Statement of Basis

Permit to Construct No. P-2013.0005
Project ID 61632

Idaho Forest Group LLC - Chilco
Athol, Idaho

Facility ID 055-00024

Final

November 16, 2016
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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
Btu	British thermal units
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
IFG	Idaho Forest Group, LLC - Chilco Facility
km	kilometers
lb/hr	pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
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
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
T/yr	tons per consecutive 12 calendar month period
TAP	toxic air pollutants
U.S.C.	United States Code
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

Idaho Forest Group, LLC - Chilco Facility (IFG) is a manufacturer of dimensional lumber and located at 4447 East Chilco Road, in Athol. The primary processes at the facility are the sawmill, steam plant, dry kilns, planer mill, and by-products handling. Logs are stored in the log yard until they can be processed. Logs are debarked, then cut to dimension in the sawmill. Bark from the debarker is hogged and transferred to the boiler for use as fuel. Surplus bark is sold as a by-product. Green lumber from the sawmill may be sold as planed or rough green lumber, or dried in the dry kilns then trimmed to the desired length planed in the planer mill. The lumber is packaged and shipped by truck and by railcar. By-products include surplus bark, sawdust, sawmill chips, planer chips, and shavings. By-products are shipped primarily by truck.

Permitting History

Refer to the permit history presented in the statement of basis for the Tier I operating permit.

This PTC replaces PTC No. P-2013.0005, issued May 10, 2013, the terms and conditions of which shall no longer apply.

Application Scope

This PTC is for a modification at an existing Tier I facility.

The applicant has proposed to:

- Change the CO emission limit on the hog fuel fired boiler.
- Change the VOC limit on the lumber drying kilns.
- Add a 95 MMBtu/hr natural gas fired boiler to the steam plant.
- Replace the hog fuel fired boiler electrified filter bed (EFB) with an electrostatic precipitator (ESP).

Even though the permittee is replacing the EFB with an ESP, the permit is written to allow either to be used to control emissions. This was done because it is not anticipated that the ESP will be operational at the time of permit issuance, until then the EFB is required to be used.

Application Chronology

November 23, 2015	DEQ received an application.
November 24, 2015	DEQ received an application fee.
December 24, 2015	DEQ determined that the application was incomplete.
February 3, 2016	DEQ received supplemental information from the applicant.
March 14, 2016	DEQ determined that the application was incomplete.
May 19, 2016	DEQ received supplemental information from the applicant.
June 28, 2016	DEQ determined that the application was complete.
August 18, 2016	DEQ made available the draft permit and statement of basis for peer and regional office review.
August 30, 2016	DEQ made available the draft permit and statement of basis for applicant review.
September 14- October 14, 2016	DEQ provided a public comment period on the proposed action.
November 8, 2016	DEQ received the permit processing fee.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source Description	Emissions Control(s)
Hog Fuel Boiler Manufacturer: Kipper & Sons, #1018 Rated Heat Input Capacity: 125 MMBtu/hr Burner Type: Spreader Stoker Rated Steam Capacity: 75,000 lb/hr	Multiclone Electrostatic Precipitator (ESP) Fine Dust Collector or electrified filter bed (EFB)
Natural Gas Fired Boiler Manufacturer: John Zink Hamsworth Rated Input Capacity: 95 MMBtu/hr Rated Steam Capacity: 80,000 lb/hr	None
Kilns	None
Sawdust Bin Target Box	None
Sawmill Chip Bin Target Box	None
Planer Shavings Cyclone	Baghouse
Planer Chip Bin Target Box	None

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit 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 hours 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 emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

The following tables provide a summary of the potential to emit of the lumber mill. The details of the potential to emit emissions calculations may be seen in the emission inventory spreadsheet provided in the application[1]. A summary of the emissions calculations are included in Appendix A.

Uncontrolled Potential to Emit

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits.

The uncontrolled potential to emit is greater than 100 tons per year for all criteria air pollutants except sulfur dioxide. Hazardous air pollutant (HAP) emissions are greater than 10 tons per year for methanol and total HAP emissions are greater than 25 tons per year.

1 TRIM Record # 2016AAG201

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

Table 2 PRE-PROJECT POTENTAIL TO EMIT

Sources	PM10 (ton/yr)	PM2.5 (ton/yr)	SO2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
Sawmill Process Fugitives							
LUMBER DRY KILNS	6.18	5.36	---	---	176	---	23.8
Sawmill Point Sources							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
Planer Point Sources							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
Steam Plant							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111	8.61	238.5	20.2
EFB MEDIA BAGHOUSE (1)	1.00	0.30	---	---	---	---	---
BRC NATURAL GAS BOILER(2)	0.11	0.09	0.13	13.46	1.18	7.06	0.4
Current Point Source Totals (tpy)	**52.45**	**40.59**	**12.79**	**124.85**	**185.29**	**245.54**	44.5

1) will be removed from the site
2) will replaced by new natural gas fired boiler

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all emissions from the facility while complying with the permit conditions.

Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Sources	PM10 (ton/yr)	PM2.5 (ton/yr)	SO2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
Lumber Drying							
LUMBER DRY KILNS	6.18	5.36	---	---	238.5	---	23.8
Sawmill Point Sources							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
Planer Point Sources							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
Steam Plant							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111.39	8.6	249.4	20.2
NEW NATURAL GAS BOILER	0.22	0.18	0.25	26.05	2.28	15.86	0.78
Proposed Point Source Totals (tpy)	**51.55**	**40.37**	**12.91**	**137.45**	**249**	**265**	**44.8**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	HAP
Pre-Project Potential to Emit	52.5	40.6	12.8	124.9	185.3	245.5	44.5
Post Project Potential to Emit	51.6	40.4	12.9	137.5	249	265	44.8
Changes in Potential to Emit	**-0.9**	**-0.2**	**0.1**	**12.6**	**63.7**	**19.5**	**0.3**

TAP Emissions

In accordance with IDAPA 58.01.01.210.20 if the owner or operator demonstrates that the toxic air pollutant from the source or modification is regulated by the Department at the time of permit issuance under 40 CFR Part 60, 40 CFR Part 61 or 40 CFR Part 63, no further procedures for demonstrating preconstruction compliance will be required.

Emissions changes that are part of this project, which are subject to TAP requirements, originate from the addition of a natural gas boiler and increasing the allowable VOC emissions from the lumber drying kilns. The natural gas fired boiler is a 40 CFR 63 Subpart DDDDD affected unit and all toxic air pollutants (TAPs) that are also HAPs are excluded from the need to demonstrate preconstruction compliance for toxic air pollutants. The lumber drying kilns are affected sources in accordance with 40 CFR 63 Subpart DDDD and all TAP emissions are regulated by that subpart therefore they are excluded from the need to demonstrate preconstruction compliance.

Post Project HAP Emissions

Post project HAP emissions are over the major source thresholds for hazardous air pollutants (10 tons per year for any single HAP and 25 tons per year for all HAPs combined). Methanol emissions are 14.3 tons per year and total HAP emissions are 44.8 tons per year.

Ambient Air Quality Impact Analyses

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix B.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Kootenai County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

A = Use when any one HAP has actual or potential emissions $\geq$ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions $\geq$ 25 T/yr.

SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits $\geq$ 8 T/yr of a single HAP or $\geq$ 20 T/yr of THAP.

SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.

B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 5 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	> 100	51.6	**100**	SM
$PM_{10}/PM_{2.5}$	> 100	51.6/40.4	**100**	SM
SO_2	< 100	12.9	**100**	B
NO_X	> 100	137.5	**100**	A
CO	> 100	265	**100**	A
VOC	> 100	249	**100**	A
HAP (single)	> 10	14.3	**10**	A
HAP (Total)	> 25	44.8	**25**	A

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the addition of a natural gas fired boiler and for the increase of VOC emissions from the lumber drying kilns. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625.. Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676 .... Standards for New Sources

The fuel burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, are subject to a particulate matter limitation of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer.

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

IDAPA 58.01.01.301 .... Requirement to Obtain Tier I Operating Permit

As presented in the PTE tables the facility has the potential to emit more than 100 T/yr of regulated air pollutants and the potential to emit HAPs at greater than major source thresholds. Therefore, this facility is a Major Source subject to Tier I permitting requirements. The facility has requested that the PTC be incorporated into the Tier I permit as an administrative amendment in accordance with IDAPA 58.01.01.209.05.c.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 .... Prevention of Significant Deterioration of Air Quality

The facility is not an existing PSD major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a).

The facility has requested that the carbon monoxide emission limit on the hog fuel fired boiler be relaxed from 246 tons per year to 249.4 tons per year. However, initially the applicant requested to increase the CO limit on the hog fuel fired boiler to 480 tons per year. This original proposed relaxation would have triggered PSD in accordance with 40 CFR 52.21(r)(4). In accordance with 40 CFR 52.21(r)(4), at such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, the PSD requirements are triggered due to that type of relaxation as though construction had not yet commenced on the source. The initial 246 tons per year carbon monoxide emission limit was established to prevent the facility from triggering PSD and relaxing it to 250 tons per year or more would trigger PSD. Ongoing CO testing is required in the permit to assure compliance with the 249.4 tons per year emission limit on the hog fuel fired boiler.

Facility-wide VOC and CO emission from existing equipment at the lumber mill remain below the 250 ton per year PSD major facility threshold. Therefore the criteria of triggering PSD by relaxing emissions standards such that PSD is triggered is not met for VOC or CO emissions.

For future permitting actions the facility will be classified as an existing PSD major source because the potential to emit CO is 265 tons per year after the modification is completed (which includes the addition of a new natural gas fired boiler that emits CO). The increases of facility-wide CO emissions above the 250 ton per year PSD threshold is not solely due to a relaxation of an emission standard.

NSPS Applicability (40 CFR 60)

40 CFR 60, Subpart Dc .... Standards of Performance for Small Industrial–Commercial–Institutional Steam Generating Units

The new natural gas fired boiler with a rated input capacity of 95 MMBtu/hr is an affected source by this subpart.

§ 60.40c..Applicability and Delegation of Authority

Section (a) specifies that except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

There are no applicable emission standards for affected source that combust natural gas exclusively, which is the case for the new natural gas fired boiler.

The only substantive applicable requirements are Reporting and Recordkeeping in accordance with 40 CFR 60.48c as follows:

60.48c (a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility; and

60.48c (g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

The requirements of 40 CFR 60 Subpart Dc are included in the permit to construct as a high level citation. They will be added in detail to the Tier I operating permit as administrative amendment in accordance with IDAPA 58.01.01.209.05.c.

A detailed regulatory breakdown of the

NESHAP Applicability (40 CFR 63)

There are new applicable requirements that apply to the existing hog fuel fired boiler and the new natural gas fired boiler. The permit to construct includes a high level citation to the applicable requirements of 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. The requirements of this subpart will be included in detail as an administrative amendment to the Tier I permit in accordance with IDAPA 58.01.01.209.05.c.

A detailed regulatory breakdown of the subpart is provided in Appendix C.

The facility is removing the existing electrified filter bed (EFB) and associated baghouse that controls emissions from the hog fuel fired boiler with an electrostatic precipitator (ESP). This is being done so that the facility can more reliably comply with the particulate matter standards of Subpart DDDDD.

CAM Applicability (40 CFR 64)

The existing Tier I operating permit includes compliance assurance monitoring (CAM) requirements for particulate matter emissions from the hog fuel fired boiler. 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.

Other particulate matter standards on the hog fuel fired boiler are subject to CAM. These include the PM and PM_{10} emission limits on the hog fuel fired boiler that are in the permit to construct issued for that source. However, in satisfying the monitoring requirements for CAM (40 CFR 64.4(b)) for those standards, presumptively acceptable monitoring requirements includes: "Monitoring included for standards exempt from this part pursuant to §64.2(b)(1)(i) or (vi) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant-specific emissions unit" – [40 CFR 64.4(b)(4)].

In short, if the NESHAP standard is more stringent than the standards that are applicable to CAM then the CAM requirements are satisfied by complying with the NESHAP monitoring requirements for that pollutant.

Table 6 provides a comparison of the stringency of the particulate matter CAM applicable emissions standards to the NESHAP standard of40 CFR 63 Subpart DDDDD. The NESHAP emission standard is the most stringent standard. Therefore the monitoring requirements in the NESHAP are presumptively sufficient to assure compliance with the less stringent standards. For these reasons the existing CAM requirements for particulate matter emissions from the hog fuel fired boiler will be removed from the existing Tier I operating permit.

