

Statement of Basis

Tier I Operating Permit No. T1-2016.0017

Project ID 61695

**The Amalgamated Sugar Company LLC - Twin Falls
Twin Falls, Idaho**

Facility ID 083-00001

Final

September 18, 2017

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The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

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1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
B&W	Babcock and Wilcox Boiler
BACT	Best Available Control Technology
BMP	best management practices
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CaO	calcium oxide
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	CO ₂ equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
FW	Foster Wheeler Boiler
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MRRR	Monitoring, Recordkeeping and Reporting Requirements
MSP	monitoring system performance
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	nanograms per joule
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O ₂	oxygen

PC	permit condition
PM	particulate matter
PM _{2.5}	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM ₁₀	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
RICE	reciprocating internal combustion engines
<i>Rules</i>	<i>Rules for the Control of Air Pollution in Idaho</i>
scf	standard cubic feet
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SO _x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T1	Tier I operating permit
T2	Tier II operating permit
TAP	toxic air pollutants
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compound

2. INTRODUCTION AND APPLICABILITY

The Amalgamated Sugar Company LLC – Twin Falls Facility (TASCO) is a manufacturer of beet sugar, and is located at 2320 Orchard Drive East in Twin Falls. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit PM, PM₁₀, SO₂, NO_x, and CO above the major source threshold of 100 tons-per-year and has the potential to emit over 100,000 tons-per-year CO_{2e} of greenhouse gas pollutants. The facility is also classified as a major facility, as defined by Subsection 008.10.a, because it emits or has the potential to emit methanol and hydrochloric acid above the major source thresholds of 10 tons-per-year for any single HAP and/or 25 tons-per-year for any combination of HAP.

IDAPA 58.01.01.362 requires that as part of its review of the Tier I application, DEQ shall prepare a technical memorandum (i.e. statement of basis) that sets forth the legal and factual basis for the draft Tier I operating permit terms and conditions including reference to the applicable statutory provisions or the draft denial. This document provides the basis for the draft Tier I operating permit for TASCO.

The format of this Statement of Basis follows that of the permit with the exception of the facility's information discussed first followed by the scope, the applicable requirements and permit shield, and finally the general provisions.

TASCO's Tier I operating permit is organized into sections. They are as follows:

Section 1 – Acronyms, Units, and Chemical Nomenclature

The acronyms, units, and chemical nomenclature used in the permit are defined in this section.

Section 2 - Tier I Operating Permit Scope

The scope describes this permitting action.

Section 3 - Facility-Wide Conditions

The Facility-wide Conditions section contains the applicable requirements (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each permit condition follows the permit condition.

Sections 4 through 12 – Foster Wheeler Boiler, B&W Boiler, Keeler Boiler, Pulp Dryer, Pellet Coolers, Lime Kilns, Process Slaker, Granulator System, Pulp Dryer Material Handling, Lime Kiln Building Material Handling, Main Mill, and Sulfur Stove

The emissions unit-specific sections of the permit contain the applicable requirements that specifically apply to each regulated emissions unit. Some requirements that apply to an emissions unit (e.g. opacity limits) may be contained in the facility-wide conditions. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each applicable requirement immediately follows the applicable requirement.

Section 13 – Boiler MACT Requirements

This section contains the applicable requirements that apply specifically to the Foster Wheeler, B&W, and Keeler Boilers.

Sections 14 and 15 - Non-applicable Requirements and Insignificant Activities

This section lists those requirements that the applicant has requested as non-applicable, and DEQ proposes to grant a permit shield in accordance with IDAPA 58.01.01.325.

If requested by the applicant, this section also lists emissions units and activities determined to be insignificant activities based on size or production as allowed by IDAPA 58.01.01.317.01.b.

Section 16 - General Provisions

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I sources. These conditions have been reviewed by EPA and contain all terms required by IDAPA 58.01.01 et al as well as requirements from other air quality laws and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and the rule or permit, the rule or permit shall govern.

3. FACILITY INFORMATION

3.1 Facility Description

TASCO operates an existing beet sugar manufacturing plant which is located south of Twin Falls, ID. At this facility two coal-fired boilers provide steam for sugar production processes in the main mill, heating, evaporation, and electricity production. There is an additional boiler that is only fired with natural gas. Pulp drying consists of one dual fired pulp dryer that is used to dry press beet pulp and produce cattle feed. Two lime kilns convert lime rock into calcium oxide rocks along with a crusher and two slakers. The warehouse/shipping area contains several sugar silos and rail car loading and unloading areas.

3.2 Facility Permitting History

Tier I Operating Permit History - Previous 5-year permit term October 7, 2011 to October 7, 2016

The following information is the permitting history of this Tier I facility during the previous five-year permit term which was from October 7, 2011. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

October 7, 2011 T1-050415, renewed Title V operating permit, Permit status (A)

Underlying Permit History - Includes every underlying permit issued to this facility

The following information is the comprehensive permitting history of all underlying applicable permits issued to this Tier I facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A), superseded (S), or expired (E).

March 19, 1981	13-1480-0001, Air pollution source permit which established requirements for the boilers and the pulp dryer, Permit status (E)
January 1, 1984	1480-0001, Air pollution source permit which established emission limits and operating requirements and to incorporate existing requirements, Permit status (E)
December 17, 2002	9505-063-1, Initial T1 operating permit, Permit status (S)
May 21, 2004	T1-030415, Reopening of T1 which incorporated revisions resulting from a contested case petition, Permit status (S)
August 20, 2008	O-2008.0080, Applicability concurrence determining the use of anthracite coal in addition to coke as fuel was not a modification, Permit status (A)
October 25, 2010	P-2010.0108, Initial PTC to replace the granulator system, Permit status (A)
November 9, 2012	P-2012.0054, PTC to increase granulation capacity and to install sugar end equipment, Permit status (A)

4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

4.1 Application Scope

This permit is the renewal of the facility's currently effective Tier I operating permit.

Changes from the previous permit include:

- Incorporation of P-2012.0054, issued November 9, 2012
- Boiler MACT requirements
- Compliance Assurance Monitoring (CAM) limits modified

4.2 Application Chronology

April 7, 2016	DEQ received an application.
June 6, 2016	DEQ determined that the application was complete.
April 12, 2017	DEQ made available the draft permit and statement of basis for peer and regional office review.
April 24, 2017	DEQ made available the draft permit and statement of basis for applicant review.
June 19 – July 19, 2017	DEQ provided a public comment period on the proposed action.

July 28, 2017

DEQ provided the proposed permit and statement of basis for EPA review.

September 18, 2022

DEQ issued the final permit and statement of basis.

5. EMISSIONS UNITS, PROCESS DESCRIPTION(S), AND EMISSIONS INVENTORY

This section lists the emissions units, describes the production or manufacturing processes, and provides the emissions inventory for this facility. The information presented was provided by the applicant in its permit application. Also listed in this section are the insignificant activities based on size or production rate.

5.1 Process Description

Table 5.1 lists the emissions units and control devices associated with production and manufacturing processes.

Table 5.1 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Source Description	Control Equipment	Installation Date
<u>Foster Wheeler Boiler (S-B1)</u> Operational capacity: 220,000 lb/hr steam Fuel: coal	Baghouse (A-B1)	1973
<u>B&W Boiler (S-B2)</u> Operational capacity: 250,000 lb/hr steam Fuels: coal, natural gas, combination of coal and gas	Baghouse (A-B2)	prior to 1970
<u>Keeler Boiler (S-B3)</u> Operational capacity: 80,000 lb/hr steam Fuel: natural gas	None	1968
<u>Pulp Dryer (S-D1)</u> PW input rate: 74.8 T/hr Fuels: coal, natural gas, combination of coal and gas	Cyclone and spray-impingement-type scrubber (A-D1A, A-D1B)	prior to 1970
<u>Pellet Cooler No. 1 (S-D2)</u> PW input rate: 8.3 T/hr	Cyclone (A-D2/3)	prior to 1970
<u>Pellet Cooler No. 2 (S-D3)</u> PW input rate: 8.3 T/hr		prior to 1970
<u>South Lime Kiln (S-K1)</u> Lime rock input capacity: 102 T/day Fuel input capacity: 9.2 T/day of fuel Fuels: coke, anthracite coal	Exhaust vent scrubber (A-K1/2)	prior to 1970
<u>North Belgian Lime Kiln (S-K2)</u> Lime rock input: 238 T/day Fuel input capacity: 21 T/day Fuels: coke, anthracite coal		prior to 1970
<u>Process Slaker (S-K4)</u> Operational capacity: 190 T/day CaO	Cyclone (A-K4)	1988
<u>Granulator System (P-W1A) with Baghouse (A-W1A)</u> Operational capacity: 110,230 lb/hr wet sugar and ≤ 1,200 lb/hr steam usage	None	2011

Source Description	Control Equipment	Installation Date
<u>Pulp Dryer Material Handling (S-D4)</u> Operational capacity: 469 T/day	Baghouse (A-D4)	prior to 1970
<u>Lime Kiln Material Handling (S-K5)</u> Operational capacity: 370 T/day	Baghouse 1 (A-K5A) Baghouse 2 (A-K5B)	prior to 1970
<u>Main mill (S-O5)</u> Operational capacity: 105,000 gph juice	None	prior to 1970
<u>Sulfur stove (S-O6)</u> Operational capacity: 1.8 T/day sulfur	Sulfur tower (A-O6)	prior to 1970

Sugarbeet processing operations consist of several steps, including diffusion, juice purification, evaporation, crystallization, dried pulp manufacturing, and sugar recovery from molasses.

Prior to removing sucrose from sugar beets by diffusion, the cleaned and washed beets are sliced into long, thin strips called cossettes. The cossettes are conveyed to a continuous diffuser, in which hot water is used to extract sucrose. The sugar-enriched water that flows from the outlet of the diffuser is called raw juice and contains between 13% to 18% sugar. The raw juice proceeds to the juice purification operation. The processed cossettes, or pulp, leaving the diffuser is conveyed to the dried pulp manufacturing operation.

In the juice purification stage, non-sucrose impurities in the raw juice are removed so that the pure sucrose can be crystallized. First, the juice passes through screens to remove any small cossette particles. The juice is then heated to 80-85°C (176-185°F) and proceeds to the liming system. In the liming system tank, milk of lime [Ca(OH)₂ aqueous solution] is added to the juice to absorb or adhere to the impurities. The juice is then sent to the first carbonation tank where carbon dioxide (CO₂) gas is bubbled to precipitate the lime as insoluble calcium crystals. Lime kilns are used to produce the CO₂ and the lime, which are both used in carbonation; the lime is converted to milk of lime in a lime slaker. After filtration, the juice is softened. Then a small amount of sulfur dioxide (SO₂) is added to the juice to inhibit reactions that lead to darkening of the juice. Burning elemental sulfur in a sulfur stove produces the SO₂ or it is purchased in liquid form. Following the addition of SO₂, the juice (known as thin juice) proceeds to the evaporators.

The evaporation process, which increases the sucrose concentration in the juice by removing water, is performed in a series of five evaporators. Steam from boilers is used to heat the first evaporator, and the steam from the water evaporated in the first evaporator is used to heat the second evaporator, and so on through the five evaporators. After evaporation, the percentage of sucrose in the “thick juice” is 65% to 75%. Some of this thick juice is sent to storage tanks. Most of the thick juice is combined with crystalline sugars produced later in the process and dissolved in the high melter. The mixture is then filtered, yielding a clear liquid known as standard liquor, which proceeds to the crystallization operation.

