# Statement of Basis

**Permit to Construct No. P-2017.0031**
**Project ID 61894**

**Blackfoot Facility of Basic American Foods**
**Blackfoot, Idaho**

**Facility ID 011-00012**

**Final**

**September 12, 2017** SYC
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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.

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## ACRONYMSE, UNITS, AND CHEMICAL NOMENCLATURE

| | |
|---|---|
| AAC | acceptable ambient concentrations |
| AACC | acceptable ambient concentrations for carcinogens |
| acfm | actual cubic feet per minute |
| ASTM | American Society for Testing and Materials |
| BACT | Best Available Control Technology |
| BAF | Blackfoot Facility of Basic American Foods |
| BAPCI | Basic American Potato Company, Inc. |
| BMP | best management practices |
| Btu | British thermal units |
| CAA | Clean Air Act |
| CAM | Compliance Assurance Monitoring |
| CAS No. | Chemical Abstracts Service registry number |
| CBP | concrete batch plant |
| CEMS | continuous emission monitoring systems |
| cfm | cubic feet per minute |
| CFR | Code of Federal Regulations |
| CI | compression ignition |
| CMS | continuous monitoring systems |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | $CO_2$ equivalent emissions |
| COMS | continuous opacity monitoring systems |
| DEQ | Department of Environmental Quality |
| dscf | dry standard cubic feet |
| EL | screening emission levels |
| EPA | U.S. Environmental Protection Agency |
| FEC | Facility Emissions Cap |
| GACT | generally available control technology |
| GHG | greenhouse gases |
| gph | gallons per hour |
| gpm | gallons per minute |
| gr | grains (1 lb = 7,000 grains) |
| HAP | hazardous air pollutants |
| HHV | higher heating value |
| HMA | hot mix asphalt |
| hp | horsepower |
| hr/yr | hours per consecutive 12 calendar month period |
| ICE | internal combustion engines |
| IDAPA | a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act |
| iwg | inches of water gauge |
| km | kilometers |
| lb/hr | pounds per hour |
| lb/qtr | pound per quarter |
| m | meters |
| MACT | Maximum Achievable Control Technology |
| mg/dscm | milligrams per dry standard cubic meter |
| MMBtu | million British thermal units |
| MMscf | million standard cubic feet |
| 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&M | operation and maintenance |
| $O_2$ | oxygen |
| PAH | polyaromatic hydrocarbons |
| PC | permit condition |
| PCB | polychlorinated biphenyl |
| PERF | Portable Equipment Relocation Form |
| 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 |
| POM | polycyclic organic matter |
| ppm | parts per million |
| ppmvd | parts per million by volume, dry |
| ppmw | parts per million by weight |
| PSD | Prevention of Significant Deterioration |
| psig | pounds per square inch gauge |
| PTC | permit to construct |
| PTC/T2 | permit to construct and Tier II operating permit |
| PTE | potential to emit |
| PW | process weight rate |
| RAP | recycled asphalt pavement |
| RFO | reprocessed fuel oil |
| RICE | reciprocating internal combustion engines |
| *Rules* | *Rules for the Control of Air Pollution in Idaho* |
| scf | standard cubic feet |
| SCL | significant contribution limits |
| SIC | Standard Industrial Classification |
| 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 |
| $SO_x$ | sulfur oxides |
| T/day | tons per calendar day |
| T/hr | tons per hour |
| T/yr | tons per consecutive 12 calendar month period |
| T2 | Tier II operating permit |
| TAP | toxic air pollutants |
| TEQ | toxicity equivalent |
| T-RACT | Toxic Air Pollutant Reasonably Available Control Technology |
| ULSD | ultra-low sulfur diesel |
| U.S.C. | United States Code |
| VOC | volatile organic compounds |
| wt% | weight percentage |
| $yd^3$ | cubic yards |
| $\mu g/m^3$ | micrograms per cubic meter |

## FACILITY INFORMATION

### *Description*

Blackfoot Facility of Basic American Foods (BAF), a division of Basic American, Inc. is a manufacturer of dried food products and is located at 415 West Collins Road, Blackfoot. Basic American Potato Company, Inc. (BAPCI) is a potato processing company and is located at 409 West Collins Road, Blackfoot, Idaho. Because BAPCI and BAF have the same owner, are adjacent, and have same first two digits of Standard Industrial Classification (SIC) code, the two plants are considered as one source or one facility for NSR program and Title V program purposes.

The facility is classified as a PSD major stationary source, as defined in 40 CFR 52.21(b)(1) because the facility is a Designated Facility as defined in the Rules (i.e., the total heat input rate of the boilers at the facility exceeds 250 MMBtu/hr) and because the emissions of $PM_{10}$, $PM_{2.5}$, $SO_2$, $NO_X$, and CO exceed 100 T/yr, respectively.

However, the facility will become a PSD minor source after this permitting action. The facility has proposed to install a new natural gas-fired Boiler 2A to retire Boilers 1 and 2. The change will reduce the total heat input rate of the boilers at the facility to below 250 MMBtu/hr, and the facility will no longer be a Designated Facility. The facility has also proposed to take a CO enforceable emissions limit of 195 T/yr so that the emissions of each regulated pollutant at the facility will be below 250 T/yr, the major source threshold for a non-Designated Facility. With these changes, the facility will be a PSD minor source.

### *Permitting History*

This PTC is for a modification at an existing Tier I facility. This permit will replace PTC No. P-050301 issued on September 16, 2005. Permitting history can be found in the statement of basis of the current Tier I operating permit.

### *Application Scope*

This PTC is for a minor modification at an existing Tier I facility. The facility will be a PSD minor source after this permitting action.

The applicant has proposed to:

- Install and operate a new natural gas-fired Boiler 2A to replace existing Boilers 1 and 2.
- Limit facility-wide CO emissions to 195 T/yr to keep the facility as a PSD minor source.

### *Application Chronology*

| | |
|---|---|
| May 26, 2017 | DEQ received an application and an application fee. |
| June 14 – June 29, 2017 | DEQ provided an opportunity to request a public comment period on the application and proposed permitting action. |
| June 8, 2017 | DEQ approved pre-permit construction. |
| June 20 and June 21, 2017 | DEQ received supplemental information from the applicant. |
| June 23, 2017 | DEQ determined that the application was complete. |
| August 11, 2017 | DEQ made available the draft permit and statement of basis for peer and regional office review. |
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| September 6, 2017 | DEQ received the permit processing fee. |
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# TECHNICAL ANALYSIS

## *Emissions Units and Control Equipment*

**Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION[1]**

| Source ID No. | Sources | Emissions Control |
|---|---|---|
| Boiler 2A | Boiler 2A:<br>Manufacturer: Victory Energy<br>Model: VE-9772<br>Burner Model: low NOx burners, 30 ppmvd for NOx and 100 ppmvd for CO at 3% $O_2$<br>Manufacture Date: 2017<br>Heat input rating: 91.5 MMBtu/hr<br>Estimated steam rate: 76,000 lb/hr at 250 psig<br>Fuel: natural gas | Low NOx burners |

[1] For stack parameters, refer to the modeling memo.

## *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.

Using this definition of Potential to Emit, an emission inventory was developed for Boiler 2A by the applicant and reviewed by DEQ staff (see Appendix A). PTE emissions estimates of criteria pollutant and hazardous air pollutants for Boiler 2A were based on 91.5 MMBtu/hr heat rate, emission factors from AP-42 for HAP, PM, VOC, $SO_2$, and Pb, manufacturer's emissions data for NOx and CO, and operation of 8,760 hours per year. PTE for other existing emissions units are unchanged.

### 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. It is taken from PTC No. P-2017.0011 Project 61851 issued on 7/31/2017.

**Table 2 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS[1]**

| | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_X$ | CO | VOC | Lead |
|---|---|---|---|---|---|---|---|
| **Facility-Wide PTE (T/yr)** | 246.62 | 243.32 | 162.3 | 323.69 | 331.39 | 13.74 | 2.65E-03 |

[1] Facility includes BAF and BAPCI

### 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.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility based on pre-project PTE and the emissions changes due to this project (i.e., adding Boiler 2A and removing Boilers 1 and 2) that were provided by the applicant and reviewed by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions changes.

**Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS (T/yr)**

| | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_X$ | CO | VOC | Lead |
|---|---|---|---|---|---|---|---|
| Pre-Project Facility-Wide PTE | 246.62 | 243.32 | 162.3 | 323.69 | 331.39 | 13.74 | 2.65E-03 |
| Boiler 2A (new boiler) | 2.99 | 2.99 | 0.24 | 14.61 | 29.64 | 2.16 | 1.96E-04 |
| To-be-removed Boilers 1 and 2 | -16.77 | -16.77 | -143.25 | -180.07 | -43.84 | -3.11 | -2.43E-03 |
| **Post Project Facility-Wide PTE** | 232.84 | 229.54 | 19.29 | 158.23 | 195[1] | 12.79 | 4.16E-04 |

[1] While CO emissions could potentially reach 317 T/yr, the facility's current actual CO emissions are well below that value. The applicant has proposed to take 195 T/yr as an enforceable emissions limit in the 6/21/2017 email.

## 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**

| | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_X$ | CO | VOC | Lead |
|---|---|---|---|---|---|---|---|
| Pre-Project Potential to Emit | 246.62 | 243.32 | 162.3 | 323.69 | 331.39 | 13.74 | 2.65E-03 |
| Post Project Potential to Emit | 232.84 | 229.54 | 19.29 | 158.23 | 195 | 12.79 | 4.16E-04 |
| **Changes in Potential to Emit** | -13.78 | -13.78 | -143.01 | -165.46 | -136.39 | -0.95 | -2.23E-03 |

As presented previously in Table 3, the post project facility-wide potential to emit does not exceed 250 T/yr for any regulated pollutants. After this project, the total heat input rate of the boilers at the facility will below 250 MMBtu/hr (130.5 MMBtu/hr from BAF and 112.8 MMBtu/hr from BAPCI. Total are 243.3 MMBtu/hr) so that the facility is no longer a Designated Facility as defined in the Rules. Therefore, the facility will be a PSD minor source after this project. Based on the EPA guidance (Appendix B), a permit modification that changes a facility to a non-PSD major status does not constitute major modification under PSD regulations. Therefore a PSD applicability analysis is not required.

## TAP Emissions

Table D-6 in Appendix A identifies TAP that are also HAP. As Table D-6 indicates, all TAP associated with natural gas combustion except for pentane and nitrous oxide is also HAP. Emissions of HAP from boilers are regulated by EPA under 40 CFR 63, Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources). According to IDAPA 58.01.01.210, no further review is required for these pollutants for sources subject to 40 CFR Part 63, including sources specifically exempted within the subpart. The TAP that are not one of the 187 Hazardous Air Pollutants will still need to be evaluated for compliance with IDAPA 58.01.01.210. As shown in the following table, the emissions of these TAP (i.e., pentane and nitrous oxide) are below the respective ELs, and a modeling analysis is not required.

**Table 5 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR TOXIC AIR POLLUTANTS[1]**

| Non-Carcinogenic Toxic Air Pollutants | Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr) | Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr) | Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr) | Non-Carcinogenic Screening Emission Level (lb/hr) | Exceeds Screening Level? (Y/N) |
|---|---|---|---|---|---|
| Pentane | 0.00E-03 | 2.33E-01 | 2.33E-01 | 1.18E+02 | No |
| Nitrous Oxide | 0.00E-03 | 1.97E-01 | 1.97E-01 | 6.00E+00 | No |

[1] Based on Boiler 2A at natural gas firing rate of 91.5 MMBtu/hr

## Post Project HAP Emissions

The following table presents the post project potential to emit for HAP pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

**Table 6 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY**

| Fuel Combustion Activity | Maximum Combustion | Total HAP Emissions | | Maximum Individual HAP Emissions | | |
|---|---|---|---|---|---|---|
| | Total Capacity MMBtu/hr | Emission Factor lb/MMBtu | tons/yr | Maximum Individual HAP | Emission Factor lb/MMBtu | tons/yr |
| Total Installed NG Firing Capacity, such as boilers, dryers, air makeups, annual average | 604.80 | 1.85E-03 | 4.90 | Hexane | 1.76E-03 | 4.67 |
| Maximum Annual Permitted #2 Oil Combustion - Boiler 3 | 51,106 | 3.69E-04 | 0.01 | Formaldehyde | 3.69E-04 | 0.01 |
| **Total** | | | **4.91** | | | **4.67** |

### *Ambient Air Quality Impact Analyses*

As presented in the Modeling Memo in Appendix C, the estimated emission rates of NOx, $PM_{10}$, and $PM_{2.5}$ from Boiler 2A exceed the published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline[1]. Therefore, modeling is required for these pollutants.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this project will not significantly contribute to a violation of any ambient air quality standard. The impact of this project is less than significant impact level (SIL) for NOx, $PM_{10}$, and $PM_{2.5}$.

An ambient air quality impact analyses document (Appendix C) has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action.

## REGULATORY ANALYSIS

### *Attainment Designation (40 CFR 81.313)*

The BAF facility is located in Bingham County, which is designated as unclassifiable/attainment for $PM_{2.5}$, $PM_{10}$, $SO_2$, $NO_X$, CO, and Ozone for federal and state criteria air pollutants. Reference 40 CFR 81.313.

### *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

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[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

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 7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION**

| Pollutant | Uncontrolled PTE (T/yr) | Permitted PTE (T/yr) | Major Source Thresholds (T/yr) | AIRS/AFS Classification |
|---|---|---|---|---|
| PM | >100 | >100 | **100** | A |
| $PM_{10}$ | >100 | >100 | **100** | A |
| $PM_{2.5}$ | >100 | >100 | **100** | A |
| $SO_2$ | >100 | >100 | **100** | A |
| $NO_X$ | >100 | >100 | **100** | A |
| CO | >100 | >100 | **100** | A |
| VOC | <100 | <100 | **100** | B |
| HAP (single) | <10 | <10 | **10** | B |
| HAP (total) | <25 | <25 | **25** | B |
| Pb | <100 | <100 | **100** | B |

## *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 proposed new natural gas-fired boiler. 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. This requirement is assured by Permit Conditions in the current Tier I operating permit.

## *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 and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting liquid fuel. 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. This requirement is incorporated as Permit Condition 3.4 and is assured by Permit Conditions 3.3, emissions limits and 3.6, fuel requirements.

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

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

Post project facility-wide emissions from this facility have a potential to emit greater than 100 tons per year for $PM_{10}$, $SO_2$, $NO_X$, and CO as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, this facility is classified as a major facility, as defined in IDAPA 58.01.01.008.10. The facility currently has a Tier I operating permit for BAF and a Tier I operating permit for BAPCI. Per IDAPA 58.01.01.209.05, the facility will have to apply to modify BAF Tier I operating permit to incorporate the requirements of this PTC.

### *PSD Classification (40 CFR 52.21)*

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

The facility is currently a major source as defined in 40 CFR 52.21(b) ("PSD Major Source") because total installed boiler capacity exceeds 250 MMBtu/hr and because emissions of some criteria air pollutants exceed 100 ton/yr.

With the installation of Boiler 2A and the retirement of Boilers 1and 2, facility-wide boiler capacity will be less than 250 MMBtu/hr, and the only criteria air pollutant with emissions exceeding 250 ton/yr would be carbon monoxide. Thus, by creating an enforceable limit of 195 ton/yr on facility-wide carbon monoxide, the facility will no longer be a PSD major source when the permit is issued. Further, as documented in Section 4 of the application, the changes in emissions associated with this modification are less than the "Significant" emission increase levels identified in IDAPA 58.01.01.006.106.

### *NSPS Applicability (40 CFR 60)*

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

Boiler 2A is subject to this subpart. Boiler 2A only combusts natural gas as fuel. Therefore, the only sections of this subpart that are applicable to the boiler are the Applicability and Delegation of Authority specified in 40 CFR 60.40c(a), the Recordkeeping requirements of 40 CFR 60.48c(g), and the Reporting requirements of 40 CFR 60.48c(a), (a)(1), and (a)(3).

Detailed regulatory analysis can be found in Appendix D of the SOB. DEQ is delegated to this subpart.

### *NESHAP Applicability (40 CFR 61)*

Boiler 2A is not subject to any NESHAP requirements in 40 CFR 61.

### *MACT/GACT Applicability (40 CFR 63)*

Boiler 2A is not subject to any MACT/GACT standards in 40 CFR Part 63. Specifically, Boiler 2A is not subject to 40 CFR 63 Subpart DDDDD (Boiler MACT) because the facility is not a major source for HAP. Boiler 2A is not subject to 40 CFR 63 Subpart JJJJJJ because Boiler 2A will only burn natural gas, and it is not included in any of the source categories to which the subpart applies.

### *Permit Conditions Review*

This section describes the permit conditions that have been added, revised, modified or deleted as a result of this permitting action. All permit conditions for Boiler 1 and Boiler 2 are obsolete and removed as a result of retiring these two boilers.

PERMIT SCOPE

Permit Conditions 1.1 to 1.3

Permit Condition 1.1 states the purpose of this permitting action. Permit Condition 1.2 states those permit conditions that have been modified or revised by this permitting action are identified by the permit issue date citation located directly under the permit condition and on the right-hand margin. Permit Condition 1.3 states this PTC replaces Permit to Construct No. P-050301, issued on September 16, 2005 which was the PTC issued only for the boilers at BAF.

Table 1.1

Table 1.1 lists regulated sources by this permit.

FACILITY-WIDE CONDITIONS

Permit Condition 2.1

Permit Condition 2.1 establishes facility-wide annual CO emissions limit to be less than the PSD major source threshold so that the facility becomes PSD minor source after this permitting action. The facility means BAF and BAPCI.

This limit supersedes the CO limit in Permit Condition 3.3 of BAF's facility emissions cap (FEC) PTC No. P-2009.0043, issued on January 20, 2011.

While CO emissions could potentially reach 317 T/yr, the facility's current actual CO emissions are well below that value. The applicant has proposed to take 195 T/yr as an enforceable emissions limit in the 6/21/2017 email. This limit would give the facility enough flexibility for future growth and meanwhile avoid more stringent monitoring if the limit is 249 T/hr.

When the limit is almost reaching the PSD major source threshold of 250 T/yr, there are regulatory concerns on how to ensure the facility stays as a PSD minor source. Source testing on process dryers would be required because of the uncertainty of CO emissions from the process dryers.

Permit Condition 2.2

Permit Condition 2.2 is a CO limit compliance method and is taken from PC 3.4 of BAF FEC PTC No. P-2009.0043, issued on January 20, 2011 with revisions to reflect that this is for the new CO limit applying to both BAF and BAPCI.

Permit Condition 2.3

Permit Condition 2.3 is a reporting requirement and is taken from PC 3.6.1 of BAF FEC PTC No. P-2009.0043, issued on January 20, 2011 with some changes to reflect that this is for the new CO limit applying to both BAF and BAPCI.

BOILER 2A AND BOILER 3

Permit Condition 3.2 states that Boiler 2A uses a low NOx burner to lower NOx emissions and that emissions from Boiler 3 are uncontrolled.

Permit Condition 3.3

The short term emission limits for Boiler 3 is taken from Appendix of BAF FEC PTC No. P-2009.0043, issued on January 20, 2011; the long-term limits are taken from Tables D7-b and D7-c of the application. Refer to Appendix A for more details.

Emissions limits for Boiler 2A are taken from Table D-4 of the application using EFs in Table D-3. Refer to Appendix A for more details. CO and NOx emissions from Boiler 2A are estimated using the manufacturer's emissions data. Others use the EFs in AP-42. The calculated emissions rates are in the following table.

As requested by the applicant during the draft permit review, the VOC limits are removed from the final permit. Refer to Appendix E for detailed explanations.

| Source Description | $PM_{2.5}/PM_{10}$ | | $SO_2$ | | $NO_X$ | | CO | | VOC | |
|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr |
| Boiler 2A | 0.68 | 2.99 | 0.05 | 0.24 | 3.34 | 14.61 | 6.77 | 29.64 | 0.49 | 2.16 |
| Boiler 3 | 0.30 | 1.53 | 1.90 | 1.75 | 5.40 | 17.93 | 1.80 | 2.16 | 0.21 | 0.91 |

Permit Condition 3.4

Permit Condition 3.4 is old Permit Condition 2.7 in the PTC No. P-050301, issued on September 16, 2005.

Permit Condition 3.5

Permit Condition 3.5 is old Permit Condition 2.5 in the PTC No. P-050301, issued on September 16, 2005. The compliance method for this standard is specified in the current Tier I operating permit.

Permit Condition 3.6

Permit Condition 3.6 is revised PC 3.1of PTC No. P-050301, issued on September 16, 2005. It limits the fuel types of the boilers. This permit condition has ensured that the boilers meet the grain loading standard for fuel burning equipment as in Permit Condition 3.4.

Permit Conditions 3.7 and 3.8 are old PCs 3.2 and 3.8 of PTC No. P-050301, issued on September 16, 2005.