Table 6 COMPARISONS OF PARTICULATE MATTER STANDARDS

Source	$PM_{10}/PM_{2.5}$		PM		PM	
	PTC Limits (Filterable + Condensable) (lb/hr)	**Equivalent Standard in lb/MMBtu (Filterable + Condensable) (lb/MMBtu)**	IDAPA 58.01.01.676 (Filterable) (gr/dscf @ 8% O_2)	**Equivalent Standard in lb/MMBtu (Filterable + Condensable) (lb/MMBtu)**	NESHAP Subpart DDDDD (Filterable) (lb/MMBtu)	Equivalent **Standard in lb/MMBtu (Filterable + Condensable) (lb/MMBtu)**
Hog Fuel Fired Boiler	6.93	**0.055**[1]	0.08	**0.17**[2]	0.037	**0.054**[3]

1) (6.93 lb/hr)/(125 MMBtu/hr) = 0.055 lb/MMBtu

2) Calculated using EPA's F_d-factor for wood combustion. (9240 dscf/MMBtu)

- (9240 dscf/MMBtu)(.21/(.21-.08)) = 14,926 dscf @ 8% O_2/MMBtu
- (14,926 dscf @ 8% O_2)/MMBtu *125 MMBtu/hr = 1,865,769 dscf/hr @ 8%O_2
- 1,865,769 dscf/hr @ 8%O_2 (0.08 gr/dscf @ 8% O_2)(lb/ 7,000 gr) = 21.3 lb/hr
- (21.3 lb/hr)/(125 MMBtu/hr) = 0.17 lb/MMBtu

3) The filterable NESHAP standard (0.037 lb/MMBtu) + AP-42 condensable emission factor (0.017 lb/MMBtu) = 0.054 lb/MMBtu

Permit Conditions Review

This section describes only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

Table 1.1

This table was updated to add the new 95 MMBtu/hr natural gas fired boiler and indicate that particulate matter emissions from the hog fuel fired boiler may either be controlled by an ESP or EFB control device.

Existing Permit Condition 2.11.3

This permit condition was updated to reflect changes to the source testing reporting requirements at IDAPA 58.01.01.157. Source test reports are now due after 60 days instead of 30 days as cited in the existing permit condition.

Permit Condition 3.2 and Table 3.1 were updated to describe that emissions from the hog fuel fired boiler will be controlled by an ESP or an EFB.

Permit Conditions 3.3 and Table 3.2 were updated to remove mention of the EFB. Now the emissions limits are simply stated be for the boiler stack.

The permit (Table 3.2) now limits $PM_{2.5}$ as well as PM_{10} to 6.93 pounds per hour. This is equivalent to the emission rates used in the modeling analysis to assure that the source will not cause or significantly contribute to a violation of an ambient standard (i.e. emission increase were less than modeling thresholds).

A carbon monoxide emission limit was added in units of pounds per hour. The pound per hour limit was included in the permit instead of the pounds per thousand pounds of steam limit because compliance determinations are easier and more reliable on a pound per hour basis. Source testing is required for CO. With the pound per hour emission limit the compliance determination is directly tied to the source test results and is not dependent how much steam may be produced. With a pound per thousand pound of steam limit the source would be required to accurately measure the pounds of steam produced during the test. This unnecessarily complicates the compliance determination.

The pound per hour CO limit is set at 56.9 pounds per hour which assures compliance with the 249.4 ton per year emissions limit that is set to prevent the boiler from triggering PSD requirements.

$$249.4 \text{ T/yr}(2000 \text{ lb/T})(\text{yr}/8760 \text{ hr}) = 56.9 \text{ lb/hr}$$

The permit also now limits NOx emissions from the hog fuel fired boiler to 27.5 pounds per hour which is the emission rate that the facility used in the modeling analysis to assure that the source will not cause or significantly contribute to a violation of an ambient standard. Estimated impacts plus background concentrations were determined to be within 90% of the one hour ambient air quality standard for NO_2. Therefore a source testing is warranted.

The footnotes to Table 3.2 were updated to include DEQ standard language.

Permit Condition 3.4 which limited CO emissions to pounds per thousand pounds of steam was removed from the permit for the reasons discussed above.

Permit Condition 3.4 and 3.5 were amended to remove reference to the EFB stack. They now simply refer to the boiler stack, the substantive requirements of these permit condition remain unchanged.

Permit Condition 3.8

Was updated to specify that a multiclone and ESP or a multiclone and EFB shall be used to control emissions from the hog fuel fired boiler.

Permit Condition 3.9 requires periodic NOx testing. NO_x testing is required because predicted impacts plus background concentrations are within 90% of the one hour NO_2 ambient standard. The testing schedule in the permit remains the same. In absence of limiting hourly operations the permittee is required to source test at worst case normal conditions but no less than 80% of the boilers rated capacity. Periodic source tests at these production rates serve to reasonably assure compliance with the pound per hour emission limits.

Permit Condition 3.10. Carbon monoxide testing was conducted under the previous permit. The most recent test was conducted March 26, 2015. The measured carbon monoxide emission rate was 62% of the standard. However, the next most previous source test conducted on October 22, 2014 measured a violation of CO emissions limit. Because of the widely ranging CO source test results DEQ is requiring that carbon monoxide emission be measured in units of pounds per hour during each test required for carbon monoxide by 40 CFR 63.7510 and 40 CFR 63.7515. In absence of limiting hourly operations the permittee is required to source test at worst case normal conditions but no less than 80% of the boilers rated capacity. Periodic source tests at these production rates serve to reasonably assure compliance with the pound per hour emission limits.

Permit Condition 3.11. Since the facility is installing a new piece of control equipment a onetime source test for PM_{10} is required after the ESP has been installed.

Permit Condition 3.13. The permit condition that required pressure drop monitoring for the EFB baghouse has been removed from the permit because the pressure drop is not a reliable indicator of the baghouse operation. Instead DEQ standard language for baghouses has been included in the permit. In short, the baghouse conditions require corrective action be taken in accordance with a written procedures document developed by the permittee should visible emissions be observed from the baghouse at any time. The procedures document and associated monitoring requirements do not need to be in place until 180 days after issuance of this permit. The permittee has proposed to remove the EFB system and place an ESP in its place. However, it is not likely that the ESP will be operational at the time of permit issuance therefore the EFB requirements are included in the permit. It is anticipated that the ESP will be operational within 180 days after permit issuance[2]. In that scenario the permittee does not have to comply with the EFB baghouse monitoring requirements because the EFB will not be used control emissions.

Permit Condition 3.14 – This permit condition is a high level citation of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Boilers. A detailed breakdown the regulation will be provided in the Tier I operating permit.

Section 4 of the permit includes requirements for the new natural gas fired boiler. Emissions from the 95 MMBtu/hr natural gas fired boiler are uncontrolled as described in Permit Condition 4.1 and 4.2.

Permit Condition 4.3 limits NOx emissions from the boiler. The permit limits NOx emissions from the natural gas fired boiler to 5.1 pounds per hour which is the emission rate that the facility used in the modeling analysis to assure that the source will not cause or significantly contribute to a violation of an ambient standard. Documentation was not provided for the NOx emission factor. Estimated impacts plus background concentrations were determined to be within 90% of the one hour ambient air quality standard for NO_2. Therefore a source testing is warranted.

Permit Condition 4.4 requires periodic source testing for NOx emissions from the natural gas fired boiler. The testing schedule is the same as it is for the hog fuel fired boiler.

Emission limits are not necessary for particulate matter emissions from this natural gas fired boiler. Emission estimates are based on EPA's National Emissions Inventory particulate matter emissions from natural gas fired boilers. Additionally, there is no need for CO or VOC emissions limits. Ambient impact for these pollutants at the estimated emissions rates is not an issue. The most limiting regulatory threshold that needs to be protected for CO and VOC emissions is to assure that emissions changes at the facility do not exceed the 250 T/yr PSD threshold. Estimated emissions of CO are 15.9 tons per year, well below the 250 T/yr PSD threshold. VOC emissions from the boiler are estimated to be 2.3 T/yr and when combined with the 63 T/yr VOC increase at the lumber drying kilns equals a 65.3 T/yr emissions increase which is well below the 250 T/yr PSD threshold.

Permit Section 5 includes requirements for the lumber drying kilns. The only changes to the existing permit conditions is to increase the allowable VOC emissions from 175.5 T/yr to 238.5 T/yr and the require monitoring of VOC emissions using factors provided in the application that were previously approved for use in the July 8, 2014 permit construct issued to IFG's Moyie Springs facility.

No changes were made to the Sawmill (Section 6) and Planer (Section 7) permit conditions.

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2 IFG is installing the ESP in anticipation of achieving compliance with 40 CFR 63 Subpart DDDDD which has a compliance date of January 31, 2017. Therefore it is likely that the ESP will be installed by that date.

PUBLIC REVIEW

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.05.c. During this time, comments were not submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

Public Hearing

Pursuant to Section 58.01.01.364, opportunity for a public hearing for interested persons to appear and submit written or oral comments was provided. DEQ did not receive a request for a public hearing.

APPENDIX A – EMISSIONS INVENTORIES

Required Tables for Emissions Inventory

Table 1 PRE-PROJECT POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS[a]

Emissions Unit	PM10	PM2.5	CO	NO2	VOC	SO2
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
Dry Kilns	6.18	5.36			175.5	
Sawmill Chip Bin Vent	6.27	1.88				
Sawdust Bin Vent	2.65	0.80				
Planer Chipper Target Box	0.40	0.12				
Planer Shavings Cyclone Baghouse	5.44	1.63				
Hog Fuel Boiler	30.4	30.4	238	111	8.61	12.66
EFB Media Baghouse	1.0	0.30				
BRC Gas Boiler	0.11	0.09	7.06	13.46	1.18	0.13
Fugitive Sources emissions are not required because it is not listed source.						
Totals	52.45	40.59	246	125	185	12.79

a) For permitted emissions units provide the PTE under the existing permit conditions, for unpermitted emissions units provide the PTE based on the operational design capacity of the sources that are part of the project. The BRC Gas Boiler is not permitted because it is Below Regulatory Concern (BRC).

Table 2 POST PROJECT POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS[a]

Emissions Unit	PM10	PM2.5	CO	NO2	VOC	SO2
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
Dry Kilns	6.18	5.36			238.5	
Sawmill Chip Bin Vent	6.27	1.88				
Sawdust Bin Vent	2.65	0.80				
Planer Chipper Target Box	0.40	0.12				
Planer Shavings Cyclone Baghouse	5.44	1.63				
Hog Fuel Boiler	30.4	30.4	249	111	8.61	12.66
Natural Gas Boiler	0.22	0.18	15.86	26.05	2.28	0.25
Fugitive Sources emissions are not required because it is not listed source.						
Totals	51.55	40.37	265	137	249	12.91

a) Provide the requested permitted emission rates as the PTE.

Table 3 CHANGES IN POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS

Emissions Unit	PM10	PM2.5	CO	NO2	VOC	SO2
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
Dry Kilns	0.00	0.00			63.0	
Sawmill Chip Bin Vent	0.00	0.00				
Sawdust Bin Vent	0.00	0.00				
Planer Chipper Target Box	0.00	0.00				
Planer Shavings Cyclone Baghouse	0.00	0.00				
Hog Fuel Boiler	0.00	0.00	10.94	0.00	0.00	0.00
Natural Gas Boiler	0.22	0.18	15.86	26.05	2.28	0.25
EFB Media Baghouse	No Credit Taken for Reductions from EFB Media Baghouse.					
BRC Gas Boiler	No Credit Taken for Reductions from BRC Gas Boiler.					
Fugitive Sources emissions are not required because it is not listed source.						
Totals	0.22	0.18	26.80	26.05	65.28	0.25

The following tables, Table 1a, Table 2a and Table 3a list the greenhouse gas emissions from the project. Units are in English tons per year (tpy), followed by metric tons carbon equivalent (CO_2e). Only combustion sources are listed.

Table 1a PRE-PROJECT POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS[a]

Emissions Unit	CO_2, biomass	CO_2, fossil fuel	CH_4	N_2O	CO_2e	
	T/yr	T/yr	T/yr	T/yr	Metric tons	
Point Sources						
Hog Fuel Boiler	104,810	0.00	35.7	4.69	2,081	
BRC Gas Boiler		25,542	0.48	0.05	23,246	
Totals	104,810	25,542	36.2	4.74	25,327	

a) For permitted emissions units provide the PTE under the existing permit conditions, for unpermitted emissions units provide the PTE based on the operational design capacity of the sources that are part of the project.

Table 2a POST PROJECT POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS[a]

Emissions Unit	CO_2, biomass	CO_2, fossil fuel	CH_4	N_2O	CO_2e	CO_2, biomass
	T/yr	T/yr	T/yr	T/yr	Metric tons	T/yr
Point Sources						
Hog Fuel Boiler	104,810		35.7	4.69	2,081	
Natural Gas Boiler		49,597	0.94	0.09	45,133	
Totals	104,810	49,597	36.6	4.78	47,214	

a) Provide the requested permitted emission rates as the PTE.

Table 3a CHANGES IN POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS

Emissions Unit	CO_2, biomass	CO_2, fossil fuel	CH_4	N_2O	CO_2e	
	T/yr	T/yr	T/yr	T/yr	Metric tons	
Point Sources						
Hog Fuel Boiler	0.00		0.00	0.00	0.00	
Natural Gas Boiler		49,597	0.94	0.09	45,133	
BRC Gas Boiler	No Credit Taken for Reductions from BRC Gas Boiler.					
Totals	0.00	49,597	0.94	0.09	45,133	

NSR Regulated air Pollutants are defined[1] as:

Particulate Matter (PM, PM-10, PM-2.5)
Carbon Monoxide
Lead
Nitrogen Dioxide
Ozone (VOC)
Sulfur Dioxide
All pollutants regulated by NSPS (40 CFR 60)(i.e. TRS, fluoride, sulfuric acid mist)
Class I & Class II Ozone Depleting Substances (40 CFR 82)(i.e. CFC, HCFC, Halon, etc.)
CO2e[2]
Green House Gases Mass (GHG - carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride)

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[1] 40 CFR 52.21(b)(50), as incorporated by reference at IDAPA 58.01.01.107.03.d

[2] Multiply each green house gas (GHG) by the global warming potential (GWP) listed at 40 CFR 98, Table A- 1 of Subpart A then sum all values to determine CO_2e (GHGs are carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride). Be sure to show all calculations as described in the instructions.