Sugar is crystallized by low-temperature pan boiling. The standard liquor is boiled in vacuum pans until it becomes supersaturated. To begin crystal formation, the liquor is “seeded” with finely milled sugar. When the crystals reach the desired size, the mixture of liquor and crystals, known as massecuite or fillmass, is discharged to the mixer. From the mixer, the massecuite is poured into high-speed centrifugals, in which the liquid is centrifuged into the outer shell, and the crystals are left in the inner centrifugal basket. The sugar crystals are washed with pure hot water, and then sent to the granulator / cooling system. After cooling, the sugar is screened and then either packaged or stored in large silos for future packaging.

The liquid that was separated from the sugar crystals in the centrifugals is called syrup. This syrup serves as feed liquor for the second boiling step and is introduced into a second set of vacuum pans. The crystallization/centrifugation process is repeated once again, resulting in the production of molasses.

The molasses produced in the third boiling step can be used in the production of livestock feed. This molasses can be further desugarized using the separator process. The products of the separator process are “extract” (the high sugar fraction) and – “concentrated separator by-product” (CSB, the low sugar fraction). The extract can be stored in tanks or immediately processed in the sugar operation, like thick juice. The CSB is used as livestock feed in a liquid form or is added to the wet pulp.

Wet pulp from the diffusion process is another product of sugar beet processing. Some of the wet pulp is sold directly as cattle feed. However, most of the wet pulp is mechanically pressed to reduce the moisture content from about 95% to 75%. After pressing, the pulp may be sold as cattle feed or sent to the dryer. Before entering the rotary drum dryer, CSB or molasses is added to the pressed pulp. The pressed pulp is then dried by hot air in a direct-fired horizontal rotating drum known as a pulp dryer. The pulp dryer can be fired by natural gas or coal. The resulting product is typically pelletized and is sold as livestock feed. The remainder of the dried pulp is sold as livestock feed in an unpelletized form.

5.2 Insignificant Emissions Units Based on Size or Production Rate

No emissions unit or activity subject to an applicable requirement may qualify as an insignificant emissions unit or activity. As required by IDAPA 58.01.01.317.01.b, insignificant emissions units (IEU's) based on size or production rate must be listed in the permit application. Table 5.2 lists the IEU's identified in the permit application. Also summarized is the regulatory authority or justification for each IEU.

Table 5.2 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION

Location	Description	Insignificant Activities IDAPA 58.01.01.317.01(b)(i)
Beet End	Sulfur Stove Hood Vent	(b)(i)30
Sugar End	Gas Water Heater Vent 203	(b)(i)18
Dry Lime Handling Building	Muriatic Acid Tank Vent ITK-26G	(b)(i)19
Lime Kiln Building	Flume Slaker	(b)(i)30
Boiler House	Coal Bunker Vent	(b)(i)30
Front Office Building	Natural Gas Furnace Vent	(b)(i)18
Chemical Storage Tanks	Muriatic Acid Tank Vent	(b)(i)19
	Caustic Tank Vent	(b)(i)19
	Sulfuric Acid Tank Vent	(b)(i)19
	Caustic Tank Vent	(b)(i)19
	South Ammonium Bisulfite Tank Vent	(b)(i)19
Miscellaneous	Propane lances for heating rail cars	(b)(i)5
	Wet and pressed pulp handling	(b)(i)30
	Pebble lime storage tanks and pneumatic conveyance system	(b)(i)30
	Lime rock and coke handling from rail cars and storage piles into lime kiln building	(b)(i)30
	Sugar baghouse handling	(b)(i)30
	Coke unloading and storage pile	(b)(i)30
	Lime rock unloading and storage pile	(b)(i)30
	Pellet cooler fan vents P-D2 and P-D3	(b)(i)30
	Beet hauling	(b)(i)30

5.3 Non-applicable Requirements for Which a Permit Shield is Requested

This section of the permit lists the regulations for which the facility has requested, and DEQ proposes to grant, a permit shield pursuant to IDAPA 58.01.01.325. The findings on which this shield is based are presented below:

- Requirements for Which a Permit Shield Will Be Granted

IDAPA 58.01.01.675, Fuel-burning Equipment - Particulate Matter, is not applicable to the Pulp Dryer (Section 7) or to the Lime Kilns (Section 9).

40 CFR 60 Subpart D, Standards of Performance for Fossil-fuel-fired Steam Generators for Which Construction is Commenced After August 17, 1971, is not applicable to the B&W Boiler (Section 5).

These permit conditions grant a permit shield pursuant to IDAPA 58.01.01.325 with regard to the applicability determinations made when the initial Title V permit was issued.

- Requirements for Which a Permit Shield Will Not Be Granted

None requested

5.4 Emissions Inventory

Table 5.3 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emission is state or federally enforceable.

Listed below Table 5.3 are the references for the emission factors used to estimate the emissions. The documentation provided by the applicant for the emissions inventory and emission factors is provided as Appendix B of this statement of basis.

Table 5.3 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr)

Source Description	PM ₁₀ T/yr	NO _x T/yr	SO ₂ T/yr	CO T/yr	VOC T/yr	HAP T/yr	GHG CO ₂ e T/yr
Foster Wheeler Boiler	93.2	650.2	1120.6	189.6	2.1	14.71	287542
B&W Boiler	118.9	451.5	913.1	13.4	2.1	3.49	
Keeler Boiler	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pulp Dryer	105.3	82.2	61.5	330.8	5.4	6.48	40491
Pellet Cooler No. 1	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Pellet Cooler No. 2	1.22	0.0	0.0	0.0	0.0	0.0	0.0
Pulp Dryer Material Handling	1.35	0.0	0.0	0.0	0.0	0.0	0.0
South Lime Kiln	0.55	4.11	0.22	361.6	0.29	0.05	12112
North Lime Kiln	1.54	11.53	0.62	1015.7	0.82		
Process Slaker	1.19	0.0	0.0	0.0	0.0	0.0	0.0
Material Handling & Crushing	0.11	0.0	0.0	0.0	0.0	0.0	0.0
Drying Granulator #1	1.10	0.0	0.0	0.0	0.0	0.0	0.0
Cooling Granulator #2	1.10	0.0	0.0	0.0	0.0	0.0	0.0
Main Mill	0.0	0.0	0.0	0.0	57.7	39.45	0.0
Sulfur Stove	0.0	0.0	11.2	0.0	0.0	0.0	0.0
Coal Unloading	2.64	0.0	0.0	0.0	0.0	0.0	0.0
Coal Storage	5.23	0.0	0.0	0.0	0.0	0.0	0.0
Boiler Coal Loading	1.05	0.0	0.0	0.0	0.0	0.0	0.0
Beet Hauling	2.35	0.0	0.0	0.0	0.0	0.0	0.0
Boiler Railcar Unloading	2.18	0.0	0.0	0.0	0.0	0.0	0.0
Dryer Railcar Unloading	0.30	0.0	0.0	0.0	0.0	0.0	0.0
Dried Pulp Storage & Loadout	2.29	0.0	0.0	0.0	0.0	0.0	0.0
Total Emissions	342.8	1199.5	2107.2	1911.1	68.4	64.24	340,145

The emission inventory (EI) was developed in PTC No. P-2012.0054, issued on November 9, 2012, and is carried over into this Tier I operating permit. The PTE emissions estimates of PM₁₀/PM_{2.5}, NO_x, SO₂, CO, and VOC were based on emission factors and process information specific to the facility. Emissions are included in Appendix A.

6. EMISSIONS LIMITS AND MRRR

This section contains the applicable requirements for this major facility. Where applicable, monitoring, recordkeeping and reporting requirements (MRRR) follow the applicable requirement and state how compliance with the applicable requirement is to be demonstrated.

This section is divided into several subsections. The first subsection lists the requirements that apply facility wide. The next subsection lists the emissions units- and emissions activities-specific applicable requirements. The final subsection contains the general provisions that apply to all major facilities subject to Idaho DEQ's Tier I operating permit requirements.

This section contains the following subsections:

- Facility-Wide Conditions;
- Foster Wheeler Boiler;
- B&W Boiler;
- Keeler Boiler;

- Pulp Dryer;
- Pellet Coolers;
- Lime Kilns;
- Process Slaker;
- Granulator System;
- Pulp Dryer Material Handling, Lime Kiln Building Material Handling, Main Mill, and Sulfur Stove;
- Boiler MACT – 40 CFR 63 Subpart DDDDD;
- Tier I Operating Permit General Provisions.

MRRR

Immediately following each applicable requirement (permit condition) is the periodic monitoring regime upon which compliance with the underlying applicable requirement is demonstrated. A periodic monitoring regime consists of monitoring, recordkeeping and reporting requirements for each applicable requirement. If an applicable requirement does not include sufficient monitoring, recordkeeping and reporting to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit. This is known as gap filling. In addition to the specific MRRR described under each permit condition, generally applicable facility-wide conditions and general provisions may also be required, such as monitoring, recordkeeping, performance testing, reporting, and certification requirements.

The discussion of each permit condition includes the legal and factual basis for the permit condition. If a permit condition was changed due to facility draft or public comments, a description of why and how the condition was changed is provided.

State Enforceability

An applicable requirement that is not required by the federal CAA and has not been approved by EPA as a SIP-approved requirement is identified as a "State-only" requirement and is enforceable only under state law. State-only requirements are not enforceable by the EPA or citizens under the CAA. State-only requirements are identified in the permit within the citation of the legal authority for the permit condition.

Federal Enforceability

Unless identified as "State-only," all applicable requirements, including MRRR, are state and federally enforceable. It should be noted that while a violation of a MRRR is a violation of the permit, it is not necessarily a violation of the underlying applicable requirement (e.g. emissions limit).

To minimize the length of this document, the following permit conditions and MRRR have been paraphrased. Refer to the permit for the complete requirements.

6.1 Facility-Wide Conditions

Permit Condition 3.1 - Fugitive Dust

All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651, 3/30/07]

MRRR (Permit Conditions 3.2 through 3.4)

- Monitor and maintain records of the frequency and the methods used to control fugitive dust emissions;
- Maintain records of all fugitive dust complaints received and the corrective action taken in response to the complaint;

- Conduct facility-wide inspections of all sources of fugitive emissions. If any of the sources of fugitive dust are not being reasonably controlled, corrective action is required.
[IDAPA 58.01.01.322.06, 07, 08, 4/5/2000]

Permit Condition 3.5 - Odors

The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.
[IDAPA 58.01.01.775-776 (State-only), 5/1/94]

MRRR (Permit Condition 3.6)

- Maintain records of all odor complaints received and the corrective action taken in response to the complaint;
- Take appropriate corrective action if the complaint has merit, and log the date and corrective action taken.

[IDAPA 58.01.01.322.06, 07 (State only), 5/1/94]

Permit Condition 3.7 - Visible Emissions

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.
[IDAPA 58.01.01.625, 4/5/00]

MRRR (Permit Condition 3.8 through 3.9)

- Conduct facility-wide inspections of all emissions units subject to the visible emissions standards (or rely on continuous opacity monitoring);
- If visible emissions are observed, take appropriate corrective action and/or perform a Method 9 opacity test;
- Maintain records of the results of each visible emissions inspection.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

Permit Conditions 3.10 through 3.14 - Excess Emissions

The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between the excess emissions facility wide conditions and the regulations of IDAPA 58.01.01.130-136.

MRRR (Permit Conditions 3.11 through 3.14)

Monitoring, recordkeeping and reporting requirements for excess emissions are provided in Sections 131 through 136.

- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events;
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory;
- Notify DEQ of each excess emissions events as soon as possible, including information regarding upset, breakdown, or safety events.
- Submit a report for each excess emissions event to DEQ;
- Maintain records of each excess emissions event.

Permit Condition 3.15 – Fuel-Burning Equipment PM Standards

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid, 0.050 gr/dscf of effluent gas corrected to 8% oxygen by volume for coal, and 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume for wood products.