Permit Conditions 3.9 and 3.10

This project is to install Boiler 2A and to retire Boilers 1 and 2. When performing ambient impact analysis, the facility modeled emissions from Boiler 2A as positive values and emissions from Boilers 1 and 2 as negative values. In addition, the emissions of Boiler 2A were modeled as being emitted from the existing 100-foot tall stack that was designed to serve Boilers 1 and 2 when either boiler burned fuel oil. Permit Conditions 3.9 and 3.10 are used to capture the conditions used in the modeling analysis.

Permit Condition 3.11

Permit Condition 3.11 is old PC 4.11 of PTC No. P-050301, issued on September 16, 2005.

Permit Condition 3.12

Permit Condition 3.12 is revised old PC 4.12 of PTC No. P-050301, issued on September 16, 2005 by removing no longer applicable conditions of the retiring Boilers 1 and 2.

Permit Condition 3.13

Permit Condition 3.13 is old PC 4.13 of PTC No. P-050301, issued on September 16, 2005.

Permit Condition 3.14

Permit Condition 3.14 is the recordkeeping requirements. It requires the permittee to maintain documentation showing that Boiler 2A uses low NOx burner and has manufacturer's guarantee of 30 ppmvd for NOx and 100 ppmvd for CO at 3% $O_2$. The manufacturer guaranteed CO and NOx emissions concentrations are the basis for the EI calculation and modeling analysis.

Permit Condition 3.15

Permit Condition 3.15 requires an initial performance test of Boiler 2A to verify and confirm the manufacturer's guarantees for CO and NOx emissions.

Permit Conditions 3.16 to 3.19

Boiler 2A is subject to 40 CFR 60 Subpart Dc and Subpart A General Provisions for 40 CFR 60. Permit Conditions 3.16 to 3.19 are applicable requirements to Boiler 2A. Refer to the federal regulation analysis in Appendix D for details. Table 3.2 about 40 CFR 60 Subpart A is taken from DEQ's internal guidance for federal regulations.

GENERAL PROVISIONS

General Provisions are updated using the current PTC template.

## PUBLIC REVIEW

### *Public Comment Opportunity*

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this time, there were no comments on the application and there was not a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

# APPENDIX A – EMISSIONS INVENTORIES

**Table D-1**
**Operating Information for Affected Equipment**

| Emissions Unit Date | | | | Maximum Heat Rate* | | Maximum Steam Production* | |
|---|---|---|---|---|---|---|---|
| **Emissions Unit ID** | **Operating Status** | **Type of Emission Unit** | **Production Activity** | **Fuel Type** | **Heat Rate, MMBTU/hr** | **lb/hr** | **lb/yr** |
| Boiler 2A | New | Steam Boiler | Process steam | NG | 91.5 | 70,000 | 613,200,000 |
| Boiler 1 | Removed | Steam Boiler | Process steam | NG | 55.2 | 45,500 | 398,580,000 |
| | | | | #2 Oil | 53.3 | 45,500 | 398,580,000 |
| | | | | #6 Oil | 34.8 | 30,000 | † |
| Boiler 2 | Removed | Steam Boiler | Process steam | NG | 73.5 | 60,000 | 525,600,000 |
| | | | | #2 Oil | 71.0 | 60,000 | 525,600,000 |
| | | | | #6 Oil | 58.6 | 50,000 | † |
| *Maximum Capacity, Pre-project:* | | | | | 128.7 | 105,500 | 924,180,000 |
| *Maximum Capacity, Post-project:* | | | | | 91.5 | 70,000 | 613,200,000 |
| *Change in Capcity:* | | | | | -37.2 | -35,500 | -310,980,000 |

* Steam Rate and Fuel Combustion Data for Boilers 1 and 2 from April 25, 2005 letter from Bruce Wright, Basic American Foods, to Ken Hanna, Idaho Department of Environmental Quality. Subject: Revised Emission Estimates for Basic American Foods *Application for Permit to Construct - Refiring of Boilers 6 and 8* (February 2005). (Note that Boiler 8 and Boiler 6 have been
† Subject to 4,097,682 limit on #6 oil combustion limit for Boilers 1 and 2.

| Table D-2 | | | |
|---|---|---|---|
| **Constants and Calculated Values Used in Emissions Calculations** | | | |
| **PARAMETER** | **VALUE** | **UNITS** | **BASIS/DISCUSSION** |
| Stoichiometric NG combustion parameters | | | |
| Fd, dry exhaust gas factor | 8710 | dscf/MMBtu | From Table 19-2, EPA Test Method 19 |
| Fw, wet exhaust gas factor | 10610 | wscf/MMBtu | From Table 19-2, EPA Test Method 19 |
| FW, NO2 | 46 | | |
| FW, CO | 28 | | |
| | | | |
| barometric pressure | 12.5 | psia | |
| | | | |
| | | | |
| HHV, NG | 1020 | Btu/scf | |
| HHV, No. 2 Oil | 130000 | Btu/gal | |
| HHV, No. 6 Oil | 146000 | Btu/gal | |
| GWP, NG | 120000 | lb CO2e/MMScf | |
| | | | |
| | | | |
| Boiler 2A data | | | |
| Boiler heat rate | 91.52 | MMBtuh | Victory boiler customer data sheet |
| excess air | 15% | | Victory boiler customer data sheet |
| oxygen content in flue gas | 3% | | |
| exhaust temperature | 294 | °F | Victory boiler customer data sheet |
| flue gas leaving system | 81432 | lb/hr | |
| MW of flue gas | 27.68 | lb/lb-mole | |
| | | | |
| NOx | 30 | ppm @ 3% O2 | Victory boiler customer data sheet |
| CO | 100 | ppm @ 3% O2 | Victory boiler customer data sheet |
| PM | 7.600 | lb/MMscf | AP-42, Table 1.4-2. |
| SO2 | 0.600 | lb/MMscf | AP-42, Table 1.4-2. |
| VOC | 5.500 | lb/MMscf | AP-42, Table 1.4-2. |
| Pb | 5.00E-04 | lb/MMscf | AP-42, Table 1.4-2. |
| | | | |
| Boiler 1-2 #6 oil release parameters | | | |
| Easting UTM | 387767.68 | m | from April 2017 data submittal for PTC for new production line. |
| Northing UTM | 4784172.25 | m | from April 2017 data submittal for PTC for new production line. |
| Base Elevation | 1365 | m | from April 2017 data submittal for PTC for new production line. |
| stack height | 100 | ft | from April 2017 data submittal for PTC for new production line. |
| exhaust temp | 116 | °F | from April 2017 data submittal for PTC for new production line. |

| Table D-2 | | | |
|---|---|---|---|
| Constants and Calculated Values Used in Emissions Calculations | | | |
| **PARAMETER** | **VALUE** | **UNITS** | **BASIS/DISCUSSION** |
| exhaust velocity | 50 | fps | from April 2017 data submittal for PTC for new production line. |
| diameter | 3.5 | ft | from April 2017 data submittal for PTC for new production line. |
| | | | |
| Boiler 1 NG parameters - tall stack | | | |
| Easting UTM | 387767.68 | m | from April 2017 data submittal for PTC for new production line. |
| Northing UTM | 4784172.25 | m | from April 2017 data submittal for PTC for new production line. |
| Base Elevation | 1365 | m | from April 2017 data submittal for PTC for new production line. |
| stack height | 100 | ft | from April 2017 data submittal for PTC for new production line. |
| exhaust temp | 300 | °F | from April 2017 data submittal for PTC for new production line. |
| exhaust velocity | 32.77 | fps | from April 2017 data submittal for PTC for new production line. |
| diameter | 3.5 | ft | from April 2017 data submittal for PTC for new production line. |
| | | | |
| Boiler 1 NG parameters - short stack | | | |
| Easting UTM | 387756.83 | m | from model "Bft Alt3-01 161111.BST" |
| Northing UTM | 4784174.1 | m | from model "Bft Alt3-01 161111.BST" |
| Base Elevation | 1365 | m | from model "Bft Alt3-01 161111.BST" |
| stack height | 47 | ft | from model "Bft Alt3-01 161111.BST" |
| exhaust temp | 300 | °F | from model "Bft Alt3-01 161111.BST" |
| exhaust velocity | 32.77 | fps | from model "Bft Alt3-01 161111.BST" |
| diameter | 3.5 | ft | from model "Bft Alt3-01 161111.BST" |
| | | | |
| Boiler 2 NG parameters | | | |
| Easting UTM | 387740.25 | m | from April 2017 data submittal for PTC for new production line. |
| Northing UTM | 4784181.26 | m | from April 2017 data submittal for PTC for new production line. |
| Base Elevation | 1365 | m | from April 2017 data submittal for PTC for new production line. |
| stack height | 50 | ft | from April 2017 data submittal for PTC for new production line. |
| exhaust temp | 300 | °F | from April 2017 data submittal for PTC for new production line. |
| exhaust velocity | 43.64 | fps | from April 2017 data submittal for PTC for new production line. |
| diameter | 3.5 | ft | from April 2017 data submittal for PTC for new production line. |
| | | | |
| | | | |
| Boiler 1-2 #6 oil max operating rate data (24 months ending 4/30/2009) | | | |
| max day steam rate | -59,644 | lb/hr | from BF Boilers 10 year operating data record. May 10, 2007) |
| #6 oil fuel rate on max day | 446 | gal/hr | from BF Boilers 10 year operating data record. May 10, 2007) |
| average annual steam from #6 oil | -18.5 | MMlb/yr | from BF Boilers 10 year operating data record |

| Table D-2 | | | |
|---|---|---|---|
| **Constants and Calculated Values Used in Emissions Calculations** | | | |
| **PARAMETER** | **VALUE** | **UNITS** | **BASIS/DISCUSSION** |
| #6 oil average annual fuel rate | -135.1 | kgal/yr | from BF Boilers 10 year operating data record |
| | | | |
| Average annual steam from NG combustion (24 months ending 4/30/2009) | | | |
| Boiler 1 | -151.14 | MMlb/yr | from BF Boilers 10 year operating data record |
| Boiler 2 | -231.71 | MMlb/yr | from BF Boilers 10 year operating data record |
| | | | |
| Average annual NG combustion (24 months ending 4/30/2009) | | | |
| Boiler 1 | 164.34 | MMscf/yr | |
| | 167622 | MMBtu/yr | |
| Boiler 2 | 295.07 | MMscf/yr | |
| | 300968 | MMBtu/yr | |
| | | | |
| Steam Based Emission Factors - Boilers 1-2 #6 oil | | | |
| CO | 0.04 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| NOx | 0.44 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| SO2 + SO3 | 0.555 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| PM10 | 0.021 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Direct PM2.5 | 0.021 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| VOC | 0.002 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Pb | 1.20E-05 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| | | | |
| | | | |
| Steam Based Emission Factors - Boiler 1 NG | | | |
| CO | 0.100 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| NOx | 0.119 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| SO2 + SO3 | 0.0072 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| PM10 | 0.0091 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Direct PM2.5 | 0.0091 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| VOC | 0.0066 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Pb | 5.95E-07 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| | | | |
| | | | |
| Steam Based Emission Factors - Boiler 2 NG | | | |
| CO | 0.101 | | from April 2017 data submittal for PTC for new production line.. Table 6 |

| Table D-2 | | | |
|---|---|---|---|
| **Constants and Calculated Values Used in Emissions Calculations** | | | |
| **PARAMETER** | **VALUE** | **UNITS** | **BASIS/DISCUSSION** |
| NOx | 0.06 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| SO2 + SO3 | 0.0072 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| PM10 | 0.0091 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Direct PM2.5 | 0.0091 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| VOC | 0.0066 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| Pb | 6.00E-07 | | from April 2017 data submittal for PTC for new production line.. Table 6 |
| | | | |
| Allocation of amu between stacks NND and NNG | | | |
| NND allocation | 38% | | prorated to dryer air flow rates |
| NNG allocation | 62% | | prorated to dryer air flow rates |
| | | | |
| Boiler 1 Operating Data | | | |
| heat rate - NG | 55.2 | MMBtuh | from April 2005 data submittal for PTC No. P-050301 |
| fuel rate - #2 oil | 390 | gal/hr | from April 2005 data submittal for PTC No. P-050301 |
| heat rate, #2 oil | 50.7 | MMBtuh | |
| fuel rate - #6 oil | 239 | gal/hr | from April 2005 data submittal for PTC No. P-050301 |
| Heat rate, #6 oil | 34.9 | MMBtuh | |
| fuel rate, #6 oil, annual average | 174.4 | gal/hr | maximum #6 oil allowance pro-rated bsed hourly fuel rate |
| Heat rate, #6 oil, annual average | 25.5 | MMBtuh | |
| | | | |
| | | | |
| Boiler 2 Operating Data | | | |
| heat rate - NG | 73.5 | MMBtuh | from April 2005 data submittal for PTC No. P-050301 |
| fuel rate - #2 oil | 513 | gal/hr | from April 2005 data submittal for PTC No. P-050301 |
| heat rate, #2 oil | 66.7 | MMBtuh | |
| fuel rate - #6 oil | 402 | gal/hr | from April 2005 data submittal for PTC No. P-050301 |
| Heat rate, #6 oil | 58.7 | MMBtuh | |
| fuel rate, #6 oil, annual average | 293.4 | gal/hr | |
| Heat rate, #6 oil, annual average | 42.8 | MMBtuh | |
| | | | |
| | | | |
| Boiler 1-2 Operating Data | | | |
| #6 oil usage | 15384 | gal/day | PTC No. P-050301 |
| | 4097682 | gal/yr | PTC No. P-050301 |
| maximum steam rate | 80000 | lb/hr | PTC No. P-050301 |
| | | | |

| Table D-2 | | | |
|---|---|---|---|
| Constants and Calculated Values Used in Emissions Calculations | | | |
| **PARAMETER** | **VALUE** | **UNITS** | **BASIS/DISCUSSION** |
| Boiler 3 Operating Data | | | |
| Heat rate - NG | 39 | MMBtuh | from April 2005 data submittal for PTC No. P-050301 |
| Fuel rate - No. 2 Oil | 273 | gal/hr | from April 2005 data submittal for PTC No. P-050302 |
| heat rate, #2 oil | 35.5 | MMBtuh | |
| NG combustion limit | 328 | MMscf/yr | PTC No. P-050301 |
| #2 oil combustion limit | 393120 | gal/yr | PTC No. P-050301 |
| max fuel oil sulfur content | 0.05 | wt% | PTC No. P-050301 |
| | | | |
| Boiler 3 - NG Emission Factors | | | |
| CO | 8.4 | lb/MMscf | AP-42, Section 1.4. Table 1.4-1. |
| NOx | 100 | lb/MMscf | AP-42, Section 1.4. Table 1.4-1. |
| SO2 | 2.4 | lb/MMscf | AP-42, Section 1.4. Assume 0.8 gr S/Ccf. |
| PM10 | 7.6 | lb/MMscf | AP-42, Section 1.4 |
| PM2.5 | 7.6 | lb/MMscf | AP-42, Section 1.4 |
| VOC | 5.5 | lb/MMscf | AP-42, Section 1.4 |
| Pb | 5.00E-04 | lb/MMscf | AP-42, Section 1.4 |
| CO2e | 120000 | lb/MMscf | AP-42, Section 1.4, Table 1.4-2. Assume CO2e equals CO2. |
| | | | |
| Boiler 3 - #2 Oil Emission Factors | | | |
| CO | 5 | lb/kgal | AP-42, Section 1.3.,Table 1.3-1. |
| NOx | 20 | lb/kgal | AP-42, Section 1.3.,Table 1.3-1. |
| SO2 | 7.2 | lb/kgal | AP-42, Section 1.3, Table 1.3-1. S=0.05 |
| Filterable PM10 | 1.08 | lb/kgal | AP-42, Section 1.3.,Table 1.3-6 |
| Filterable PM2.5 | 0.25 | lb/kgal | AP-42, Section 1.3.,Table 1.3-6 |
| CPM | 1.3 | lb/kgal | AP-42, Section 1.3.,Table 1.3-12 |
| VOC | 0.34 | lb/kgal | AP-42, Section 1.3.,Table 1.3-3, using NMTOC. |
| Pb | 0.000009 | lb/MMBtu | AP-42, Section 1.3.,Table 1.3-10. |
| CO2e | 22300 | lb/kgal | AP-42, Section 1.3, Table 1.3-12. Assume CO2e equals CO2. |

**Table D-3**
**Criteria Pollutant Emission Factors for Boiler 2A**

| Parameter | Value | Units | Basis |
|---|---|---|---|
| *Calculation Constants* | | | |
| Boiler Heat Rate | 91.52 | MMBtuh | Victory boiler customer data sheet |
| Fd, dry exhaust gas factor | 8710 | dscf/MMBtu | From Table 19-2, EPA Test Method 19 |
| Fa, Fd adjusted to 3% O2 | 10170 | dscf/MMBtu @ 3% O2 | =Fd*(20.9/(20.9-3)) |
| HHV, natural gas | 1020 | Btu/scf | |
| *Boiler 2A NOx emission factor* | | | |
| PPM, stack gas concentration | 30 | ppm @ 3% O2 | Victory boiler customer data sheet |
| FW, formula weight | 46 | - | NOx as NO2 |
| E, emissions | 0.00000358 | lb/dscf | =PPM*FW/(385.1*10^6) |
| fuel rate emission factor | 37.17 | lb/MMscf NG | heat rate EF/HHV natural gas |
| heat rate emission factor | 0.036 | lb/MMBtu | =E*Fa |
| *Boiler 2A SO2 emission factor* | | | |
| fuel rate emission factor | 0.600 | lb/MMscf | AP-42, Table 1.4-2. |
| heat rate emission factor | 5.88E-04 | lb/MMBtu | Based on HHV = 1020 Btu/scf |
| *Boiler 2A CO emission factor* | | | |
| PPM, stack gas concentration | 100 | ppm @ 3% O2 | Victory boiler customer data sheet |
| FW, formula weight | 28 | - | |
| E, emissions | 0.00000727 | lb/dscf | =PPM*FW/(385.1*10^6) |
| EFf, fuel rate based emission factor | 75.42 | lb/MMscf NG | |
| EFh, heat rate emission factor | 0.074 | lb/MMBtu | =E*Fa |
| *Boiler 2A PM emission factor* | | | |
| fuel rate emission factor | 7.6 | lb/MMscf | AP-42, Table 1.4-2. |
| heat rate emission factor | 7.45E-03 | lb/MMBtu | lb/MMscf ÷ HHV NG |
| *Boiler 2A VOC emission factor* | | | |
| fuel rate emission factor | 5.5 | lb/MMscf | AP-42, Table 1.4-2. |
| heat rate emission factor | 5.39E-03 | lb/MMBtu | lb/MMscf ÷ HHV NG |
| *Boiler 2A Pb emission factor* | | | |
| fuel rate emission factor | 5.00E-04 | lb/MMscf | AP-42, Table 1.4-2. |
| heat rate emission factor | 4.90E-07 | lb/MMBtu | lb/MMscf ÷ HHV NG |

**Table D-4**
**Criteria Air Pollutant Emissions PTE for Boiler 2A**

| Pollutant | Emission Factor, lb/MMBtu | Emission Rate* | |
|---|---|---|---|
| | | lb/hr | ton/yr |
| CO | 0.074 | 6.767 | 29.6 |
| NOx | 0.036 | 3.335 | 14.6 |
| SO2 + SO3 | 0.0006 | 0.054 | 0.24 |
| PM10 | 0.007 | 0.682 | 3.0 |
| Direct PM2.5 | 0.007 | 0.682 | 3.0 |
| VOC | 0.005 | 0.493 | 2.2 |
| Pb | 4.90E-07 | 4.49E-05 | 1.96E-04 |

* Based on 91.5 MMBtuh heat rate.