IDAHO FOREST GROUP - CHILCO, IDAHO
REVISED PROPOSAL MAY 2, 2016
Emission Inventory/Calculations

Point Sources, Proposed	PM10 (ton/yr)	PM2.5 (ton/yr)	SO2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
Lumber Drying							
LUMBER DRY KILNS	6.18	5.36	---	---	238.5	---	23.8
Sawmill Point Sources							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
Planer Point Sources							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
Steam Plant							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111.39	8.6	249.4	20.2
NEW NATURAL GAS BOILER	0.22	0.18	0.25	26.05	2.28	15.86	0.78
Proposed Point Source Totals (tpy)	**51.55**	**40.37**	**12.91**	**137.45**	**249**	**265**	**44.8**
Proposed Point Source Totals (lb/hr)	**11.8**	**9.21**	**3.18**	**33.4**		**65.20**	

Point Sources, Current	PM10 (ton/yr)	PM2.5 (ton/yr)	SO2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
Sawmill Process Fugitives							
LUMBER DRY KILNS	6.18	5.36	---	---	176	---	23.8
Sawmill Point Sources							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
Planer Point Sources							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
Steam Plant							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111	8.61	238.5	20.2
EFB MEDIA BAGHOUSE(1)	1.00	0.30	---	---	---	---	---
BRC NATURAL GAS BOILER(2)	0.11	0.09	0.13	13.46	1.18	7.06	0.4
Current Point Source Totals (tpy)	**52.45**	**40.59**	**12.79**	**124.85**	**185.29**	**245.54**	**44.5**
Current Totals w/o Media BH and BRC Boiler(tpy)	**51.34**	**40.19**	**12.66**	**111.39**	**184.11**	**238.48**	**44.5**
Current Point Source Totals for modeling (lb/hr)	**11.71**	**9.17**	**3.13**	**27.50**		**58.88**	

(1) EFB Media Baghouse Emissions omitted from calculation because they haven't been measured and are suspected to be over-estimated.

(2) Emissions from the rented natural gas boiler (BRC) are excluded from the calculations because it is not a permitted source.

	PM10	PM2.5	SO2	NOx	VOCs	CO	HAPS
Proposed changes (tpy)	0.216	0.178	0.249	26.055	65.279	26.796	0.377
Proposed changes(lb/hr)	0.049	0.041	0.057	5.949		6.321	
Level II Modeling Threshold, tpy		4.1	14	14			
Level II Modeling Threshold, lb/hr	2.6	0.63	2.5	2.4		175	
Level I Modeling Threshold, tpy		0.35	1.2	1.2			
Level I Modeling Threshold, lb/hr	0.22	0.054	0.21	0.2		15	
Modeling Required?	No	No	No	Yes		No	

IDAHO FOREST GROUP - CHILCO

Emission Inventory/Calculations

PTE Production, Unchanged

Lumber Production		
Sawmill	325,000	mbdft/year
Dry Kilns	325,000	mbdft/year
Planer	325,000	mbdft/year
Logs Used	1,170,000	tons/year
Sawmill Hours	5,200	hours/year, est
Planer Hours	5,200	hours/year

Hog Fuel Boiler	607,594	1000 lbs/yr Steam Produced

Residuals Production			
	tons/year	**Actual**	
Sawmill Chips	158,925	978	BDT/mbf sawmill
Sawdust	69,550	428	BDT/mbf sawmill
Hog Bark	92,060		Tons burned, from heat
Planer Chips	7,800	48	BDT/mbf planer
Shavings	26,975	166	BDT/mbf planer

KIPPER & SONS HOG FUEL BOILER

Proposed Emissions

75	klb steam/hr	Boiler Capacity
125	mmBtu/hr maximum	Boiler Capacity
1.6667	mmBtu/klb	
607,594	klb steam, rolling 12-month	Permit Limit, unchanged
1,012,657	MMBtu/yr maximum	Based on permit limit

CRITERIA POLLUTANTS

PM10/PM2.5 (controlled), old permit limit, less stringent than MACT limit.

Emissions:	30.4	tons/year	Current Permit Limit, used in modeling
	6.93	lbs/hr	Current Permit Limit, used in modeling

PM, front and back half, based on MACT limit.
PM10/PM2.5 (controlled), based on MACT limit.

Emission Factor:	0.054	lb/mmBtu	MACT limit of 0.037 plus AP-42 factor
Emissions:	27.34	tons/year	for condensable PM of 0.017 lb/MMBtu
	6.75	lbs/hr	

Sulfur Dioxide:

Emission Factor:	0.025	lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	12.66	tons/year	Unchanged
	3.125	lbs/hr	

Nitrogen Oxides (NOx)

Emission Factor:	0.22	lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	111.39	tons/year	Unchanged
	27.50	lbs/hr	

Volatile Organic Compounds (VOC)

Emission Factor:	0.017	lb/mmBtu	AP-42 TABLE 1.6-2, Rev 9/03
Emissions:	8.61	tons/year	Unchanged
	2.13	lbs/hr	

Lead (Pb)

Emission Factor:	4.80E-05	lb/mmBtu	(AP-42 TABLE 1.6-4, Rev 9/03)
Emissions:	3.038	tons/year	Unchanged
	6.00E-03	lbs/hr	

Carbon Monoxide (CO)

Emission Factor:	0.821	lb/1000 lb steam	Proposed Permit Limit
Emissions:	249.42	tons/year	Proposed Permit Limit
	61.58	lbs/hr	Max based on boiler capacity

Carbon Monoxide (CO)

Emission Factor:	0.785	lb/1000 lb steam	Current Permit Limit
Emissions:	238.48	tons/year	Current Permit Limit
	58.88	lbs/hr	Max based on boiler capacity

Greenhouse Gas Calculations

Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)

Emission Factor:	207	lb/mmbtu
Emissions:	104,810	tpy CO2

Methane

Emission Factor:	0.0705	lb/mmbtu
Emissions:	35.7	tpy
	811.28	metric tons CO2e, GWP = 25

Nitrous Oxide

Emission Factor:	0.00926	lb/mmbtu
Emissions:	4.69	tpy
	1,270.18	metric tons CO2e, GWP = 298

Metric tons CO2e 2,081.46

Greenhouse Gas Emissions (CH4, N2O, CO2, CO2e [Carbon Dioxide equivalent]) uses emission factors from the Mandatory Greenhouse Gas Reporting Rule, 40 CFR Part 98 - Table C-1, Table C-2 - Wood Fuel and Table A-1 (Global Warming Potential GWP).

EFB MEDIA BAGHOUSE

Note: the media BH will be removed along with the EFB.

5000 scf/min — Baghouse design flow.

PM10:

Emission Factor:	0.0054	gr/dscf	Baghouse design emission rate.
Emissions:	1.00	tpy	Permit Limit
	0.23	lb/hr	Permit Limit

PM10:

Emission Factor:	0.0016	gr/dscf	30% of PM10 for material handling sources
Emissions:	0.30	tpy	Based on data from EPA's PM Claculator
	0.069	lb/hr	

NEW NATURAL GAS BOILER
Burners Modified to Restrict heat input to <100 MMBtu/hr

8,760	Hours/Year
80,000	pph steam, approx.
94,618	scfh gas, manufactuer
1,000	btu/cf gas - low estimate
94.6	mmBtu/hr
0.095	mmscf gas per hour
829	mmscf gas per year

CRITERIA POLLUTANTS

PM10			
Emission Factor:	0.52	lb/mmscf	EPA NEI Emission Factors Revise March 30, 2012
Emissions:	0.216	tons/year	
	0.0492	lb/hr	
PM2.5			
Emission Factor:	0.43	lb/mmscf	EPA NEI Emission Factors Revise March 30, 2012
Emissions:	0.178	tons/year	
	0.0407	lb/hr	
Sulfur Dioxide:			
Emission Factor:	0.6	lb/mmscf	(AP-42 TABLE 1.4-2, Rev 7/98)
Emissions:	0.249	tons/year	
	0.057	lb/hr	
Nitrogen Oxides (NOx) as NO2			
Emission Factor:	62.87	lb/mmscf	Based on 50 ppm @ 3% O2 Manufacturer Specifications
Emissions:	26.05	tons/year	
	5.95	lb/hr	
Volatile Organic Compounds (VOC)			
Emission Factor:	5.5	lb/mmscf	(AP-42 TABLE 1.4-2, Rev 7/98)
Emissions:	2.279	tons/year	
	0.520	lb/hr	
Carbon Monoxide (CO)			
Emission Factor:	38.27	lb/mmscf	Based on 50 ppm @ 3% O2 Manufacturer Specifications
Emissions:	15.86	tons/year	
	3.62	lb/hr	

Development of NOx and CO Emission Factors

f-factor natural gas, 0% O2	8710	dscf/mmBtu
Gas vol at Std conditions	379.49	dscf/lbmol
Mass exhaust flow at 3% O2	27	lbmol/mmBtu
Gas Heat Content	1020	mmBtu/mmscf
NO2 PPM	50	ppm @3% O_2
NO2 Molecular Weight	46	lb/lbmol
NO2 Emissions	62.87	lb/mmscf
CO PPM	50	ppm @3% O_2
CO Molecular Weight	28	lb/lbmol
CO Emissions	38.27	lb/mmscf

Greenhouse Gas Emissions

Natural Gas Combustion	850,404	MMBtu/year
Carbon Dioxide (CO2)		
Emission Factor:	53.02	kg/mmbtu
Emissions:	45,088	metric tons CO2
	49,597	tpy
	45,088	metric tons CO2e, GWP = 1
Methane		
Emission Factor:	0.001	kg/mmbtu
Emissions:	0.85	metric tons CO2
	0.94	tpy
	17.86	metric tons CO2e, GWP = 21
Nitrous Oxide		
Emission Factor:	1.00E-04	kg/mmbtu
Emissions:	0.09	metric tons CO2
	0.09	tpy
	26.36	metric tons CO2e, GWP = 310
Metric tons CO2e	45,132.63	

Greenhouse Gas Emissions (CH4, N2O, CO2, CO2e [Carbon Dioxide equivalent]) uses emission factors from the Mandatory Greenhouse Gas Reporting Rule. 40 CFR Part 98 - Table C-1, Table C-2 - Wood Fuel and Table A-1 (Global Warming Potential GWP).

NATURAL GAS BOILER, TEMP
Below Regulatory Concern
Won't be used after permanent boiler is installed.

8,760	Hours/Year, PTE
50.00	mmBtu/hr, PTE
1,020	btu/cf gas, typical value

CRITERIA POLLUTANTS

PM10 (controlled):			
Emission Factor:	0.52	lb/mmscf	EPA NEI Emission Factors Revised
Emissions:	0.11	tons/year	March 30, 2012
	0.03	lbs/hr	
PM2.5 (controlled):			
Emission Factor:	0.43	lb/mmscf	EPA NEI Emission Factors Revised
Emissions:	0.09	tons/year	March 30, 2012
	0.02	lbs/hr	
Sulfur Dioxide:			
Emission Factor:	0.6	lb/mmscf	(AP-42 TABLE 1.4-2, Rev 7/98)
Emissions:	0.13	tons/year	
	0.03	lbs/hr	
Nitrogen Oxides (NOx)			
Emission Factor:	62.68	lb/mmscf	Based on 50 ppm @ 3% O2
Emissions:	13.5	tons/year	Manufacturer Specifications
	3.07	lbs/hr	
Volatile Organic Compounds (VOC)			
Emission Factor:	5.5	lb/mmscf	(AP-42 TABLE 1.4-2, Rev 7/98)
Emissions:	1.18	tons/year	
	0.27	lbs/hr	
Carbon Monoxide (CO)			
Emission Factor:	32.87	lb/mmscf	Based on 50 ppm @ 3% O2
Emissions:	7.06	tons/year	Manufacturer Specifications
	1.61	lbs/hr	
HAPS, Total			
Emission Factor:	1.89E+00	lb/mmscf	(AP-42 TABLE 1.4-2, Rev 7/98)
Emissions:	4.05E-01	tons/year	
	9.25E-02	lbs/hr	

Greenhouse Gas Emissions

Natural Gas Combustion	438,000	MMBtu/year
Carbon Dioxide (CO2)		
Emission Factor:	53.02	kg/mmbtu
Emissions:	23,223	metric tons CO2
	25,545	tpy
	23,223	metric tons CO2e, GWP = 1
Methane		
Emission Factor:	0.001	kg/mmbtu
Emissions:	0.44	metric tons CO2
	0.48	tpy
	9.20	metric tons CO2e, GWP = 21
Nitrous Oxide		
Emission Factor:	1.00E-04	kg/mmbtu
Emissions:	0.04	metric tons CO2
	0.05	tpy
	13.58	metric tons CO2e, GWP = 310
Metric tons CO2e	23,245.54	

Greenhouse Gas Emissions (CH4, N2O, CO2, CO2e [Carbon Dioxide equivalent]) uses emission factors from the Mandatory Greenhouse Gas Reporting Rule. 40 CFR Part 98 - Table C-1, Table C-2 - Wood Fuel and Table A-1 (Global Warming Potential GWP).