[IDAPA 58.01.01.676-677, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.16 - Sulfur Content Limits

The permittee shall not sell, distribute, use, or make available for use any of the following:

- Distillate fuel oil containing more than the following percentages of sulfur:
 - ASTM Grade 1 fuel oil, 0.3% by weight.
 - ASTM Grade 2 fuel oil, 0.5% by weight.
- Coal containing greater than 1.0% sulfur by weight.
- DEQ may approve an exemption from these fuel sulfur content requirements (IDAPA 58.01.01.725.01 725.04) if the permittee demonstrates that, through control measures or other means, SO₂ emissions are equal to or less than those resulting from the combustion of fuels complying with these limitations.

[IDAPA 58.01.01.725, 3/29/10]

MRRR - (Permit Condition 3.17)

The permittee shall maintain documentation of supplier verification of fuel sulfur content on an as received basis.

[IDAPA 58.01.01.322.06, 5/1/94]

Permit Condition 3.18 - Open Burning

The permittee shall comply with the *Rules for Control of Open Burning*, IDAPA 58.01.01.600-623.

[IDAPA 58.01.01.600-623, 5/08/09]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.19 - Asbestos

The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

[40 CFR 61, Subpart M]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.20 - Accidental Release Prevention

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR 68.10 (a)]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.21 - Recycling and Emissions Reductions

The permittee shall comply with applicable standards for recycling and emissions reduction of refrigerants and their substitutes pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction.

[40 CFR 82, Subpart F]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.22 through 3.23- NSPS/NESHAP General Provisions

This facility is subject to NSPS Subpart D and NESHAP Subpart DDDDD, and is therefore required to comply with applicable General Provisions.

[40 CFR 60, Subpart A]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.24 - Monitoring and Recordkeeping

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating permit. Records of monitoring information shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application.

Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Conditions 3.25 through 3.28 - Performance Testing

If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

- The type of method to be used
- Any extenuating or unusual circumstances regarding the proposed test
- The proposed schedule for conducting and reporting the test

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

MRRR (Permit Conditions 3.26 and 3.28)

The permittee shall submit compliance test report(s) to DEQ following testing.

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

Permit Condition 3.29 - Reports and Certifications

This permit condition establishes generally applicable MRRR for submittal of reports, certifications, and notifications to DEQ and/or EPA as specified.

[IDAPA 58.01.01.322.08, 11, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.30 – O&M Manuals

The permittee shall maintain an operation and maintenance (O&M) manual for the appropriate emission control equipment and any associated CAM monitoring equipment for each of the following sources: (a) the B&W Boiler, (b) the Pulp Dryer, (c) the Pellet Coolers, (d) the Lime Kilns, and (e) the Process Slaker.

[IDAPA 58.01.01.322.08, 11, 4/5/00]

MRRR (Permit Conditions 3.31 and 3.32)

O&M manuals shall be developed by the permittee and are incorporated by reference into the permit as enforceable permit conditions.

[IDAPA 58.01.01.322.06, 5/1/94]

Permit Condition 3.33 - Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein.

[IDAPA 58.01.01.107, 4/7/11]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.34 – Facility-Wide Emission Limits

The permittee shall comply with the applicable facility-wide emission limits for criteria pollutants.

[PTC No. P-2012.0054, 11/09/12]

MRRR (Permit Conditions 3.35 and 3.36)

The permittee shall monitor and report to DEQ with facility-wide annual emissions.

[PTC No. P-2012.0054, 11/09/12]

6.2 Emissions Unit-Specific Emissions Limits and MRR

Foster Wheeler Boiler

Permit Conditions 4.1 – 4.7

These permit conditions incorporate federal NSPS requirements and MRRR in accordance with 40 CFR 60, Subpart D (refer to the NSPS Applicability (40 CFR 60) section for additional information).

As indicated in these permit conditions, the use of SO₂ span values specified in 40 CFR 60.45(c) or the use of dry or wet basis procedures approved in accordance with 40 CFR 60.45(e) are also available as compliance options in addition to the methods explicitly cited.

Permit Conditions 4.8, 4.10 – 4.15

Permit Condition 4.8 incorporates fuel-burning equipment particulate matter standards for existing sources in accordance with IDAPA 58.01.01.677. Fuel burning equipment includes the Foster Wheeler Boiler.

For MRRR requirements please refer to the regulatory analysis in Section 7.6 of the Statement of Basis (MACT Applicability) for details. The PM limit is permit condition 4.8 is less stringent than the PM limit in permit condition 13.2.

It may be noted that the permittee has expressed concern with regard to boiler performance during startup, shutdown, and malfunction events. Specifically, because the Foster Wheeler Boiler is not equipped to burn natural gas, there is little or no ability to control emissions during startup. The baghouse has historically been bypassed during startup events to keep it from being clogged with soot. Diesel fuel oil is used to accelerate ignition of the coal during startup events, and the permittee has requested explicit acknowledgement of this practice within the permit condition since the boiler has historically been operated in this manner. During malfunctions and shutdown the baghouse can generally be kept on line. TASC0 has developed an Excess Emission Procedure to address these events (and corresponding excursions and/or exceedances, as applicable).

Permit Condition 4.9

This permit condition limits the fuel type for combustion in the Foster Wheeler Boiler.

No specific monitoring was required for this permit condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

B&W Boiler

Permit Conditions 5.1

Permit Condition 5.1 incorporates fuel-burning equipment particulate matter standards for existing sources in accordance with IDAPA 58.01.01.677-678. Fuel burning equipment includes the B&W Boiler.

For MRRR requirements please refer to the regulatory analysis in Section 7.6 of the Statement of Basis (MACT Applicability) for details. The PM limit is permit condition 5.1 is less stringent than the PM limit in permit condition 13.2.

Additional performance testing for both the Foster Wheeler Boiler and the B&W Boiler to demonstrate compliance with the NSPS PM limit or the PM standard for fuel-burning equipment is not required. Both boilers are required to conduct a performance test for PM under the Boiler MACT requirements. Please see the MACT applicability section for more details.

Permit Condition 5.2 and 5.3

Permit Condition 5.2 limits the fuel type for combustion in the B&W Boiler.

MRRR includes (Permit Condition 5.3) monitoring and recording changes in boiler fuel.

Keeler Boiler

Permit Condition 6.1

This permit condition incorporates fuel-burning equipment particulate matter standards in accordance with IDAPA 58.01.01.676-677. Fuel-burning equipment includes the Keeler Boiler.

No specific monitoring was required for this permit condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 6.2

This permit condition limits the fuel type for combustion in the Keeler Boiler.

No specific monitoring was required for this permit condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Pulp Dryer

Permit Conditions 7.1 and 7.4 – 7.10

Permit Condition 7.1 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.703.

MRRR for CAM include the following (Permit Conditions 7.4 – 7.10)

- Water flow rate monitoring
- Pressure drop monitoring
- Annual inspection and maintenance of each cyclone and scrubber
- Take corrective action upon detecting any excursion or exceedance (opacity, oxygen concentration, scrubber pressure drop, and/or control device bypass)
- Recordkeeping and reporting of excursions and exceedances

Permit Condition 7.2

This permit condition requires process weight monitoring in the Pulp Dryer.

An approved method for the Pulp Dryer Material Input Rate Calculation can be referenced in Appendix B to Air Quality Tier I Operating Permit No. 9505-063-1, issued December 17, 2002.

Permit Condition 7.3

This permit condition requires visible emissions inspection monitoring for the Pulp Dryer.

Permit Condition 7.11

This permit condition requires PM compliance testing within one year of permit issuance. It is considered reasonable at this time to require testing using the minimum recommended test frequency.

Pellet Coolers

Permit Conditions 8.1 and 8.2

Permit Condition 8.1 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.703.

MRRR includes (Permit Condition 8.2) annual inspection and maintenance of the pellet coolers cyclone.

Lime Kilns

Permit Conditions 9.1 – 9.4

Permit Condition 9.1 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.702.

MRRR includes the following (Permit Conditions 9.2 – 9.4):

- Water pressure range for the lime kilns scrubber.
- Installation, operation, calibration, and maintenance of the scrubber pressure drop monitoring device.
- Annual inspection and maintenance of the lime kilns scrubber.

Process Slaker

Permit Conditions 10.1 and 10.2

Permit Condition 10.1 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.702.

MRRR includes (Permit Condition 10.2) annual inspection and maintenance of the process slaker cyclone.

Granulator System

Permit Condition 11.1 and 11.2

Permit Condition 11.1 establishes the opacity limit for the granulator system in accordance with IDAPA 58.01.01.700-703.

Permit Condition 11.2 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.702.

MRRR includes visible emissions inspection monitoring (Facility-wide Permit Conditions 3.7 – 3.9).

No specific monitoring was required for Permit Condition 11.2. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Pulp Dryer Material Handling, Lime Kiln Building Material Handling, Main Mill, and Sulfur Stove

Permit Conditions 12.1 and 12.2

Permit Condition 12.1 incorporates process weight particulate matter standards in accordance with IDAPA 58.01.01.702.

MRRR includes (Permit Condition 12.2) annual inspection and maintenance of the Pulp Dryer Material Handling and Lime Kiln Material Handling Baghouses.

Boiler MACT – 40 CFR 63 Subpart DDDDD

Permit Conditions 13.1 – 13.30

The FW, B&W, and Keeler Boilers are subject to the emission limits in 40 CFR 63 Subpart DDDDD.

For MRRR requirements please refer to the regulatory analysis in Section 7.6 of the Statement of Basis (MACT Applicability) for details.

6.3 General Provisions

Unless expressly stated, there are no MRRR for the general provisions.

General Compliance, Duty to Comply

The permittee must comply with the terms and conditions of the permit.

[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

General Compliance, Need to Halt or Reduce Activity Not a Defense

The permittee cannot use the fact that it would have been necessary to halt or reduce an activity as a defense in an enforcement action.

[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

General Compliance, Duty to Supplement or Correct Application

The permittee must promptly submit such supplementary facts or corrected information upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application. The permittee must also provide information as necessary to address any new requirements that become applicable after the date a complete application has been filed but prior to the release of a draft permit.

[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

Reopening, Additional Requirements, Material Mistakes, Etc.

This term lists the instances when the permit must be reopened and revised, including times when additional requirements become applicable, when the permit contains mistakes, or when revision or revocation is necessary to assure compliance with applicable requirements.

[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

Reopening, Permitting Actions

This term discusses modification, revocation, reopening, and/or reissuance of the permit for cause. If the permittee files a request to modify, revoke, reissue, or terminate the permit, the request does not stay any permit condition, nor does notification of planned changes or anticipated noncompliance.

[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

Information Requests

The permittee must furnish, within a reasonable time to DEQ, any information, including records required by the permit, that is requested in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.

[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Information Requests, Confidential Business Information

Upon request, the permittee must furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Severability

If any provision of the permit is held to be invalid, all unaffected provisions of the permit will remain in effect and enforceable.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213, or complying with IDAPA 58.01.01.220 through 223. The permittee must comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223, 4/2/08; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01.383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/11/06; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

All permit conditions are federally enforceable unless specified in the permit as a state or local only requirement. State and local only requirements are not required under the CAA and are not enforceable by EPA or by citizens.

[IDAPA 58.01.01.322.15.j, 5/1/94; IDAPA 58.01.01.322.15.k, 3/23/98; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

Inspection and Entry

Upon presentation of credentials, the facility shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

New Applicable Requirements

The permittee must continue to comply with all applicable requirements and must comply with new requirements on a timely basis.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

Certification

All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

[IDAPA 58.01.01.322.15.o, 5/1/94; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

Renewal

The permittee shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

Permit Shield

Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
 - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
 - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
 - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
 - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and
 - The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00;
IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99;
IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]

Compliance Schedule and Progress Reports

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.
- For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.