**Table D-5**
**Toxic and Hazardous Air Pollutant Emission Factors - NG Combustion**

| Air Pollutant | lb/MMBTU | Emission Factor Reference | CAA Hazardous Air Pollutant? | ID TAP (C, NC, or No)? |
|---|---|---|---|---|
| POM Components | | | | |
| Acenaphthene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Acenaphthylene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Anthracene | 2.35E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Benz(a)anthracene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| Benzo(a)pyrene | 1.18E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| Benzo(b)fluoranthene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| Benzo(g,h,i)perylene | 1.18E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Benzo(k)fluoroanthene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| Chrysene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| Dibenzo(a,h)anthracene | 1.18E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| 7,12-Dimethylbenz(a)anthracene | 1.57E-08 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Fluoranthene | 2.94E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Fluorene | 2.75E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Indeno(1,2,3-cd)pyrene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (7-PAH Group) |
| 2-Methylnaphthalene | 2.35E-08 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| 3-Methylchloroanthene | 1.76E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Naphthalene | 5.98E-07 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Phenanthrene | 1.67E-08 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| Pyrene | 4.90E-09 | AP-42, Table 1.4-3 | Yes | C (General PAH) |
| *PAH (Idaho)* | *6.73E-07* | *Summation of individual ID PAH components* | *Yes (EPA POM component)* | *C* |
| *POM (Idaho)* | *1.12E-08* | *Summation of ID POM 7-PAH components* | *Yes (EPA POM component)* | *C* |
| *POM (EPA)* | *6.85E-07* | *Sum of individual POM componnents* | *Yes* | - |
| Benzene | 2.06E-06 | AP-42, Table 1.4-3 | Yes | C |
| Dichlorobenzene | 1.18E-06 | AP-42, Table 1.4-3 | Yes | NC |
| Formaldehyde | 7.35E-05 | AP-42, Table 1.4-3 | Yes | C |
| Hexane | 1.76E-03 | AP-42, Table 1.4-3 | Yes | NC |
| Pentane | 2.55E-03 | AP-42, Table 1.4-3 | No | NC |
| Toluene | 3.33E-06 | AP-42, Table 1.4-3 | Yes | NC |
| Arsenic | 1.96E-07 | AP-42, Table 1.4-4 | Yes | C |
| Beryllium | 1.18E-08 | AP-42, Table 1.4-4 | Yes | C |
| Cadmium | 1.08E-06 | AP-42, Table 1.4-4 | Yes | C |
| Chromium | 1.37E-06 | AP-42, Table 1.4-4 | Yes | NC |
| Chromium (VI) | 6.86E-08 | AP-42, Table 1.4-4 | Yes (included in chromium) | C |
| Cobalt | 8.24E-08 | AP-42, Table 1.4-4 | Yes | NC |
| Manganese | 3.73E-07 | AP-42, Table 1.4-4 | Yes | NC |
| Mercury | 2.55E-07 | AP-42, Table 1.4-4 | Yes | No |
| Nickel | 2.06E-06 | AP-42, Table 1.4-4 | Yes | C |
| Selenium | 2.35E-08 | AP-42, Table 1.4-4 | Yes | NC |
| Nitrous Oxide | 2.16E-03 | AP-42, Table 1.4-2 | No | NC |
| EPA Total HAPs | 1.85E-03 | Summation of individual EPA HAP components | Yes | No |
| Largest Individual HAP | 1.76E-03 | Hexane | Yes | Yes |

Based on 1020 BTU/scf natural gas heat content

**Table D-6**
**Boiler 2A Toxic Air Pollutant Emissions**

| Air Pollutant | Idaho TAP Category | EPA Hazardous Air Pollutant? | Emission Factor, lb/MMBtu | Emission Rate, lb/hr* | SEL, lb/hr | % of SEL |
|---|---|---|---|---|---|---|
| PAH (Idaho) | C | Yes (EPA POM component) | 6.73E-07 | 6.16E-05 | NA† | - |
| POM (Idaho) | C | Yes (EPA POM component) | 1.12E-08 | 1.02E-06 | NA† | - |
| Benzene | C | Yes | 2.06E-06 | 1.88E-04 | NA† | - |
| Dichlorobenzene | NC | Yes | 1.18E-06 | 1.08E-04 | NA† | - |
| Formaldehyde | C | Yes | 7.35E-05 | 6.73E-03 | NA† | - |
| Hexane | NC | Yes | 1.76E-03 | 1.62E-01 | NA† | - |
| Pentane | NC | No | 2.55E-03 | 2.33E-01 | 1.18E+02 | 0.2% |
| Toluene | NC | Yes | 3.33E-06 | 3.05E-04 | NA† | - |
| Arsenic | C | Yes | 1.96E-07 | 1.79E-05 | NA† | - |
| Beryllium | C | Yes | 1.18E-08 | 1.08E-06 | NA† | - |
| Cadmium | C | Yes | 1.08E-06 | 9.88E-05 | NA† | - |
| Chromium | NC | Yes | 1.37E-06 | 1.25E-04 | NA† | - |
| Chromium (VI) | C | Yes (included in chromium) | 6.86E-08 | 6.28E-06 | NA† | - |
| Cobalt | NC | Yes | 8.24E-08 | 7.54E-06 | NA† | - |
| Manganese | NC | Yes | 3.73E-07 | 3.41E-05 | NA† | - |
| Mercury | No | Yes | 2.55E-07 | 2.33E-05 | NA† | - |
| Nickel | C | Yes | 2.06E-06 | 1.89E-04 | NA† | - |
| Selenium | NC | Yes | 2.35E-08 | 2.15E-06 | NA† | - |
| Nitrous Oxide | NC | No | 2.16E-03 | 1.97E-01 | 6.00E+00 | 3.3% |

* Based on NG firing rate = 91.5 MMBtuh

† TAP analysis not needed because ambient impacts of TAP addressed in 40 CFR 63, Subpart JJJJJJ.

**Table D7a**

**Maximum Boiler 3 Fuel Combustion Under Existing Enforceable Operating Limits**

| Fuel Combustion Scenario | Maximum NG Firing | | | Maximum #2 Oil Firing | | |
|---|---|---|---|---|---|---|
| | | Annual | | | Annual | |
| | Hourly, MMscf | Hours | MMscf | Hourly, kgal | Hours | kgal |
| Maximum NG Firing | 0.0382 | 8578 | 328 | 0 | 182 | 49.56 |
| Maximum #2 Oil Firing | 0 | 7320 | 280 | 0.273 | 1440 | 393.12 |

**Table D7-b**

**Maximum Hourly Criteria Air Pollutant Emissons from Boiler 3 Based on Enforcemable Operating Limits, lb/hr**

| Fuel Combustion Scenario | Fuel Firing Rate | | CO* | | NOx* | | SOx* | | PM10* | | PM2.5* | | VOC | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NG, MMscf/hr | #2 Oil, kgal/hr | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions |
| Maximum NG Firing | 0.04 | 0.00 | 1.80 | | 5.40 | | 1.90 | | 0.30 | | 0.30 | | 0.21 | 0.00 | 1.91E-05 | 0.00E+00 |
| Maximum #2 Oil Firing | 0.00 | 0.27 | | | | | | | | | | | 0.00 | 0.09 | 0.00E+00 | 3.19E-04 |
| *Maximum Emissions:* | | | 1.80 | | 5.40 | | 1.90 | | 0.30 | | 0.30 | | 0.21 | | 3.19E-04 | |

* Enforceable limit in Permit to Construct P-050301. For PM2.5, all PM10 assumed to be PM2.5

**Table D-7c**

**Maximum Annual Criteria Air Pollutant Emissons from Boiler 3 Based on Enforcemable Operating Limits, ton/yr**

| Fuel Combustion Scenario | Fuel Firing Rate | | CO | | NOx | | SOx | | PM10 | | PM2.5 | | VOC | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NG, MMscf/yr | #2 Oil, kgal/yr | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions | NG Emissions | #2 Oil Emissions |
| Maximum NG Firing | 328.0 | 49.6 | 1.4 | 0.1 | 16.4 | 0.5 | 0.4 | 0.2 | 1.2 | 0.1 | 1.2 | 0.0 | 0.9 | 0.0 | 8.20E-05 | 2.23E-07 |
| Maximum #2 Oil Firing | 279.9 | 393.1 | 1.2 | 1.0 | 14.0 | 3.9 | 0.3 | 1.4 | 1.1 | 0.5 | 1.1 | 0.3 | 0.8 | 0.1 | 7.00E-05 | 1.77E-06 |
| *Maximum Emissions:* | | | 2.2 | | 17.9 | | 1.8 | | 1.5 | | 1.4 | | 0.9 | | 8.22E-05 | |

**Table D-8**
**Change in PTE for Boiler Emissions**

| Air Pollutant | CO | | NOx | | PM2.5 | | PM10 | | SO2 | | VOC | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr |
| *Pre-project PTE Boiler Emission Limits from PTC P-050301* | | | | | | | | | | | | | | |
| Boiler 1 | 4.60 | - | - | - | - | - | - | - | - | - | 0.30 | 1.3 | 2.40E-04 | 7.32E-04 |
| Boiler 2 | 6.10 | - | - | - | - | - | - | - | - | - | 0.41 | 1.8 | 3.31E-04 | 1.45E-03 |
| Boiler 3 | 1.80 | - | 5.40 | - | 0.30 | - | 0.30 | - | 1.90 | - | 0.21 | 0.9 | 3.51E-04 | 3.28E-04 |
| Boilers 1 and 2 | - | - | 61.90 | - | 5.70 | - | 5.70 | - | 45.30 | - | - | - | - | - |
| Boilers 1, 2, and 3 | - | 46.0 | - | 198.0 | - | 18.3 | - | 18.3 | - | 145.00 | - | - | - | - |
| *Post-project PTE* | | | | | | | | | | | | | | |
| Boiler 3 | 1.80 | 2.2 | 5.40 | 17.9 | 0.30 | 1.4 | 0.30 | 1.5 | 1.90 | 1.8 | 0.21 | 0.9 | 3.19E-04 | 8.22E-05 |
| *Change in Emissions Due to Removal of Boilers 1 and 2* | -10.7 | -43.8 | -61.9 | -180.1 | -5.7 | -16.9 | -5.7 | -16.8 | -45.3 | -143.2 | -0.7 | -3.1 | -6.02E-04 | -2.43E-03 |

Table D-9

Steam Generation in Boilers 1 and 2 - May 1, 2007 through April 30, 2009

| Day | Steam Generated, lbs | | | Fuels Combusted | | | | Heat Supplied, MMBtu | | | | Steam Provided by Fuel Type, lbs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | NG, scf | | #6 Oil, gal | | NG | | #6 Oil | | NG Combustion | | | #6 Oil Combustion | | |
| | Boiler 1 | Boiler 2 | Total | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Combined | Boiler 1 | Boiler 2 | Combined |
| 5/1/2007 | 522,620 | 520,200 | 1,042,820 | 120,450 | 623,360 | 3,989 | 206 | 123 | 636 | 582 | 30 | 5 | 495,681 | 495,686 | 522,615 | 24,519 | 547,134 |
| 5/2/2007 | 665,820 | 837,230 | 1,503,050 | 0 | 1,103,750 | 5,172 | 0 | 0 | 1,126 | 755 | 0 | 0 | 837,230 | 837,230 | 665,820 | 0 | 665,820 |
| 5/3/2007 | 625,340 | 610,440 | 1,235,780 | 0 | 380,130 | 5,343 | 2,681 | 0 | 388 | 780 | 391 | 0 | 296,950 | 296,950 | 625,340 | 313,490 | 938,830 |
| 5/4/2007 | 678,090 | 606,030 | 1,284,120 | 0 | 0 | 5,165 | 4,909 | 0 | 0 | 754 | 717 | 0 | 0 | 0 | 678,090 | 606,030 | 1,284,120 |
| 5/5/2007 | 459,150 | 433,200 | 892,350 | 0 | 28,900 | 3,999 | 1,442 | 0 | 29 | 584 | 211 | 0 | 51,153 | 51,153 | 459,150 | 382,047 | 841,197 |
| 5/6/2007 | 225,060 | 345,240 | 570,300 | 0 | 415,550 | 4,468 | 0 | 0 | 424 | 652 | 0 | 0 | 345,240 | 345,240 | 225,060 | 0 | 225,060 |
| 5/7/2007 | 397,760 | 511,390 | 909,150 | 0 | 277,450 | 5,202 | 2,298 | 0 | 283 | 759 | 336 | 0 | 228,323 | 228,323 | 397,760 | 283,067 | 680,827 |
| 5/8/2007 | 716,480 | 580,210 | 1,296,690 | 0 | 0 | 5,300 | 4,504 | 0 | 0 | 774 | 658 | 0 | 0 | 0 | 716,480 | 580,210 | 1,296,690 |
| 5/9/2007 | 753,710 | 585,010 | 1,338,720 | 0 | 0 | 5,568 | 4,561 | 0 | 0 | 813 | 666 | 0 | 0 | 0 | 753,710 | 585,010 | 1,338,720 |
| 5/10/2007 | 723,520 | 707,940 | 1,431,460 | 0 | 0 | 5,296 | 5,409 | 0 | 0 | 773 | 790 | 0 | 0 | 0 | 723,520 | 707,940 | 1,431,460 |
| 5/11/2007 | 644,190 | 647,600 | 1,291,790 | 133,770 | 327,490 | 3,774 | 2,962 | 136 | 334 | 551 | 432 | 7 | 275,127 | 275,134 | 644,183 | 372,473 | 1,016,656 |
| 5/12/2007 | 509,960 | 532,200 | 1,042,160 | 0 | 684,630 | 3,515 | 0 | 0 | 698 | 513 | 0 | 0 | 532,200 | 532,200 | 509,960 | 0 | 509,960 |
| 5/13/2007 | 478,740 | 474,350 | 953,090 | 0 | 585,900 | 3,237 | 0 | 0 | 598 | 473 | 0 | 0 | 474,350 | 474,350 | 478,740 | 0 | 478,740 |
| 5/14/2007 | 643,700 | 518,530 | 1,162,230 | 0 | 659,370 | 4,621 | 0 | 0 | 673 | 675 | 0 | 0 | 518,530 | 518,530 | 643,700 | 0 | 643,700 |
| 5/15/2007 | 494,210 | 525,010 | 1,019,220 | 196,480 | 658,600 | 2,027 | 0 | 200 | 672 | 296 | 0 | 15 | 525,010 | 525,025 | 494,195 | 0 | 494,195 |
| 5/16/2007 | 677,640 | 613,440 | 1,291,080 | 0 | 781,770 | 4,930 | 0 | 0 | 797 | 720 | 0 | 0 | 613,440 | 613,440 | 677,640 | 0 | 677,640 |
| 5/17/2007 | 688,120 | 462,770 | 1,150,890 | 0 | 570,480 | 4,994 | 0 | 0 | 582 | 729 | 0 | 0 | 462,770 | 462,770 | 688,120 | 0 | 688,120 |
| 5/18/2007 | 584,210 | 433,810 | 1,018,020 | 0 | 525,570 | 4,185 | 0 | 0 | 536 | 611 | 0 | 0 | 433,810 | 433,810 | 584,210 | 0 | 584,210 |
| 5/19/2007 | 564,940 | 439,500 | 1,004,440 | 0 | 531,690 | 4,026 | 0 | 0 | 542 | 588 | 0 | 0 | 439,500 | 439,500 | 564,940 | 0 | 564,940 |
| 5/20/2007 | 659,240 | 510,590 | 1,169,830 | 0 | 648,950 | 4,918 | 0 | 0 | 662 | 718 | 0 | 0 | 510,590 | 510,590 | 659,240 | 0 | 659,240 |
| 5/21/2007 | 729,050 | 621,310 | 1,350,360 | 0 | 805,620 | 5,474 | 0 | 0 | 822 | 799 | 0 | 0 | 621,310 | 621,310 | 729,050 | 0 | 729,050 |
| 5/22/2007 | 619,970 | 724,310 | 1,344,280 | 312,080 | 940,830 | 2,403 | 0 | 318 | 960 | 351 | 0 | 26 | 724,310 | 724,336 | 619,944 | 0 | 619,944 |
| 5/23/2007 | 508,550 | 665,030 | 1,173,580 | 518,750 | 855,050 | 0 | 0 | 529 | 872 | 0 | 0 | 508,550 | 665,030 | 1,173,580 | 0 | 0 | 0 |
| 5/24/2007 | 559,330 | 683,950 | 1,243,280 | 578,520 | 875,710 | 0 | 0 | 590 | 893 | 0 | 0 | 559,330 | 683,950 | 1,243,280 | 0 | 0 | 0 |
| 5/25/2007 | 492,620 | 700,030 | 1,192,650 | 494,790 | 894,210 | 0 | 0 | 505 | 912 | 0 | 0 | 492,620 | 700,030 | 1,192,650 | 0 | 0 | 0 |
| 5/26/2007 | 502,310 | 697,320 | 1,199,630 | 507,270 | 895,080 | 0 | 0 | 517 | 913 | 0 | 0 | 502,310 | 697,320 | 1,199,630 | 0 | 0 | 0 |
| 5/27/2007 | 505,760 | 684,420 | 1,190,180 | 510,700 | 869,640 | 0 | 0 | 521 | 887 | 0 | 0 | 505,760 | 684,420 | 1,190,180 | 0 | 0 | 0 |
| 5/28/2007 | 479,100 | 624,760 | 1,103,860 | 477,460 | 790,820 | 0 | 0 | 487 | 807 | 0 | 0 | 479,100 | 624,760 | 1,103,860 | 0 | 0 | 0 |
| 5/29/2007 | 478,100 | 621,660 | 1,099,760 | 475,960 | 793,090 | 0 | 0 | 485 | 809 | 0 | 0 | 478,100 | 621,660 | 1,099,760 | 0 | 0 | 0 |
| 5/30/2007 | 490,650 | 634,690 | 1,125,340 | 489,340 | 808,540 | 0 | 0 | 499 | 825 | 0 | 0 | 490,650 | 634,690 | 1,125,340 | 0 | 0 | 0 |
| 5/31/2007 | 495,040 | 663,630 | 1,158,670 | 493,520 | 845,460 | 0 | 0 | 503 | 862 | 0 | 0 | 495,040 | 663,630 | 1,158,670 | 0 | 0 | 0 |
| 6/1/2007 | 456,220 | 635,620 | 1,091,840 | 442,430 | 798,050 | 0 | 0 | 451 | 814 | 0 | 0 | 456,220 | 635,620 | 1,091,840 | 0 | 0 | 0 |
| 6/2/2007 | 418,950 | 462,360 | 881,310 | 396,890 | 571,520 | 0 | 0 | 405 | 583 | 0 | 0 | 418,950 | 462,360 | 881,310 | 0 | 0 | 0 |
| 6/3/2007 | 381,430 | 402,400 | 783,830 | 354,180 | 491,890 | 0 | 0 | 361 | 502 | 0 | 0 | 381,430 | 402,400 | 783,830 | 0 | 0 | 0 |
| 6/4/2007 | 160,920 | 470,070 | 630,990 | 147,420 | 587,930 | 0 | 0 | 150 | 600 | 0 | 0 | 160,920 | 470,070 | 630,990 | 0 | 0 | 0 |
| 6/5/2007 | 0 | 595,650 | 595,650 | 0 | 744,000 | 0 | 0 | 0 | 759 | 0 | 0 | 0 | 595,650 | 595,650 | 0 | 0 | 0 |
| 6/6/2007 | 0 | 580,110 | 580,110 | 0 | 725,110 | 0 | 0 | 0 | 740 | 0 | 0 | 0 | 580,110 | 580,110 | 0 | 0 | 0 |
| 6/7/2007 | 0 | 622,540 | 622,540 | 0 | 777,640 | 0 | 0 | 0 | 793 | 0 | 0 | 0 | 622,540 | 622,540 | 0 | 0 | 0 |
| 6/8/2007 | 173,920 | 444,180 | 618,100 | 0 | 543,300 | 1,214 | 0 | 0 | 554 | 177 | 0 | 0 | 444,180 | 444,180 | 173,920 | 0 | 173,920 |
| 6/9/2007 | 452,290 | 369,070 | 821,360 | 0 | 457,330 | 3,051 | 0 | 0 | 466 | 445 | 0 | 0 | 369,070 | 369,070 | 452,290 | 0 | 452,290 |
| 6/10/2007 | 514,620 | 579,540 | 1,094,160 | 0 | 741,280 | 3,656 | 0 | 0 | 756 | 534 | 0 | 0 | 579,540 | 579,540 | 514,620 | 0 | 514,620 |
| 6/11/2007 | 513,670 | 802,650 | 1,316,320 | 0 | 1,039,770 | 3,655 | 0 | 0 | 1,061 | 534 | 0 | 0 | 802,650 | 802,650 | 513,670 | 0 | 513,670 |
| 6/12/2007 | 606,550 | 660,650 | 1,267,200 | 0 | 842,390 | 4,541 | 0 | 0 | 859 | 663 | 0 | 0 | 660,650 | 660,650 | 606,550 | 0 | 606,550 |
| 6/13/2007 | 241,990 | 847,370 | 1,089,360 | 9,520 | 1,089,630 | 1,772 | 0 | 10 | 1,111 | 259 | 0 | 0 | 847,370 | 847,370 | 241,990 | 0 | 241,990 |
| 6/14/2007 | 161,580 | 933,860 | 1,095,440 | 1,080,230 | 1,211,190 | 0 | 0 | 1,102 | 1,235 | 0 | 0 | 161,580 | 933,860 | 1,095,440 | 0 | 0 | 0 |
| 6/15/2007 | 565,040 | 607,620 | 1,172,660 | 607,990 | 777,680 | 0 | 0 | 620 | 793 | 0 | 0 | 565,040 | 607,620 | 1,172,660 | 0 | 0 | 0 |
| 6/16/2007 | 468,860 | 570,410 | 1,039,270 | 489,310 | 727,840 | 0 | 0 | 499 | 742 | 0 | 0 | 468,860 | 570,410 | 1,039,270 | 0 | 0 | 0 |
| 6/17/2007 | 441,350 | 710,760 | 1,152,110 | 460,380 | 916,660 | 0 | 0 | 470 | 935 | 0 | 0 | 441,350 | 710,760 | 1,152,110 | 0 | 0 | 0 |
| 6/18/2007 | 433,320 | 736,570 | 1,169,890 | 447,130 | 954,830 | 0 | 0 | 456 | 974 | 0 | 0 | 433,320 | 736,570 | 1,169,890 | 0 | 0 | 0 |
| 6/19/2007 | 509,940 | 738,920 | 1,248,860 | 545,230 | 961,860 | 0 | 0 | 556 | 981 | 0 | 0 | 509,940 | 738,920 | 1,248,860 | 0 | 0 | 0 |
| 6/20/2007 | 565,340 | 663,810 | 1,229,150 | 613,590 | 858,970 | 0 | 0 | 626 | 876 | 0 | 0 | 565,340 | 663,810 | 1,229,150 | 0 | 0 | 0 |