IDAHO FOREST GROUP - CHILCO BOILER

HAZARDOUS AIR POLLUTANTS (HAPS)

Operating Parameters:

Potential Hours of Operation 8,760 hours/yr

Annual Boiler Heat Input, actual 1,012,657 mmBtu /yr

Emission Factors:		
AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03)	Emission Factor (lb/mmBtu)	Total Annual Emissions (tons/yr)
Acetaldehyde	8.3E-04	4.20E-01
Acetophenone	3.2E-09	1.62E-06
Acrolein	4.0E-03	2.03E+00
Benzene	4.2E-03	2.13E+00
Benzo(a)pyrene	2.6E-06	1.32E-03
bis(2-ethylhexyl)phthalate	4.7E-08	2.38E-05
Bromomethane (methyl bromide)	1.5E-05	7.59E-03
2-Butanone (MEK)	5.4E-06	2.73E-03
Carbon tetrachloride	4.5E-05	2.28E-02
Chlorine	7.9E-04	4.00E-01
Chlorobenzene	3.3E-05	1.67E-02
Chloroform	2.8E-05	1.42E-02
Chloromethane (Methyl Chloride)	2.3E-05	1.16E-02
1,2-Dichloroethane	2.9E-05	1.47E-02
Dichloromethane (Methylenechloride)	2.9E-04	1.47E-01
1,2-Dichloropropane (Propolyene dichloride)	3.3E-05	1.67E-02
Ethylbenzene	3.1E-05	1.57E-02
Formadehyde (Permit Limit = 2.41 tpy)	4.4E-03	2.23E+00
Hydrogen chloride	1.9E-02	9.62E+00
Methanol (from ODEQ)	1.4E-03	7.09E-01
Naphthalene	9.7E-05	4.91E-02
4-Nitrophenol	1.1E-07	5.57E-05
Pentachlorophenol	5.1E-08	2.58E-05
Phenol	5.1E-05	2.58E-02
Polycyclic Organic Matter (POM)	2.9E-06	1.46E-03
Benzo(a)anthracene	6.5E-08	
Benzo(a)pyrene	2.6E-06	
Benzo(b)fluoranthene	1.0E-07	
Benzo(k)fluoranthene	3.6E-08	
Indeno(1,2,3,cd)pyrene	8.7E-08	
Styrene	1.9E-03	9.62E-01
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.6E-12	4.35E-09
Toluene	9.2E-04	4.66E-01
1,1,1-Trichloroethane (Methyl Chloroform)	3.1E-05	1.57E-02
2,4,6-Trichlorophenol <	2.2E-08	1.11E-05
Vinyl Chloride	1.8E-05	9.11E-03
o-Xylene	2.5E-05	1.27E-02
Antimony	7.9E-06	4.00E-03
Arsenic	2.2E-05	1.11E-02
Beryllium	1.1E-06	5.57E-04
Cadmium	4.1E-06	2.08E-03
Chromium, total	2.1E-05	1.06E-02
Chromium, hexavalent	3.5E-06	1.77E-03
Cobalt	6.5E-06	3.29E-03
Lead	4.8E-05	2.43E-02
Manganese	1.6E-03	8.10E-01
Mercury	3.5E-06	1.77E-03
Nickel	3.3E-05	1.67E-02
Selenium	2.8E-06	1.42E-03
	TOTAL HAPS	20.23

Natural Gas Boiler HAPs

Operating Parameters: New Boiler

Potential Hours of Operation 8,760 hours/yr

Annual Gas Input 829 mmscf/yr

Emission Factors:

AP-42 Ch.1.4, Tables 1.4-3 and 1.4-4 (7/98) emission factors	Emission Factor (lb/mmscf)	Total Annual (tons/yr)	Total Annual (lb/yr)
Acenaphthene	1.8E-06	7.46E-07	1.49E-03
Acenaphthylene	1.8E-06	7.46E-07	1.49E-03
Anthracene	2.4E-06	9.95E-07	1.99E-03
Benzene	2.1E-03	8.70E-04	1.74E+00
Benzo(a)pyrene	1.2E-06	4.97E-07	9.95E-04
Benzo(g,h,i)perylene	1.2E-06	4.97E-07	9.95E-04
7,12-Dimethylbbenz(a)anthracene	1.6E-05	6.63E-06	1.33E-02
Dichlorobenzene	1.2E-03	4.97E-04	9.95E-01
Fluoranthene	3.0E-06	1.24E-06	2.49E-03
Fluorene	2.8E-06	1.16E-06	2.32E-03
Formadehyde	7.5E-02	3.11E-02	6.22E+01
Hexane	1.8E+00	7.46E-01	1.49E+03
2-Methylnaphthalene	2.4E-05	9.95E-06	1.99E-02
3-Methylchloranthrene	1.8E-06	7.46E-07	1.49E-03
Naphthalene	6.1E-04	2.53E-04	5.06E-01
Phenanathrene	1.7E-05	7.05E-06	1.41E-02
Pyrene	5.0E-06	2.07E-06	4.14E-03
Polycyclic Organic Matter (POM)	1.2E-05	4.97E-06	9.95E-03
Benzo(a)anthracene	1.8E-06		
Benzo(a)pyrene	1.2E-06		
Benzo(b)fluoranthene	1.8E-06		
Benzo(k)fluoranthene	1.8E-06		
Chrysene	1.8E-06		
Dibenzo(a,h)anthracene	1.8E-06		
Indeno(1,2,3-cd)pyrene	1.8E-06		
Toluene	3.4E-03	1.41E-03	
Arsenic	2.4E-04	9.95E-05	2.82E+00
Beryllium	1.2E-05	4.97E-06	1.99E-01
Cadmium	1.1E-03	4.56E-04	9.95E-03
Chromium	1.4E-04	5.80E-05	9.12E-01
Cobalt	8.4E-05	3.48E-05	1.16E-01
Manganese	3.8E-04	1.57E-04	6.96E-02
Mercury	2.6E-04	1.08E-04	3.15E-01
Nickel	2.1E-03	8.70E-04	2.16E-01
Selenium	2.4E-05	9.95E-06	1.74E+00
TOTAL HAPS	1.887	0.78	1563.81

LUMBER DRY KILNS

Production Unchanged	325,000	mbdft/yr, lumber dried
Production Unchanged	65,000	mbdft/kiln/yr

CRITERIA POLLUTANTS 890.4109589 37.10045662

PM10 :	Emission Factor:	0.038	lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Unchanged Emissions	6.18	tons/year	See below.
	Unchanged Emissions	1.41	lb/hr	References available upon request.
PM2.5 :	Emission Factor:	0.033	lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Unchanged Emissions	5.36	tons/year	See below.
	Unchanged Emissions	1.22	lb/hr	References available upon request.
VOC:	Emission Factor:	1.47	lbs/1000 bd.ft.	Based on weight emission factor
	Proposed Emissions	238.5	tons/year	Proposed Permit Limit
	Current Emissions	175.50	tons/year	Permit Limit

VOC emissions based on species-dependent weighted emission factor, using information below.

Wood Species:	% of Total	VOC as VOC (lb/MBdft)	Weighted (lb/Mbdft)	Source of Emission Factor
Ponderosa Pine	26.2%	2.46	0.64	2007 OSU Study, interpolated for temperature 210 F
Douglas Fir (DF, DFL)	38.2%	1.03	0.39	2007 OSU Study, interpolated for temperature 220 F
Larch	0.0%	0.25	0.00	2007 OSU Study, test result for 235 F
Hemlock	0.0%	0.24	0.00	2007 OSU Study, interpolated for temperature 220 F
Grand (white) fir (WW)	0.0%	0.70	0.00	1996 U of I study
Hem Fir	6.5%	0.70	0.05	1996 U of I study
Lodgepole	0.0%	1.32	0.00	2007 OSU Study, interpolated for temperature 210 F
Spruce	0.0%	0.11	0.00	2007 OSU Study for spruce
Englemann Spruce/Lodge Pole (ESLP)	29.1%	1.32	0.38	2007 OSU Study, interpolated for temperature 210 F
Alpine Fir	0.0%	0.70	0.00	1996 U of I study
Cedar	0.0%	0.15	0.00	1996 U of I study
Any Other Type	0.0%	2.46	0.00	Highest factor
TOTAL	100.0%		1.47	

Dry Kiln Emission Factors, based on research

Units are pounds per thousand board feet (lb/MBF)

1998 Source Test	PM Total (lb/MBF)	PM_{10} (lb/MBF)	$PM_{2.5}$ (lb/MBF)
coastal hemlock	0.051	0.051	0.048
Douglas-fir	0.024	0.024	0.018
Average	0.038	0.038	0.033

Total PM was assumed to be PM10. Condensable fraction was determine to be PM2.5 fraction

Riley Creek - Chilco
Dry Kiln Haps

PROPOSED PTE

* white wood is Engleman spruce, white fir, etc.

ENTER			
Total MBF processed	325,000		
% Douglas Fir /Larch	38.2%	124,150	*MBF/Yr by species calculated by Total MBF * % species*
% Hem Fir	6.5%	20,995	
% Ponderosa Pine	26.2%	85,001	
% ESLP	29.2%	94,998	
% Cedar	0.0%	0	
% AF (WW)	0.0%	0	
	100%	325,143	

EMISSION FACTORS: units of pounds per thousand board feet (lb/mbf)						
Pollutant	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Douglas Fir / Larch	0.1700	0.0964	0.0033	0.0687	0.0007	0.0009
Hem Fir	0.2500	0.1328	0.0030	0.1039	0.0084	0.0018
Pinderosa Pine	0.1483	0.1021	0.0067	0.0334	0.0027	0.0034
ESLPAF	0.0915	0.0539	0.0030	0.0333	0.0005	0.0008
Cedar	0.0915	0.0539	0.0030	0.0333	0.0005	0.0008
AF (WW)	0.2500	0.1328	0.0030	0.1039	0.0084	0.0018

EMISSIONS units of pounds per year (lb/yr)						
Species	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Douglas Fir / Larch	21104	11972	406	8531	89	106
Hem Fir	5248	2788	64	2182	176	39
Pinderosa Pine	12604	8677	570	2838	230	291
ESLP	8689	5121	284	3161	49	73
Cedar	0	0	0	0	0	0
AF (WW) or Other	0	0	0	0	0	0
TOTAL, lb/yr	47,645	28,557	1,324	16,711	543	509
TOTAL, ton/yr	23.82	14.28	0.66	8.36	0.27	0.25

SAWMILL CHIP BIN VENT - POINT SOURCE
Emissions based on permit limits in current permit.

	Sawmill Chips	250,792 BDT/yr (Permit Cond. 6.1, chips portion of 356,906 BDT/yr))	
PM10:			
	Emission Factor:	0.05 lbs/BDT	Idaho DEQ Target Box Factor (in App. A)
		6.27 tpy	Calculated Emission
	Emissions:	6.27 tons/year	Permit Limit
		1.4315 lb/hr	based on permit limit
PM25:			
	Emission Factor:	0.015 lbs/ton	30% of PM10 for material handling sources
	Emissions:	1.88 tons/year	Based on data from EPA's PM Claculator
		0.4295 lb/hr	

SAWDUST BIN VENT - POINT SOURCE

	Sawmill Sawdust	106,144 BDT/yr (Permit Cond. 6.1, sawdust portion of 356,906 BDT/yr))	
PM10:			
	Emission Factor:	0.05 lbs/ton	**Idaho DEQ Target Box Factor.**
		2.65 tpy	Calculated Emission
	Emissions:	2.65 tons/year	Permit Limit
		0.6050 lb/hr	based on permit limit
PM25:			
	Emission Factor:	0.015 lbs/ton	30% of PM10 for material handling sources
	Emissions:	0.80 tons/year	Based on data from EPA's PM Claculator
		0.1815 lb/hr	

PLANER CHIPPER TARGET BOX - POINT SOURCE

	Planer Chips	16,000 BDT/yr (Permit Cond. 9.5)	
PM10 :			
	Emission Factor:	0.05 lbs/ ton	**Idaho DEQ Target Box Factor.**
		0.40 tpy	Calculated Emission
	Emissions:	0.40 tons/year	Permit Limit
		0.0913 lb/hr	
PM2.5 :			
	Emission Factor:	0.015 lbs/ ton	30% of PM10 for material handling sources
	Emissions:	0.1200 tons/year	Based on data from EPA's PM Claculator
		0.02740 lb/hr	

PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE

	Planer Chips	120,000 BDT/yr (Permit Cond. 9.6)	
		29,000 dscfm	Baghouse Throughput
		8,760 Hours per Year, potential	
PM10 :			
	Emission Factor:	0.005 gr/dscf	**Baghouse Design**
	Emissions:	5.44 tpy	Calculated Emission
		5.40 tpy	Permit Limit
		1.243 lb/hr	
PM25:			
	Emission Factor:	0.0015 gr/dscf	30% of PM10 for material handling sources
	Emissions:	1.63 tpy	Based on data from EPA's PM Claculator
		0.3729 lb/hr	

Subtotals, Proposed and Current

PM10 (tpy)	14.764
PM10 (lb/hr)	3.371
PM2.5 (tpy)	4.429
PM2.5 (lb/hr)	1.011

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

MEMORANDUM

DATE: August 29, 2016

TO: Daniel Pitman, Permit Writer, Air Program

FROM: Kevin Schilling, Stationary Source Modeling Coordinator, Air Program

PROJECT: P-2013.0005 PROJ 61632, PTC for Modifications to Idaho Forest Group's lumber facility in Chilco, ID

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality modeling system
CO	Carbon Monoxide
DEM	Digital Elevation Map
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
GEP	Good Engineering Practice
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
IFG	Idaho Forest Group
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
Lorenzen	Lorenzen Engineering, Inc.
m	Meters
m/sec	Meters per second
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NWS	National Weather Service
O_3	Ozone
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	parts per billion
PRIME	Plume Rive Model Enhancement
PTC	Permit to Construct
PTE	Potential to Emit

SIL	Significant Impact Level
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TCEQ	Texas Commission on Environmental Quality
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

Idaho Forest Group (IFG) submitted a Permit to Construct (PTC) application for proposed modifications to their lumber facility in Chilco, ID. The original PTC application was received on November 25, 2015. DEQ determined the application was incomplete on December 24, 2015. After additional data/analyses were received, the application was again determined incomplete on March 14, 2016. On May 20, 2016, revised air impact analyses were received by DEQ and the application was determined complete on June 28, 2016.