- For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.
- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00; 40 CFR 70.6(c)(3) and (4)]

Periodic Compliance Certification

The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA as specified.

- Compliance certifications for all emissions units shall be submitted annually unless otherwise specified;
- All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.

[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

False Statements

The permittee may not make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

No Tampering

The permittee may not render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Semiannual Monitoring Reports.

In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months as specified.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

Each and every applicable requirement, including MRRR, is subject to prompt deviation reporting. Deviations due to excess emissions must be reported in accordance Sections 130-136. All instances of deviation from Tier I operating permit requirements must be included in the deviation reports. The reports must describe the probable cause of the deviation and any corrective action or preventative measures taken. Deviation reports must be submitted at least every six months unless the permit specifies a different time period as required by IDAPA 58.01.01.322.08.c. Examples of deviations include, but are not limited to, the following:

- Any situation in which an emissions unit fails to meet a permit term or condition
- Emission control device does not meet a required operating condition
- Observations or collected data that demonstrate noncompliance with an emissions standard
- Failure to comply with a permit term that requires a report

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/11/06; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required, Emissions Trading

No permit revision will be required, under any approved, economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in the permit.

[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

Emergency

In accordance with IDAPA 58.01.01.332, an “emergency” as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

7. REGULATORY REVIEW

7.1 Attainment Designation (40 CFR 81.313)

The facility is located in Twin Falls County which is designated as attainment or unclassifiable for PM₁₀, PM_{2.5}, CO, NO₂, SO_x, and Ozone. Refer to 40 CFR 81.313 for additional information.

7.2 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The Twin Falls Facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because the facility emits or has the potential to emit a regulated air pollutant in an amount greater than or equal to 100 T/yr, the facility emits or has the potential to emit a single regulated HAP in excess of 10 T/yr, and the facility emits or has the potential to emit a combination of regulated HAP in excess of 25 T/yr.

Because the facility has a fossil-fuel boiler of more than 250 MMBtu/hr heat input, the boiler house (which includes the Foster Wheeler Boiler, B&W Boiler, and Keeler Boiler) is a designated facility as defined in IDAPA 58.01.01.006.30, and fugitive emissions are required to be included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

7.3 PSD Classification (40 CFR 52.21)

The facility is classified as an existing major stationary source as defined in 40 CFR 52.21(b), because the boiler house steam plant (which includes the Foster Wheeler Boiler, B&W Boiler, and Keeler Boiler) has a fossil-fuel boiler of more than 250 MMBtu/hr heat input.

7.4 NSPS Applicability (40 CFR 60)

The facility is subject to the requirements of 40 CFR 60 Subpart D – New Source Performance Standards for Fossil Fuel Fired Steam Generators constructed after August 17, 1971, and Subpart A – General Provisions.

- The Foster Wheeler Boiler is an affected facility subject to NSPS requirements.

7.5 NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP standards in 40 CFR 61.

7.6 MACT Applicability (40 CFR 63)

The facility is subject to the requirements of 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

- The Foster Wheeler Boiler (FW), Babcock & Wilcox Boiler (B&W), and Keeler Boiler are affected facilities subject to MACT requirements.

Below is a breakdown of Subpart DDDDD for the three affected boilers at the facility.

40 CFR 63, Subpart DDDDD.....National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

§63.7485 *Am I subject to this subpart?*

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as

specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

TASCO – Twin Falls operates three boilers and is subject to this subpart. TASCO is a major source of HAP emissions.

§63.7490 *What is the affected source of this subpart?*

(a) *This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.*

(1) *The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.*

(2) *The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.*

(b) *A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.*

(c) *A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.*

(d) *A boiler or process heater is existing if it is not new or reconstructed.*

(e) *An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.*

The Foster Wheeler Boiler (FW), Babcock & Wilcox Boiler (B&W), and Keeler Boilers are considered affected sources because they are located at a major source of HAPs and are considered existing sources because construction or reconstruction of the boilers commenced before June 4, 2010.

§63.7491 *Are any boilers or process heaters not subject to this subpart?*

(a) *An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.*

(b) *A recovery boiler or furnace covered by subpart MM of this part.*

(c) *A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.*

(d) *A hot water heater as defined in this subpart.*

(e) *A refining kettle covered by subpart X of this part.*

(f) *An ethylene cracking furnace covered by subpart YY of this part.*

(g) *Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).*

(h) *Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.*

(i) *Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.*

(j) *Temporary boilers and process heaters as defined in this subpart.*

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

TASCO does not have any boilers or process heaters that are not subject to the Subpart.

§63.7495 *When do I have to comply with this subpart?*

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

All three boilers are existing sources and must comply with this Subpart by January 31, 2016. The notification requirements also apply.

§63.7499 *What are the subcategories of boilers and process heaters?*

The subcategories of boilers and process heaters, as defined in §63.7575 are:

- (a) Pulverized coal/solid fossil fuel units.*
- (b) Stokers designed to burn coal/solid fossil fuel.*
- (c) Fluidized bed units designed to burn coal/solid fossil fuel.*
- (d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.*
- (e) Fluidized bed units designed to burn biomass/bio-based solid.*
- (f) Suspension burners designed to burn biomass/bio-based solid.*
- (g) Fuel cells designed to burn biomass/bio-based solid.*
- (h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.*
- (i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.*
- (j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.*
- (k) Units designed to burn liquid fuel that are non-continental units.*
- (l) Units designed to burn gas 1 fuels.*
- (m) Units designed to burn gas 2 (other) gases.*
- (n) Metal process furnaces.*
- (o) Limited-use boilers and process heaters.*
- (p) Units designed to burn solid fuel.*
- (q) Units designed to burn liquid fuel.*
- (r) Units designed to burn coal/solid fossil fuel.*
- (s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.*
- (t) Units designed to burn heavy liquid fuel.*
- (u) Units designed to burn light liquid fuel.*

The B&W Boiler falls into two subcategories: (a), pulverized coal/solid fossil fuel unit and (l), units designed to burn gas 1 fuels. The FW boiler fall into subcategory (b), stokers designed to burn coal/solid fossil fuel. The Keeler boiler falls into subcategory (l), units designed to burn gas 1 fuels.

§63.7500 *What emission limitations, work practice standards, and operating limits must I meet?*

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits,

in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under §63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

Table 2 is for existing boilers. It contains the applicable emission limits applying to the B&W and FW boilers.

In Table 2, items 1, 2, and 3 apply to the B&W Boiler as follows:

The Subpart requires all existing affected units to limit emissions of hydrogen chloride (HCl) to 0.022 (2.2E-02) pounds per million British thermal unit (lb/MMBtu) of heat input and mercury (Hg) emissions to 0.0000057 (5.7E-06) lb/MMBtu of heat input. Units designed to burn coal/solid fossil fuel are required to limit emissions of filterable PM (or TSM) to 0.04 lb per MMBtu of heat input. Pulverized coal boilers designed to burn coal/solid fossil fuel are required to limit emissions of carbon monoxide (CO) (or CEMS) to 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis correct to 3 percent oxygen, 30-day rolling average).

In Table 2, items 1, 2, and 4 apply to the FW Boiler as follows:

The Subpart requires all existing affected units to limit emissions of hydrogen chloride (HCl) to 0.022 (2.2E-02) pounds per million British thermal unit (lb/MMBtu) of heat input and mercury (Hg) emissions to 0.0000057 (5.7E-06) lb/MMBtu of heat input. Units designed to burn coal/solid fossil fuel are required to limit emissions of filterable PM (or TSM) to 0.04 lb per MMBtu of heat input. Stokers/others designed to burn coal/solid fossil fuel are required to limit emissions of carbon monoxide (CO) (or CEMS) to 160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis correct to 3 percent oxygen, 30-day rolling average).

These emission limits apply at all times, except during startup and shutdown along with steam output-based limits that are available as alternatives to the limits based on heat input (these also apply at all times except during startup and shutdown). There are also alternative limits based on electrical production, but they do not apply in this case because steam from the boilers is not used to generate electricity that is sold to the grid.

Table 3 contains applicable work practice standards for the boilers.

In Table 3, items 1, 4, and 5 apply to both the B&W and FW Boilers. Only item 4 applies to the Keeler Boiler. The B&W and FW Boilers must conduct a tune-up of the boiler every 5 years as specified in §63.7540, must operate all CMS during startup, use clean fuels during startup, use work practice standards, and comply with all applicable emission limits at all times except during startup and shutdown periods. All three boilers must have a one-time energy assessment performed by a qualified energy assessor. Refer to Table 3 of the Subpart for further details.

Table 4 contains operating limits applicable to the B&W and FW Boilers. Items 3 and 7 apply as follows:

The Subpart requires existing boilers to maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation or install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period. For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.

§63.7505 *What are my general requirements for complying with this subpart?*

(a) *You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).*

(b) *[Reserved]*

(c) *You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must*

demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

For the B&W and FW Boilers, compliance with all applicable emission limits will be demonstrated using performance stack testing to demonstrate compliance with standards for CO and PM. Oxygen trim systems and COMS are used to demonstrate ongoing compliance and a site specific monitoring plan for

each CMS has been developed by the facility. Fuel monitoring is used to demonstrate compliance with standards for HCl and Hg. Only work practice standards apply for natural gas firing.

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in §63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

For the B&W and FW Boilers, compliance with all applicable emission limits will be demonstrated using performance stack testing to demonstrate compliance with standards for CO and PM. In Table 5, items 1 and 5 apply to the performance testing. See Table 5 for further information.

Fuel monitoring by the fuel supplier is used to demonstrate compliance with standards for HCl and Hg. In Table 6, items 1 and 2 apply to the B&W and FW Boilers. See Table 6 for further information. The boilers' initial source tests were due July 29, 2016 (180 days after the compliance date). The initial tune-up and one-time energy assessment were due January 31, 2016. All three boilers have had the initial tune-ups and energy assessments completed.

§63.7515 *When must I conduct subsequent performance tests, fuel analyses, or tune-ups?*

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and

according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).

Annual performance testing is required for the B&W and FW Boilers unless results of the testing enable reduced frequency. Both boilers are also subject to a tune-up every 5 years. The Keeler Boiler is subject to an annual tune-up. The B&W and FW Boilers have ongoing fuel analysis by the fuel supplier. The facility will report results of the performance tests within the time frame specified in the section and operating levels during the performance tests will be documented.

§63.7520 *What stack tests and procedures must I use?*

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in

calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

Site-specific stack test plans have been developed for the B&W and FW Boilers and equipment will be operated during testing as required by the EPA reference methods in Table 5.

§63.7521 *What fuel analyses, fuel specification, and procedures must I use?*

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in §63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in §63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this

subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

A site-specific fuel monitoring plan has been prepared for the B&W and FW Boilers consistent with the Subpart and methods specified in Table 6. Fuel sampling and analysis is conducted by TASCOS's fuel suppliers.

§63.7522 *Can I use emissions averaging to comply with this subpart?*

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

This section is not applicable as TASCOS is not demonstrating compliance using emissions averaging.