Table D-9

Steam Generation in Boilers 1 and 2 - May 1, 2007 through April 30, 2009

| Day | Steam Generated, lbs | | | Fuels Combusted | | | | Heat Supplied, MMBtu | | | | Steam Provided by Fuel Type, lbs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | NG, scf | | #6 Oil, gal | | NG | | #6 Oil | | NG Combustion | | | #6 Oil Combustion | | |
| | Boiler 1 | Boiler 2 | Total | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Boiler 1 | Boiler 2 | Combined | Boiler 1 | Boiler 2 | Combined |
| 4/14/2009 | 175,065 | 345,388 | 520,453 | 214,540 | 423,270 | 0 | 0 | 219 | 432 | 0 | 0 | 175,065 | 345,388 | 520,453 | 0 | 0 | 0 |
| 4/15/2009 | 0 | 734,775 | 734,775 | 0 | 900,460 | 0 | 0 | 0 | 918 | 0 | 0 | 0 | 734,775 | 734,775 | 0 | 0 | 0 |
| 4/16/2009 | 74,925 | 493,011 | 567,936 | 91,820 | 604,180 | 0 | 0 | 94 | 616 | 0 | 0 | 74,925 | 493,011 | 567,936 | 0 | 0 | 0 |
| 4/17/2009 | 359,946 | 0 | 359,946 | 441,110 | 0 | 0 | 0 | 450 | 0 | 0 | 0 | 359,946 | 0 | 359,946 | 0 | 0 | 0 |
| 4/18/2009 | 336,306 | 0 | 336,306 | 412,140 | 0 | 0 | 0 | 420 | 0 | 0 | 0 | 336,306 | 0 | 336,306 | 0 | 0 | 0 |
| 4/19/2009 | 353,581 | 0 | 353,581 | 433,310 | 0 | 0 | 0 | 442 | 0 | 0 | 0 | 353,581 | 0 | 353,581 | 0 | 0 | 0 |
| 4/20/2009 | 386,417 | 0 | 386,417 | 473,550 | 0 | 0 | 0 | 483 | 0 | 0 | 0 | 386,417 | 0 | 386,417 | 0 | 0 | 0 |
| 4/21/2009 | 412,659 | 0 | 412,659 | 505,710 | 0 | 0 | 0 | 516 | 0 | 0 | 0 | 412,659 | 0 | 412,659 | 0 | 0 | 0 |
| 4/22/2009 | 395,450 | 18,939 | 414,389 | 484,620 | 23,210 | 0 | 0 | 494 | 24 | 0 | 0 | 395,450 | 18,939 | 414,389 | 0 | 0 | 0 |
| 4/23/2009 | 398,616 | 490,465 | 889,081 | 488,500 | 601,060 | 0 | 0 | 498 | 613 | 0 | 0 | 398,616 | 490,465 | 889,081 | 0 | 0 | 0 |
| 4/24/2009 | 343,536 | 632,694 | 976,230 | 421,000 | 775,360 | 0 | 0 | 429 | 791 | 0 | 0 | 343,536 | 632,694 | 976,230 | 0 | 0 | 0 |
| 4/25/2009 | 264,327 | 588,948 | 853,275 | 323,930 | 721,750 | 0 | 0 | 330 | 736 | 0 | 0 | 264,327 | 588,948 | 853,275 | 0 | 0 | 0 |
| 4/26/2009 | 240,655 | 652,147 | 892,802 | 294,920 | 799,200 | 0 | 0 | 301 | 815 | 0 | 0 | 240,655 | 652,147 | 892,802 | 0 | 0 | 0 |
| 4/27/2009 | 360,125 | 610,033 | 970,159 | 441,330 | 747,590 | 0 | 0 | 450 | 763 | 0 | 0 | 360,125 | 610,033 | 970,159 | 0 | 0 | 0 |
| 4/28/2009 | 248,219 | 519,700 | 767,919 | 304,190 | 656,210 | 0 | 0 | 310 | 669 | 0 | 0 | 248,219 | 519,700 | 767,919 | 0 | 0 | 0 |
| 4/29/2009 | 404,793 | 703,230 | 1,108,023 | 496,070 | 907,720 | 0 | 0 | 506 | 926 | 0 | 0 | 404,793 | 703,230 | 1,108,023 | 0 | 0 | 0 |
| 4/30/2009 | 352,006 | 632,760 | 984,766 | 431,380 | 810,920 | 0 | 0 | 440 | 827 | 0 | 0 | 352,006 | 632,760 | 984,766 | 0 | 0 | 0 |
| *Totals:* | *333,328,298* | *469,356,057* | *802,684,355* | *328,670,801* | *590,132,832* | *225,722* | *44,434* | *335,244* | *601,935* | *32,955* | *6,487* | *302,287,568* | *463,416,864* | *765,704,433* | *31,040,729* | *5,939,193* | *36,979,922* |

**Table D-10**

**Boiler 1 and 2 Emission Factors**

| Fuel | Pollutant | Emission Factor | | |
|---|---|---|---|---|
| | | Value | Units | Basis |
| #6 Oil | CO | 5 | lb/kgal | AP-42, Table 1.3-1 for boilers <100 MMBtuh. |
| | NOx | 55 | lb/kgal | AP-42, Table 1.3-1 for boilers <100 MMBtuh. |
| | Filterable PM10 | 1.17 | lb/kgal | AP-42, Figure 1.3-1 (scrubber curve). PM10 = 0.06*A. A = 1.12(S) + 0.37, where S is wt% S in oil. |
| | Filterable PM2.5 | 1.13 | lb/kgal | AP-42, Figure 1.3-1 (scrubber curve). PM2.5 = 0.058*A. A = 1.12(S) + 0.37, where S is wt% S in oil. |
| | Condensable PM | 1.5 | lb/kgal | AP-42, Table 1.3-2 |
| | PM10 | 2.67 | lb/kgal | Sum of filterable PM10 and condensable PM |
| | Direct PM2.5 | 2.63 | lb/kgal | Sum of filterable PM2.5 and condensable PM |
| | VOC | 0.28 | lb/kgal | AP-42, Table 1.3-3. NMTOC for #6 oil-fired industrial boilers |
| | Pb | 0.0015 | lb/kgal | AP-42, Table 1.3-11 |
| NG | CO | 0.0824 | lb/MMBtu | AP-42, Table 1.4-1. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. |
| | NOx - Boiler 1 | 0.098 | lb/MMBtu | AP-42, Table 1.4-1. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. |
| | NOx - Boiler 2 | 0.055 | lb/MMBtu | See note below. |
| | SO2 | 0.00588 | lb/MMBtu | AP-42, Table 1.4-2. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. |
| | PM10 | 0.00745 | lb/MMBtu | AP-42, Table 1.4-1. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. All PM assumed to lbbe PM10. |
| | PM2.5 | 0.00745 | lb/MMBtu | AP-42, Table 1.4-1. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. All PM assumed to lbbe PM2.5. |
| | VOC | 0.00539 | lb/MMBtu | AP-42, Table 1.4-1. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. |
| | Pb | 4.90E-07 | lb/MMBtu | AP-42, Table 1.4-2. Converted to lb/MMbtu based on 1020 MMBtu/MMscf NG. |

Note:

From Table 6 of April 20, 2005 letter from Bruce Wright, Basic American Foods, to Ken Hanna, Idaho DEQ, regarding "Revised Emission Estimates for Basic American Foods Application for Permit to Construct – Refiring of Boilers 6 and 8 (February 2005)". See attachment included with March 23, 2017 email from Steve Brockett, BAF, to Shawnee Chen, DEQ, "RE: BLACKFOOT FACILITY OF BASIC AMERICAN FOODS - P-2017.0011 PROJ 61851". Note that Boilers 6 and 8 have renumbered to Boilers 2 and 1, respectively.

Table D-11
CEMS SO2 Emissions Data

| Date | Oil Combusted | | SO2 Emissions | |
|---|---|---|---|---|
| | gal | MMBtu | lb/MMBtu | lbs |
| 5/1/2007 | 4195 | 612.47 | 0.0898 | 55.0 |
| 5/2/2007 | 5172 | 755.11 | 0.0553 | 41.7 |
| 5/3/2007 | 8024 | 1171.50 | 0.7865 | 0.0 |
| 5/4/2007 | 10074 | 1470.80 | 0.3581 | 526.7 |
| 5/5/2007 | 5441 | 794.39 | 0.1402 | 111.4 |
| 5/6/2007 | 4468 | 652.33 | 0.0687 | 44.8 |
| 5/7/2007 | 7500 | 1095.00 | 0.2424 | 265.4 |
| 5/8/2007 | 9804 | 1431.38 | 0.2349 | 336.2 |
| 5/9/2007 | 10129 | 1478.83 | 0.2276 | 336.6 |
| 5/10/2007 | 10705 | 1562.93 | 0.1681 | 262.8 |
| 5/11/2007 | 6736 | 983.46 | 0.1738 | 170.9 |
| 5/12/2007 | 3515 | 513.19 | 0.0697 | 35.8 |
| 5/13/2007 | 3237 | 472.60 | 0.0154 | 7.3 |
| 5/14/2007 | 4621 | 674.67 | 0.0188 | 12.7 |
| 5/15/2007 | 2027 | 295.94 | 0.1015 | 30.0 |
| 5/16/2007 | 4930 | 719.78 | 0.0170 | 12.2 |
| 5/17/2007 | 4994 | 729.12 | 0.0207 | 15.1 |
| 5/18/2007 | 4185 | 611.01 | 0.0193 | 11.8 |
| 5/19/2007 | 4026 | 587.80 | 0.0185 | 10.9 |
| 5/20/2007 | 4918 | 718.03 | 0.0313 | 22.5 |
| 5/21/2007 | 5474 | 799.20 | 0.0385 | 30.8 |
| 5/22/2007 | 2403 | 350.84 | 0.0458 | 16.1 |
| 6/8/2007 | 1214 | 177.24 | 0.0190 | 3.4 |
| 6/9/2007 | 3051 | 445.45 | 0.0177 | 7.9 |
| 6/10/2007 | 3656 | 533.78 | 0.0267 | 14.3 |
| 6/11/2007 | 3655 | 533.63 | 0.0277 | 14.8 |
| 6/12/2007 | 4541 | 662.99 | 0.0363 | 24.0 |
| 6/13/2007 | 1772 | 258.71 | 0.4285 | 110.9 |
| 7/5/2007 | 6 | 0.88 | 0.107* | 0.1 |
| 7/6/2007 | 2011 | 293.61 | 0.107* | 31.5 |
| 7/7/2007 | 3908 | 570.57 | 0.107* | 61.3 |
| 7/8/2007 | 4400 | 642.40 | 0.0310 | 19.9 |
| 7/9/2007 | 7999 | 1167.85 | 0.110* | 128.5 |
| 7/10/2007 | 8606 | 1256.48 | 0.110* | 138.3 |
| 7/13/2007 | 1744 | 254.62 | 0.0248 | 6.3 |
| 7/14/2007 | 4092 | 597.43 | 0.0227 | 13.6 |
| 7/15/2007 | 4474 | 653.20 | 0.0297 | 19.4 |
| 7/16/2007 | 6329 | 924.03 | 0.1205 | 111.3 |
| 7/17/2007 | 9083 | 1326.12 | 0.1286 | 170.6 |
| 7/18/2007 | 5794 | 845.92 | 0.0539 | 45.6 |
| 7/19/2007 | 4290 | 626.34 | 0.0310 | 19.4 |
| 7/20/2007 | 5121 | 747.67 | 0.0520 | 38.9 |
| 7/21/2007 | 5209 | 760.51 | 0.0641 | 48.8 |
| 7/22/2007 | 4744 | 692.62 | 0.0256 | 17.7 |
| 7/23/2007 | 4439 | 648.09 | 0.0393 | 25.5 |
| 7/24/2007 | 4402 | 642.69 | 0.0444 | 28.5 |
| 7/25/2007 | 4881 | 712.63 | 0.0415 | 29.6 |
| 7/26/2007 | 5359 | 782.41 | 0.0513 | 40.1 |
| 7/27/2007 | 5374 | 784.60 | 0.0350 | 27.5 |
| 7/28/2007 | 5201 | 759.35 | 0.0327 | 24.8 |
| 7/29/2007 | 4850 | 708.10 | 0.0455 | 32.2 |
| 7/30/2007 | 5472 | 798.91 | 0.0449 | 35.9 |
| 7/31/2007 | 5721 | 835.27 | 0.0458 | 38.3 |

**Table D-11**
**CEMS SO2 Emissions Data**

| Date | Oil Combusted | | SO2 Emissions | |
|---|---|---|---|---|
| | gal | MMBtu | lb/MMBtu | lbs |
| 8/1/2007 | 1863 | 272.00 | 0.0489 | 13.3 |
| 1/20/2009 | 155 | 22.70 | 0.044* | 1.0 |
| 1/21/2009 | 161 | 23.53 | 0.044* | 1.0 |
| | | | *Total, lbs:* | 3700.9 |
| | | | *Maximum Day, lbs:* | 526.7 |

* Data considered invalid. Replaced with average of five preceding valid readings.

**Table D-12a**
**Baseline Actual Emissions for NG Combustion - Boilers 1 and 2**

| Boiler | NG Combustion, MMBtu/yr | Emissions, ton/yr | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | CO | NOx | SO2 | PM10 | PM2.5 | VOC | Pb |
| Boiler 1 | 167,622 | 6.90 | 8.22 | 0.49 | 0.62 | 0.62 | 0.45 | 4.11E-05 |
| Boiler 2 | 300,968 | 12.39 | 8.28 | 0.89 | 1.12 | 1.12 | 0.81 | 7.38E-05 |

**Table D-12b**
**Baseline Actual Emissions for #6 Oil Combustion - Boilers 1 and 2**

| Boiler | #6 Oil Combustion, kgal/yr | Emissions, ton/yr | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | CO | NOx | SO2* | PM10 | PM2.5 | VOC | Pb |
| Boiler 1 | 113 | 0.28 | 3.10 | 0.93 | 0.15 | 0.15 | 0.02 | 8.52E-05 |
| Boiler 2 | 22 | 0.06 | 0.61 | | 0.03 | 0.03 | 0.00 | 1.68E-05 |

* SO2 emissions from CEMS. Data is for combined emissions from Boilers 1 and 2.

**Table D-12c**
**Baseline Actual Emissions for All Fuels - Boilers 1 and 2**

| Baseline Actual Emissions | Emissions, ton/yr | | | | | | |
|---|---|---|---|---|---|---|---|
| | CO | NOx | SO2 | PM10 | PM2.5 | VOC | Pb |
| Boilers 1 and 2 - all fuels | 19.63 | 20.21 | 2.30 | 1.93 | 1.92 | 1.28 | 0.00 |

## Proposed Minor Modification to an Existing Major Facility - Major Modification Test

**Table D13a**

**PROJECTED ACTUAL EMISSIONS or PTE FOR PROJECTED ACTUAL EMISSIONS**

| Emissions Unit | CO | NOx | SO2 + SO3 | PM10 | Direct PM2.5 | VOC | Pb |
|---|---|---|---|---|---|---|---|
| | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr |
| Point Sources | | | | | | | |
| Boiler 2A | **29.6** | **14.6** | **0.2** | **3.0** | **3.0** | **2.2** | **1.96E-04** |
| ***{Note: all quantifiable fugitive emissions, regardless of source category, are required to be included}*** **Fugitive Sources** | | | | | | | |
| no quantifiiable emissions | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.00E+00** |
| Facility Totals | | | | | | | |
| Total, Projected Actual Emissions | **29.6** | **14.6** | **0.2** | **3.0** | **3.0** | **2.2** | **1.96E-04** |

**Table D-13b**

**BASELINE ACTUAL EMISSIONS**

| Emissions Unit | CO | NOx | SO2 + SO3 | PM10 | Direct PM2.5 | VOC | Pb |
|---|---|---|---|---|---|---|---|
| | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr |
| Point Sources | | | | | | | |
| Boiler 2A | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.00E+00** |
| Boilers 1 and 2 - all fuels | **19.6** | **20.2** | **2.3** | **1.9** | **1.9** | **1.3** | **2.17E-04** |
| ***{Note: all quantifiable fugitive emissions, regardless of source category, are required to be included }*** **Fugitive Sources** | | | | | | | |
| no quantifiiable emissions | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.00E+00** |
| Facility Totals | | | | | | | |
| Total, Baseline Actual Emissions | **19.6** | **20.2** | **2.3** | **1.9** | **1.9** | **1.3** | **2.17E-04** |

**Table D-13c**

**COMPARISON OF THE PROJECT EMISSIONS INCREASE TO THE SIGNIFICANT EMISSIONS RATE THRESHOLDS**

| Emissions Unit | CO | NOx | SO2 + SO3 | PM10 | Direct PM2.5 | VOC | Pb |
|---|---|---|---|---|---|---|---|
| | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr | T/yr |
| Project Emissions Increase | **29.6** | **14.6** | **0.2** | **3.0** | **3.0** | **2.2** | **1.96E-04** |
| PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)* | **100.0** | **40.0** | **40.0** | **15.0** | **10.0** | **40.0** | **6.00E-01** |
| Does the Project Emissions Increase Exceed the Significant Emission Rate Threshold? | **No** | **No** | **No** | **No** | **No** | **No** | **No** |

**Table D-14**
**Pre- and Post Project Facility Wide PTE**
**Preproject Facility-Wide PTE (without facility-wide enforceable emission limits)**

| **Air Pollutant** | **CO** | | **NOx** | | **PM2.5** | | **PM10** | | **SO2** | | **VOC** | | **Pb** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr |
| Business Unit | | | | | | | | | | | | | | |
| BAF | 65.09 | 262.36 | 84.82 | 258.08 | 35.98 | 96.25 | 41.41 | 110.84 | 52.71 | 162.00 | 2.31 | 9.19 | 1.05E-03 | 3.06E-03 |
| BAPCI | 17.84 | 78.12 | 18.62 | 81.54 | 28.95 | 126.81 | 29.66 | 129.89 | 0.13 | 0.56 | 1.17 | 5.12 | 1.06E-04 | 4.65E-04 |
| *Total* | 82.93 | 340.49 | 103.44 | 339.62 | 64.93 | 223.05 | 71.07 | 240.73 | 52.84 | 162.56 | 3.48 | 14.31 | 1.15E-03 | 3.53E-03 |

**Changes in PTE**

| **Air Pollutant** | **CO** | | **NOx** | | **PM2.5** | | **PM10** | | **SO2** | | **VOC** | | **Pb** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr |
| **BAF New Production Line** | | | | | | | | | | | | | | |
| New Equipment | 1.28 | 5.59 | 0.37 | 1.61 | 0.35 | 1.51 | 0.40 | 1.73 | 0.03 | 0.15 | 0.08 | 0.37 | 7.60E-06 | 3.33E-05 |
| Removed equipment | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00E+00 | 0.00E+00 |
| *Δ PTE, new production line* | 1.28 | 5.59 | 0.37 | 1.61 | 0.35 | 1.51 | 0.40 | 1.73 | 0.03 | 0.15 | 0.08 | 0.37 | 7.60E-06 | 3.33E-05 |
| **BAF Boiler 2A** | | | | | | | | | | | | | | |
| New Equipment | 6.77 | 29.64 | 3.34 | 14.61 | 0.68 | 2.99 | 0.68 | 2.99 | 0.05 | 0.24 | 0.49 | 2.16 | 4.49E-05 | 1.96E-04 |
| Removed equipment | -10.70 | -43.84 | -61.90 | -180.07 | -5.70 | -16.93 | -5.70 | -16.77 | -45.30 | -143.25 | -0.71 | -3.11 | -6.02E-04 | -2.43E-03 |
| *Δ PTE, Boiler 2A project* | -3.93 | -14.20 | -58.56 | -165.47 | -5.02 | -13.94 | -5.02 | -13.78 | -45.25 | -143.01 | -0.21 | -0.95 | -5.58E-04 | -2.23E-03 |

**Post-project Facility-Wide PTE**

| **Air Pollutant** | **CO** | | **NOx** | | **PM2.5** | | **PM10** | | **SO2** | | **VOC** | | **Pb** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr | lb/hr | ton/yr |
| Revised Facility-Wide PTE | 80.3 | 332 | 45.2 | 176 | 60.3 | 211 | 66.4 | 229 | 7.6 | 20 | 3.3 | 14 | 6.04E-04 | 1.33E-03 |
| Requested Facility-Wide Emission Lim | - | 249 | - | - | - | - | - | - | - | - | - | - | - | - |
| *Facility-Wide PTE with Requested Emission Limits* | 80.3 | 249 | 45.2 | 176 | 60.3 | 211 | 66.4 | 229 | 7.6 | 20 | 3.3 | 14 | 6.04E-04 | 1.33E-03 |

**Table D-15**

**HAP and TAP Emission Factors for #2 Oil Combustion**

| Pollutant | CAA HAP? | ID TAP (C, NC, or No)? | Emission Factor lb/1000 gal | Emission Factor lb/MMBtu* | Basis |
|---|---|---|---|---|---|
| PAH | No | C | 0.0033 | 2.54E-05 | AP-42 Table 1.3-8. All POM counted as PAH |
| POM | Yes | C | 3.30E-03 | 2.54E-05 | AP-42 Table 1.3-8. No PAH breakdown provided. All POM counted as Idaho POM. |
| formaldehyde | Yes | C | 4.80E-02 | 3.69E-04 | AP-42 Table 1.3-8 |
| arsenic | Yes | C | | 4.00E-06 | AP-42 Table 1.3-10 |
| beryllium | Yes | C | | 3.00E-06 | AP-42 Table 1.3-10 |
| cadmium | Yes | C | | 3.00E-06 | AP-42 Table 1.3-10 |
| chromium | Yes | NC | | 3.00E-06 | AP-42 Table 1.3-10 |
| chromium (VI) | No | C | | 1.50E-07 | 5% of chromium assumed to be Cr+6. See "AB 2588 Combustion Emission Factors", Ventura County APCD, May 17, 2001. |
| copper | Yes | NC | | 6.00E-06 | AP-42 Table 1.3-10 |
| lead | Yes | No | | 9.00E-06 | AP-42 Table 1.3-10 |
| manganese | Yes | NC | | 6.00E-06 | AP-42 Table 1.3-10 |
| mercury | Yes | No | | 3.00E-06 | AP-42 Table 1.3-10 |
| nickel | Yes | C | | 3.00E-06 | AP-42 Table 1.3-10 |
| selenium | Yes | NC | | 1.50E-05 | AP-42 Table 1.3-10 |
| zinc | No | NC | 5.48E-04 | 4.22E-06 | AP-42 Table 1.3-10 |
| nitrous oxide | No | NC | 1.10E-01 | 8.46E-04 | AP-42 Table 1.3-8 |
| | | | *HAP summation:* | *4.24E-04* | |
| | | | *Largest HAP (formaldehyde* | *3.69E-04* | |

* Baed on 0.13 MMBtu/gallon

† AB2588 emission factor when AP-42 not available. AB2588 emission factors from Table B-2, "Supplemental Instructions, Reporting Procedures for AB2588 Facilities for Reporting their Quadrennial Air Toxics Emissions Inventory", South Coast Air Quality Management District, December 2016.