This memorandum provides a summary of the ambient air impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification and sensitivity analyses, additional clarifications, and conclusions.

Project-specific ambient air quality impact analyses, involving atmospheric dispersion modeling of estimated emissions associated with the facility, were submitted to DEQ to demonstrate that the modification would not cause or significantly contribute to a violation of any ambient air quality standard as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

Lorenzen Engineering, Inc. (Lorenzen), on behalf of IFG, prepared the PTC application and performed the air impact analyses for this project to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Toxic Air Pollutants (TAPs). The DEQ review of submitted data and analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with the modification of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emissions estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emissions calculation methods were not evaluated in this modeling review memorandum.

The submitted information and analyses, in combination with DEQ's verification analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that TAP emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Idaho Air Rules require air impact analyses be conducted according to methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses, in combination with DEQ's analyses, demonstrated to the satisfaction of the Department that operation of the proposed modification will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit provisions/restrictions to assure the requirements of Appendix W are met with regard to emissions representing design capacity or permit allowable rates.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
General Emissions Rates. Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, must represent maximum potential emissions or the change in potential emissions as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses (see Tables 3 and 4).
Stack Parameter Variability. Stack locations and stack height of the natural gas boiler and the hog fuel boiler must not vary from what is specified in this memorandum (as built stack locations should be within 3 meters and stack height should be within 0.3 meters of what was used in the modeling analyses).	Emissions release locations and stack heights have a large effect on ambient air impacts. Compliance with NAAQS has not been demonstrated for any alternate stack locations or stack heights.
Co-contributing NOx Sources. The analyses assume that the natural gas boiler and hog fuel boiler are the only NOx sources at the facility.	The presence of other NOx sources at the site may invalidate the cumulative NAAQS impact analyses unless such sources could be considered as negligible.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

The proposed modification includes: 1) addition of a natural gas-fired boiler to the steam plant; 2) replacement of the hog fuel boiler electrified filter bed with an electrostatic precipitator (ESP); 3) increase the CO emissions limit for the hog fuel boiler; 4) increase allowable emissions of volatile organic compounds (VOCs)from the lumber dry kiln; 5) other permit modifications unrelated to air impacts.

2.2 Location and Area Classification

The IFG Chilco facility is located about 6.2 miles south, southwest of the Athol, Idaho. It is located in Kootenai County, Idaho. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS.*** *The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.*** *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

> ***02. Estimates of Ambient Concentrations.*** *All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Idaho Air Rules state that air impact analyses must be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that impact analyses use emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts from facility-wide potential/allowable emissions and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. The modeled value used for comparison to the applicable standard is referred to as the "design value" and is consistent with the statistical form of the standard. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	**Averaging Period**	**Significant Impact Levels[a] (μg/m³)[b]**	**Regulatory Limit[c] (μg/m³)**	**Modeled Design Value Used[d]**
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 μg/m³)	75 ppb[p] (196 μg/m³)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 μg/m³)	100 ppb[s] (188 μg/m³)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years. The O_3 standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. As an example, consider a hypothetical case where the SIL analysis indicates the project (new source or modification) has impacts exceeding the SIL and the cumulative impact analysis indicates a violation of the NAAQS. If project-specific impacts are below the SIL at the specific receptors showing the violations during the time periods when modeled violations occurred, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emissions increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance at all receptor locations; or c) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis resulted in modeled NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the proposed modification of the IFG Chilco facility were provided by Lorenzen for various applicable averaging periods.

Review and approval of estimated emissions is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emissions estimates is not addressed in this modeling memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the air impact analyses. The emission rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emissions inventory. All modeled criteria air pollutant and TAP emissions rates must be equal to or greater than the modification's or facility's potential emissions as calculated in the PTC emissions inventory or proposed permit allowable emissions rates.

3.1.1 Modeling Applicability and Modeled Criteria Pollutant Emissions Rates

An air impact analysis must be performed for pollutant emissions increases that do not qualify for a BRC exemption from the requirement to perform an air impact analysis. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled Potential to Emit (PTE) not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

The proposed modifications to the IFG Chilco facility do not qualify for a BRC permit exemption as per Idaho Air Rules Section 221, even though some emissions increases are below the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant. The proposed modifications require changes in the existing permit, and such changes cannot be performed under a BRC exemption.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling thresholds, below which a site-specific modeling analysis is not required. DEQ generic modeling analyses that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If project-specific total emissions rate increases of a pollutant are below Level I Modeling Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Thresholds are conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emissions sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

Table 3 provides a summary of the site-specific modeling applicability analysis provided by Lorenzen. Lorenzen used Level 1 Modeling Thresholds to evaluate the need for site-specific modeling analyses. It appears that Lorenzen used the net change in emissions for the evaluation even though the release parameters of the hog fuel boiler stack changed. The *Idaho Air Quality Modeling Guideline*[2] indicates in Section 3.3.2 that when stack parameters change, the emissions increase should be calculated as the total allowable rate rather of the modified source rather than the change in the emissions rate. Lorenzen's calculations indicated that site-specific modeling analyses were required for 1-hour NO_2 and annual NO_2. The submitted modeling report also indicated that 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ were also modeled to evaluate the effect of differing stack parameters associated with the new stack for the hog fuel boiler. This approach results in the same modeling applicability conclusions as the method prescribed in the DEQ guidance for basing the emissions increase on the total emissions from the modified source (not considering just the change in emissions) for cases where stack locations and/or parameters change as a result of the modification.

Site-specific modeling was not performed for CO, SO_2, nor Pb, on the basis of project emissions increases below Level I Modeling Applicability Thresholds, even though the stack parameters have changed as a result of the modification. Although total proposed PTE of 1-hour SO_2 (3.18 pound/hour), annual SO_2 (12.91 ton/year), and CO (65.2 pound/hour) exceed Level 1 Modeling Thresholds, total facility-wide emissions are below Level 2 Modeling Thresholds for CO and annual SO_2, and are only slightly over Level 2 Modeling Thresholds for 1-hour SO_2 (3.2 pounds/hour compared to 2.5 pounds/hour). DEQ is confident that NAAQS compliance for CO and SO_2 is assured on the basis of the following: 1) Modeling Thresholds are designed to assure impacts of a given emissions level are below the SIL, which is well below the applicable NAAQS; 2) the release parameters for the sources are such that Level 2 Modeling Thresholds are more representative (although not conservative) than Level 1 Modeling Thresholds; and 3) facility-wide PTE are either below or only slightly above Level 2 Modeling Thresholds.

Table 3. SITE-SPECIFIC MODELING APPLICABILITY ANALYSIS RESULTS

Pollutant	Averaging Period	Emissions Increase	Level I Modeling Thresholds	Level II Modeling Thresholds[a]	Site-Specific Modeling Required
PM_{10}	24-hour	0.049 lb/hr	0.22	2.6	No
$PM_{2.5}$	24-hour	0.041 lb/hr	0.054	0.63	No
	Annual	0.18 ton/yr	0.35	4.1	No
CO	1-hour, 8-hour	6.32 lb/hr	15	175	No
SO_2	1-hour	0.057 lb/hr	0.21	2.5	No
	Annual	0.25 ton/yr	1.2	14	No
NOx	1-hour	5.95 lb/hr	0.20	2.4	Yes
	Annual	26.0 ton/yr	1.2	14	Yes
Pb	monthly	<14 lb/month	14	14	No

a. Level II Modeling Thresholds were not approved by DEQ for this project.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis because allowable emissions increases of VOCs and NOx are below the 100 tons/year threshold.

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NOx, SO_2, and/or VOCs was assumed by DEQ to be negligible on the basis of the magnitude of emissions and the short distance from emissions sources to locations where maximum PM_{10} and $PM_{2.5}$ impacts are anticipated.

Emissions Rates Used in Impact Analyses

Table 4 lists the emissions rates used for specified averaging periods in the SIL modeling analyses. These rates must be representative of, or greater than, the increase in PTE as indicated by design capacity or as limited by an enforceable permit provision. Table 5 provides the emissions rates used in the cumulative impact analyses.

Table 4. EMISSIONS RATES USED IN SIL MODELING ANALYSES

Source Modeled Id. Code	Description	UTM[a] Coordinates (meters)		Emissions (pounds/hour)			
		Easting	Northing	1-Hour NO_2	Annual NO_2	24-hour PM_{10}	24-hour $PM_{2.5}$
NEWGAS	Natural gas boiler	518541	5301320	5.95	5.95	0.049	0.041
HOGBOIL	New hog fuel boiler stack	518528	5301316	27.5	25.43	6.93	6.93
OLDSTACK	Existing hog fuel boiler stack	518534	5301315	-27.5	-25.43	-6.93	-6.93

a. Universal Transverse Mercator

Table 5. EMISSIONS RATES USED IN THE CUMULATIVE NAAQS MODELING ANALYSES					
Source Modeled Id. Code	Description	UTM[a] Coordinates (meters)		Emissions (pounds/hour)	
		Easting	Northing	1-Hour NO_2	Annual NO_2
NEWGAS	Natural gas boiler	518541	5301320	5.95	5.95
HOGBOIL	New hog fuel boiler stack	518528	5301316	27.5	25.43

b. Universal Transverse Mercator

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 210 are only applicable to new or modified sources constructed after July 1, 1995.

All of the TAP emissions increases associated with proposed modification occur from sources regulated under 40 CFR 60, 61, or 63. These sources are exempt from TAP rules as per Idaho Air Rules Section 210 and were excluded from the TAP modeling applicability calculation.

After excluding emissions from sources exempt from the TAPs rules, no project-wide emissions of any TAP exceeded the applicable emissions screening levels (ELs) of Idaho Air Rules Section 585 or Section 586. Consequently, air impact modeling analyses were not required to demonstrate that impacts of TAP emissions are below the applicable ambient increment standards expressed in Idaho Air Rules Section 585 and 586.

3.1.3 Emissions Release Parameters

Table 6 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for emissions sources modeled in the air impact analyses.

Table 6. POINT SOURCE STACK PARAMETERS USED INIMPACT MODELING ANALYSES							
Release Point	Description	UTM[a] Coordinates		Stack Height (m)	Stack Gas Flow Temp. (K)[c]	Stack Flow Velocity (m/sec)[d]	Stack Dia. (m)
		Easting (m)[b]	Northing (m)				
NEWGAS	Natural gas boiler	518541	5301320	21.3	394	14.2	1.04
HOGBOI	New hog fuel boiler stack	518528	5301316	24.4	401	8.0	1.78
OLDSTA	Existing hog fuel boiler	518534	5301315	24.4	401	12.9	1.40

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters/second. All sources release uninterrupted in the vertical direction (not horizontal or rain capped releases).

Lorenzen provided documentation and justification of emissions release parameters within the *Air Impact Modeling Analyses Report* (Section 4.3), submitted as part of the application on May 20, 2016. Parameters for the natural gas boiler represent best or conservative design information at the time of permit application submittal. Lorenzen indicated that the exhaust temperature at the point of release was a design parameter. Lorenzen stated that the flow rate was calculated based on the fuel combustion rate, f-factor, target oxygen content, and target moisture content. The parameters for the natural gas boiler exhaust appeared reasonably accurate for the type of source and DEQ did not require further verification of the value used. The flue gas temperature and flow rate for the hog fuel boiler was based on a 2015 source test, as stated by Lorenzen. It was assumed that the temperature and flow rate will not change after the modification. DEQ determined the data, methods, and assumptions used for stack parameters of the hog fuel boiler were adequately accurate, results were within a range expected for the source, and additional verification of release parameters was not performed.

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS air impact modeling analysis is needed to demonstrate compliance with applicable NAAQS. Cumulative impact analyses were needed for 1-hour and annual NO_2.