§63.7525 *What are my monitoring, installation, operation, and maintenance requirements?*

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO₂)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or CO₂) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO₂) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO₂ as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO₂ analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS

and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO₂ is used to correct CO emissions and CO₂ is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O₂ both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry basis O₂ values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO₂) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO₂) data concurrently. Collect at least four CO and oxygen (or CO₂) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO₂ percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see <http://www.epa.gov/ttn/chief/ert/erttool.html/>).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

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

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

- (3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).
- (4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).
- (5) You must record the results of each inspection, calibration, and validation check.
- (e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.
- (1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.
 - (2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.
 - (3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
 - (4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.
- (f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.
- (1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).
 - (2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.
 - (3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.
 - (4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).
 - (5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.
 - (6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.
- (g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.
- (1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.
 - (2) Ensure the sample is properly mixed and representative of the fluid to be measured.
 - (3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.
 - (4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring

system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily be recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the Federal Register or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO₂) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO₂ CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO₂ CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO₂ CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO₂ CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO₂ data, you must operate the SO₂ CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when SO₂ data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values.

Both the B&W and FW Boilers operate O₂ trim systems per 63.7525(a)(7). Neither boiler is subject to PM CPMS under 63.7525(b). Both boilers are subject to an opacity operating limit and TASCOS has installed and certified a COMS on each boiler per 63.7525(c). No other monitoring systems described in this section are utilized.

§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (C_{input}) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (C_i).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$C_{input} = \sum_{i=1}^n (C_i \times Q_i) \quad (\text{Eq. 7})$$

Where:

C_{input} = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

C_i = Arithmetic average concentration of chlorine in fuel type, i , analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level ($Mercury_{input}$) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Q_i) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HG_i).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercury_{input} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Eq. 8})$$

Where:

$Mercury_{input}$ = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HG_i = Arithmetic average concentration of mercury in fuel type, i , analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSM_{input}) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSM_i).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSM_{input} = \sum_{i=1}^n (TSM_i \times Q_i) \quad (\text{Eq. 9})$$

Where:

TSM_{input} = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSM_i = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(1) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(2) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(3) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(1) through (4) of this section.

(1) Determine your instrument zero output with one of the following procedures:

(i) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(iii) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(iv) If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of this section are possible, you must use a zero output value provided by the manufacturer.

(2) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{Y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

X_i = the PM CPMS data points for the three runs constituting the performance test,

Y_i = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(3) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \quad (\text{Eq. 11})$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(4) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_1 = z + \frac{0.75L}{R} \quad (\text{Eq. 12})$$

Where:

O_1 = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

X_i = the PM CPMS data points for all runs i ,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30\text{-day} = \frac{\sum_{i=1}^n H_{pw}}{n} \quad (\text{Eq. 14})$$

Where:

30-day = 30-day average.

H_{pvi} = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO₂ CEMS is to install and operate the SO₂ according to the requirements in §63.7525(m) establish a maximum SO₂ emission rate equal to the highest hourly average SO₂ measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = \text{mean} + (SD \times t) \quad (\text{Eq. 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. *SD* is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile (t0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 16})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, *i*, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, *i*, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for *Qi*. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$\text{Mercury} = \sum_{i=1}^n (\text{Hgi90} \times \text{Qi}) \quad (\text{Eq. 17})$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$\text{Metals} = \sum_{i=1}^n (\text{TSMi90} \times \text{Qi}) \quad (\text{Eq. 18})$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO₂ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO₂ CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO₂ operating limit by collecting the maximum hourly SO₂ emission rate on the SO₂ CEMS during the paired 3-run test for HCl. The maximum SO₂ operating limit is equal to the highest hourly average SO₂ concentration measured during the HCl performance test.

The B&W and FW Boilers demonstrate compliance with performance tests (PM and CO), fuel analysis (HCl and Hg), and applicable operating limits (COMS) per 63.7520. The facility is not required to establish maximum Cl and Hg fuel input because stack testing is not used for HCl and Hg compliance. No other parameter operating limits in 63.7530(b)(4) apply. Section 63.7530(c) applies to fuel analysis for HCl and Hg. The facility is required to submit the Notification of Compliance Status per 63.7530(e). During startup and shutdown, items 5 and 6 of Table 3 apply.

§63.7533 *Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?*

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to §63.7522(e) and for demonstrating monthly compliance according to §63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>.

TASCO has elected not to use efficiency credits for compliance.

§63.7535 *Is there a minimum amount of monitoring data I must obtain?*

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

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

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

This entire section applies to the B&W and FW Boilers.

§63.7540 *How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?*

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an

alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

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

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made

(measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

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

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

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

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i)

and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the Federal Register or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average

data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamperes) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

TASCO will demonstrate continuous compliance with applicable limits and work practice standards for the B&W and FW boilers. Ongoing fuel analysis is used to demonstrate compliance for HCl and Hg including any new type of fuel. A tune-up is required for both boilers every 5 years. Requirements for Hg CEMS, HCl CEMS, TSM stack testing, and PM CPMS or CEMS do not apply. Per 63.7540(b), deviations from emission limits or operating limits must be documented and reported.

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

This section is not applicable as TASCO is not using emissions averaging for compliance.

§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to §63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

TASCO has already submitted initial notifications for the boilers. TASCO must submit timely notifications of the intent to conduct performance tests. TASCO must also submit Notification of Compliance Status reports and notifications of fuel switching.

§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

- (ii) *Process unit information, emissions limitations, and operating parameter limitations.*
- (iii) *Date of report and beginning and ending dates of the reporting period.*
- (iv) *The total operating time during the reporting period.*
- (v) *If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.*
- (vi) *The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.*
- (vii) *If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.*
- (viii) *A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).*
- (ix) *If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.*
- (x) *A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).*

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO₂, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods of startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) *The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).*

(2) *The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.*

(3) *The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).*

(4) *The date and time that each deviation started and stopped.*

(5) *A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.*

(6) *A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.*

(7) *A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.*

(8) *A brief description of the source for which there was a deviation.*

(9) *A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.*

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (<http://www.epa.gov/ttn/chief/ert/index.html>), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in §63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (<http://www.epa.gov/ttn/chief/cedri/index.html>), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

TASCO must submit semi-annual reports specified in Table 9 for the B&W and FW boilers. The first semi-annual report was due on January 31, 2017. Subsequent reports are due every 6 months after January 31, 2017. Compliance reports must contain information specified in 63.7550(c) – (e). Reports of performance tests must be submitted including test data through the EPA Electronic Reporting Tool.

§63.7555 *What records must I keep?*

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

- (2) *Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).*
- (3) *Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).*
- (4) *Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).*
- (5) *Records of the date and time that each deviation started and stopped.*
- (c) *You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.*
- (d) *For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.*
- (1) *You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.*
- (2) *If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).*
- (3) *A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.*
- (4) *A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.*

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of "startup" in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of "startup" in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

TASCO must maintain records consistent with 63.7555(a) through (d).

§63.7560 *In what form and how long must I keep my records?*

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

All of the requirements of 63.75560 apply to the boilers.

§63.7565 *What parts of the General Provisions apply to me?*

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

Table 10 applies to the boilers. A summary of Subpart A requirements was included in the permit.

§63.7570 *Who implements and enforces this subpart?*

(a) *This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.*

(b) *In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.*

(1) *Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).*

(2) *Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).*

(3) *Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).*

(4) *Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.*

Idaho DEQ has been delegated authority to implement and enforce this subpart.

7.7 CAM Applicability (40 CFR 64)

Based upon criteria pollutant emission estimates provided (refer to Appendix A for additional information), the Foster Wheeler Boiler, B&W Boiler, and Pulp Dryer emissions units have been determined to be subject to the requirements of 40 CFR 64 - Compliance Assurance Monitoring. An approved CAM plan and a complete CAM applicability analysis can be seen in the Statement of Basis for T1-050415 issued on October 7, 2011. Those CAM requirements were established before 40 CFR 63 Subpart DDDDD had been promulgated.

In accordance with 40 CFR 64.2(b)(1)(i), standards that are exempt from CAM requirements include those proposed by EPA after November 15, 1990 pursuant to section 112 of the Clean Air Act (i.e. NESHAP requirements). 40 CFR 63 Subpart DDDDD NESHAP requirements were proposed on January 13, 2003, after the November 15, 1990 exemption deadline. Therefore, the NESHAP standards of 40 CFR 63 Subpart DDDDD, including particulate matter standards, are exempt from CAM requirements. This is because the NESHAP standard has monitoring requirements that are sufficient to assure compliance with NESHAP standards. For these reasons the existing CAM requirements for particulate matter emissions from the Foster Wheeler Boiler and B&W Boiler will be removed from the existing Tier I operating permit.

7.8 Acid Rain Permit (40 CFR 72-75)

This facility is not an affected source per §72.6 of this part, nor is it a Phase I or Phase II source per §73.10 of this part. Therefore, an acid rain permit is not required.

8. PUBLIC COMMENT

As required by IDAPA 58.01.01.364, a public comment period was made available to the public from June 19 – July 19, 2017. During this time, comments were submitted in response to DEQ's proposed action.

9. EPA REVIEW OF PROPOSED PERMIT

As required by IDAPA 58.01.01.366, DEQ provided the proposed permit to EPA Region10 for its review and comment and no response was received after 45 days.

Appendix A - Emissions Inventory

Table 4-1 SUMMARY OF FACILITY WIDE CRITERIA POLLUTANT EMISSIONS
TASCO Twin Falls Facility

Source	ID	PM			PM10			SO2			CO			NOx			VOC		
		max lbs/hr	avg lbs/h	year tns/yr															
Foster Wheeler Boiler	S-B1	28.6	21.3	93.2	28.6	21.3	93.2	344.0	255.8	1120.6	64.8	48.2	211.1	199.6	148.4	650.2	0.7	0.5	2.1
B&W Boiler	S-B2	60.6	30.3	132.6	60.6	30.3	132.6	474.0	235.5	1031.6	8.1	4.1	17.8	220.0	111.4	487.8	0.8	0.4	1.9
Keeler Boiler	S-B3	2.2	0.0	0.0	2.2	0.0	0.0	0.1	0.0	0.0	0.5	0.0	0.0	27.8	0.0	0.0	0.6	0.0	0.0
Pulp Dryer	S-D1	47.6	17.2	75.3	59.5	21.5	94.2	33.5	12.7	55.5	186.9	67.5	295.8	44.8	16.9	74.2	2.9	1.1	4.8
Pellet Cooler No. 1	S-D2	2.66	0.46	2.04	1.33	0.23	1.02												
Pellet Cooler No. 2	S-D3	2.66	0.46	2.04	1.33	0.23	1.02												
Pulp Dryer Material Handling	S-D4		0.26	1.16		0.26	1.16												
South Lime Kiln	S-K1		0.12	0.55		0.12	0.55				82.6	361.6		0.94	4.11		0.07	0.29	
North Lime Kiln	S-K2		0.35	1.54		0.35	1.54		0.14	0.62	231.9	1015.7		2.63	11.53		0.19	0.82	
Process Slaker	S-K4		0.27	1.19		0.27	1.19												
Material Handling & Crushing	S-K5		0.03	0.11		0.03	0.11												
Drying Granulator #1	S-W1	3.21	1.84	8.08	3.21	1.84	8.08												
Cooling Granulator #2	S-W2	0.55	0.32	1.38	0.55	0.32	1.38												
Main Mill	S-O5																24.3	11.5	50.3
Sulfur Stove	S-O6							2.6	2.4	10.5									
Coal Unloading	F-O1			5.28		0.60	2.64												
Coal Storage	F-O2			10.44		1.19	5.23												
Boiler Coal Loading	F-O3			2.11		0.24	1.06												
Beet Hauling	F-O4			4.69		0.54	2.35												
Boiler Railcar Unloading	F-B4			4.46		0.51	2.23												
Dryer Railcar Unloading	F-D5			0.53		0.06	0.26												
Dried Pulp Storage & Loadout	F-D6			4.56		0.52	2.29												
TOTAL	TOTAL	148.1	72.9	351.2	157.3	80.4	352.0	854.2	506.6	2219.0	260.3	434.2	1902.0	492.2	280.3	1227.8	29.2	13.8	60.3
Adjusted Emissions per 12/10/2012 PTC Application and PTC P-2012.0054																			
Adjusted Total Emissions per PTC P-2012.0054 (See Table 4-1)				351			352			2219			1902.0			1228			68