‡ AP-42. Tables 1.3-8 and 1.3-10.

**TABLE D-16**
**POST PROJECT PTE for HAPs**

| Fuel Combustion Activity | Maximimum Combustion | | Total HAP Emissions | | | Maximum Individual HAP Emissions | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Amount | Units | Emission Factor | Units | tons/yr | Maximum HAP | Emission Factor | Units | tons/yr |
| Total Installed NG Firing Capacity, annual average | 604.80 | MMBtuh | 1.85E-03 | lb/MMBtu | 4.90 | Hexane | 1.76E-03 | lb/MMBtu | 4.67 |
| Maximum Annual Permitted #2 Oil Combustion - Boiler 3 | 51,106 | MMBtu/yr | 3.69E-04 | lb/MMBtu | 0.01 | Formaldehyde | 3.69E-04 | lb/MMBtu | 0.01 |
| | | *HAP PTE Suumation:* | | | *4.91* | | *Hexane PTE Suumation:* | | *4.67* |

Notes: This is a worst case calculation based on maximum firing rates for each fuel. Boiler 3 cannot combust both NG, and No. 2 oil at maximum annual

Table D-17

HAP UNCONTROLLED PTE AND PTE COMPARED TO THE MAJOR SOURCE THRESHOLDS

| HAP Pollutant | Potential to Emit, ton/yr | | Major Source Threshold Test | |
|---|---|---|---|---|
| | Uncontrolled | Controlled | Threshold, tpy | Exceeds Threshold (Yes/No)? |
| sum of all HAPs | 4.91 | 4.91 | 25 | No |
| Hexane* | 4.67 | 4.67 | 10 | No |

*Largest individual HAP

**Table D-18**
**Comparison of Project Emissions with Level I Modeling Thresholds**

| Pollutant | Level I Threshold | Emission Rate | % of Threshold |
|---|---|---|---|
| CO | 15 lb/hr | 6.77 lb/hr | 45% |
| NOx | 0.20 lb/hr | 3.34 lb/hr | 1668% |
| | 1.2 ton/yr | 14.6 ton/yr | 1217% |
| SO2 | 0.21 lb/hr | 0.05 lb/hr | 26% |
| | 1.2 ton/yr | 0.2 ton/yr | 20% |
| PM10 | 0.22 lb/hr | 0.68 lb/hr | 310% |
| PM2.5 | 0.054 lb/hr | 0.68 lb/hr | 1263% |
| | 0.35 ton/yr | 3.0 ton/yr | 853% |
| Pb | 14 lb/month | 3.3E-02 lb/month | 0% |

Table D-19

Change in Actual Emissions from Removal of Boilers 1 and 2

| Pollutant | Boiler 1-2, #6 Oil Firing | | | Boiler 1 - NG Firing | | | Boiler 2 - NG Firing | | |
|---|---|---|---|---|---|---|---|---|---|
| | Emission Factor, lb/kgal | Emissions, lb/hr | | Emission Factor, lb/MMBtu | Emissions, lb/hr | | Emission Factor, lb/MMBtu | Emissions, lb/hr | |
| | | Max Day†: 446.04 gal/hr | Annual average: -135.1 kgal/yr | | Max Day†: 0.00 MMBtu/hr | Annual average: 167,622 MMBtu/yr | | Max Day†: 0.00 MMBtu/hr | Annual average: 300,968 MMBtu/yr |
| CO | 5.000 | -2.23 | -0.08 | 0.082 | 0 | -1.58 | 0.082 | 0 | -2.83 |
| NOx | 55.000 | -24.53 | -0.85 | 0.098 | 0 | -1.88 | 0.055 | 0 | -1.89 |
| SO2 + SO3 | * | -10.95 | -0.21 | 0.006 | 0 | -0.11 | 0.006 | 0 | -0.20 |
| PM10 | 2.667 | -1.19 | -0.04 | 0.007 | 0 | -0.14 | 0.007 | 0 | -0.26 |
| Direct PM2.5 | 2.628 | -1.17 | -0.04 | 0.007 | 0 | -0.14 | 0.007 | 0 | -0.26 |
| VOC | 0.280 | -0.12 | 0.00 | 0.005 | 0 | -0.10 | 0.005 | 0 | -0.19 |
| Pb | 1.51E-03 | -6.74E-04 | -2.33E-05 | 4.90E-07 | 0 | -9.38E-06 | 4.90E-07 | 0 | -1.68E-05 |

* SO2 emissions determined from CEMS output. See Table D-11

† May 10, 2007 selected as the day during the baseline period for maximum day emissions.

Table D-20a
Proposed Emissions from New Equipment

| Emissions Unit | Stack or Emissions Point ID | $PM_{10}$ | $PM_{2.5}$ | | $NO_x$ | |
|---|---|---|---|---|---|---|
| | | lb/hr | lb/hr | lb/hr | lb/hr | lb/hr |
| | | 24-hr Avg. | 24-hr Avg. | Annual Avg. | Max. | Annual Avg. |
| **Point Sources** | | | | | | |
| **Boiler 2A** | Blr2A | 0.68 | 0.68 | 0.68 | 3.34 | 3.34 |
| **Fugitive Sources** | | | | | | |
| **NA** | - | - | - | - | - | - |

Table D-20b
Actual Emissions from Retired Equipment

| Emissions Unit | Stack or Emissions Point ID | $PM_{10}$ | $PM_{2.5}$ | | $NO_x$ | |
|---|---|---|---|---|---|---|
| | | lb/hr | lb/hr | lb/hr | lb/hr | lb/hr |
| | | 24-hr Avg. | 24-hr Avg. | Annual Avg. | Max. | Annual Avg. |
| **Point Sources** | | | | | | |
| **Boiler 1 - NG fired** | BLR1_NG | 0.00 | 0.00 | -0.14 | 0.00 | -1.88 |
| **Boiler 2 - NG fired** | BLR2_NG | 0.00 | 0.00 | -0.26 | 0.00 | -1.89 |
| **Boilers 1 and 2 - #6 Oil fired** | BL1_2_OIL6 | -1.19 | -1.17 | -0.04 | -24.53 | -0.85 |
| **Fugitive Sources** | | | | | | |
| **NA** | - | - | - | - | - | - |

**Table D-21**
**Results of Significant Impact Analysis**

| Pollutant | Averaging Period | Maximum Modeled Concentration, µg/m$^3$ | Significant Contribution Level, µg/m$^3$ | Impact Percentage of Significant Contribution Level | Cumulative NAAQS Analysis Required |
|---|---|---|---|---|---|
| $PM_{2.5}$ | 24-hour | 0.0000 | 1.2 | 0.00% | No |
| | Annual | 0.0038 | 0.3 | 1.27% | No |
| $PM_{10}$ | 24-hour | 0.0000 | 5 | 0.00% | No |
| $NO_2$[d] | 1-hour | 0.0011 | 7.5 | 0.01% | No |
| | Annual | 0.0000 | 1 | 0.00% | No |

# APPENDIX B – EPA GUIDANCE

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON. D.C. 20460

APR 1 1981

OFFICE OF
ENFORCEMENT

MEMORANDUM

SUBJECT: PSD Questions

FROM: Director
Division of Stationary Source Enforcement

TO: Merrill S. Hohman, Director
Air & Hazardous Materials Division, Region I

This is to respond to your memo of February 26, 1901 in which you requested answers to five questions that were raised by industry representatives concerning PSD. I would like to respond to your questions in the order in which they were raised.

(1) The answer to this question is found in section 52.21 (b)(3)(i) of the August 7, 1980 amendments to the PSD regulations. In order for a decrease in emissions to be considered contemporaneous, the actual decrease itself must take place within five years of the particular physical change or change in method of operation at a stationary source. The decrease must be enforceable in order to be creditable; however, enforceability is a requirement distinct from the five year contemporaneous time frame of the actual emissions decrease.

(2) In order to determine if PSD review is applicable for a modification, it is necessary to look at the source status (major vs. non- major) before and after the proposed modification. If the existing source is of major status for one pollutant but the results of the modification will bring the source below the major source threshold for that pollutant, PSD review will not be required. In order for PSD review to be applicable for the case in question, the source must either retain its major status for SO2 or propose increases that would make the source major for TSP after the modification. Any contemporaneous creditable increases or decreases in emissions should be included when determining the emission results of the proposed modification.

(3) PSD review, or exemptions to PSD review are based on preconstruction information. A major source which qualifies as a non-profit health institution may receive an exemption from PSD review. The effect of a change in the source's non-profit status upon its exemption would depend on any conditions of the exemption or factors concerning the change in status. This office would like to reserve judgement on your question until more specific information on the source in

question is available.

(4) The following definition of "municipal solid waste," which is found in 40 CFR 60.51(b) should be used when determining a possible exemption under 40 CFR 52.21(b) (2).

> "Solid Waste" means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

This definition is used to maintain consistency between the PSD and NSPS programs. The policy of using NSPS definitions (where appropriate) for PSD and NSR is supported by language in the PSD workshop manual and in an October 24, 1980 memo from OAQPS to the Regional Offices (copy attached).

(5) The definition of "steam generating unit" given in 40 CFR 60.41 a should be used when determining an exemption under 40 CFR 52.21 (b)(2)(iii)(d). As you mentioned in your memo, the application of the aforementioned exemption was more narrowly defined between proposal and promulgation of the PSD amendments. The proposed rule exempted from modification any use of RDF generated from municipal solid waste. The promulgated rules exempted the use of RDF only at steam generating units. The language in the August 7, 1980 preamble and the purpose of the exemption itself, however, supports the use of the broader definition of "steam generating unit."

If you have any questions regarding this response, please contact Janet Littlejohn of my staff at 755-2564.

Edward E. Reich

Attachment

cc: Mike Trutna (OAQPS)
Peter Wyckoff (OGC)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

DATE: February 26, 1981

SUBJECT: PSD Questions

FROM: Merrill S. Hohman, Director
Air & Hazardous Materials Division

TO: Edward E. Reich, Director
Division of Stationary Source Enforcement
Washington, DC

Subsequent to our recent PSD workshop, representatives of the attending industries presented us with some interesting questions. I am hopeful that you can assist us in answering the following questions. Assume all sources are in PSD areas for all pollutants.

Question 1: A source shuts down an old boiler in 1976. Several years after the shutdown, the source decides to build a new boiler and commence construction on it in 1983. (Therefore, the emissions reduction from the old facility would not normally be considered contemporaneous because it occurred beyond the five year period before the new source construction.) However, the old boiler shutdown was not federally enforceable until the source consented to a permit condition in 1979.Question: Would the reduction from the shutdown be considered contemporaneous?

Question 2: An existing source is considered major for SO2 emissions only. (It has the potential to emit SO2 at a level that is slightly in excess of the 250 tons per year applicability level.) The source plans a new boiler modification that increases only TSP above the "de minimus" levels.
Normally, this would bring TSP under a PSD review. However, after the modification is completed, there will be enough contemporaneous reductions to bring the SO2 levels below 250 tons per year; therefore, making the source, as modified, a minor source. Question: is the source still considered a major source after the modification and subject to a PSD review for TSP, or would it be considered a minor source and not subject to PSD?

Question 3: A source applies to the Governor and requests an exemption from PSD because they are a nonprofit health institution. Assume the request is approved and EPA concurs.

> Scenario A: After the source commences construction, but before it starts operation,ownership changes to an organization that cannot be considered "non-profit" and would not operate the source in a "non-profit way". Question: Is Region I correct in assuming that the source being operated by the new owners would be subject to a PSD review?
>
> ScenarioB: Source is built and commences operation. Ownership changes to the organization not considered non-profit after the source is operating. Question: Would the new owners be required to retrofit BACT and be subject to other PSD requirements because they no longer qualify for the "non-profit" exemption, or would they be exempt from PSD because there is only a change in ownership (and no increase in emissions)?

Question 4: Is there a definition for municipal solid waste as that term is used under the exemption at 40 CFR 52.21(b)(2)(iii)(d)? Would construction site waste that consists mostly of wood, with some nails and bolts, bits of concrete and gravel, steel strapping, wire, shingles, etc., be considered municipal solid waste? Note: Such waste is currently being landfilled at a municipal dump.

Question 5: Under the same exemption indicated in Question 4, the term "steam generating unit" is used. On page 52704 of the August 7, 1980 revisions, the preamble states that only the switch to RDF at a "steam generating unit" is exempt. It goes on to explain that the term shall have the same meaning for the purposes of PSD as it does for the purposes of the new NSPS for certain electric utility "steam generating units". Under 40 CFR 60.41a, there is a definition for "steam generating unit" and a definition for "electric utility steam generating unit". Question: Which definition is applicable? Since the exemption may either apply to virtually all boilers, under one definition or only those that contribute to the generation of electricity for sale, under the other definition the distinction is important.

Since these are questions that involve real case situations, we would appreciate it greatly if you could respond to these questions by March 13, 1981.

Please contact John Courcier of my staff if you should have any questions. He can be reached at (FTS) 223-4448.

cc: Janet Littlejohn, DSSE

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

REPLY TO THE ATTENTION OF
AR-18J

DEC 0 7 2006

Nisha Sizemore, Chief
Permits Branch
Office of Air Quality
Indiana Department of
Environmental Management
100 North Senate Avenue
Indianapolis, Indiana 46204

Re: General Shale Brick, Inc.

Dear Ms. Sizemore:

On August 14,2006, I sent you a letter expressing the Environmental Protection Agency's (EPA) concerns with the General Shale Brick, Inc. Significant Source/Permit Modification (Permit nos. 109-22584-00002 and 109-22865-00002). More specifically, I suggested that issuance of the proposed permit could constitute circumvention of the non-attainment new source review (NSR) and Prevention of Significant Deterioration (PSD) permitting requirements, in violation of the Clean Air Act and applicable requirements.

Subsequently, we examined additional materials related to General Shale's proposal. We also reviewed additional EPA policy documents. We found that while EPA has issued guidance on circumvention, as cited in our August 14,2006 letter, this guidance does not squarely address the particular facts of this case. In the absence of more definitive EPA guidance on this issue, we have determined that Indiana reasonably exercised its discretion as a NSR/PSD permitting authority to issue the Title V and construction permits as it did in this situation. It is our understanding that General Shale plans to install sulfur dioxide control equipment to comply with the applicable MACT standards at 40 CFR Part 63, Subpart JJJJJ, which will reduce sulfur dioxide emissions below the major source threshold for this source, that it intends to continue to comply with all emission and operational limits on its original brick manufacturing lines, and that historically it has not operated its brick manufacturing facility to emit major source levels of nitrogen oxides.

EPA's determination that Indiana exercised reasonable discretion is based on the narrow, case-specific facts and unique circumstances present in this situation. In addition, given the case-specific nature of such determinations, we encourage you and your staff to consult with us when making future decisions in this regulatory area.

For future permits, we recommend that Indiana include appropriate testing requirements consistent with EPA guidance to ensure continuing compliance with relevant emission limits. Finally, it should be noted that should General Shale exceed its synthetic minor limits in the future,-full review of the permitting requirements for NSR and PSD for the new brick line could be required.

If you have any further questions regarding this matter, please feel free to call me at (312) 886-4447.

Sincerely yours,

Pamela Blakley

Pamela Blakley, Chief
Air Permits Section

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 2771 1

AUG 1 0 **2001**

Mr. Henry V. Nickel
Hunton & Williams
1900 K Street, N.W.
Washington, DC 20006

Dear Mr. Nickel:

This letter responds to your fax dated April 16, 200 1, requesting the U.S. Environmental Protection Agency's (EPA) opinion on whether the Maricopa County Environmental Services Department (MCESD) had correctly interpreted and applied EPA's nonattainment NSR rules and applicable guidance in determining that the proposed Kyrene Expansion Project (KEP) at the Kyrene Generating Station, located in Tempe, Arizona, (Permit No. V95-009) was subject to nonattainment New Source Review (NSR) requirements (including offsets) for PM-10. Based on the review of the information we have before us, including the information presented in the briefing document submitted with your fax, EPA believes that the MCESD could have concluded that the KEP was not subject to nonattainment NSR requirements for PM- 10, as long as the permit included certain safeguards described below.

As you describe in your briefing document, the existing Kyrene facility consists of two boilers (constructed in the 1950's) and three gas turbines (constructed in the 1970's) with a total generating capacity of approximately 250 M Although the facility has historically operated as a peaking plant, the facility is permitted for continuous operation. Hence, while the actual baseline emissions (for the last 2 years) of PM- 10 have been less than 20 tpy, the existing Kyrene facility is considered a major facility for PM-10 since the PTE = 1044 tpy.

The proposed expansion consists of adding a new 250 MW combined cycle unit to the facility with a proposed increase of 63.3 tpy for PM-10. At an existing major facility, such an increase would result in a major modification triggering NSR. In fact, you indicate that the initial application for the KEP was submitted as an NSR application for PM- IO and VOC. Subsequently, to avoid NSR requirements, the applicant Salt River Project (SRP) proposed to take an emission limit of 68.5 tpy (< 70 tpy major source threshold) for PM- 10, such that the entire source would become minor after the modification. Under these circumstances, MCESD determined that the KEP would be subject to NSR and added that to avoid NSR, SRP should have accepted a federally enforceable limit on PM-10 emissions to become a minor source at least 2 years prior to applying for the KEP. While MCESD would have been justified using that rationale if the source continued to be a major source after the modification, in this case since the source would be a minor source, EPA believes that MCESD could have concluded that KEP would not be subject to NSR. An EPA memo dated April 1, 1981, from Edward Reich to Meril Hohman addresses a similar question under the PSD program. This memo states "...(i)f the existing source is of major status for one pollutant but the results of the modification will bring the source below the major source threshold for that pollutant, then PSD review will not be required." The EPA believes that this same reasoning also applies to nonattainment NSR.

Based on our review of the facts, including those presented in your briefing document and appropriate EPA guidance, EPA believes that the MCESD could have concluded that the KEP would not be subject to the nonattainment NSR requirements for PM- I 0, as long as the permit included the following safeguards. First, to ensure that the proposed limit of 68.5 tpy for the entire source is practically enforceable, MCESD would also have to require short-term limitations on the hours of operation or fuel usage with appropriate monitoring requirements.
We anticipate that MCESD would work with EPA Region 9 to develop these permit conditions. Secondly, since the source would become minor while proposing an otherwise major modification, EPA believes that the permit would have to include a federally enforceable condition stating that any relaxation of the 68.5 tpy limit would trigger the provisions under 40 CFR 51.166(r)(2). Finally, it is important to note that while the source would become minor for PM- 10 after the proposed modification, it will continue to be a major source for NOx and CO.

We appreciate this opportunity to be of service and trust that this information is helpful to you. If you have any questions regarding this determination, please contact Karen Blanchard or Raj Rao at (919) 541-5319.