Background concentrations were determined by using the following web-based design value concentration tool: Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) Lookup 2009-2011 Design Values of Criteria Pollutants (http://lar.wsu.edu/nw-airquest/lookup.html). These design value air pollutant levels are based on regional scale air pollution modeling of Washington, Oregon, and Idaho, with values influenced by monitoring data as a function of distance from the monitor. Lorenzen used the background concentration tool to estimated the following background values for the IFG Chilco site: 1-hour NO_2 = 22.5 $\mu g/m^3$; annual NO_2 = 1.88 $\mu g/m^3$.

DEQ used the coordinates of the modeled maximum design value for 1-hour and annual NO_2 as input to the NW AIRQUEST design value tool to check the background levels used. At the location of the maximum 1-hour NO_2 design value impact, the background value was 18.2 $\mu g/m^3$, and at the location of the maximum annual NO_2 design value impact, the background value was 2.26 $\mu g/m^3$. Since modeled impacts were well below NAAQS, these slight variations in background concentrations were inconsequential to the conclusions of the analyses.

3.3 NAAQS Impact Modeling Methodology

This section describes the modeling methods used by the applicant's consultant and DEQ to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Impact Analyses

Lorenzen performed the project-specific air pollutant emissions inventory and air impact analyses that were submitted with the application. Results of the submitted information/analyses, in combination with DEQ's verification and sensitivity analyses, demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 7 provides a brief description of parameters used in the modeling analyses.

Table 7. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Chilco, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	Coeur d'Alene surface data, Spokane WA upper air data	Submitted analyses used 2008-2012 data. DEQ verification analyses used 2011-2015 data. See Section 3.3.5 of this memorandum for additional details of the meteorological data.
Terrain	Considered	USGS National Elevation Dataset (NED) files to establish elevations of ground level receptors. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1	20-meter spacing along the property boundary.
	Grid 2	50-meter spacing out to about 500 meters.
	Grid 3	100-meter spacing out to 1,600 meters.
	Grid 4	200-meter spacing out to 2,400 meters.
	Grid 5	500-meter spacing out to 4,000 meters.
	Grid 6	1,000-meter spacing out to 14,000 meters.

3.3.2 Modeling protocol and Methodology

A modeling protocol, describing data and methods proposed for the project, was not initially submitted to DEQ. Lorenzen corresponded with DEQ on modeling methods and data after IFG Chilco received a notice of incomplete application for the project. Final project-specific modeling and other required impact analyses were generally conducted using data and methods as discussed with DEQ and as described in the *Idaho Air Quality Modeling Guideline*[2].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 15181 was used by Lorenzen for the modeling analyses to evaluate air pollutant impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.4 NO_2 Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NOx emissions. The conversion of NO to NO_2 can be conservatively addressed through the use of several methods as outlined in a 2014 EPA NO_2 Modeling Clarification Memorandum[3]. The guidance outlines a three-tiered approach:

- Tier 1 – assume full conversion of NO to NO_2 where total NOx emissions are modeled and modeled impacts are assumed to be 100 percent NO_2.

- Tier 2 – use an ambient ratio to adjust impacts from the Tier 1 analysis.
- Tier 3 – use a detailed screening method to account for $NO/NO_2/O_3$ chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM).

Lorenzen conservatively used the Tier 1 full conversion method, assuming 100 percent of NOx is NO_2.

3.3.5 Meteorological Data

DEQ provided Lorenzen with model-ready meteorological data in October 2015, using surface data collected from the Coeur d'Alene Airport and upper air data from the Spokane Airport. The data were collected from 2008 through 2012. These data were processed using AERSURFACE version 13016 and AERMET version 12345. Lorenzen used these meteorological data for the submitted air impact analyses.

DEQ has recently processed Coeur d'Alene meteorological data for 2011 through 2015, using AERSURFACE 13016 and AERMET version 15181. These recently processed data were used in DEQ verification analyses to assure that more updated data and the use of a newer version of the meteorological data processor AERMET would still result in analyses that demonstrate compliance with NAAQS.

3.3.6 Effects of Terrain on Modeled Impacts

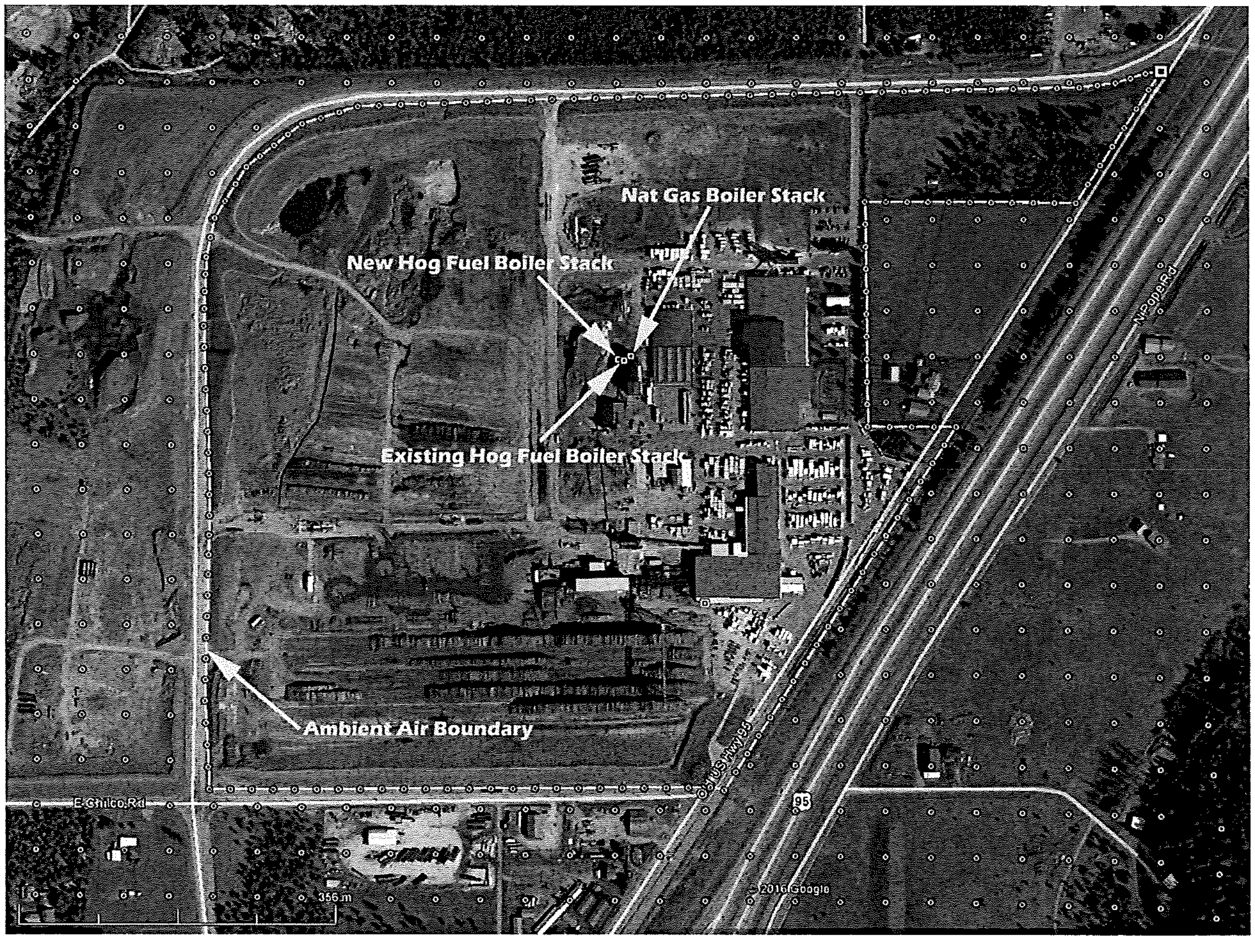
Submitted ambient air impact analyses used terrain data extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files in the WGS84 datum (approximately equal to the NAD83 datum).

The terrain preprocessor AERMAP Version 11103 was used by Lorenzen to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

3.3.7 Facility Layout

DEQ verified proper identification of the site location, equipment locations, building locations, and the ambient air boundary by comparing a graphical representation of the modeling input file to plot plans submitted in the application. Aerial photographs on Google Earth (available at https://www.google.com/earth) were used to assure that horizontal coordinates were accurate as described in the application. Figure 1 shows the IFG Chilco facility with buildings included in the model highlighted in purple and the ambient air boundary indicated by a yellow line connecting circles that represent ambient air receptors.

Figure 1: IFG Chilco site



3.3.8 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes were accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of proposed buildings were used as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME) to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information for input to AERMOD. Structures that could most significantly cause plume downwash appear to have been accounted for in the model, as indicated by the purple highlighting in Figure 1. Some minor structures may have been omitted from consideration; however, given the level of conservatism in assumptions and methods used and the large margin of NAAQS compliance shown by the model results, omission of these structures would not change the conclusions of the impact analyses.

3.3.9 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." Ambient air was considered areas external to the IFG property boundary except for the western boundary. A public roadway bisects the facility and only the property east of the roadway was excluded from ambient air. The submitted modeling report indicates that public access is precluded by gates on access roads and by signs. DEQ has determined that measures described in the application to preclude public access to areas of the site excluded from ambient air are adequate.

3.3.10 Receptor Network

Table 7 describes the receptor grid used in the submitted analyses. The receptor grid used in the submitted analyses met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[2] and DEQ determined that it was adequate to resolve maximum modeled impacts. To assure adequate resolution of the maximum modeled concentration, Lorensen used a refined receptor grid of 10-meter spacing centered on the receptor showing maximum design value impact.

3.3.11 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

$H = S + 1.5L$, where:

- H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.
- S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.
- L = lesser dimension, height or projected width, of the nearby structure.

All IFG sources are below GEP stack height. Therefore, it is important to account for plume downwash caused by structures at the facility.

3.3.12 Neighboring Co-Contributing Emissions Sources

No co-contributing emissions sources were identified by Lorenzen or DEQ for the area adjacent or close to the IFG Chilco facility. Impacts from small nearby sources and larger more distant sources are considered through the use of a background concentration.

4.0 NAAQS Impact Modeling Results

4.1 Results for NAAQS Analyses

4.1.1 Submitted Analyses

A SIL analysis was performed for 1-hour NO_2, annual NO_2, 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$, and results are listed in Table 8. Maximum impacts of 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ were below applicable SILs and no further analyses were required to demonstrate compliance with Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis was performed for 1-hour NO_2 and annual NO_2, and results are presented in Table 9.

Table 8. RESULTS FOR SUBMITTED SIGNIFICANT IMPACT ANALYSES				
Pollutant	Maximum Modeled Impact ($\mu g/m^3$)[a]	SIL[b] ($\mu g/m^3$)	Percent of SIL	Cumulative Impact Analysis Required?
24-hour PM_{10}	0.97	5.0	19	No
24-hour $PM_{2.5}$	0.96	1.2	80	No
Annual $PM_{2.5}$	0.057	0.3	19	No
1-hour NO_2	64.4	7.5	859	Yes
Annual NO_2	1.45	1.0	145	Yes

a. micrograms per cubic meter.
b. Significant Impact Level.

Table 9. RESULTS FOR SUBMITTED CUMULATIVE NAAQS AIR IMPACT ANALYSES					
Pollutant	Modeled Design Value Impact ($\mu g/m^3$)[a]	Background Value ($\mu g/m^3$)	Total Maximum Concentration ($\mu g/m^3$)	NAAQS[b] ($\mu g/m^3$)	Percent of NAAQS
1-hour NO_2	148	22.5	170	188	90
Annual NO_2	5.04	1.88	6.92	100	7

a. micrograms per cubic meter.
b. National Ambient Air Quality Standard.

4.1.2 DEQ Sensitivity and Verification Analyses

DEQ performed verification analyses of impacts associated with the proposed modification of the IFG Chilco facility. Verification analyses assured that model output results, given the specified input parameters, are accurate and reproducible. The DEQ verification analysis for 1-hour NO_2 used updated meteorological data for years 2011 through 2015.

The 1-hour NO_2 design value result, equal to the maximum impact of modeled 8th highest of daily 1-hour maximum modeled concentrations, from the DEQ verification analysis was 148.1 $\mu g/m^3$. This value is identical to that obtained from the analysis performed by Lorenzen and submitted with the application. The location of the maximum impact was also identical to that of the submitted analysis.

4.2 Results for TAPs Impact Analyses

Site-specific TAP impact analyses were not required for the proposed modification because applicable emissions of all TAPs are below ELs.

5.0 Conclusions

The information submitted with the PTC application, combined with DEQ air impact verification analyses, demonstrated to DEQ's satisfaction that emissions from the proposed modifications of the IFG Chilco facility will not cause or significantly contribute to a violation of any ambient air quality standard.

References

1. *Policy on NAAQS Compliance Demonstration Requirements.* Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard.* Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

APPENDIX C – 40 CFR 63 SUBPART DDDDD

Title 40: Protection of Environment. Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAPS). Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Based on Regulation obtained from eCFR on January 31, 2016. Regulation Version is: [76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

Only sections of the regulation that are could possibly be applicable to IFG are included. Comments related IFG's compliance methodology are in green font and are underlined.

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§ 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. IFG operates industrial boilers at the Chilco sawmill and is subject to this subpart (DDDDD). The Chilco sawmill is a major source of HAP emissions.

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§ 63.7490 What is the affected source of this subpart?