Table 4-4A EMISSIONS - BOILER HOUSE (beet)

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-B1	FW BOILER (beet) coal	PM	28.6	26.3	55.5
		PM10	28.6	26.3	55.5
		SO2	344.0	316.5	667.4
		CO	64.8	59.6	125.7
		NOx	200	184	387.2
		VOC	0.7	0.6	1.3
S-B2	B&W BOILER (beet) coal	PM	60.6	49.4	99.3
		PM10	60.6	49.4	99.3
		SO2	474.0	386.3	776.8
		CO	8.1	6.6	13.3
		NOx	220	179	360.5
		VOC	0.8	0.7	1.3
S-B2	B&W BOILER (beet) gas	PM	5.8	0.3	0.5
		PM10	5.8	0.3	0.5
		SO2	0.2	0.0	0.0
		CO	1.3	0.1	0.1
		NOx	75.0	3.3	7.0
		VOC	1.5	0.1	0.1
S-B3	KEELER BOILER (beet) gas	PM	2.2	0.0	0.0
		PM10	2.2	0.0	0.0
		SO2	0.1	0.0	0.0
		CO	0.5	0.0	0.0
		NOx	27.8	0.0	0.0
		VOC	0.6	0.0	0.0

Table 4-4A EMISSIONS - BOILER HOUSE (juice & sep)

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-B1	FW BOILER (juice & sep) coal	PM	28.6	21.7	37.7
		PM10	28.6	21.7	37.7
		SO2	344.0	261.4	453.2
		CO	64.8	49.2	85.4
		NOx	199.6	151.7	263.0
		VOC	0.7	0.5	0.9
S-B2	B&W BOILER (juice & sep) coal	PM	60.6	27.0	32.6
		PM10	60.6	27.0	32.6
		SO2	474.0	210.9	254.8
		CO	8.1	3.6	4.4
		NOx	220.0	97.9	118.3
		VOC	0.8	0.4	0.4
S-B2	B&W BOILER (juice & sep) gas	PM	0.01	0.13	0.15
		PM10	0.01	0.13	0.15
		SO2	0.000	0.004	0.004
		CO	0.00	0.03	0.03
		NOx	0.11	1.65	1.97
		VOC	0.002	0.03	0.04
S-B3	KEELER BOILER (juice & sep) gas	PM	2.2	0.00	0.00
		PM10	2.2	0.00	0.00
		SO2	0.1	0.00	0.00
		CO	0.5	0.00	0.00
		NOx	27.8	0.00	0.00
		VOC	0.6	0.00	0.00

Table 4-4B EMISSIONS - PULP DRYING AND PELLETIZING

NO.	SOURCE	POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-D1	PULP DRYER	PM	48	35	75.3
		PM10	60	44	94.2
		CO	187	139	295.8
		SO2	34	26	55.5
		NOx	45	35	74.2
		VOC	2.9	2.3	4.8
S-D2	PELLET COOLER NO.1 - PELLETS	PM	2.66	0.96	2.0
		PM10	1.33	0.48	1.0
S-D3	PELLET COOLER NO.2 - PELLETS	PM	2.66	0.96	2.0
		PM10	1.33	0.48	1.0
S-D4	PULP DRYER MATERIAL - PELLETS/SHREDS	PM	(1)	(1)	1.2
		PM10	(1)	(1)	1.2

Table 4-4C EMISSIONS - LIME KILN AND CO2 PRODUCTION

NO.	SOURCE	POLLUTANT	MAX LBS/HR.	MAX LBS/DAY	TONS/YR (1)
S-K1	SOUTH KILN	PM	(2)	6.22	0.55
		PM10	(2)	6.22	0.55
		SO2	(2)	2.52	0.22
		CO	(2)	4,107.0	361.6
		NOx	(2)	46.62	4.11
		VOC	(2)	3.30	0.29
S-K2	NORTH KILN	PM	(2)	17.39	1.54
		PM10	(2)	17.39	1.54
		SO2	(2)	7.04	0.6
		CO	(2)	11,488.5	1015.7
		NOx	(2)	130.41	11.53
		VOC	(2)	9.22	0.82
S-K4	PROCESS SLAKER	PM	(2)	13.44	1.19
		PM10	(2)	13.44	1.19
S-K5	MATERIAL HANDLING	PM	(2)	1.28	0.11
		PM10	(2)	1.28	0.11

(1) Annual production rates are based on 365 days of operation.
(2) Hourly production data cannot be determined, because of a batch process with significant hourly variability.

Table 4-4D EMISSIONS - SUGAR WAREHOUSE AND HANDLING

NO.	SOURCE	POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-W1	DRYING GRANULATOR - SUGAR (tons)	PM	3.21	2.65	8.08
		PM10	3.21	2.65	8.08
S-W2	NO. 1 COOLING GRANULATOR - SUGAR	PM	0.55	0.45	1.38
		PM10	0.55	0.45	1.38

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Table 4-4E EMISSIONS - OTHER SOURCES

NO.	SOURCE	POLLUTANT	Max lbs/h	Max lbs/day	Tons/yr
S-05	MAIN MILL	VOC	24.3	582.4	50.3
S-06	SULFUR STOVE	SO2	2.6	61.6	10.5

Note: ANNUAL PRODUCTION BASED ON 365 DAYS OF OPERATION.

Table 4-5 Fugitive Dust Emissions

4/7/2016

ID	DESCRIPTION	POLLUTANT	UNIT	PROCESS INPUT	EMISSION FACTOR LB/UNIT	REFERENCE	EMISSION PM10 (tons/yr)
F-01	Coal Unloading Railcar to Storage						
	Railcar unloading	PM	Tons	160,000	6.60E-02	AP-42 Table 11.9-4	5.28
	Railcar unloading	PM10	Tons	160,000	3.30E-02	50% of Total PM	2.64
	F-01 PM10 total						2.64
						F-01 PM total	5.28
F-02	Coal Storage Area						
	Coal Handling (2 transfers)	PM	Tons	160,000	5.60E-02	AP-42 Table 11.9-4	4.48
		PM10	Tons	160,000	2.80E-02	50% of Total PM	2.24
	Vehicle Traffic	PM	Days	365	2.96	AP-42, Chapter 13.2.2-4	0.54
		PM10		365	1.48	50% of Total PM	0.27
	Active / Inactive Pile	PM	Days	365	29.7	AP-42 Table 11.9-4	5.42
		PM10		365	14.9	50% of Total PM	2.72
	F-02 PM10 total						5.23
	F-02 PM total						10.44
	F-03	Coal Loading Railcars					
Coal loading to boilers & pulp dryer		PM	Tons	151,000	2.80E-02	AP-42 Table 11.9-4	2.11
Coal loading to boilers & pulp dryer		PM10	Tons	151,000	1.40E-02	50% of Total PM	1.06
F-B3 PM10 total						1.06	
						F-B3 PM total	2.11
F-04	Beet Hauling						
	Vehicle Traffic - Unloading	PM	Days	365	15.3	AP-42, Chapter 13.2.2-4	2.79
		PM10		365	7.65	50% of Total PM	1.40
	Vehicle Traffic - To Process	PM	Days	365	10.4	AP-42, Chapter 13.2.2-4	1.90
		PM10		365	5.20	50% of Total PM	0.95
	F-B4 PM10 total						2.35
F-B4 PM total						4.69	
F-B4	Boilerhouse Coal Unloading						
	Railcar Unloading	PM	Tons	135,000	6.60E-02	AP-42 Table 11.9-4 7/98	4.46
	Railcar Unloading	PM10	Tons	135,000	3.30E-02	50% of Total PM	2.23
	F-B4 PM10 total						2.23
						F-B4 PM total	4.46
F-D5	Dryer Coal Unloading						
	Railcar Unloading	PM	Tons	16,000	6.60E-02	AP-42 Table 11.9-4	0.53
	Railcar Unloading	PM10	Tons	16,000	3.30E-02	50% of Total PM	0.26
	F-D6 PM10 total						0.26
F-D6	Dried Pulp Storage & Loadout						
	F-D6 PM total						0.53
	Pellets and Shreds	PM	Tons	62,000	1.47E-01	AP-42 Table 10.4-2	4.56
	Pellets and Shreds	PM10	Tons	62,000	7.40E-02	50% of Total PM	2.29
F-D7 PM10 total						2.29	
F-D7 PM total						4.56	

**Table 4-7
GHG Emissions
The Amalgamated Sugar Co. LLC
Twin Falls Facility**

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
FW Boiler	S-B1	1,303,000	klbs steam - coal	CO ₂	267	lbs/klb steam	40CFR98 Subpart C Table C-1	173951
		1,303,000	klbs steam - coal	CH ₄	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	20
		1,303,000	klbs steam - coal	N ₂ O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	3
B&W Boiler	S-B2	770,500	klbs steam - coal	CO ₂	267	lbs/klb steam	40CFR98 Subpart C Table C-1	102862
		770,500	klbs steam - coal	CH ₄	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	12
		770,500	klbs steam - coal	N ₂ O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	2
		148,000	klbs steam - gas	CO ₂	145	lbs/klb steam	40CFR98 Subpart C Table C-1	10730
		148,000	klbs steam - gas	CH ₄	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.21
		148,000	klbs steam - gas	N ₂ O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.02

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Boilers	287542	31	5

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
Pulp Dryer	S-D1	17582	tons - coal	CO ₂	4606	lbs/ton coal	40CFR98 Subpart C Table C-1	40491
		17582	tons - coal	CH ₄	0.518	lbs/ton coal	40CFR98 Subpart C Table C-2	5
		17582	tons - coal	N ₂ O	0.076	lbs/ton coal	40CFR98 Subpart C Table C-2	0.7

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Pulp Dryers	40491	5	1

Source Name	Source ID	Annual	Units	Emissions Parameter	Factor	Units	Reference	Annual Emissions (tons/y)
South Kiln	S-K1	1114	tons - coal/coke	CO ₂	5728	lbs/ton	40CFR98 Subpart C Table C-1	3190
		1114	tons - coal/coke	CH ₄	0.602	lbs/ton	40CFR98 Subpart C Table C-2	0
		1114	tons - coal/coke	N ₂ O	0.0878	lbs/ton	40CFR98 Subpart C Table C-2	0.05
North Kiln	S-K2	3115	tons - coal/coke	CO ₂	5728	lbs/ton	40CFR98 Subpart C Table C-1	8921
		3115	tons - coal/coke	CH ₄	0.602	lbs/ton	40CFR98 Subpart C Table C-2	0.9
		3115	tons - coal/coke	N ₂ O	0.0878	lbs/ton	40CFR98 Subpart C Table C-2	0.1

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Lime Kilns	12112	1	0.2

Table 4-7
GHG Emissions
The Amalgamated Sugar Co. LLC
Twin Falls Facility

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
FW Boiler	S-B1	1,303,000	klbs steam - coal	CO ₂	267	lbs/klb steam	40CFR98 Subpart C Table C-1	173951
		1,303,000	klbs steam - coal	CH ₄	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	20
		1,303,000	klbs steam - coal	N ₂ O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	3
B&W Boiler	S-B2	770,500	klbs steam - coal	CO ₂	267	lbs/klb steam	40CFR98 Subpart C Table C-1	102862
		770,500	klbs steam - coal	CH ₄	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	12
		770,500	klbs steam - coal	N ₂ O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	2
		148,000	klbs steam - gas	CO ₂	145	lbs/klb steam	40CFR98 Subpart C Table C-1	10730
		148,000	klbs steam - gas	CH ₄	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.21
		148,000	klbs steam - gas	N ₂ O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.02