Sincerely,

/S/ Robert G. Kellam for

William T. Harnett
Acting Director
Information Transfer and Program
Integration Division

# APPENDIX C – AMBIENT AIR QUALITY IMPACT ANALYSES

*MEMORANDUM*

**DATE:** August 21, 2017

**TO:** Shawnee Chen, P. E., Permit Writer, Air Program

**FROM:** Darrin Mehr, Analyst, Air Program

**PROJECT:** P-2017.0031 PROJ 61894 – Permit to Construct (PTC) Application for Basic American Foods (BAF) for the Replacement of Two Existing Boilers with One New Boiler for the Facility in Blackfoot, Idaho.

**SUBJECT:** Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs)

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## 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 |
| ARM | Ambient Ratio Method |
| BAF | Basic American Foods |
| BPIP | Building Profile Input Program |
| BRC | Below Regulatory Concern |
| Btu/hr | British Thermal Units per hour |
| CFR | Code of Federal Regulations |
| CMAQ | Community Multi-Scale Air Quality Modeling System |
| CO | Carbon Monoxide |
| Coal Creek | Coal Creek Environmental Associates, LLC (BAF's permitting and modeling consultant) |
| DEQ | Idaho Department of Environmental Quality |
| EL | Emissions Screening Level of a TAP |
| EPA | United States Environmental Protection Agency |
| fps | Feet per second |
| GEP | Good Engineering Practice |
| hr | Hours |
| Idaho Air Rules | Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01 |
| INL | Idaho National Laboratory |
| ISCST3 | Industrial Source Complex Short Term 3 dispersion model |
| K | Kelvin |
| m | Meters |
| m/s | Meters per second |
| MMBtu | Million British Thermal Units |
| NAAQS | National Ambient Air Quality Standards |
| NED | National Elevation Dataset |
| NO | Nitrogen Oxide |
| $NO_2$ | Nitrogen Dioxide |
| $NO_x$ | Oxides of Nitrogen |
| NEI | National Emissions Inventory |
| 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 Rise Model Enhancement |

| | |
|---|---|
| PTC | Permit to Construct |
| PTE | Potential to Emit |
| SIL | Significant Impact Level |
| $SO_2$ | Sulfur Dioxide |
| TAP | Toxic Air Pollutant |
| tons/year | Ton(s) per year |
| T/yr | Tons per year |
| ULSD | Ultra Low Sulfur Diesel |
| USGS | United States Geological Survey |
| UTM | Universal Transverse Mercator |
| VCU | Vapor Control Unit |
| VOCs | Volatile Organic Compounds |
| °F | Degrees Fahrenheit |
| $\mu g/m^3$ | Micrograms per cubic meter of air |

## 1.0 Summary

### *1.1 General Project Summary*

On May 26, 2017, Basic American Foods (BAF) submitted an application for a 15-day pre-permit construction approval Permit to Construct (PTC) modification to allow the installation of a single boiler to replace two existing boilers at the facility located in Blackfoot, Idaho.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the project would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02 and 203.03 [Idaho Air Rules Section 203.02 and 203.03]). Coal Creek, BAF's permitting and modeling consultant, submitted analyses and applicable information and data to enable DEQ to evaluate potential impacts to ambient air.

Coal Creek performed project-specific air quality impact analyses to demonstrate compliance with air quality standards for the proposed project. The project consisted of a PTC modification for the following:

- Existing Boiler 1 and existing Boiler 2 are not capable of reliable operation and are to be disabled and removed from service. Boilers 1 and 2 are capable of being fired on three fuel types and each fuel type has a unique heat input capacity:

  Boiler 1: Natural gas – 55.2 MMBtu/hr
  #2 Distillate fuel oil – 34.8 MMBtu/hr
  #6 Residual fuel oil – 34.8 MMBtu/hr

  Boiler 2: Natural gas – 73.5 MMBtu/hr
  #2 Distillate fuel oil – 71.0 MMBtu/hr
  #6 Residual fuel oil – 58.6 MMBtu/hr

- Proposed Boiler 2A will be fired exclusively on natural gas and will have a rated heat input capacity of 91.5 MMBtu/hr, and replaces Boilers 1 and 2 in the facility's high pressure steam header that supplied steam to the facility's process units.

The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the pollutant dispersion modeling analyses used to demonstrate that the estimated emissions associated with operation of the facility as modified will not cause or significantly contribute to a violation of the applicable air quality standards. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. This modeling review also did not evaluate the accuracy of emissions estimates. Evaluation of emissions estimates was the responsibility of the permit writer and is addressed in the main body of the DEQ Statement of Basis.

The submitted air quality impact analyses: 1) utilized appropriate methods and models according to established DEQ/EPA rules, policies, guidance, and procedures; 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 predicted pollutant concentrations from emissions associated with the facility as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from applicable emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable National Ambient Air Quality Standards (NAAQS) at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project do not result in increased emissions and modeling was not required to demonstrate compliance with any TAPs increments. Table 1 presents key assumptions and results to be considered in the development of the permit.

**Table 1. KEY CONDITIONS USED IN MODELING ANALYSES**

| Criteria/Assumption/Result | Explanation/Consideration |
|---|---|
| **Existing Boilers 1 and 2**<br>Boilers 1 and 2 will be disabled with the fuel supply lines interrupted for natural gas, distillate fuel oil #2, and residual fuel oil #6. Potential to emit for these two sources will be 0.0 lb/hr and zero ton/yr. | Ambient impacts for the new Boiler 2A were offset by the effects of removal of both Boilers 1 and 2, with the project's ambient impacts kept below significant contribution levels.<br><br>The air impact analyses are only representative of operations if the existing boilers are not in operation. |
| **Proposed Boiler 2A**<br>Boiler 2A will be fired exclusively on natural gas. Emissions will be uncontrolled.<br><br>This boiler will exhaust to the existing 100 feet tall stack that previously served Boilers 1 and 2 for oil combustion. | The boiler will not be equipped with any backup fuel capabilities.<br><br>The existing wet scrubber emission control system will be removed. Ambient impacts were determined using a release height of 100 feet above grade and an exit diameter of 3.5 feet.<br><br>Compliance with NAAQS and TAPs increments has not been demonstrated for use of alternate fuels or exhaust of emissions from an alternate stack. |

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department, using DEQ/EPA established guidance, policies, and procedures, that operation of the proposed facility or 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.

### 1.2 *Summary of Submittals and Actions*

May 8, 2017: Coal Creek submitted a modeling protocol and initial emissions inventory spreadsheet to DEQ, on behalf of BAF, via email.

May 22, 2017: DEQ issued a modeling protocol approval letter with comments.

May 26, 2017: DEQ received the application for the 15-Day Pre-Permit PTC.

June 8, 2017: DEQ issued approval for 15-Day Pre-Permit construction for Boiler 2A.

June 21, 2017: BAF submitted notice that the annual CO emissions limit will be reduced to 195 T/yr from the initial requested limit of 249 T/yr. Modeling applicability was not affected.

June 23, 2017: DEQ declared the application complete.

## 2.0 Background Information

### 2.1 Permit Requirements for Permits to Construct

PTCs are issued to authorize the construction of a new source or modification of an existing source or permit. Idaho Air Rules Section 203.02 requires that emissions from the new source or modification not cause or significantly contribute to a violation of an air quality standard, and Idaho Air Rules Section 203.03 requires that emissions from a new source or modification comply with applicable toxic air pollutant (TAP) increments of Idaho Air Rules Sections 585 and 586.

### 2.2 Project Location and Area Classification

The facility is located in Blackfoot, Idaho, in Bingham County. 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 ($PM_{2.5}$).

### 2.3 Modeling Applicability for Criteria Pollutants

#### *2.3.1 Below Regulatory Concern and DEQ Modeling Guideline Level I and II Thresholds*

Idaho Air Rules Section 203.02 state that a PTC cannot be issued unless the application demonstrates to the satisfaction of DEQ that the new source or modification will not cause or significantly contribute to a NAAQS violation. Atmospheric dispersion modeling is used to evaluate the potential impact of a proposed project to ambient air and demonstrate NAAQS compliance. However, if the emissions associated with a project are very small, project-specific modeling analyses may not be necessary.

If project-wide potential to emit (PTE) values for criteria pollutants would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more criteria pollutants exceeding the BRC threshold of 10% of emissions defined by Idaho Air Rules as significant, then an air impact analysis may not be required for those pollutants. DEQ's regulatory interpretation policy[1] of exemption provisions of Idaho Air Rules Section 221 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." The interpretation policy also states that the exemption criteria of uncontrolled 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. This permitting project cannot qualify for a BRC exemption from Idaho Air Rules Section 203.02 because there are existing permit conditions that require changes.

Site-specific air impact analyses may not be required for a project, even when the project cannot use the BRC exemption from the NAAQS demonstration requirements. If the emissions increases associated with a project are below modeling applicability thresholds established in the *Idaho Air Modeling Guideline* ("State of Idaho Guideline for Performing Air Quality Impact Analyses[2]," available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf), then a project-specific analysis is not required. Modeling applicability emissions thresholds were developed by DEQ based on modeling of a hypothetical source and were designed to reasonably ensure that impacts are below the applicable SIL. DEQ has established two threshold levels: Level 1 thresholds are unconditional thresholds, requiring no DEQ approval for use; Level 2 thresholds are conditional upon DEQ approval, which depends on evaluation of the project and the site, including emissions quantities, stack parameters, number of sources emissions are distributed amongst, distance between the sources and the ambient air boundary, and the presence of sensitive receptors near the ambient air boundary.

Modeling applicability was evaluated for the project based on Level I modeling thresholds rather than BRC thresholds. Applicability was evaluated based on potential emissions from the proposed 91.5 MMBtu/hr natural gas-fired boiler—Boiler 2A. The project will include the removal of two emissions units and the construction of one emissions unit, and the applicant applied negative emissions rates for the removed units to offset the emissions of the proposed emissions unit, so the BRC modeling exemption evaluation was not appropriate for this project. No offsets accounting for the reduction in emissions due to disabling existing Boilers 1 and 2 were included in these modeling applicability emissions calculations.

Modeling applicability was established using Level 1 modeling thresholds instead of BRC modeling exemption thresholds. As shown below in Table 2, the project's emissions of $PM_{10}$, $PM_{2.5}$, and $NO_x$ exceeded the Level I thresholds, requiring project-specific air impact modeling for the SIL analysis for these pollutants. Project-specific impact modeling was not required for CO, $SO_2$, lead, and, as discussed in Section 2.3.2 below, ozone emissions.

**Table 2. CRITERIA POLLUTANT SIL/NAAQS COMPLIANCE DEMONSTRATION APPLICABILITY**

| Criteria Pollutant / Averaging Period | | Level I Modeling Threshold | Applicable Project Potential Emissions | Modeling Compliance Exempted? |
|---|---|---|---|---|
| $PM_{10}$[a] | 24-hour average | 0.22 lb/hr[c] | 0.68 lb/hr | No |
| $PM_{2.5}$[b] | 24-hour average | 0.054 lb/hr | 0.68 lb/hr | No |
| | Annual average | 0.35 T/yr[d] | 3.0 T/yr | No |
| Carbon Monoxide (CO) | 1-hour and 8-hour | 15 lb/hr | 6.77 lb/hr | Yes |
| Sulfur Dioxide ($SO_2$) | 1-hour, 3-hour | 0.21 lb/hr | 0.054 lb/hr | Yes |
| | Annual | 1.2 T/yr | 0.24 T/yr | Yes |
| Nitrogen Oxides (NOx) | 1-hour | 0.20 lb/hr | 3.34 lb/hr | No |
| | Annual | 1.2 T/yr | 14.6 T/yr | No |
| Lead (Pb), monthly | | 14 lb/month[e] | 4.5E-05 lb/hr, or approximately 0.033 lb/month | Yes |
| Ozone as VOC or NOx | | See Section 2.3.2[f] | 2.2 T/yr | Yes |

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Pounds per hour.
d. Tons per year.
e. Pounds per month.
f. DEQ has not established Level I or II modeling applicability thresholds for ozone.

### *2.3.2 Ozone Modeling Applicability*

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, $NO_x$, 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 $O_3$ 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."*

Allowable emissions estimates of VOCs at 2.2 tons/year and NOx at 14.6 tons/year are well below the 100 tons/year threshold, and DEQ determined it was not appropriate or necessary to require a quantitative source specific $O_3$ impact analysis.

### *2.3.3 Secondary Particulate Formation Modeling Applicability*

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 modeled receptors where maximum $PM_{10}$ and $PM_{2.5}$ impacts would be anticipated.

## 2.4 Significant and Cumulative NAAQS Impact Analyses

If maximum modeled pollutant impacts to ambient air from emissions sources associated with a new facility or the emissions increase associated with a modification exceed the SILs of 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, 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 may also be required for permit revisions driven by compliance/enforcement actions, any correction of emissions limits or other operational parameters that may affect pollutant impacts to ambient air, or other cases where DEQ believes NAAQS may be threatened by the emissions associated with the facility or proposed project.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts, according to established DEQ/EPA guidance, policies, and procedures, from applicable facility-wide emissions and emissions from any nearby co-contributing sources. A DEQ-approved background concentration value is then added to the modeled result that is appropriate for the criteria pollutant/averaging-time 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 3. Table 3 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.

**Table 3. APPLICABLE REGULATORY LIMITS**

| Pollutant | Averaging Period | Significant Impact Levels[a] ($\mu g/m^3$)[b] | Regulatory Limit[c] ($\mu g/m^3$) | 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 $\mu g/m^3$) | 75 ppb[p] (196 $\mu g/m^3$) | Mean of maximum 4th highest[q] |
| | 3-hour | 25 | 1,300[m] | Maximum 2nd highest[n] |
| Nitrogen Dioxide ($NO_2$) | 1-hour | 4 ppb (7.5 $\mu g/m^3$) | 100 ppb[s] (188 $\mu g/m^3$) | 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] | 70 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.

If the cumulative NAAQS impact analysis shows a violation of the standard, the permit cannot be issued if the proposed project or facility has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. The facility or project does not have a significant contribution to a violation if impacts are below the SIL at all specific receptors showing violations during the time periods when modeled violations occurred.

Compliance with Idaho Air Rules Section 203.02 is demonstrated if: a) specific applicable criteria pollutant emissions increases are at a level defined as Below Regulatory Concern (BRC), using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the cumulative NAAQS impact analysis (modeling applicable 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 showed 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. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion. TAPs modeling was not triggered for this project.

## 3.0 Analytical Methods and Data

### 3.1 Modeling Methodology

This section describes the modeling methods used by the applicant's consultant, Coal Creek, to demonstrate compliance with applicable air quality standards.

#### 3.1.1 Overview of Analyses

Coal Creek performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the facility, using established DEQ policies, guidance, and procedures. Results of the submitted analyses, in combination with DEQ's analyses, demonstrated 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 4 provides a brief description of parameters used in the modeling analyses.

**Table 4. MODELING PARAMETERS**

| Parameter | Description/Values | Documentation/Addition Description |
|---|---|---|
| General Facility Location | Blackfoot, Idaho | The area is an attainment or unclassified area for all criteria pollutants. |
| Model | AERMOD | AERMOD with the PRIME downwash algorithm, version 16216r. |
| Meteorological Data | 2002-2006 | Blackfoot INL met tower with Pocatello airport ASOS data fill and Boise upper air data. |
| Terrain | Considered | Receptor, building, and emissions source stack base elevations were determined using USGS 1 arc second National Elevation Dataset (NED) files based on the NAD83 datum. The facility is located within Zone 12. |
| Building Downwash | Considered | Plume downwash was considered for the structures associated with the facility and nearby structures. |
| Receptor Grid | **Criteria Air Pollutants** | |
| | Grid 1 | 25-meter spacing along the ambient air boundary |
| | Grid 2 | 25-meter spacing extending at least 225 meters from the ambient air boundary. |
| | Grid 3 | 100-meter spacing in a 3,900-meter (x) by 3,200-meter (y) rectangular grid centered on Grid 2. |
| | Grid 4 | 250-meter spacing in a 8,000-meter (x) by 7,250-meter (y) rectangular grid centered on Grid 3. |

#### 3.1.2 Modeling Protocol

A modeling protocol for a 15-Day Pre-Permit Construction Approval PTC application was submitted to DEQ via email by Coal Creek, on behalf of BAF on May 8, 2017. On May 22, 2017, DEQ issued a conditional modeling protocol approval letter to BAF and Coal Creek. Project-specific modeling was conducted using data and methods described in the modeling protocol and the *Idaho Air Modeling Guideline*[2].

#### 3.1.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of air pollutant concentrations in ambient air 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.

Coal Creek used AERMOD version 16216r to evaluate pollutant impacts to ambient air from the facility, which is the current version of AERMOD.

$NO_2$ 1-hour impacts can be assessed using a tiered approach to account for $NO/NO_2/O_3$ chemistry. Tier 1 assumes full conversion of NO to $NO_2$. The previous Tier 2 Ambient Ratio Method (ARM) assumed a 0.80 default ambient ratio of $NO_2$/NOx. Tier 2 ARM2[3] was recently developed and replaces the previous ARM. Recent EPA guidance[4] on compliance methods for $NO_2$ states the following for ARM2:

> "This method is based on an evaluation of the ratios of $NO_2/NO_x$ from the EPA's Air Quality System (AQS) record of ambient air quality data. The ARM2 development report (API, 2013) specifies that ARM2 was developed by binning all the AQS data into bins of 10 ppb increments for $NO_x$ values less than 200 ppb and into bins of 20 ppb for $NO_x$ in the range of 200-600 ppb. From each bin, the 98th percentile $NO_2/NO_x$ ratio was determined and finally, a sixth-order polynomial regression was generated based on the 98th percentile ratios from each bin to obtain the ARM2 equation, which is used to compute a $NO_2/NO_x$ ratio based on the total $NO_x$ levels."

Tier 3 methods account for more refined assessment of the NO to $NO_2$ conversion, using a supplemental modeling program with AERMOD to better account for $NO/NO_2/O_3$ atmospheric chemistry. Either the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM) can be specified within the AERMOD input file for the Tier 3 approach. EPA guidance (Memorandum: from Tyler Fox, Leader, Air Quality Modeling Group, C439-01, Office of Air Quality Planning and Standards, USEPA; to Regional Air Division Directors. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard.* March 01, 2011) has not indicated a preference for one option over the other (PVMRM vs OLM) for particular applications.

The Tier 2 ARM2 and Tier 3 PVMRM and OLM methods are now regulatory options following the publication of final changes to EPA's Guideline on Air Quality Models on January 17, 2017.

Coal Creek used the Tier 2 ARM compliance method which applies an 80% conversion of NOx to $NO_2$ method to model 1-hour average impacts. Based on how far below the SIL modeled impacts were, impacts would also be below SILs had the more conservative Tier 1 approach (full conversion of NO to $NO_2$) been used. Coal Creek used the Tier 1 compliance method with an assumption of 100% conversion of NOx to $NO_2$ for annual $NO_2$ impacts. DEQ determined the assumption of full conversion is appropriate and conservative for negative emissions modeling (using negative emissions values to account for sources removed by implementation of the proposed project) for this project because both sources are expected to have similar $NO_2$ to NOx ratios for NOx emissions.

### 3.2 Background Concentrations

Ambient background concentrations were not needed for this project. Design impacts for the boiler replacement project were far below any SIL.

### 3.3 Meteorological Data

Coal Creek used a meteorological dataset that was also used for an ongoing $PM_{10}$ compliance plan permitting project. The dataset covers 2002 through 2006 and uses Pocatello ASOS data for the same time period for data fill. The INL met tower at Mountain View Middle School in Blackfoot was used as the primary data source, or on-site data, which is located approximately 2.5 miles east of the BAF facility, as shown in Figure 1, providing a representative dataset for conditions at the BAF facility. Coal Creek described similar land use and building heights for the INL tower and BAF project sites as well. A wind rose of the submitted surface winds is presented in Figure 2. DEQ determined these data were representative for the BAF site and approves use of this dataset for the project.