§ 63.7490(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.

§ 63.7490(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. The natural gas (gas 1) boiler is a new boiler which will be installed at the facility in 2016.

§ 63.7490(c) A boiler or process heater is reconstructed ... Does not apply.

§ 63.7490(d) A boiler or process heater is existing if it is not new or reconstructed. The Chilco wood-fired (hog fuel) boiler is an affected source and is an existing boiler.

§ 63.7490(e) An existing electric utility steam generating unit (EGU) ... Does not apply.

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§ 63.7491 Are any boilers or process heaters not subject to this subpart? IFG- Chilco does not have any boilers or process heaters that are not subject to this subpart.

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

§ 63.7495(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. The natural gas boiler will be a new source and must comply with applicable work practices, summarized in Table 3, upon startup.

§ 63.7495(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). IFG has been granted a one-year extension for compliance as provided in § 63.6(i). The applicable compliance date is January 31, 2017.

§ 63.7495(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... Does not apply to IFG-Chilco.

§ 63.7495(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. Notification compliance is discussed under § 63.7545.

§ 63.7495(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, ... Does not apply.

§ 63.7495(f), (g), (h), (i) ... Do not apply.

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§ 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. The IFG-Chilco hog fuel boiler falls into this subcategory.
(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. The natural gas (gas 1) boiler falls into this subcategory.
(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.

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§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?
Tables are listed at the end of this analysis.

§ 63.7500(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. IFG will meet the requirements.

§ 63.7500(a)(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 steam. 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 electricity. 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 (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

Table 1 contains no emission limits for new boilers burning gas 1 fuel, so there are no emission limits that apply to the natural gas boiler.

Table 2 contains the applicable emission limits for existing boilers that apply to the hog fuel boiler: HCl, mercury, CO and PM.

Table 3 contains applicable work practice standards for the hog fuel boiler and the natural gas boiler. The hog fuel boiler will have to have annual tune-ups and a one-time energy assessment. The natural gas boiler is retained, it will also have to have annual tune-ups and a one-time energy assessment.

The startup and shutdown requirements in Items 5 and 6 of Table 3 are applicable and have been revised to allow clean dry biomass during startup.

§ 63.7500(a)(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).

Table 4 contains operating limits for the hog fuel boiler. MACT limits the opacity to 10% (daily block average), while the permit allows 20% over a 3-minute average. MACT requires that the boiler can only be operated at 110% of the average steaming limit during the PM source test.

§ 63.7500(a)(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. IFG currently meets this requirement and will continue to comply.

§ 63.7500(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section. IFG will request approval for alternative work practice standards if needed.

§ 63.7500(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. IFG does not have or expect to have any limited use boilers or process heaters.

§ 63.7500(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. ... Does not apply.

§ 63.7500(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. The IFG natural gas boiler is larger than 10 million Btu/hr and does not have an oxygen trim system. Annual tune-ups will be required.

§ 63.7500(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 Table 3 to this subpart. The opacity and emission limits on the hog fuel boiler do not apply during startup and shutdown.

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§ 63.7501 Reserved.

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

§ 63.7505(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f). IFG will comply with all applicable emission limits, work practice standards and operating limits in this subpart, as summarized in Tables 2, 3 and 4.

§ 63.7505(b) [Reserved]

§ 63.7505(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), continuous parameter monitoring system (CPMS), 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 testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart. IFG will use source testing and fuel analysis as appropriate to demonstrate compliance. Note that the COMS has been removed from this section because opacity is not an emission limit.

§ 63.7505(d) (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). IFG will develop a site-specific monitoring plan for the COMS.

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§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?
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§ 63.7510(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 testing, your initial compliance requirements include all the following:

§ 63.7510(a)(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart. IFG will comply.

§ 63.7510(a)(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. IFG will comply.

§ 63.7510(a)(2)(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. Noted.

§ 63.7510(a)(2)(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels. Does not apply

§ 63.7510(a)(2)(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. Noted.

§ 63.7510(a)(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart. Compliance is discussed under § 63.7530

§ 63.7510(a)(4) Conduct CMS performance evaluations according to § 63.7525. IFG will need to install a CMS for opacity (COMS) on the hog fuel boiler and will conduct the performance evaluations as required.

§ 63.7510(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. ... IFG will use either fuel testing or source testing for HCl and mercury compliance. PM testing will be used as allowed for TSM compliance demonstration.

§ 63.7510(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 12, 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. IFG will source test the hog fuel boiler for CO.

§ 63.7510(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. IFG will source test the hog-fuel boiler for PM.

§ 63.7510(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, 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, except as specified in paragraph (j) of this section. The hog-fuel boiler source tests are due by July 29, 2017 based on the one-year compliance extension granted by the Administrator. .

§ 63.7510(f) For new or reconstructed affected sources...The natural gas boiler is a new gas 1 boiler, and is not subject to any emission limits.

§ 63.7510(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 § 63.7540(a) 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 § 63.7540(a). The first tune-up for the natural gas boiler will be completed when the boiler is installed and starts operating.

§ 63.7510(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) ... Does not apply.

§ 63.7510(i) For an existing EGU that becomes subject after January 31, 2013... Does not apply.

§ 63.7510(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. Noted.

§ 63.7510(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. Noted.

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

§ 63.7515(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. IFG will schedule source tests as required.

§ 63.7515(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
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every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. This provision is similar to the current permit. IFG will schedule source tests as required/allowed under the rule.

If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. IFG has no current plans to use emission averaging.

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. IFG may source test for HCl and TSM (PM as a surrogate). IFG will comply with the maximum chloride and maximum TSM input requirements as necessary.

§ 63.7515(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). This provision is similar to the current permit. IFG will schedule source tests as required under the rule.

§ 63.7515(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 the initial startup of the new or reconstructed affected source. IFG will schedule boiler tune-ups as required under the rule.

§ 63.7515(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 IFG choses to use fuel analysis, the sampling program will comply with the schedule in Paragraph (e).

§ 63.7515(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. IFG will report results of performance tests and fuel analyses in the specified time frame. Boiler operating levels during the source tests will be documented.

§ 63.7515(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. <u>Noted.</u>

§ 63.7515(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory ... <u>Does not apply.</u>

§ 63.7515(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). <u>IFG does not plan to use a CO CEMS.</u>

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§ 63.7520 What stack tests and procedures must I use?

§ 63.7520(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. <u>Source test protocols will be submitted as required and equipment will be operated during testing as required by the EPA reference methods.</u>

§ 63.7520(b) You must conduct each performance test according to the requirements in Table 5 to this subpart. <u>Source tests will be performed following the appropriate EPA reference methods.</u>

§ 63.7520(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. <u>This may not apply because the hog fuel boiler is a single fuel boiler. Chlorine and mercury concentrations in the hog fuel are only trace amounts and vary naturally.</u>

§ 63.7520(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. <u>Each test will comply with the reference method requirements.</u>

§ 63.7520(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. <u>Source test results will be converted to heat-input basis using the F-Factors as required.</u>

§ 63.7520(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.,
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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. If measured emissions are below the detection limit, the detection limit will be used as the measured emission level.

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

§ 63.7521(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. This section applies to hog fuel (wood, biomass).

For gas 2 (other) fuels... Does not apply.

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 and Table 6 to this subpart. This section applies to hog fuel only, not to natural gas (gas 1).

§ 63.7521(b) *et seq.* 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. IFG will provide the site-specific fuel monitoring plan as required.

§ 63.7521(c) *et seq.* At a minimum, you must obtain three 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. IFG will collect fuel samples as required. Details will be provided in the fuel monitoring plan.

§ 63.7521(d) *et seq.* You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section. IFG will prepare fuel samples are required. Details will be provided in the fuel monitoring plan.

§ 63.7521(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. IFG will follow the specified procedures and use the required calculations.

§ 63.7521(f) To demonstrate that a gaseous fuel other than natural gas ... Does not apply.

§ 63.7521(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels ... Does not apply.

§ 63.7521(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels. Does not apply.

§ 63.7521(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 ... Does not apply.

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§ 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. IFG-Chilco does not have more than one existing boiler in any subcategory. This section does not apply.

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

§ 63.7525(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 according to the procedures in paragraphs (a)(1) through (7) of this section.

§ 63.7525(a)(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. IFG has an oxygen analyzer system in place and does not intend to install a CO CEMS.

§ 63.7525(a)(2) To demonstrate compliance with the applicable alternative CO CEMS emission ... Does not apply. IFG does not plan to install a CO CEMS.

§ 63.7525(a)(3) – (6) ... Do not apply because IFG does not plan to use a CO CEMS.

§ 63.7525(a)(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. The oxygen level measured during the CO MACT compliance test becomes the lower set point for the oxygen trim system. If IFG operates an oxygen trim system on the Chilco boiler, this requirement will be met.

§ 63.7525(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 ... Does not apply.

§ 63.7525(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. IFG will install and operate a COMS on the ESP stack. IFG will install the COMS as required before the January 31, 2017 compliance date.

§ 63.7525(c)(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter. The COMS installation will conform to PS1.

§ 63.7525(c)(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. The COMS calibration and certification will conform to PS1.

§ 63.7525(c)(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. The COMS will be set up as required.

§ 63.7525(c)(4) The COMS data must be reduced as specified in § 63.8(g)(2). The COMS will be set up as required.

§ 63.7525(c)(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
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annual zero alignment audit of each COMS. The COMS monitoring plan will include the calibration and audit requirements.

§ 63.7525(c)(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. The COMS will be operated and maintained according to the monitoring plan.

§ 63.7525(c)(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. The COMS will be programmed to provide the appropriate averages.

§ 63.7525(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. Does not apply.

§ 63.7525(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.... Does not apply. IFG does not intend to install a gas flow monitoring system.

§ 63.7525(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. .... Does not apply

§ 63.7525(g) If you have an operating limit that requires a pH monitoring system.... Does not apply

§ 63.7525(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, ... Does not apply.

§ 63.7525(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate .... Does not apply

§ 63.7525(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 .... Does not apply

§ 63.7525(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. IFG will follow the requirements if they install or convert a boiler to limited use.

§ 63.7525(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.... Does not apply

§ 63.7525(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 use an SO_2 CEMS, ... Does not apply

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

§ 63.7530(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,
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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)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525. IFG will demonstrate initial compliance by source testing or fuel analyses.

§ 63.7530(b) If you demonstrate compliance through performance 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). IFG will establish site-specific operating limits based on performance testing as required. IFG will follow all the applicable procedures listed in Paragraph (b).

§ 63.7530(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. If demonstrating compliance through fuel analysis, IFG will follow all the applicable procedures listed in Paragraph (c).

§ 63.7530(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory. ... Does not apply. The natural gas boiler is a new unit designed to burn gas 1.

§ 63.7530(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment. IFG will provide appropriate notification for the energy assessment.

§ 63.7530(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). IFG will provide all required notifications.

§ 63.7530(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575... Does not apply.

§ 63.7530(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 item 5 of Table 3 of this subpart. The work practices standards in Items 5 and 6 of Table 3 have been amended to allow the use of clean dry biomass during startup. IFG will comply.

§ 63.7530(i) If you opt to comply with the alternative SO_2 CEMS operating limit ... Does not apply.

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

IFG may choose to use efficiency credits at Chilco, and will follow all the requirements of this section.

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§ 63.7535 How do I monitor and collect data to demonstrate continuous compliance?

§ 63.7535(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d). IFG will comply with this section of the regulation and the site-specific monitoring plan when collecting data from the COMS.

§ 63.7535(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. Noted.

§ 63.7535(c) You may not use data recorded during 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. Noted.

§ 63.7535(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 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 annual report. Noted.

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

§ 63.7540(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. Applicable portions of the tables are included at the end of this analysis.

§ 63.7540(a)(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. Noted.

§ 63.7540(a)(2) As specified in § 63.7550(c), 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
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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. IFG will keep appropriate records.

§ 63.7540(a)(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. IFG may demonstrate HCl compliance through fuel analysis. The Chilco boiler only burns woody biomass, and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(4) *et seq.* 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... IFG will likely demonstrate HCl compliance through source testing. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(5) *et seq.* 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 13 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. IFG may demonstrate mercury compliance through fuel analysis. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(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. IFG may demonstrate mercury compliance through source testing. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(7) If your unit is controlled with a fabric filter... Does not apply.

§ 63.7540(a)(8) To demonstrate compliance with the applicable alternative CO CEMS ...IFG does not intend to use this provision of the rule.

§ 63.7540(a)(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS ...IFG does not intend to use this provision of the rule.

§ 63.7540(a)(10) *et seq.* 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. 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. IFG will conduct the annual boiler tune-ups on the hog fuel boiler as required. IFG will also tune-ups on the natural gas boiler as required.

§ 63.7540(a)(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour ... Does not apply.

§ 63.7540(a)(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 IFG installs and operates a continuous oxygen trim system that maintains an optimum air to fuel ratio, they may switch to the 5-year tune up schedule for the hog fuel boiler.

§ 63.7540(a)(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. Noted.

§ 63.7540(a)(14) If you are using a CEMS measuring mercury emissions to meet requirements ... Does not apply.

§ 63.7540(a)(15) If you are using a CEMS to measure HCl emissions ... Does not apply.

§ 63.7540(a)(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 ...The IFG Chilco boiler burns only woody biomass and no other fuel is expected to be used.