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Boilers	287542	31	5

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
Pulp Dryer	S-D1	17582	tons - coal	CO ₂	4606	lbs/ton coal	40CFR98 Subpart C Table C-1	40491
		17582	tons - coal	CH ₄	0.518	lbs/ton coal	40CFR98 Subpart C Table C-2	5
		17582	tons - coal	N ₂ O	0.076	lbs/ton coal	40CFR98 Subpart C Table C-2	0.7

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Pulp Dryers	40491	5	1

Source Name	Source ID	Annual	Units	Emissions Parameter	Factor	Units	Reference	Annual Emissions (tons/y)
South Kiln	S-K1	1114	tons - coal/coke	CO ₂	5728	lbs/ton	40CFR98 Subpart C Table C-1	3190
		1114	tons - coal/coke	CH ₄	0.602	lbs/ton	40CFR98 Subpart C Table C-2	0
		1114	tons - coal/coke	N ₂ O	0.0878	lbs/ton	40CFR98 Subpart C Table C-2	0.05
North Kiln	S-K2	3115	tons - coal/coke	CO ₂	5728	lbs/ton	40CFR98 Subpart C Table C-1	8921
		3115	tons - coal/coke	CH ₄	0.602	lbs/ton	40CFR98 Subpart C Table C-2	0.9
		3115	tons - coal/coke	N ₂ O	0.0878	lbs/ton	40CFR98 Subpart C Table C-2	0.1

	CO ₂ (tons/y)	CH ₄ (ton/y)	N ₂ O(tons/y)
Total - Lime Kilns	12112	1	0.2

Table 4-8 HAP Emissions Summary - 2016 Tier I Permit Renewal Application TF Facility

HAP	Foster Wheeler Boiler	B & W Boiler	Keeler	Dryer	Dryer	Kilns	Main Mill	Constituent Totals	
	Coal (tons/year)	Coal (tons/year)	Nat Gas (tons/year)	Nat Gas (tons/year)	Coal (tons/year)	Nat Gas (tons/year)	(tons/year)		
Acetaldehyde	0.022	0.01	-	-	2.38	-	0.0E+00	1.99E+00	4.40
Acrolein	0.011	0.01	-	-	1.15	-	0.0E+00	4.60E-02	1.22
Formaldehyde	0.009	0.01	0.01	0.0000	1.17	0.00	0.0E+00	1.82E-02	1.21
Methanol					1.60			37.4	39.04
Arsenic	0.015	0.01	0.00	0.0000	0.00	2.00E-07	9.7E-04		0.03
Benzene	0.049	0.03	0.00	0.0000	0.01	2.10E-06	0.0E+00		0.09
Beryllium	0.001	0.00	0.00	0.0000	0.00	1.20E-08	5.0E-05		0.00
Cadmium	0.002	0.00	0.00	0.0000	0.00	1.10E-06	3.0E-02		0.03
Chromium	0.010	0.01	0.00	0.0000	0.00	1.40E-06	6.2E-04		0.02
Cyanide	0.094	0.06	-	-	0.02	-	5.9E-03		0.19
Hydrochloric Acid	11.94	0.90	-	-	0.04	-	0.0E+00		12.88
Hydrogen Fluoride	2.31	2.09	-	-	0.06	-	0.0E+00		4.46
Lead	0.016	0.01	0.00	0.0000	0.00	5.00E-07	9.9E-04		0.03
Manganese	0.019	0.01	0.00	0.0000	0.00	3.80E-07	1.2E-03		0.04
Mercury	0.004	0.00	0.00	0.0000	0.001	2.60E-07	5.3E-03		0.01
Nickel	0.011	0.01	0.00	0.0000	0.002	2.10E-06	6.6E-04		0.02
Selenium	0.049	0.03	0.00	0.0000	0.011	2.40E-08	3.1E-03		0.10
Toluene	0.009	0.01	0.00	0.0000	0.002	3.40E-06	0.0E+00		0.02
Xylenes	0.001	0.00	-	-	0.000	-			0.00
PAHs and other HAPs	0.142	0.10	0.18	0.0000	0.03	1.80E-03	0.0E+00		0.45
								Total	64.24

Appendix B - Facility Comments for Draft Permit

The following comments were received from the facility on June 1, 2017:

Facility Comment: This permit is approximately twice the number of pages as previous Title V permits, due in large part to the inclusion of federal rules recited verbatim from the Code of Federal Regulations (CFR), and creation of lengthy summary tables. Reciting the rules from the CFR could lead a reviewer to conclude that certain provisions are applicable to TASC0, when under the sitespecific circumstances, they are not. Rule summary tables can be misleading because they are not the complete rule and require referring to the entire rule for context and completeness. TASC0 observes that this approach to including federal requirements subjects the permittee to potential scrutiny and increases the burden to comply. TASC0 proposes that instead the Department include a reference to the federal part in the relevant portion of the permit, plus language that holds the permittee accountable for determining applicability and for compliance.

For example, in Section 13 of the draft permit “Boiler MACT” TASC0 suggests that DEQ delete the thirty-five pages that recite the rule, including provisions that apply, as well as those that do not apply, to the plant. Insert for Section 13 “Boiler MACT” using Tables 13.1 and 13.2: *The permittee is subject to 40 CFR Part 63, Subpart DDDDD. The permittee shall review 40 CFR Part 63, Subpart DDDDD, determine which portions of the Boiler MACT apply to the Keeler, Foster, B&W boilers, develop a compliance summary of those provisions, and ensure compliance with the applicable requirements. The compliance summary may be requested by the Department for review at any time.*”

A similar approach may be applied to other federal requirements to streamline the permit without compromising completeness. A more streamlined document would ease implementation, compliance certifications, and recordkeeping for sources. This approach is consistent with EPA’s current policies to reduce redundancy and clarify regulatory obligations.

DEQ Response: Title V permits require the inclusion of all applicable requirements to a source. DEQ has therefore incorporated all applicable requirements by recitation of the rule. Specific to the facility, non-applicable requirements will be removed from the permit as pointed out by the facility in subsequent comments.

Comments on T1 Permit

Facility Comment: Page 11, P.C. 3.15 - This permit condition is for new sources installed on or after October 1, 1979. The heading for this condition should state this.

DEQ Response: The October 1, 1979 date has been added into the permit condition.

Facility Comment: Page 13, P.C. 3.22, Table 3.2 - This table was not included in the previous Tier I permit and is not needed. Many of these requirements have been addressed. At minimum, this condition should state that NSPS applies only to the FW boiler. Also, if kept, for continuity Table 3.3 should be moved to follow permit condition 3.33.

DEQ Response: NSPS/NESHAP general provisions tables are included in the Tier I operating permit when there are sources that are applicable to these requirements. In this case, the FW Boiler is subject to the NSPS and therefore the NSPS Subpart A general provisions are included.

Facility Comment: Page 14, P.C. 3.22, Table 3.2, Section 60.13, Second bullet - The first sentence is difficult to understand and should be clarified.

DEQ Response: Table 3.2 in the permit is a DEQ developed template table taken from 40 CFR 60, Subpart A. This table is the standard table used in all DEQ issued Tier I operating permits when the facility has sources that are applicable to NSPS requirements.

Facility Comment: Page 15, P.C. 3.23, Table 3.3 - This summary table was not included in the previous Tier I permit and is not needed. It could be a point of confusion since it does not include all the provisions of the rule. The permit only needs to reference 40 CFR Part 63. At minimum this condition should specify that NESHAPS only applies only to industrial boilers. Also, if kept, for continuity Table 3.3 should be moved to follow permit condition 3.33.

DEQ Response: Table 3.3 in the permit is a DEQ developed template table taken from 40 CFR 63, Subpart A. This table is the standard table used in all DEQ issued Tier I operating permits when the facility has sources that are applicable to NESHAP requirements.

Facility Comment: Page 15, P.C. 3.23, Table 3.3, Section 63.13 - The mailing address of the EPA recipient should be consistent with P.C. 3.29. All reports that have to be mailed to EPA should go to the same address. The permit must specify which reports are to be mailed and which reports are to be submitted through CEDRI as per P.C. 13.28. Submitting both paper and electronic reports is duplicative and burdensome. The permit should fully specify the method and means for submitting deviation and excess emission reports, performance test reports for the boilers, performance test report for the dryer, boiler MACT notices for the B&W, MACT semi-annual compliance reports, semi-annual monitoring reports, and annual compliance certifications.

DEQ Response: The address specified in permit condition 3.29 is consistent with the the address specified in Table 3.3. Permit Condition 13.25 outlines the timing and methods for submission of reports for Boiler MACT.

Facility Comment: Page 15, P.C. 3.23, Table 3.3 Section 63.6(e) & (f) - The first 3 bullets in this section should be deleted. Per Table 10 of 40 CFR 63 Subpart DDDDD, Startup, Shutdown & Malfunction (SSM) Plans are not required.

DEQ Response: The requested change has been made.

Facility Comment: Page 17, P.C. 3.23, Table 3.3, Section 63.9, bullet 5 - This bullet should be deleted. Rule 63.9(h)(5) referenced under 63.9 does not apply to TASC0 because both boilers are equipped with COMS. Also, it is not practical for TASC0 to submit written notice of the date of each and every opacity or VE observation.

DEQ Response: The requested change has been made.

Facility Comment: Page 17, P.C. 3.23, Table 3.3, Section 63.9, bullets 6, 7, and 8 - These bullets should be deleted. TASC0 has submitted the required initial notification of compliance status under Subpart D and no subsequent notifications are required.

DEQ Response: The requested change has been made.

Facility Comment: Page 18, P.C. 3.23, Table 3.3 Section 63.10, bullet 2 - Most of the narrative in the first half of this bullet should be deleted. According to 40 CFR 63 Subpart DDDDD Table 10, rule 63.10(b)(2)(ii), (iv), and (v) do not apply to TASC0. Table 10 points to 63.7555(d)(7) and(d)(8) which are included on page 76 of this permit.

DEQ Response: The requested change has been made.

Facility Comment: Page 18, P.C. 3.23, Table 3.3, Section 63.10, bullet 3 - This bullet should be deleted. According to 40 CFR 63 Subpart DDDDD Table 10, rule 63.10(b)(3) does not apply.

DEQ Response: The requested change has been made.

Facility Comment: Page 19, P.C. 3.24 - The reference to strip-chart recordings should be deleted. TASC0 does not use this technology.

DEQ Response: Permit Condition 3.24 is standard DEQ developed template language in all Tier I operating permits. Although TASC0 does not use strip-chart recordings it is included in the template language for facilities that do employ this technology.

Facility Comment: Page 19, P.C. 3.27 - TASC0 requests clarification of the meaning of the phrase, “within 60 days upon request following the date in which a compliance test required by this permit is concluded.” First, what does “upon request” refer to? Secondly, if DEQ intends to interpret this phrase in the same manner as rule 63.7(g), it should be so stated in this permit condition. In other words clarify that the performance test is “completed” when field sample collection is terminated.

DEQ Response: Permit Condition 3.27 has been revised to clarify performance testing requirements. The revised permit condition language now states “Within 60 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.”

Facility Comment: Page 20, P.C. 3.29. The semi-annual reports required under Subpart DDDDD are due on January 31 and July 31, which are more than 30 days specified in this permit condition. The mailing address for EPA should be the same as that cited in Table 3.3.

DEQ Response: The semi-annual reports required under Subpart DDDDD are different and separate than the semi-annual reports required by the Tier I operating permit.

Facility Comment: Page 21, P.C. 3.33 - For continuity if tables 3.2 and 3.3 are retained in the permit, they should be moved to follow this permit condition because it refers to Part 60 and Part 63.

