxidizer is provided in Table 9.

Table 9. Proposed Monitoring Plan for Wet Scrubber on the Thermal Oxidizer

	Indicator No. 1	**Indicator No. 2**
Indicator	Recirculation Flow Rate	Scrubber Medium Effluent pH
Monitoring Approach	Continuous Measurement	Continuous Measurement
Indicator Range	Minimum of 294 gallons per minute[1]	Minimum of 6.7[1]
QIP Threshold	> 5% excursions at FDEP discretion and request	> 5% excursions at FDEP discretion and request
	Performance Criteria	
Data Representativeness	The recirculation flow rate will be measured using standard instrumentation provided for this purpose	The scrubber medium effluent pH will be measured using standard instrumentation provided for this purpose
Verification of Operational Status	N/A	N/A
QA/QC Practices and Criteria	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer's recommendation	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer's recommendation
Monitoring Frequency	Measured continuously; records will be kept when NCGs and/or SOGs are directed to the Thermal Oxidizer; minimum value should not apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)	Measured continuously; records will be kept when NCGs and/or SOGs are directed to the Thermal Oxidizer; minimum value should not apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)
Data Collection Procedure	Recorded as a 15-minute average	Recorded as a 15-minute average
Averaging Period	1-hour block (average of the recorded 15-minute values collected during the 1-hour period)	1-hour block (average of the recorded 15-minute values collected during the 1-hour period)

[1] The Palatka Mill requests that Condition N.23 of the Title V permit be modified in a manner to allow for a downward adjustment of these values should future tests demonstrate compliance with lower values.

Monitoring Approach Justification

Rationale for Selection of Performance Indicators

The Palatka Mill is proposing to use the periodic monitoring requirements contained in Condition N.21 of the current Title V permit to satisfy the CAM requirements. These requirements are to continuously measure scrubber recirculation flow rate and scrubber medium effluent pH. The liquid flow rate is a key indicator of performance provided that the liquid is being properly distributed and the liquid-gas interface is maintained. Under these conditions, higher liquid flow rates are indicative of higher levels of control. Scrubber liquid pH is an indicator of acid gas removal efficiency. A drop in pH can indicate that the less acid is being neutralized.

Rationale for Selection of Indicator Ranges

The existing Title V permit, in Condition N.21, specifies a minimum flow rate of 294 gallons per minute and a minimum pH of 6.7. These are both 3-hour block average values. These values were based on initial performance testing that was performed in November 2002. These values were minimum levels recorded, on a 5-minute average basis. The Palatka Mill proposes to maintain these values, but also requests that Condition N.23 of the Title V permit be modified in a manner to allow for a downward adjustment of these values should future tests demonstrate compliance with lower values.

CAM Plan
Thermal Oxidizer (Emission Unit 037)
Destruction/Incineration Device for TRS

Source Information: Source functions as a control device for the NCGs and SOGs; sulfur dioxide is generated as a result of the combustion of the total reduced sulfur compounds contained in the NCGs and SOGs

Control Device(s): Thermal oxidizer for the destruction/incineration of TRS gases

Applicable Limits: 5 part per million by volume on a dry basis at standard conditions corrected to 10 percent oxygen as a 12-hour block average, 0.20 lb/hour, and 0.89 ton/year

Current Monitoring: Continuous measurement of temperature.

The proposed CAM Plan for TRS for the Thermal Oxidizer is provided in Table 10.

Table 10. Proposed Monitoring Plan for the Thermal Oxidizer as a Destruction/Incineration Device for TRS Gases

	Indicator No. 1	Indicator No. 2
Indicator	Temperature	Residence Time
Monitoring Approach	Continuous temperature measurement at the back end of the first pass of the unit	Per Manufacturer's Design[1]
Indicator Range	Minimum of 1200 degrees Fahrenheit	Minimum of 0.5 second
QIP Threshold	> 5% excursions at FDEP discretion and request	N/A
	Performance Criteria	
Data Representativeness	The temperature will be measured using standard instrumentation provided for this purpose	N/A
Verification of Operational Status	N/A	N/A
QA/QC Practices and Criteria	QA/QC to be performed per manufacturer's recommendation; Title V permit condition specifies an accuracy of +/- 1 percent of the value being measured	N/A
Monitoring Frequency	Measured continuously; records will be kept when NCGs and/or SOGs are directed to the Thermal Oxidizer; minimum value should not apply during start-up, shutdown, or malfunction (SSM) events (the SSM periods will be documented)	N/A
Data Collection Procedure	Recorded as a 5-minute average	N/A
Averaging Period	Using 5-minute average values, an hourly average will be calculated; compliance will be demonstrated based on a 1-hour rolling.	N/A

[1] Golder Associates provided information as part of the MACT I PCP application (November 2001, Attachment GP-EU1-J3) showing the residence time provided by the vendor, Kvaerner-Chemetics, of 0.5 to 0.6 second per equipment design.