**Figure 1. Idaho National Laboratory Meteorological Tower and BAF-Blackfoot Facility**

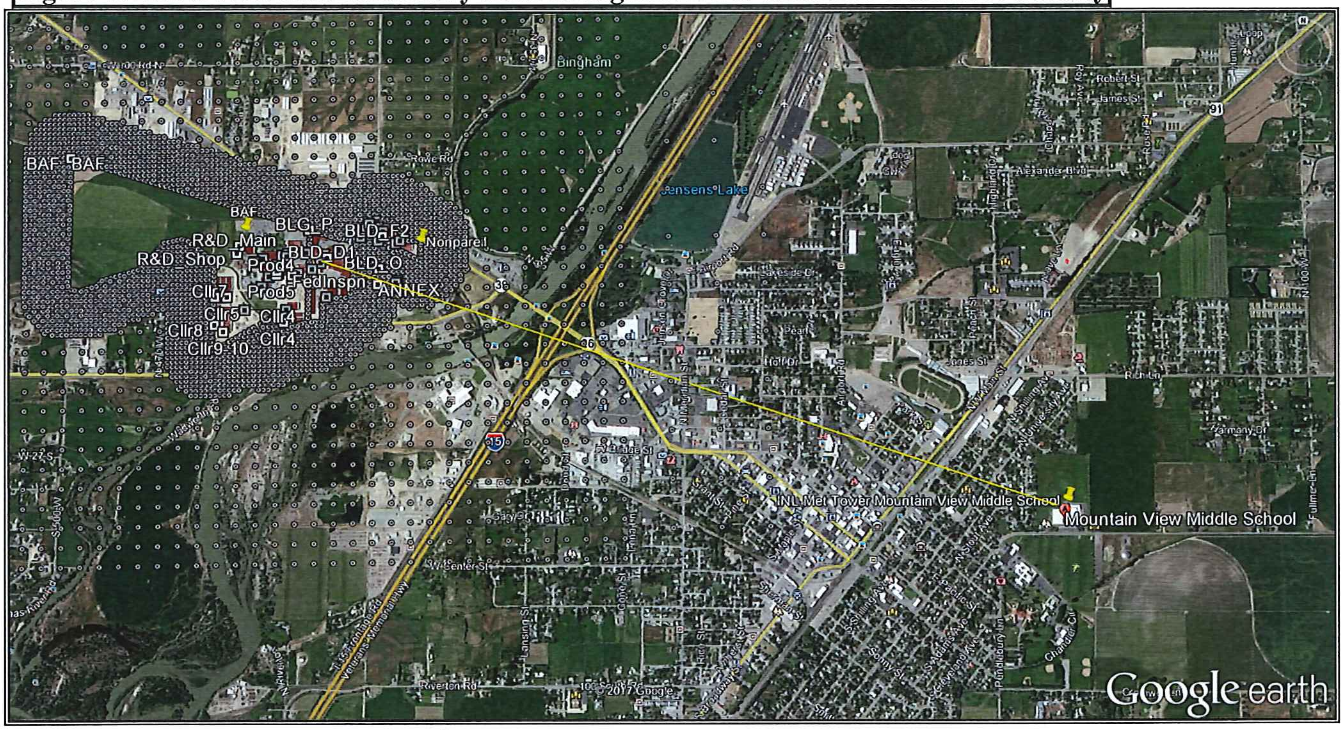
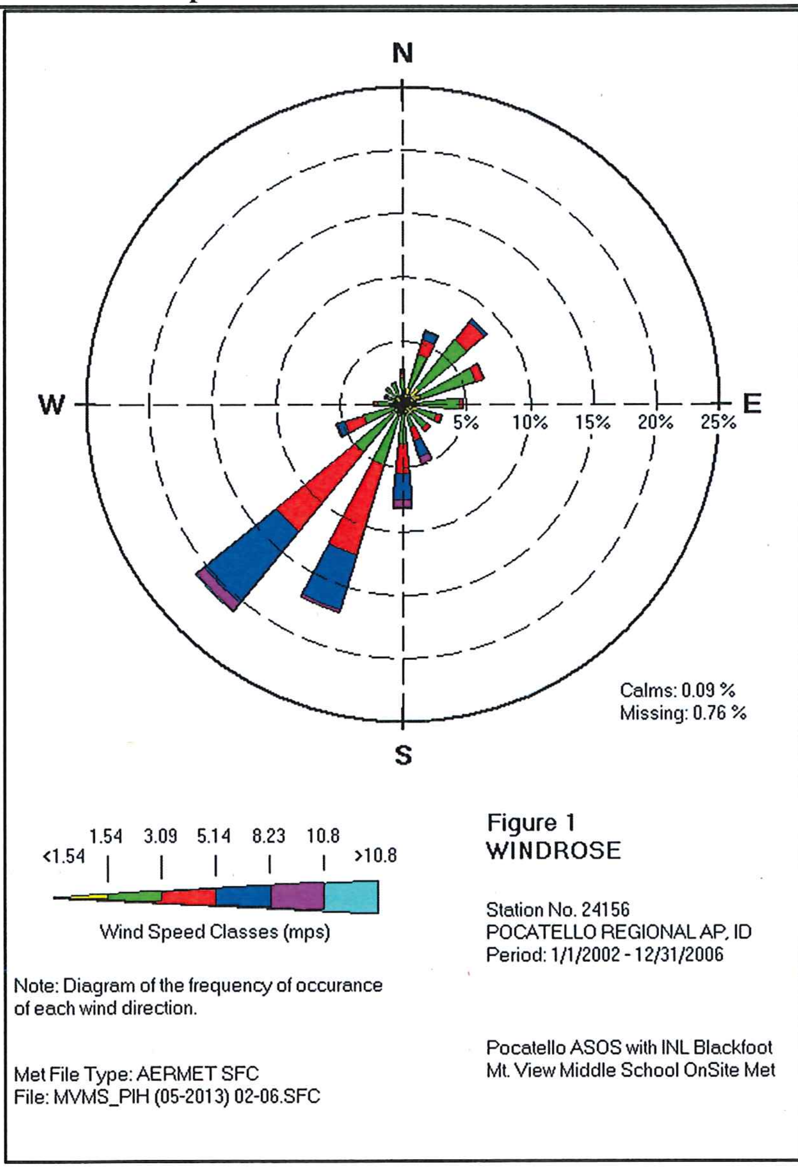


**Figure 2. 2002-2006 On-Site INL Met Tower Blackfoot Mountain View School with Pocatello Airport ASOS**




### *3.4 Terrain Effects*

Coal Creek used a National Elevation Dataset (NED) file in "tif" format in the NAD83 datum, to calculate elevations of receptors. A 1 arc second file provided 30-meter resolution of elevation data. The terrain preprocessor AERMAP version 11103 was used to extract the elevations from the NED file 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. Figure 3 of the project's modeling report provides a graphic of the project's domain, which was bounded by 43.125 degrees latitude (°lat) and 43.25 °lat and -112.25° longitude (°lon) and -112.5°lon. The NED file used to establish the elevations and hill height scales encompassed this domain and covered terrain between 42.875 °lat and 43.5 °lat and -112.0°lon and -113.0°lon.

### 3.5 Building Downwash Effects on Modeled Impacts

Potential downwash effects on the emissions plume were accounted for in the model by using building dimensions and locations as described by Coal Creek. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and release parameters for input to AERMOD. Building tier heights were shown by Coal Creek in figures 5, 6, and 7 of the application's modeling report. Base elevations of stack base elevations and building base elevations were determined using AERMAP. DEQ concluded that the building downwash was appropriately evaluated.

### 3.6 Facility Layout

DEQ exported the model setup to Google earth® and confirmed that the model setup of the facility's emission sources and structures were correctly located in the modeling analyses. Figures 3 and 4 depict the exported facility layout and a 3-dimensional view of the structures in the model setup. DEQ concluded the facility layout was appropriately represented.

**Figure 3. Building Layout**

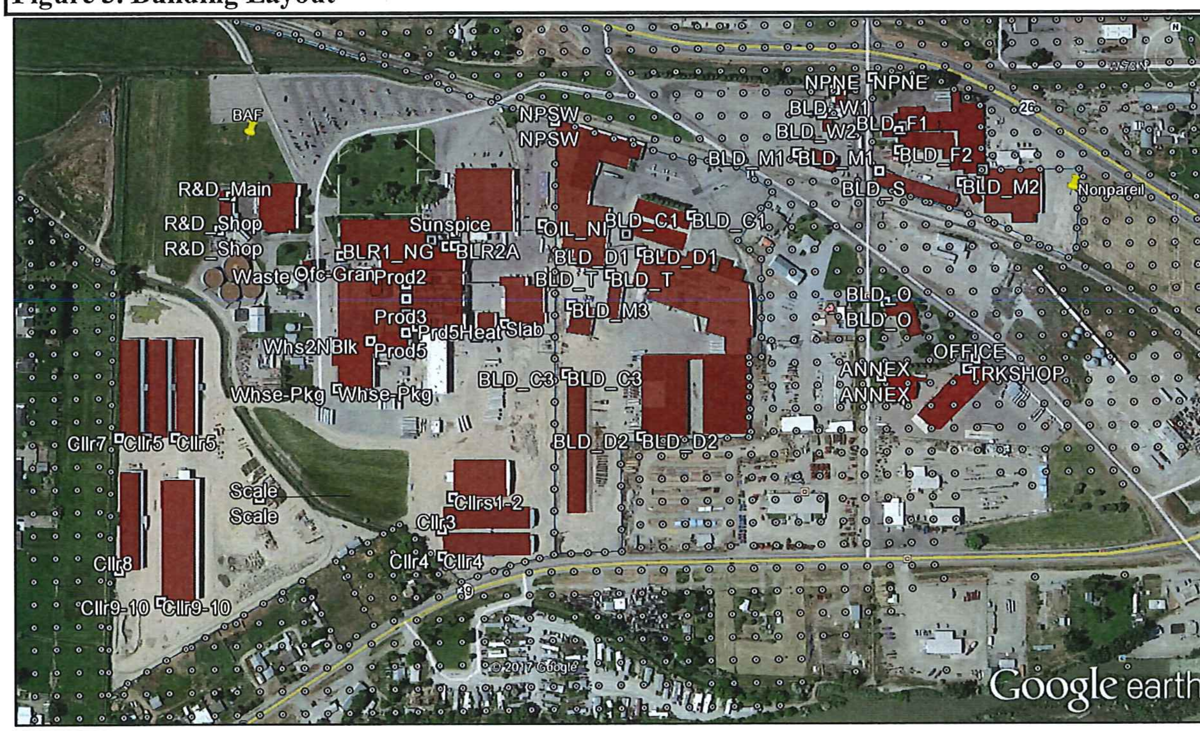
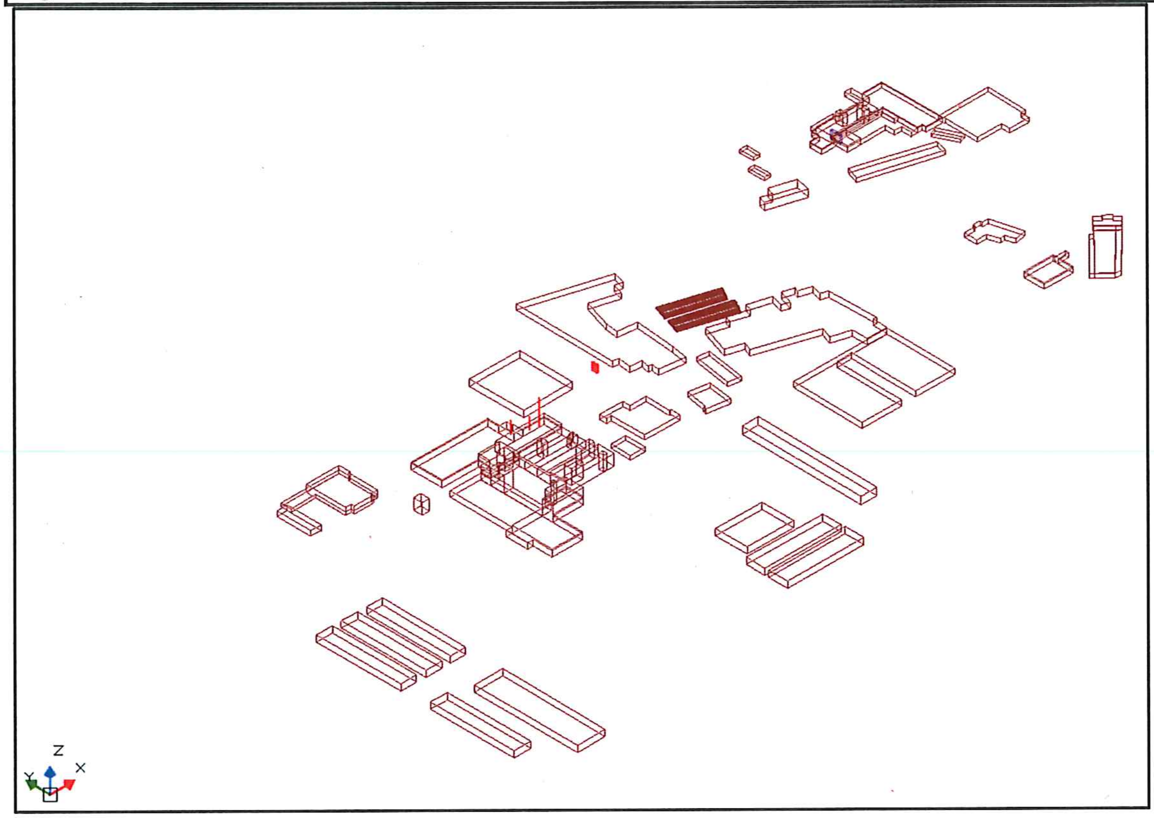


**Figure 4. Orthogonal Wireframe View of Buildings**



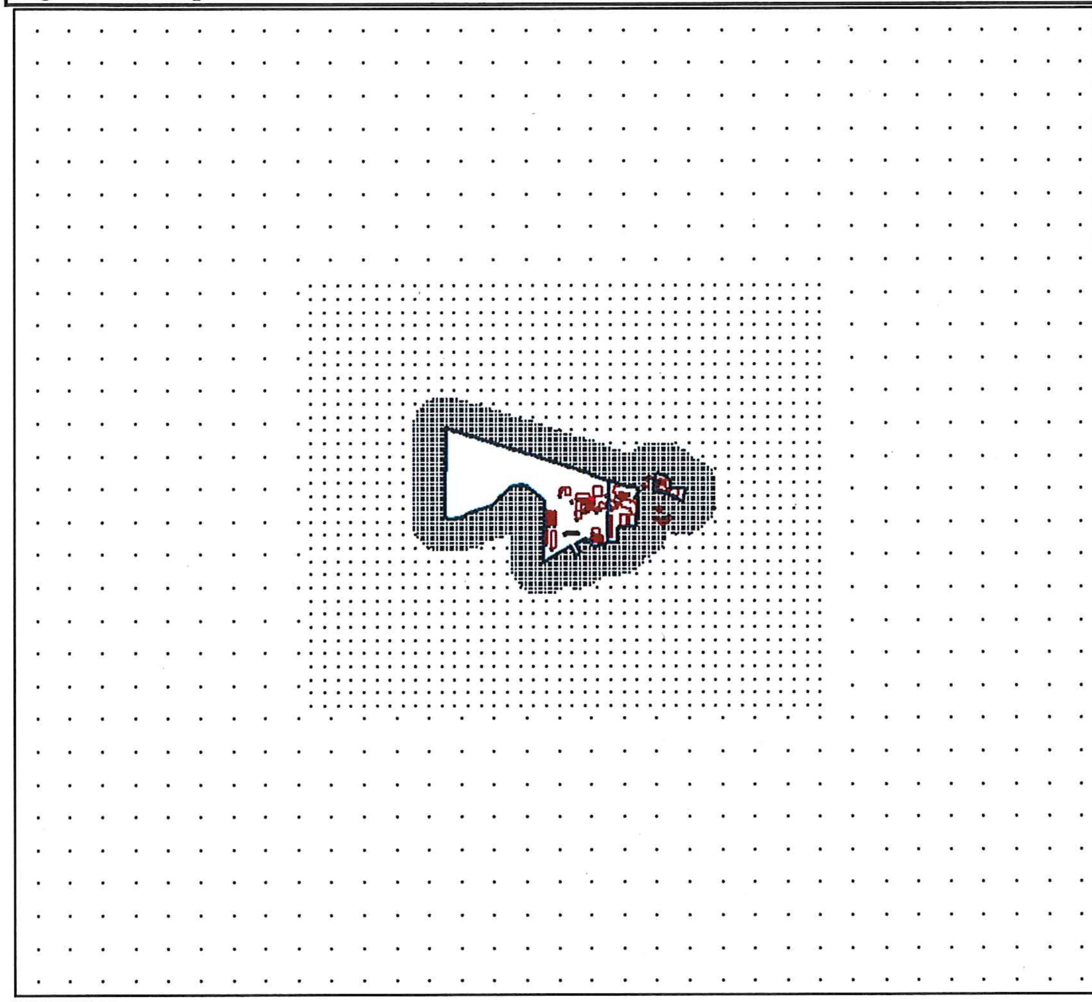

### 3.7 *Ambient Air Boundary*

Figure 8 of the project's modeling report depicts the ambient air boundary. The ambient air boundary used for this project was established along fencelines. Where buildings were located along property boundaries, and a fence was not present along these areas, ambient air was established immediately exterior to the structures. A power line running from north to south bisected the main portion of the facility between the BAF campus and the historical Nonpariel campus, which was acquired by BAF several years ago. The power line was treated as ambient air with a line of discrete receptors placed along the entire length of the bisecting line. DEQ review concluded that the ambient air boundary precluded public access based on the methods described in the modeling report according to the criteria described in DEQ's *Modeling Guideline*[2].

### 3.8 *Receptor Network*

Table 4 describes the receptor network used in the submitted modeling analyses. The receptor grids used in the model provided good resolution of the maximum design concentrations for the project and provided extensive coverage. The entire receptor grid was used for the ambient air impact analyses. DEQ determined that the receptor network was effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations. Figure 5 presents the full receptor grid.

**Figure 5. Receptor Grid**



### 3.9 Emission Rates

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 review memorandum. DEQ air impact analyses review included verification that the potential emissions rates provided in the emissions inventory were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used for the BAF Blackfoot facility 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 emissions rates must be equal to or greater than the facility's potential emissions calculated in the PTC emissions inventory or proposed permit allowable emissions rates.

Maximum demonstrated actual emissions rates were used to model negative emissions rates for the sources that will be removed. The maximum emissions rates for hourly ($NO_x$) and 24-hour ($PM_{10}$ and $PM_{2.5}$) averaging periods for Boilers 1 and 2 occurred while combusting Number 6 residual oil. Maximum hourly emissions for the 1-hour $NO_2$ SIL analysis, and the maximum average hourly emissions over a 24-hour averaging period for the 24-hour $PM_{10}$ and $PM_{2.5}$ SIL analyses, were established for modeling the negative emissions rates in the SIL analyses. There are no negative emission rates modeled from the shorter natural gas combustion stacks for Boilers 1 and 2 for the short-term averaging periods because short term emissions for existing source are maximized on Number 6 residual fuel oil. For the annual $NO_2$ and annual $PM_{2.5}$ SIL analyses, the average hourly emissions over a selected 2 year period of both natural gas and Number 6 residual oil combustion are represented in the negative modeled emissions rates for sources to be removed. All boiler exhaust stacks are represented in the annual average SIL analyses.

### *3.9.1 Criteria Pollutant Emissions Rates for Significant Impact Level and Cumulative Analyses*

Significant impact level (SIL) analyses for $PM_{10}$, $PM_{2.5}$, and NOx short-term and annual emissions were submitted for the NAAQS compliance demonstration.

Table 5 lists criteria pollutant continuous (24 hours per day) emissions rates used to evaluate SIL compliance for standards with averaging periods of 24 hours or less, except where noted. Table 6 lists criteria pollutant continuous (8,760 hours/year) emissions rates used to evaluate SIL compliance for standards with an annual averaging period. Cumulative NAAQS impact analyses were not required since project-specific impacts of all pollutants were below SILs.

**Table 5. SHORT-TERM CRITERIA POLLUTANT EMISSIONS RATES**

| Emissions Point | Description | $PM_{10}$[a] (lb/hr)[e] | $PM_{2.5}$ (lb/hr) | $NO_x$ (lb/hr) |
|---|---|---|---|---|
| BLR2A | New boiler | 0.68 | 0.68 | 3.34 |
| BLR1_NG | Boiler 1 NG short stack | 0 | 0 | 0 |
| BLR2_NG | Boiler 2 natural gas | 0 | 0 | 0 |
| BL1_2_OIL6 | Boiler1/2 #6 oil | -1.19 | -1.17 | -24.53 |

a. Particulate matter with a mean aerodynamic diameter of 10 microns or less.
b. Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
c. Nitrogen oxides.
d. Carbon monoxide.
e. Pounds per hour.

**Table 6. ANNUAL CRITERIA POLLUTANT EMISSIONS RATES**

| Emissions Point | Description | $PM_{2.5}$[a] (lb/hr)[b] | $NO_x$[c] (lb/hr) |
|---|---|---|---|
| BLR2A | new boiler | 0.68 | 3.34 |
| BLR1_NG | Boiler 1 NG short stack | -0.14 | -1.88 |
| BLR2_NG | Boiler 2 natural gas | -0.26 | -1.89 |
| BL1_2_OIL6 | Boiler1/2 #6 oil | -0.04 | -0.85 |

a. Particulate matter with a mean aerodynamic diameter of 2.5 or less.
b. Pounds per hour.
c. Nitrogen oxides.

### *3.9.2 Toxic Air Pollutant Emissions*

The increase in emissions from the proposed project are required to demonstrate compliance with the toxic air pollutant (TAP) increments, with an ambient impact analyses required for any TAP having a requested potential emission rate that exceeds the screening emissions level (EL) specified by Idaho Air Rules Section 585 or 586. Review of the TAPs emissions inventory, and authority to request alterations to the inventory, is the responsibility of the permit writer/project manager.

No TAPs were required to be modeled for this project. All TAPs subject to modeling were below screening emission rate limits.

### 3.10 Emission Release Parameters

Table 7 lists emissions release parameters for modeled sources for the BAF Blackfoot facility.