DEQ Response: The DEQ developed permit template specifies that Tables 3.2 and 3.3 be left in their current place in the Tier I operating permit.

Facility Comment: Page 22, P.C. 3.35 - Beet campaign period should be defined. The beet campaign can be defined to start on September 1 and end on August 31 of the following year. This time frame is consistent with the annual certification dates in P.C. 16.22 and semi-annual monitoring report dates in P.C. 16.26. Also, the time for monitoring facility-wide emissions should be reduced from 10 years to 5 years. The 10-year time frame applied when the PTC was issued in 2012. Better to specify a date when the monitoring ends.

DEQ Response: Permit Condition 3.35 is incorporated from P-2012.0054 issued on November 9, 2012. The condition has been revised for clarification.

Facility Comment: Page 22, P.C. 3.36 - Neither the permit nor the statement of basis specify baseline actual emissions. This permit condition should be changed to read, “The permittee shall submit a report to DEQ if facility-wide annual emissions of PM, PM10, PM2.5, SO2, NOX, or CO exceed the applicable values listed in Table 3.4 of this permit by a significant amount, and if...”

DEQ Response: Permit Condition 3.36 is incorporated from P-2012.0054 issued on November 9, 2012. The condition has been revised for clarification.

Facility Comment: Page 24, P.C. 4.6 - In the second paragraph, change the wording to read, “Emission rates shall each be determined on a consistent basis using the” Change “wet” to “consistent.”

DEQ Response: The requested change has been made.

Facility Comment: Page 29, Section 7, Pulp Dryer Summary Description, second paragraph - Change the second paragraph to read. “The dryer can be fired on natural gas, pulverized coal, or a combination of the two fuels.” Change the fifth sentence to read, “The dryer has a design capacity of 74.5 tons per hour process weight input rate (total input includes press pulp, fuel, and additives).” In this sentence “coal” was changed to “fuel.” This description correctly reflects the current pulp dryer fuel burning configuration.

DEQ Response: The requested change has been made.

Facility Comment: Page 33, P.C. 7.11 - This condition specified a compliance test for the dryer is due within one year of permit issuance. In his letter dated August 30, 2013, Bobby Dye stated that the next test is to be conducted not later than October 2, 2017. If the permit is issued after October 2, 2017, the requirement to conduct another test within one year of permit issuance should be changed to acknowledge this test.

DEQ Response: The comment is acknowledged and will be modified should the permit be issued after October 2, 2017.

Facility Comment: Page 45, Table 13.2 - The heading of the table should read "Table 13.2 Applicable Requirements Summary When Boilers Are Fired With Coal".

DEQ Response: The requested change has been made.

Facility Comment: Page 46, Table 13.2 - Under compliance demonstration, for both Hg and HCl, TASC0 has arranged for the fuel supplier to perform sampling of each lot or train shipment. Fuel sampling by the mine is much more rigorous and accurate than sampling TASC0 could perform during monthly operations. Fuel sampling by the supplier is acceptable under rule 63.7521(b)(vi).

DEQ Response: The comment is acknowledged.

Facility Comment: Page 46, P.C. 13.1 - Since this date is passed, this permit condition should be deleted.

DEQ Response: The requested change has been made.

Facility Comment: Page 46, P.C. 13.2, Table 13.3 - For CO limits change the language for the FW boiler to read, "160 ppm dry corrected to 3% O₂; or (340 ppm dry corrected to 3% O₂, 30 rolling average)" to be consistent with Table 2 of Subpart DDDDD. For the B&W boiler the table should read, "130 ppm dry corrected to 3% O₂; or (320 ppm dry corrected to 3% O₂, 30 rolling average)."

DEQ Response: The requested change has been made.

Facility Comment: Page 51, P.C. 13.10 - This condition does not apply to the FW boiler. Initial compliance has been demonstrated.

DEQ Response: The comment is acknowledged.

Facility Comment: Page 55, P.C. 13.13 - Paragraphs (c) and (d) do not apply because TASC0's fuel supplier is conducting fuel sampling as noted above.

DEQ Response: Paragraphs (c) and (d) of Permit Condition 13.12 have been removed from the permit.

Facility Comment: Page 58, P.C. 13.14 - Since both FW and B&W boilers are operated with an O₂ trim system, paragraphs (1) through (6) do not apply and should be deleted.

DEQ Response: The requested change has been made.

Facility Comment: Page 62, P.C. 13.19 - The condition should be deleted because energy assessments have been completed.

DEQ Response: The requested change has been made.

Facility Comment: Page 62, P.C. 13.20 - This condition applies only to the B&W boiler. The Notice of Compliance Status (NOCS) for initial demonstration for the FW boiler was submitted.

DEQ Response: The comment is acknowledged.

Facility Comment: Page 62, P.C. 13.21 - This condition does not apply and should be removed because the only gaseous fuel burned is natural gas.

DEQ Response: The requested change has been made.

Facility Comment: Page 65, P.C. 13.24 - Paragraph (8) does not apply and should be removed.

DEQ Response: The requested change has been made.

Facility Comment: Page 67, P.C. 13.27 - The dates specified in paragraphs (b) and (c) have passed, so they should be stricken.

DEQ Response: The requested change has been made.

Facility Comment: Page 68, P.C. 13.27 - Paragraphs (f) and (g) should be stricken. TASC0 has no ability to burn alternative fuel or solid waste.

DEQ Response: The requested change has been made.

Facility Comment: Page 76, P.C. 13.29 - Paragraph (2) should be stricken. TASC0 does not combust any secondary materials.

DEQ Response: The requested change has been made.

Facility Comment: Page 77, P.C. 13.29 - Paragraphs (12)(i) and (iii) should be stricken because TASC0 does not use electrostatic precipitator or wet scrubber.

DEQ Response: The requested change has been made.

Facility Comment: Page 78, P.C. 13.29 - Paragraphs (e), (f), (g), and (h) should be stricken because they do not apply to TASC0 operations.

DEQ Response: The requested change has been made.

Facility Comment: Page 86, P.C. 16.22 - The second bullet indicates an initial compliance certification that addresses all of the terms and conditions contained in the Tier I Permit. What is the regulatory basis for an initial compliance certification. How does it differ from other certifications?

DEQ Response: An initial compliance certification would include any new sources that need to be certified during the compliance period.

Facility Comment: Page 87, P.C. 16.26 - Semiannual monitoring report timelines overlap the MACT Subpart DDDDD compliance timeframes. Do the semiannual monitoring reports exclude the monitoring required in section 13 of the permit? If not, the semi-annual monitoring periods for Title V permit and MACT should be shifted to follow the same timeframe and prevent the overlap.

DEQ Response: The semi-annual monitoring reports required for the Title V permit include any monitoring reporting under Subpart DDDDD. In accordance with §63.7550(b)(5), for each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

Comments on Statement of Basis

Facility Comment: Page 4, Section 2, Paragraph 1, line 1 - The company name is “The Amalgamated Sugar Company LLC.” There is no comma in the name.

DEQ Response: The requested change has been made.

Facility Comment: Page 4, Section 2, paragraph 1, line 5 - Delete “equivalent” because the word is redundant.

DEQ Response: The requested change has been made.

Facility Comment: Page 5, Section 2 under heading Section 4 through 12, line 2 - Change “specially” to “specifically.”

DEQ Response: The requested change has been made.

Facility Comment: Page 5, Section 3.1, paragraph 1 - In line 3 delete “backup.” In line 6 change “sever” to “several.”

DEQ Response: The requested change has been made.

Facility Comment: Page 8, Section 5.1. In paragraph 1, line 1 and paragraph 2, line 1 - change “sugar beet” to “sugarbeet.” In paragraph 6, line 1 delete “back.”

DEQ Response: The requested change has been made.

Facility Comment: Page 9, Section 5.1, paragraph 1 - Change sentence 2 to read, “Some of the wet pulp is sold directly as cattle feed.” In line 5 insert “direct-fired” between “a” and “horizontal.”

DEQ Response: The requested change has been made.

Facility Comment: Page 11, Table 5.3 - The PTE’s for all three boilers should be combined.

DEQ Response: The PTE for all three boilers was taken from the application and P-2012.0054.

Facility Comment: Page 15, Permit Condition 3.20 - Delete “(a).”

DEQ Response: The PTE for all three boilers was taken from the application and P-2012.0054.

Facility Comment: Page 16, Permit Condition 3.29 - The myriad of reports, certifications, and notifications in the permit are confusing. Either the permit or SOB or both need to include a table that identifies all applicable or required reports, certifications, and notifications, how they are to be submitted (paper or electronic), to whom, and when they are due.

DEQ Response: The rules requiring certification and reports are clearly stated in the permit conditions in the permit. Table 9 of Subpart DDDDD summarizes the reporting requirements for the Boiler MACT. It is highly recommended that TASC schedule a meeting with the DEQ regional office after permit issuance to fully understand the compliance requirements of the permit.

Facility Comment: Page 20, Permit Conditions 13.1-13.3, line 1 - Insert “emission” between “the” and “limits.”

DEQ Response: The requested change has been made.

Facility Comment: Page 29, Section 7.6, after (f), paragraph 6 - TASC boiler steam is used to generate electricity for onsite purposes. Although TASC has capability to use the alternative limits due to electricity production, those limits appear to be more stringent than the heat input-based limits. Table 13.3 in the draft permit has one electric-based limit noted for Filterable PM.

DEQ Response: The requested clarification has been made.

Facility Comment: Page 31, Section 7.6, after (e), paragraph 1 - Change “TSP” to “PM.” TSP is not defined in acronyms.

DEQ Response: The requested change has been made.

Facility Comment: Page 31, Section 7.6, 63.7510 (a)(2)(i) - Technically, TASC is not required to sample fuels. TASC has elected to use fuel analysis to show compliance with mercury and hydrochloric acid emission limits. TASC will continue to have the fuel supplier sample by train lot as new lots are loaded and shipped to TASC.

DEQ Response: The comment is acknowledged and explained in the Statement of Basis below Section 7.6.

Facility Comment: Page 32, Section 7.6, after (k), paragraph 2 - Change “TSP” to “PM.” See comment 11.

DEQ Response: The requested change has been made.

Facility Comment: Page 34, Section 7.6, (i), paragraph 2 - The Keeler Boiler has no oxygen analyzer and is subject to the annual tune-up requirement. The B&W and FW boilers both have oxygen trim systems and are subject to the 5-year tune-up.

DEQ Response: The requested change has been made.

Facility Comment: Page 35, Section 7.6, (b), paragraph 1 - As noted in comment 13, TASC0 is not required to comply with 63.7521, but we use analysis to show compliance anyway.

DEQ Response: The comment is acknowledged.

Facility Comment: Page 61, Section 7.6, after (d), paragraph 1, line 3 - Change sentence to read, "For both boilers a tune-up is required every 5 years."

DEQ Response: The requested change has been made.

Facility Comment: Page 62, Section 7.6, (e) - The notification of compliance status described here is a onetime event. Notice of Compliance Status (NOCS) have been submitted for both boilers. The Foster Wheeler has demonstrated compliance. For the B&W boiler when firing coal, a plan is being developed to demonstrate compliance. The rule is not clear with regard the requirement to submit subsequent notices for the B&W. Subsequent compliance should be addressed in semi-annual reports, not with additional NOCS.

DEQ Response: According to 40 CFR 63.7541(e), the facility is required to submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

Facility Comment: Pages 68-72, Section 7.6 - The regulatory reference numbers for 63.75555 to 63.75570 are incorrect. There is an extra 5 in each one that should be deleted. For example, "63.75555" should be 63.7555.

DEQ Response: The requested change has been made.