Monitoring Approach Justification

Rationale for Selection of Performance Indicators

Operation at a minimum temperature of 1200 degrees Fahrenheit and a retention time of at least 0.5 second will insure proper destruction of the TRS gases. These limits are consistent with limits contained in the federal New Source Performance Standards (NSPS) and Rule 62-296.404(3)(a)1, F.A.C.

Rationale for Selection of Indicator Ranges

Minimum values are specified based on the NSPS and Florida rules. The Palatka Mill has demonstrated compliance with the TRS limits in past performance tests conducted in 2003.

CAM Plan
No. 4 Combination Boiler (Emission Unit 016)
Destruction/Incineration Device for TRS

Source Information: Boiler functions as the back-up control device for non-condensible and stripper off-gases (NCGs and SOGs); in the future, the Boiler will also function as a control device for the DNCGs

Control Device(s): Destruction/incineration of TRS gases

Applicable Limits: 5 part per million by volume on a dry basis at standard conditions corrected to 10 percent oxygen as a 12-hour block average, 0.54 lb/hour, and 0.47 ton/year

Current Monitoring: Temperature and Residence time (per design and calculation), Steam Production.

The proposed CAM Plan for TRS for the No. 4 Combination Boiler is provided in Table 11.

Table 11. Proposed Monitoring Plan for the No. 4 Combination Boiler as a Destruction/Incineration Device for TRS Gases

	Indicator(s) No. 1	**Indicator No. 2**
Indicator	Temperature/Residence Time	Steam Flow
Monitoring Approach	Per Manufacturer's Design and Calculation	Continuous measurement
Indicator Range	Minimum of 1200 degrees Fahrenheit Minimum of 0.5 second residence time	Minimum of 150,000 lbs/hour steam
QIP Threshold	N/A	N/A
	Performance Criteria	
Data Representativeness	N/A	The steam flow will be measured using standard instrumentation provided for this purpose
Verification of Operational Status	N/A	N/A
QA/QC Practices and Criteria	N/A	Confirm that the meter reads zero when the unit is not operating; other QA/QC to be performed per manufacturer's recommendation
Monitoring Frequency	N/A	Measured continuously; records will be kept when NCGs, SOGs, or DNCGs are directed to the Combination Boiler
Data Collection Procedure	N/A	Recorded as a 15-minute average
Averaging Period	N/A	1-hour block (average of the recorded 15-minute values collected during the 1-hour period)

Monitoring Approach Justification

Rationale for Selection of Performance Indicators

Operation at a minimum temperature of 1200 degrees Fahrenheit and a retention time of at least 0.5 second will insure proper destruction of the TRS gases. These limits are consistent with limits contained in the federal New Source Performance Standards (NSPS) and Rule 62-296.404(3)(f)1, F.A.C. In order to insure that these values are established, the NCGs, SOGs, and DNCGs will not be introduced into the Boiler until the 15-minute average steam flow value reaches 150,000 lbs/hour.

Due to Boiler design it is not possible to directly measure the firebox temperature. On June 30, 2004, as part of a response to a supplemental information request for the Brown Stock Washer/Oxygen Delignification project (letter from Mr. David Buff to Ms. Rita Felton-Smith), GP provided a calculation of the residence time. This calculation estimated a retention time of 1.1 second. The calculation that was provided is as follows:

Furnace volume = 12,000 ft^3
Furnace temperature (based on Babcock and Wilcox design) = 2,200 degrees Fahrenheit
Gas flow rate at stack (average from two stack tests performed prior to the letter) = 107,100 dscfm @ 16% H_2O
Flow rate through furnace = 107,100 dscfm x (2,660 R ÷ 528 R) ÷ (1 – 0.16) = 642,260 acfm
Residence time of gases in furnaces = 12,000 ft^3 ÷ 642,260 acfm x 60 sec/min = 1.1 second

Rationale for Selection of Indicator Ranges

While it is not possible to directly monitor the firebox temperature or residence time, insuring that the NCGs, SOGs, or DNCGs are not introduced to the Boiler until steam flow reaches 150,000 lbs/hour will insure that the temperature and residence time requirements are satisfied.