**Table 7. POINT SOURCE EMISSIONS RELEASE PARAMETERS**

| Release Point | Description | UTM[a] Coordinates, Zone 12, NAD83 Easting (m)[b] | UTM[a] Coordinates, Zone 12, NAD83 Northing (m) | Stack Base Elevation (m) | Stack Height (m) | Modeled Diameter (m) | Stack Gas Temp (K)[c] | Stack Flow Velocity (m/s)[d] | Stack Release Type |
|---|---|---|---|---|---|---|---|---|---|
| BLR2A | New natural gas-fired boiler | 387,767 | 4,784,172 | 1,365 | 30.5 | 1.07 | 422 | 17.4 | Default[e] |
| BLR1_NG | Boiler 1 NG short stack | 387,757 | 4,784,174 | 1,365 | 14.3 | 1.07 | 422 | 10.0 | Default[e] |
| BLR2_NG | Boiler 2 natural gas | 387,740 | 4,784,181 | 1,365 | 15.2 | 1.07 | 422 | 13.3 | Default[e] |
| BL1_2_OIL6 | Boiler1/2 #6 oil | 387,768 | 4,784,172 | 1,365 | 30.5 | 1.07 | 320 | 15.2 | Default[e] |

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters per second.
e. Default release represents a vertical orientation with an uninterrupted release point.

DEQ's permitting policies and guidance require that each permit application have stand-alone documentation to support the appropriateness of release parameters used in the air impact analyses.

This project modeled four point sources, including:

- proposed natural gas-fired boiler 2A which exhausts through an existing stack that was used for exhausting the combined flow for Boilers 1 and 2 while they operated on Number 6 oil (BLR2A).
- existing Boiler 1 fired on natural gas exhausting through its own dedicated stack (BLR1_NG).
- existing Boiler 2 fired on natural gas exhausting through its own dedicated stack (model ID BLR2_NG).
- existing Boilers 1 and 2 exhausting through a common stack equipped with a wet scrubber control device for firing on Number 6 oil (model ID BL1_2_OIL6).

**Boiler 2A**

The modeling report submitted to DEQ provided justification and documentation of assumptions and data supporting key release parameters used to model the point source for proposed boiler 2A with a Victory boiler vendor performance specification sheet.

DEQ compared the modeled flow rate to the flow rate based on rated heat input and EPA's F-Factor for natural gas of 10,610 wet standard cubic feet per million Btu of heat input (wscf/MMBtu). The modeled temperature was 300°F, which was essentially equal to the Victory Boiler 2A sheet's listed 100% load temperature from the economizer. Boiler 2A will exhaust from the existing stack used for Boilers 1 and 2 for #2 and #6 oil firing. This stack was listed with a termination height of 100 feet (30.5 meters) and an exit diameter of 3.5 feet (1.07 meters). The height and diameter of this stack was supported in this application using a reference to the values in an "...April 2014 data submittal" for the new production line (Table D-2 of the modeling report).

The modeled stack UTM coordinates for the Boiler 2A (BLR2A) stack were noted to be approximately 0.44 meters, or 1.4 feet, off from the coordinates for the existing combined Boilers 1 and 2 on residual oil stack (BL1_2_OIL6). There are to be no changes made to this stack except for the removal of the existing wet scrubber emissions control device. This discrepancy does not affect the SIL compliance demonstration.

**Boilers 1 and 2 Fired on Natural Gas**
While combusting natural gas, Boiler 1 exhausts through a stack with a release height of 47 feet above grade and 3.5 feet in diameter. This is an existing stack with support documentation consisting of a reference to 2016 project modeling file. Boiler 2 also exhausts to its own stack while combusting natural gas and has a release height of 50 feet above grade and an exit diameter of 3.5 feet, with these parameters being referenced from the April 2014 new production line project. Appendix E to the modeling report contained historical permitting project documentation dated April 25, 2005, in Table 2 – Boiler Operating Data, which listed exhaust flow rates and exit temperatures for these stacks for the 2005-era project, described as being calculated for conditions at 3% excess oxygen. DEQ compared EPA F-Factor derived flow rates for natural gas combustion and corrected the flow rates to 68°F and the pressure at 4,477 feet of elevation. BAF's modeled flow rates were 14% higher than those derived from the EPA F-Factor. An exit temperature of 300°F is acceptable for a natural gas-fired boiler.

**Boilers 1 and 2 Fired on #2 Fuel Oil or #6 Residual Oil**
Both boilers exhaust oil firing emissions to this stack. Support documentation of stack height and diameter of 100 feet and 3.5 feet, respectively, were based on Table D-2, which referenced a past permitting project. Methods used to verify these values were not described in the application. Flow rate and exit temperature were based on the April 2005 permitting analysis. Appendix E to the modeling report contained historical permitting project documentation dated April 25, 2005, in Table 2 – Boiler Operating Data, which listed exhaust flow rates and exit temperatures for these stacks for the 2005-era project, which were described as being calculated for conditions at 3% excess oxygen. DEQ's comparison value used the modeled exhaust temperature of 300°F and correction for an elevation of 4,477 feet, which provided a flow rate of 27,390 actual cubic feet per minute (ACFM), versus the modeled flow rate of 32,924 ACFM. BAF's flow rate was 20% higher than determined using the EPA F-Factor flow rate. The F-Factor is an uncontrolled exhaust flow rate and does not take into account the effect that the wet scrubber would have on the exhaust stream.

DEQ concludes that the release parameters used in the modeling analyses were adequately supported and were appropriate for this project, especially given the minimal ambient impacts from the SIL analyses.

## 4.0 Results for Air Impact Analyses

The maximum predicted ambient impacts for this project are presented in Section 4.1 for the SIL analyses.

### *4.1 Results for Significant Impact Analyses*

Table 8 provides results for the 24-hour and annual $PM_{2.5}$, 24-hour $PM_{10}$, and annual and 1-hour $NO_2$ significant impacts level analyses (SIL) analyses. Emissions increases of other criteria pollutants resulting from the proposed project (or facility-wide emissions levels) were below applicable DEQ modeling thresholds that trigger site-specific impact analyses.

| Table 8. RESULTS FOR SIGNIFICANT IMPACT ANALYSES | | | | |
|---|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Modeled Design Value Concentration ($\mu g/m^3$)[a]** | **SIL[b] ($\mu g/m^3$)** | **Percent of SIL** |
| $PM_{2.5}$[c] | 24-hour | 0.00000[f] | 1.2 | 0.0% |
| | Annual | 0.0038[g] | 0.3 | 1.3% |
| $PM_{10}$[d] | 24-hour | 0.00002[h] | 5.0 | 0.0004% |
| $NO_2$[e] | 1-hour | 0.0011[i] (0.0014)[j] | 7.5 | 0.015% (0.019%)[j] |
| | Annual | 0.00000[k] | 1.0 | 0.0% |

a. Micrograms per cubic meter.
b. Significant impact level.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
d. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
e. Nitrogen dioxide.
f. Modeled design value is the maximum 5-year mean of highest 24-hour values from each year of a 5-year meteorological dataset.
g. Modeled design value is the maximum 5-year mean of annual average values from each year of a 5-year meteorological dataset.
h. Modeled design value is the maximum of highest 24-hour values from a 5-year meteorological dataset, or the maximum of 24-hour value from five individual years of meteorological data.
i. Modeled design value is the maximum 5-year mean of maximum 1st highest daily 1-hour maximum impacts for each year of a 5-year meteorological dataset. The SIL compliance design value was calculated by Coal Creek assuming 80% conversion of total $NO_x$ to $NO_2$ based on Tier 2 ARM1.
j. Value in parentheses assumes complete conversion of NOx to $NO_2$. SIL compliance is demonstrated regardless of whether a Tier 2 ARM1 factor is applied to the design impact.
k. Modeled design value is the maximum annual impact of the individual years of a 5-year meteorological dataset. Complete conversion of $NO_x$ to $NO_2$ was assumed.

### 4.2 Results for Cumulative NAAQS Impact Analyses

Cumulative NAAQS impact analyses were not required for this project. Maximum impacts for all pollutants required to be modeled were below SILs. Cumulative NAAQS impact analyses were not required for this project.

### 4.3 Results for Toxic Air Pollutant Impact Analyses

TAPs impact analyses were not required for this project.

## 5.0 Conclusions

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the BAF-Blackfoot facility will not cause or significantly contribute to a violation of any SIL and so will not cause or contribute to any exceedance of a NAAQS and will not exceed allowable TAP increments.

**References**


1. *Policy on NAAQS Compliance Demonstration Requirements of IDAPA 58.01.01.203.02 and 01.403.02.* Idaho Department of Environmental Quality Policy Memorandum. Tiffany Floyd, Administrator, Air Quality Division, June 10, 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. *Ambient Ratio Method Version 2(ARM2) for use with AERMOD for 1-hr $NO_2$ Modeling Development and Evaluation Report,* Prepared for American Petroleum Institute, 1220 L Street NW, Washington, DC 20005, by M. Podrez, RTP Environmental Associates, Inc., 2031 Broadway, Suite 2, Boulder, Colorado 80302, September 20, 2013.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the $NO_2$ National Ambient Air Quality Standard,* R. Chris Owen and Roger Brode, Environmental Protection Agency, Office of Air Quality Planning and Standards, September 30, 2014.

# APPENDIX D – FEDERAL REGULATION ANALYSIS

**Regulatory Analysis:**
**40 CFR 60 Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

Contents

§60.40c Applicability and delegation of authority.
§60.41c Definitions.
§60.42c Standard for sulfur dioxide (SO2).
§60.43c Standard for particulate matter (PM).
§60.44c Compliance and performance test methods and procedures for sulfur dioxide.
§60.45c Compliance and performance test methods and procedures for particulate matter.
§60.46c Emission monitoring for sulfur dioxide.
§60.47c Emission monitoring for particulate matter.
§60.48c Reporting and recordkeeping requirements.

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

## §60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) 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/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NOX standards under this subpart and the SO2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

## *60.40c: No applicable requirements. Administrative only.*

§60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

### *60.41c: Fuel combusted by boiler meets the definition of natural gas.*

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential $SO_2$ emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an $SO_2$ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or $SO_2$.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§60.42c Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of SO2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO2 emissions limit or the 90 percent SO2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 50 percent (0.50) of the potential SO2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of the following:

(1) The percent of potential SO2 emission rate or numerical SO2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:
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Where:

Es = SO2 emission limit, expressed in ng/J or lb/MMBtu heat input;

Ka = 520 ng/J (1.2 lb/MMBtu);

Kb = 260 ng/J (0.60 lb/MMBtu);

Kc = 215 ng/J (0.50 lb/MMBtu);

Ha = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

Hb = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

Hc = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

***Boiler 2A will not combust any of the fuel types that are described in 60.42c.***

§60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

## *Boiler 2A will not combust any of the fuel types that are described in 60.43c.*

§60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO2 emission limits under §60.42c is based on the average percent reduction and the average SO2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO2 emission rate (Eho) and the 30-day average SO2 emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate Eao when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted Eho (Ehoo) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted Eao (Eaoo). The Ehoo is computed using the following formula:
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Where:

Ehoo = Adjusted Eho, ng/J (lb/MMBtu);

Eho = Hourly SO2 emission rate, ng/J (lb/MMBtu);

Ew = SO2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0.

Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters Ew or Xk if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO2 emission rate is computed using the following formula:
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Where:

%Ps = Potential SO2 emission rate, in percent;

%Rg = $SO_2$ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%Rf = $SO_2$ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the %Ps, an adjusted %Rg (%Rgo) is computed from Eaoo from paragraph (e)(1) of this section and an adjusted average $SO_2$ inlet rate (Eaio) using the following formula:
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Where:

%Rgo = Adjusted %Rg, in percent;

Eaoo = Adjusted Eao, ng/J (lb/MMBtu); and

Eaio = Adjusted average $SO_2$ inlet rate, ng/J (lb/MMBtu).

(ii) To compute Eaio, an adjusted hourly $SO_2$ inlet rate (Ehio) is used. The Ehio is computed using the following formula:
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Where:

Ehio = Adjusted Ehi, ng/J (lb/MMBtu);

Ehi = Hourly $SO_2$ inlet rate, ng/J (lb/MMBtu);

Ew = $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0; and

Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO2 emissions data in calculating %Ps and Eho under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %Ps or Eho pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

***Because Boiler 2A is not subject to the SO2 performance standards of 60.42c, the compliance and performance test methods of 60.44c are not applicable.***

§60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O2) or carbon dioxide (CO2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O2 or CO2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day

daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O2 (or CO2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O2 (or CO2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

***Because Boiler 2A is not subject to the PM performance standards of 60.43c, the compliance and performance test methods of 60.45c are not applicable.***

§60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO2 concentrations and either O2 or CO2 concentrations at the outlet of the SO2 control device (or the outlet of the steam generating unit if no SO2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO2 concentrations and either O2 or CO2 concentrations at both the inlet and outlet of the SO2 control device.

(b) The 1-hour average SO2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO2 CEMS at the inlet to the SO2 control device shall be 125 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted, and the span value of the SO2 CEMS at the outlet from the SO2 control device shall be 50 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO2 CEMS at the outlet from the SO2 control device (or outlet of the steam generating unit if no SO2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO2 control device (or outlet of the steam generating unit if no SO2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO2 control device (or outlet of the steam generating unit if no SO2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO2 at the inlet or outlet of the SO2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO2 and CO2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

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§60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e. , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section §60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section §60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

***Because Boiler 2A is not subject to the SO2 performance standards of 60.42c, the emission monitoring provisions for sulfur dioxide of 60.46c are not applicable.***

§60.48c Reporting and recordkeeping requirements.

(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.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

***Because the Blackfoot Facility is an affected facility under this subpart, notification is required in accordance with 60.48(c)(a).***

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO2 or diluent (O2 or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions

taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(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 SO2 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 SO2 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 Blackfoot Facility is an affected facility under this subpart and BAF is subject to the recordkeeping provisions of 40 CFR 60.48c(g) with respect to Boiler 2A. Because the facility only combusts natural gas, monthly recordkeeping is acceptable per subparagraph (2).***

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

# APPENDIX E – FACILITY DRAFT COMMENTS

**The following comments were received from the facility on August 28, 2017:**

| REFERENCE | EXISTING LANGUAGE | REQUESTED CHANGE | JUSTIFICATION | DEQ RESPONSE |
|---|---|---|---|---|
| **DRAFT PERMIT** | | | | |
| 1. Section 1.1 | "the two plants are considered as one Tier I source or Tier I facility". | Change to:<br>"the two plants are considered as one source for purposes of Procedures and Requirements for Permits to Construct (IDAPA 58.01.01.200, et. seq." | More specific clarification of the applicability provisions. Also, BAF intends to maintain separate Tier I permits for the BAF and BAPCI operations. | Changed<br>It reads: "the two plants are considered as one facility" |
| 2. Section 1.1 | "Table 1.1 lists all sources of regulated emissions in this permit." | Add:<br>"The descriptions in Table 1 are for information only and are not enforceable conditions. Enforceable conditions are identified in Section 2 of this permit." | Because the document is a permit to construct, some observers could interpret the contents of Table 1 as permit conditions. By stating that Table 1 is only informational, the permit will make clear that the descriptions in Table 1 are not enforceable requirements. | No change<br>An internal discussion was held for this topic. While the information in the table will not be enforced as a permit condition, DEQ is authorized to use the information for compliance determination as allowed under" Permit Authority" in the permit coversheet.<br>To follow the template, no change is made. |

| REFERENCE | EXISTING LANGUAGE | REQUESTED CHANGE | JUSTIFICATION | DEQ RESPONSE |
|---|---|---|---|---|
| 3. Table 1.1 – description of control equipment for Boiler 2A | "None" | Change to:<br>"Low NOx burners" | Low NOx burners are pollution control equipment. | Changed |
| 4. Table 1.1 – description of control equipment for Boiler 3 | "Good combustion" | Change to:<br>"None" | Good combustion is not equipment. | No change<br>The title of the column has been changed to "Emissions Control" as that in the existing 2005 PTC. |
| 5. Section 3.2. Control Device Descriptions | "Emissions from both boilers are uncontrolled. While no add-on control device is installed to control emissions from the boiler." | Change to:<br>"Boiler 2A uses a low NOx burner to lower NOx emissions. Emissions from Boiler 3 are uncontrolled." | Synchronize text with Table 1.1. | Changed |

<table>
<tr><th>REFERENCE</th><th>EXISTING LANGUAGE</th><th>REQUESTED CHANGE</th><th>JUSTIFICATION</th><th>DEQ RESPONSE</th></tr>
<tr><td>6. Section 3.3, Table 3.1, “Boiler 2A and Boiler 3 Emissions Limits”</td><td><table>
<tr><th rowspan="2">Source Description</th><th rowspan="2">...</th><th colspan="2">VOC</th></tr>
<tr><th>lb/hr (3)</th><th>T/yr (4)</th></tr>
<tr><td>Boiler 2A</td><td></td><td>0.49</td><td>2.16</td></tr>
<tr><td>Boiler 3</td><td></td><td>0.21</td><td>0.91</td></tr>
</table></td><td>Delete emission limits for VOC for Boiler 3.</td><td>Existing Permit to Construct No. P-050301 does not include emission limits for VOC for Boiler 3. Because no ambient impact analysis for VOC was conducted for this project, there is no regulatory bases for creating VOC limits for Boiler 3 as part of this permitting action.</td><td>Deleted</td></tr>
<tr><td>7. Section 3.6. Allowable Fuels and Fuel Sulfur Content – Boilers 2A and 3.</td><td>Boiler 3 may bum natural gas fuel as primary fuel”</td><td>Change to:<br><br>Boiler 3 may burn natural gas fuel as primary fuel”</td><td>Typo correction.</td><td>Corrected</td></tr>
<tr><td>8. Section 3.15.3</td><td>“Natural gas usage in gal/hr”</td><td>Change to”<br><br>“Natural gas usage in MMscf/hr”</td><td>Units consistency.</td><td>Changed</td></tr>
<tr><td>9. Section 3.16</td><td>“because it is a steam generating unit which construction is commenced after June 9, 1989”</td><td>Change to:<br><br>“because it is a steam generating unit which commenced construction ~~is~~ after June 9, 1989”</td><td>Grammatical clarification.</td><td>Corrected</td></tr>
</table>

| REFERENCE | EXISTING LANGUAGE | REQUESTED CHANGE | JUSTIFICATION | DEQ RESPONSE |
|---|---|---|---|---|
| **DRAFT STATEMENT OF BASIS** | | | | |
| 10. Facility Information - *Description* | "the two plants are considered as one Tier I source or Tier I facility". | Change to:<br>"the two plants are considered as one source for purposes of Procedures and Requirements for Permits to Construct (IDAPA 58.01.01.200, et. seq." | Consistency with requested changes to PTC. | Changed<br>It reads: "the two plants are considered as one source or one facility for NSR program and Title V program" |
| 11. Technical Analysis – *Ambient Air Quality Impact Analysis* | "That document is part of the final permit package for this permitting action (see Appendix B – EPA GUIDANCE" | Change to"<br>"That document is part of the final permit package for this permitting action (see Appendix C – AMBIENT AIR QUALITY IMPACT ANALYSES" | Correction to referenced appendix. | Corrected |

| REFERENCE | EXISTING LANGUAGE | REQUESTED CHANGE | JUSTIFICATION | DEQ RESPONSE |
|---|---|---|---|---|
| **DRAFT STATEMENT OF BASIS – APPENDIX C. AMBIENT AIR QUALITY IMPACT ANALYSES** | | | | |
| 12. Section 3.7 – Ambient Air Boundary | "A power line running from north to south bisected the main portion of the facility between the BAF campus and the historical Nonpariel campus, which was acquired by BAF several years ago. The power line was treated as ambient air with a line of discrete receptors placed along the entire length of the bisecting line." | Delete the discrete receptors located along the power line. | The power line can only be accessed by going through BAF or BAPCI security. There is no general public access, and employees of the power can access the line only by going through plant security.<br><br>EPA guidance[1] is clear that when a lessor maintains access control to a leased property, the leased property is not ambient air to the lessor. BAF believes a situation with an easement is fully analogous to a situation involving a leased property, | No change |

[1] June 22, 2007 Memo from Stephen D. Page, Director, Office of Air Quality Planning and Standards, US EPA, to Regional Division Directors, Subject: Interpretation of "Ambient Air" In Situations Involving Leased Land Under the Regulations for Prevention of Significant Deteri0ration (PSD). Retrieved August 21, 2017 at https://www.epa.gov/sites/production/files/2015-07/documents/ambntair.pdf

## APPENDIX F – PROCESSING FEE

| | |
|---|---|
| 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) |
| $NO_X$ | 0.0 | 165.46 | -165.5 |
| $SO_2$ | 0.0 | 143.01 | -143.0 |
| CO | 0.0 | 136.39 | -136.4 |
| $PM_{10}$ | 0.0 | 13.78 | -13.8 |
| VOC | 0.0 | 0.95 | -1.0 |
| TAPS/HAPS | 0.0 | 0 | 0.0 |
| Total: | 0.0 | 459.59 | **-459.6** |
| | | | |
| Fee Due | **$ 1,000.00** | | |