§ 63.7540(a)(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... The IFG Chilco boiler burns only woody biomass and no other fuel is expected to be used.

§ 63.7540(a)(18) If you demonstrate continuous PM emissions compliance with a PM CPMS ... Does not apply.

§ 63.7540(a)(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS ... Does not apply.

§ 63.7540(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. IFG will comply with the deviation reporting requirements.

§ 63.7540(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory... Does not apply.

§ 63.7540(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart. IFG will comply with the work practice standards in Items 5 and 6 of Table 3.

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§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision? IFG Chilco does not intend to use the emissions averaging provision because there is not more than one boiler in any one subcategory.
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§ 63.7545 What notifications must I submit and when?

§ 63.7545(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.

§ 63.7(b) *Notification of performance test.* (1) The owner or operator of an affected source must notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin to allow the Administrator, upon request, to review and approve the site-specific test plan required under paragraph (c) of this section and to have an observer present during the test. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.7(c) *Quality assurance program.* (1) The results of the quality assurance program required in this paragraph will be considered by the Administrator when he/she determines the validity of a performance test. (2)(i) *Submission of site-specific test plan.* Before conducting a required performance test, the owner or operator of an affected source shall develop and, if requested by the Administrator, shall submit a site-specific test plan to the Administrator for approval. The test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. Data quality objectives are the pretest expectations of precision, accuracy, and completeness of data. The pre-test protocol for MACT compliance testing must meet the requirements of this section.

§ 63.8(e) *Performance evaluation of continuous monitoring systems* — (1) *General.* When required by a relevant standard, and at any other time the Administrator may require under section 114 of the Act, the owner or operator of an affected source being monitored shall conduct a performance evaluation of the CMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in this section or in the relevant standard. (2) *Notification of performance evaluation.* The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required. IFG will comply with the notification requirements for the hog fuel boiler COMS.

§ 63.8(f)(4 and 6) *Use of an alternative monitoring method.* IFG does not intend to use any alternative monitoring methods.

§ 63.9(b) *Initial notifications.* (1)(i) The requirements of this paragraph apply to the owner or operator of an affected source when such source becomes subject to a relevant standard... (2) The owner or operator of an affected source that has an initial startup before the effective date of a relevant standard under this part shall notify the Administrator in writing that the source is subject to the relevant standard. The notification, which shall be submitted not later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard). IFG submitted the Subpart DDDDD initial notification on January 28, 2005 and again on May 15, 2013.

§ 63.9(c) *Request for extension of compliance.* If the owner or operator of an affected source cannot comply with a relevant standard by the applicable compliance date for that source, or if the owner or operator has installed BACT or technology to meet LAER consistent with § 63.6(i)(5) of this subpart, he/she may submit to the Administrator (or the State with an approved permit program) a request for an extension of compliance as specified in § 63.6(i)(4) through § 63.6(i)(6). § 63.6(i)(4) through § 63.6(i)(6) would allow the state to grant up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls. IFG has requested and been granted a one-year extension to allow replacement of the boiler EFB with an ESP.
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§ 63.9(d) *Notification that source is subject to special compliance requirements.* An owner or operator of a new source that is subject to special compliance requirements ... This does not apply to the IFG Chilco boiler because it is an existing source.

§ 63.9(e) *Notification of performance test.* The owner or operator of an affected source shall notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.9(f) *Notification of opacity and visible emission observations.* The owner or operator of an affected source shall notify the Administrator in writing of the anticipated date for conducting the opacity or visible emission observations specified in § 63.6(h)(5), if such observations are required for the source by a relevant standard. The notification shall be submitted with the notification of the performance test date, as specified in paragraph (e) of this section, or if no performance test is required or visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the initial performance test required under § 63.7, the owner or operator shall deliver or postmark the notification not less than 30 days before the opacity or visible emission observations are scheduled to take place. IFG will provide required notifications prior to opacity compliance tests.

§ 63.9(g) *Additional notification requirements for sources with continuous monitoring systems.* The owner or operator of an affected source required to use a CMS by a relevant standard shall furnish the Administrator written notification as follows: (1) A notification of the date the CMS performance evaluation under § 63.8(e) is scheduled to begin, submitted simultaneously with the notification of the performance test date required under § 63.7(b). ... (2) A notification that COMS data results will be used to determine compliance with the applicable opacity emission standard during a performance test required by § 63.7 in lieu of Method 9 or other opacity emissions test method data, ... The notification shall be submitted at least 60 calendar days before the performance test is scheduled to begin. IFG will submit all source test notifications at least 60 days prior to the scheduled test date.

§ 63.9(h) *Notification of compliance status.* (1) The requirements of paragraphs (h)(2) through (h)(4) of this section apply when an affected source becomes subject to a relevant standard.

§ 63.9(h)(3) After a title V permit has been issued to the owner or operator of an affected source [Applies because IFG Chilco has a Title V (Tier I) permit], the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this part. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in the relevant standard. IFG must submit compliance status reports to DEQ.

§ 63.7545(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. IFG submitted the Subpart DDDDD initial notification on January 28, 2005 and again on May 15, 2013.

§ 63.7545(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. IFG will comply when the natural gas boiler is installed.

§ 63.7545(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. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.7545(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), 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). The pre-test protocol for MACT compliance testing must meet the requirements of this section. IFG must review the pre-test protocol carefully before it is submitted by the testing firm.

§ 63.7545(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... Does not apply.

§ 63.7545(g) If you intend to commence or recommence combustion of solid waste... Does not apply.

§ 63.7545(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory ... Does not apply. IFG does not anticipate switching fuels in any boilers.

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§ 63.7550 What reports must I submit and when?

§ 63.7550(a) You must submit each report in Table 9 to this subpart that applies to you.

§ 63.7550(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 an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or 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. IFG can submit an annual compliance report for the natural gas boiler, to match the schedule of the tune-ups. IFG will submit semi-annual compliance reports for the hog fuel boiler. The first compliance report is for the period of January 31 – July 31, 2017. That report will be due January 31, 2018. The next compliance report will be for July 1 2017 to December 31, 2017, and will be due January 31, 2018. Subsequent reports will cover each calendar half and will be due at the end of July or January.

§ 63.7550(c) *et seq.* A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule. IFG will submit compliance reports with all the information specified in this paragraph.

§ 63.7550(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, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section. IFG will include all required information in the compliance report. The compliance report will follow this regulation to the letter.
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§ 63.7550(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). This section applies to opacity from the hog fuel boiler because it will have a COMs (opacity CMS). IFG will include all required information in the compliance report.

§ 63.7550(f)-(g) [Reserved]

§ 63.7550(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section. IFG will submit all reports according to the requirements of this section. IFG will use EPA's electronic reporting systems to submit the reports to EPA.

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§ 63.7555 What records must I keep?

§ 63.7555(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... IFG must keep copies of all the notifications and reports they submit.

§ 63.7555(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section. IFG must keep copies of the COMS charts and/or electronic records, as well as all performance test information and reports. Recommend storing records off-site as well.

§ 63.7555(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. IFG will keep COMS records, oxygen records and fuel analysis records as required.

§ 63.7555(d) *et seq.* (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. IFG will keep all the applicable records for the hog fuel boiler.

In accordance with § 63.7555(d)(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. IFG will make the calculations as per the required equation and will keep all calculations and supporting information on file.

In accordance with § 63.7555(d)(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
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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. IFG will make the calculations as per the required equation and will keep all calculations and supporting information on file.

In accordance with § 63.7555(d)(9), a copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530...IFG intends to show compliance through PM testing, not through TSM fuel analysis.

§ 63.7555(e) If you elect to average emissions consistent with § 63.7522...IFG does not intend to use emissions averaging.

§ 63.7555(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). IFG will keep all the applicable records if they chose to use efficiency credits from energy conservation measures.

§ 63.7555(g) If you elected to demonstrate that the unit meets the specifications for mercury for the unit designed to burn gas 1 subcategory ... Does not apply.

§ 63.7555(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 ... Does not apply.

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§ 63.7560 In what form and how long must I keep my records? IFG will keep the records in the format required for at least 5 years.

§ 63.7560(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

§ 63.7560(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.

§ 63.7560(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.

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§ 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 is included at the end of this analysis showing which General Provisions apply to IFG Chilco.

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Tables to Subpart DDDDD
Including only the items that apply to IFG Chilco

Table 1 contains no applicable emission limits for new natural gas (gas 1) boilers.

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Table 2: Emission Limits for Existing Boilers and Process Heaters
[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown...	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown...[1]	Using this specified sampling volume or test run duration...
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input.	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input.	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 \b\ collect a minimum of 3 dscm.
2,3,4,5,6	Do not apply.			
7. Stokers/sloped grate/others designed to burn west biomass fuel.	a. CO (or CEMS)...	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input).	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh).	Collect a minimum of 2 dscm per run.
8,9,10,11,12,13,14,15,16,17,18	Do not apply.			

(1) 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 electricity according to § 63.7500(a)(1).

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Table 3: Work Practices Standards

If your unit is...	You must meet the following...
1. A new or existing boiler or process heater with 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 in any of the following subcategories: unit designed to burn gas 1; unit designed to	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

If your unit is...	You must meet the following...
burn gas 2 (other); or unit designed to burn light liquid, or a limited us boiler or process heater.	
2. This requirement does not apply because both Chilco boilers are larger than 10 mmBtu/hr.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater. This requirement applies to both the natural gas boiler and the wood-fired boiler.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units. This requirement applies to both the hog fuel boiler and to the natural gas boiler.	Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy consuming systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup. This requirement applies to the wood-fired boiler.	a. You must operate all CMS during startup. b. For startup of a boiler ... you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of "startup" in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices .... Startup ends when steam or heat is supplied for any purpose. OR (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must

If your unit is...	You must meet the following...
	keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.
6. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during shutdown. This requirement applies to the wood-fired boiler.	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, ... when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

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Table 4: Operating Limits for Boilers and Process Heaters

When complying with a Table 1,2,11,12, or 13 numerical emission limit using...	You must meet these operating limits...
1,2,3,4,5. Do not apply.	
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS Applies to the IFG Chilco hog fuel boiler, which is controlled by a multiclone followed by a dry electrostatic precipitator (ESP) and no wet scrubber.	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must 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 (daily block average).
5, 6. Do not apply	
7. Performance testing. IFG will use performance testing to demonstrate compliance with one or more emission limits.	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
8. Oxygen analyzer system. IFG will comply with this requirement.	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).
10. Does not apply.	

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Table 5 lists the performance testing requirements. IFG will need to review all source test protocols very carefully to verify that they conform to the requirements listed in Table 5.

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Table 6 lists the fuel analysis requirements. If IFG decides to demonstrate compliance through fuel analysis, they will need to follow the requirements in Table 6 for sample collection and analysis.

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Table 7: Establishing Operating Limits

If you have an applicable emission limit for. . .	And your operating limits are based on ...	You must...	Using ...	According to the following requirements
1. PM, TSM, or mercury...	a. Wet scrubber operating parameters	Does not apply		
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	Does not apply. IFG has and ESP but no wet scrubber.		
2. HCl	a. Wet scrubber operating parameters	Does not apply		
	b. Dry scrubber operating parameters.	Does not apply		
	c. Alternative maximum SO_2 emission rate	Does not apply		
3. Mercury	All Activated carbon injection...	Does not apply		
4. Carbon Monoxide This applies to the hog fuel boiler.	a. oxygen...	i. Establish a unit-specific limit for minimum oxygen level according to §63.7525.	(1) data from the oxygen analyzer system specified in §63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance test. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test. This applies to the hog fuel boiler.	a. Boiler or process heater operating load	i. Establish a unit-specific limit for maximum operating load §63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

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Table 8: Demonstrating Continuous Compliance

If you must meet the following operating limits or work practice standards...	You must demonstrate continuous compliance by ...
1. Opacity... IFG will install and operate a COMS on the hog fuel boiler.	a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and b. reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average.
2 – 7	Do not apply.
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If you must meet the following operating limits or work practice standards...	You must demonstrate continuous compliance by ...
8. Emission limits using fuel analysis IFG may use this method	a. conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and B. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content Applies to the hog fuel boiler.	a. Continuously monitor the oxygen content using an oxygen analyzer according to §63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load.	a. Collecting and operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to §63.7520(c)
11.	Does not apply.

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Table 9: Demonstrating Continuous Compliance

You must submit a(n)	The report must contain...	You must submit the report...
1. Compliance Report IFG will have to do semi-annual compliance reports.	a. Information required in §63.7550(c((10 through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

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APPENDIX D – PROCESSING FEE

PTC Prcessing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company: **Idaho Forest Group LLC - Chilco**
Address: **4447 E. Chilco Road**
City: **Athol**
State: **ID**
Zip Code: **83801**
Facility Contact: **Larry**
Title: **Permitting Contac**
AIRS No.: **055-00024**

N Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N

Y Did this permit require engineering analysis? Y/N

N Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	12.6	0	12.6
SO_2	0.1	0	0.1
CO	19.5	0	19.5
PM10	0.0	0.9	-0.9
VOC	63.7	0	63.7
TAPS/HAPS	0.3	0	0.3
Total:	0.0	0.9	**95.3**
Fee Due	**$ 5,000.00**		

Comments: