# Statement of Basis

**Final**

**Idaho Power Company**
**Langley Gulch Power Plant**
**New Plymouth, Idaho**
**Facility ID No. 075-00012**
**Permit to Construct No. P-2009.0092**

**June 25, 2010**
**Morrie Lewis**
**Permit Writer**

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

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## ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

| | |
|---|---|
| AAC | acceptable ambient concentrations |
| AACC | acceptable ambient concentrations for carcinogens |
| acfm | actual cubic feet per minute |
| AQCR | Air Quality Control Region |
| AQRV | air quality related values |
| ASTM | American Society for Testing and Materials |
| BACT | Best Available Control Technology |
| Btu | British thermal units |
| CAA | Clean Air Act |
| CatOx | catalytic oxidation |
| CDPF | catalyzed diesel particulate filters |
| CEMS | continuous emission monitoring systems and continuous emission monitoring equipment |
| CFR | Code of Federal Regulations |
| CGA | cylinder gas audits |
| CI | compression ignition |
| CMS | continuous monitoring systems |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| COMS | continuous opacity monitoring systems |
| CT | combustion turbine |
| DAHS | data acquisition and handling system |
| DEQ | Department of Environmental Quality |
| DLN | dry low $NO_X$ combustors |
| DOC | diesel oxidation catalyst systems |
| DPF | diesel particulate filters |
| dscf | dry standard cubic feet |
| EGR | exhaust gas recirculation |
| EL | screening emissions levels |
| EPA | United States Environmental Protection Agency |
| FLM | Federal Land Managers |
| GCP | good combustion practices |
| gph | gallons per hour |
| gpm | gallons per minute |
| gr | grains (1 lb = 7,000 grains) |
| $H_2S$ | hydrogen sulfide |
| HAP | hazardous air pollutants |
| HHV | higher heating value |
| HP | horsepower |
| hr/yr | hours per consecutive 12 calendar month period |
| HRSG | heat recovery steam generating unit |
| ICE | internal combustion engines |
| ID No. | identification number |
| IDAPA | a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act |
| kW | kilowatts |
| lb/hr | pounds per hour |
| LEC | low emission combustors |
| LNT | lean $NO_X$ trap |
| low-load | at power outputs below 60% of base load, excluding periods defined as startup or shutdown |
| MACT | Maximum Achievable Control Technology |
| MMBtu | million British thermal units |

| | |
|---|---|
| MW | megawatts of electrical output |
| NAAQS | National Ambient Air Quality Standards |
| NAICS | North American Industry Classification System |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NFPA | National Fire Protection Association |
| ng/J | nanograms per Joule |
| NG | pipeline natural gas |
| $NH_3$ | ammonia |
| NMHC | non-methane hydrocarbons |
| No. | number |
| $NO_2$ | nitrogen dioxide |
| $NO_X$ | nitrogen oxides |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| O&M | operation and maintenance |
| $O_2$ | oxygen |
| $O_3$ | ozone |
| PAH | polycyclic aromatic hydrocarbons |
| Pb | lead |
| 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 of a gaseous contaminant per million parts of gas by volume |
| ppmw | parts of a gaseous contaminant per million parts of gas by weight |
| PSD | Prevention of Significant Deterioration |
| PTC | permit to construct |
| PTE | potential to emit |
| QA | quality assurance |
| RATA | relative accuracy test audits |
| RBLC | Reasonably available control technology/BACT/Lowest achievable emission rate Clearinghouse |
| RICE | reciprocating internal combustion engines |
| Rules | Rules for the Control of Air Pollution in Idaho |
| scf | standard cubic feet |
| SCL | significant contribution levels |
| SCR | selective catalytic reduction |
| short-term | emission limit with an averaging period of 24 hours or less |
| SIA | source impact analyses |
| SIC | Standard Industrial Classification |
| SIL | significant impact levels |
| SIP | State Implementation Plan |
| SNCR | selective non-catalytic reduction |
| $SO_2$ | sulfur dioxide |
| $SO_X$ | sulfur oxides |
| T/yr | tons per consecutive 12 calendar month period |
| T2 | Tier II operating permit |
| TAP | toxic air pollutants |
| TDS | total dissolved solids |
| ULSD | ultra-low sulfur diesel |
| U.S.C. | United States Code |
| UTM | Universal Transverse Mercator |
| VOC | volatile organic compounds |
| WC | water controls |
| $\mu g/m^3$ | micrograms per cubic meter |

## FACILITY INFORMATION

### *Description*

Idaho Power Company is proposing to construct a new natural gas-fired, combined-cycle power plant designated as the Langley Gulch Power Plant. The proposed facility will be located in Payette County, approximately 5 miles south of New Plymouth, Idaho.

The Langley Gulch Power Plant will operate as a one-on-one, combined-cycle plant, consisting of a natural gas-fired combustion turbine and a steam turbine. The combustion turbine is equipped with a heat recovery steam generator, which uses the exhaust heat to produce steam for the steam turbine. Supplemental natural gas duct firing within the HRSG provides additional heat in the exhaust gases, which increases steam production and steam turbine output for peak loads.

Ancillary equipment includes a diesel-fired emergency generator engine, a diesel-fired fire pump engine, a wet cooling tower, and no more than six dry chemical storage silos. Dry chemicals are expected to include magnesium oxide, soda ash, and lime, and will be used for cooling water treatment.

The need for a firm generation resource of this magnitude was identified in both the 2004 and 2006 Integrated Resource Plans, reviewed and acknowledged by the Idaho Public Utilities Commission, as well as the 2008 plan update. This project provides this generation need and supports a diversified portfolio of resources that includes significant amounts of energy efficiency and alternative energy resources. This project will have the features of a base load plant, and will have the flexibility to vary output quickly to integrate intermittent resources from area wind and solar projects. The plant operational schedule will be dependent upon many factors, including future load demand, ambient weather, yearly snow pack, and other conditions. As a result, the combustion turbine and the heat recovery steam generator may be subject to numerous startup, shutdown, and low-load events per year.

### *Application Scope and Permitting History*

An application was submitted for an initial permit to construct (PTC) the proposed facility. The applicant has proposed to install and operate:

- A natural gas-fired combustion turbine (CT) with a natural gas-fired duct burner and heat recovery steam generator (HRSG), utilizing the following control equipment:
  - Dry low $NO_X$ combustors (DLN) to minimize $NO_X$, CO, and VOC emissions.
  - Selective catalytic reduction (SCR) system for the control of $NO_X$ emissions.
  - Catalytic oxidation (CatOx) system for the control of CO and VOC emissions.
  - Good combustion practices (GCP) and use of pipeline quality natural gas to minimize emissions.
- A wet cooling tower with up to 7 cells, utilizing good operating practices and drift eliminators for the control of PM emissions.
- A diesel-fired emergency generator engine and a diesel-fired fire pump engine, each utilizing good combustion practices and EPA-certified technologies (Tier 2 or 3) to minimize $NO_X$, CO, VOC, and PM emissions.
- No more than six dry chemical storage silos utilizing good operating practices and bin vent filters for the control of PM emissions.

### *Application Chronology*

| | |
|---|---|
| July 8, 2009 | DEQ received an application and an application fee. |
| July 24, 2009 | DEQ provided notification and emailed application materials to the EPA and to the FLM in accordance with 40 CFR 52.21(p)(1). |
| July 31, 2009 | DEQ determined that the application was incomplete. |
| August 10, 2009 | DEQ received Addendum #1 to the application, which addressed items identified in the incompleteness letter. |
| August 14, 2009 | DEQ received Addendum #2 to the application, which provided an estimate of ammonia slip emissions and quantification of ambient concentration. |
| August 21, 2009 | DEQ received Addendum #3 to the application, which provided additional information and supporting documentation. |
| September 4, 2009 | DEQ determined that the revised application was complete. |
| September 8, 2009 | DEQ received revision 1 to the application, which incorporated the 3 addendums previously submitted. |
| September 15, 2009 | DEQ emailed revision 1 to the application to the FLM and EPA. |
| October 29, 2009 | Idaho Power met with DEQ to request additional time in order to revise the application to address design changes to ancillary equipment. |
| December 15, 2009 | DEQ received Addendum #4 to the application and revision 2 to the application, which addressed design changes to ancillary equipment and revised emission inventories and ambient air quality impact analyses. |
| January 27, 2010 | DEQ received Addendum #5 to the application, which provided an estimate of additional HAP and TAP emissions and quantification of ambient concentrations. |
| February 16, 2010 | DEQ made available the draft permit and statement of basis for peer and regional office review. |
| February 25, 2010 | DEQ received Addendum #6 to the application, which provided an estimate of additional HAP and TAP emissions and quantification of ambient concentrations. |
| March 8, 2010 | DEQ received revised CO modeling files for the application. |
| March 16, 2010 | DEQ made available the draft permit and statement of basis for applicant review. |
| March 16, 2010 | DEQ received a permit processing fee. |
| April 2, 2010 | DEQ received revision 3 to the application, which incorporated the 6 addendums previously submitted. |
| April 28, 2010 | DEQ received revision 4 to the application, which incorporated the 6 addendums previously submitted and typographical corrections. |
| May 10-12, 2010 | DEQ made available the updated draft permit and statement of basis for applicant review. |
| May 17, 2010 | DEQ published notification of the public comment period on the proposed action. |
| May 17-18, 2010 | DEQ provided notification of the public comment period on the proposed action to EPA, FLM, affected states, and interested parties. |

| | |
|---|---|
| May 19-June 18, 2010 | DEQ provided a public comment period on the proposed action. |
| June 3, 2010 | DEQ provided an informational meeting and a public hearing on the proposed action. |
| June 25, 2010 | DEQ issued the final permit and statement of basis. |

## TECHNICAL ANALYSIS

### *Emissions Units and Control Equipment*

**Table 1 EMISSIONS UNITS AND CONTROL EQUIPMENT DESCRIPTIONS**

| Emissions Unit Descriptions | | Control Equipment Descriptions | Emission Point Description | |
|---|---|---|---|---|
| Combustion turbine (CT) | | | | |
| Manufacturer: | Siemens | | | |
| Model: | SGT6-5000F | | | |
| Configuration: | 1X1 combined cycle | | | |
| Manufacture date: | 2010 | | | |
| Nominal output: | 269 MW | | | |
| Maximum capacity: | 2,134 MMBtu/hr[a] | | | |
| Maximum operation: | 7,884 hr/yr | Dry low $NO_X$ combustors | Exit height: | 160 ft |
| Fuel: | natural gas | Selective catalytic reduction system | Exit diameter: | 18 ft |
| Fuel consumption: | 2,146,600 scf/hr | Catalytic oxidation system | Exit air flow rate: | 875,168 acfm |
| | | Good combustion practices | Exit temperature: | 193 °F |
| Duct burner | | | | |
| Manufacturer: | Hamworthy Peabody | | | |
| Manufacture date: | 2010 | | | |
| Maximum capacity: | 241.28 MMBtu/hr[a] | | | |
| Maximum operation: | 7,884 hr/yr | | | |
| Fuel: | natural gas | | | |
| Fuel consumption: | 242,739 scf/hr | | | |
| Emergency generator engine | | | | |
| Manufacturer: | Cummins | | | |
| Model: | DQFAA | | | |
| Manufacture date: | 2009 | | Exit height: | 20 ft |
| Maximum capacity: | 1,102 BHP (750 kW) | EPA Tier 2 technologies | Exit diameter: | 0.5 ft |
| | 2.54 L/cylinder | Good combustion practices | Exit air flow rate: | 6,310 acfm |
| Maximum operation: | 4 hr/day and 60hr/yr[b] | | Exit temperature: | 816 °F |
| Fuel: | diesel | | | |
| Fuel consumption: | 51.3 gph | | | |
| Fire pump engine | | | | |
| Manufacturer: | John Deere | | | |
| Model: | JU6H-UFAD98 | | | |
| Manufacture date: | 2009 | | Exit height: | 20 ft |
| Maximum capacity: | 315 HP (235 kW) | EPA Tier 3 technologies | Exit diameter: | 0.42 ft |
| | 1.13 L/cylinder, 1760 rpm | Good combustion practices | Exit air flow rate: | 1,400 acfm |
| Maximum operation: | 1 hr/day and 30hr/yr[b] | | Exit temperature: | 961 °F |
| Fuel: | diesel | | | |
| Fuel consumption: | 15 gph | | | |
| Cooling tower | | | | |
| Manufacturer: | GEA Power Cooling | | | |
| Model: | 7-cell, counterflow wet | | Exit heights: | 46.5 ft |
| Manufacture date: | 2010 | Drift eliminators | Exit diameters: | 32.8 ft |
| Maximum water flow: | 63,200 gpm | Good operating practices | Exit air flow rates: | 1,659,170 acfm |
| Maximum operation: | 8,760 hr/yr | | Exit temperatures: | 77 °F |
| Maximum TDS: | 5,000 mg/L | | | |
| Dry chemical storage silos (no more than 6) | | | | |
| Manufacturer: | Seneca | | Exit heights: | 36 ft |
| Manufacture date: | 2010 | Bin vent filters | Exit diameters: | 2.0 ft |
| Maximum capacity: | 4,072 $ft^3$ (10,500 gal) | Good operating practices | Exit air flow rates: | 99 acfm |
| Maximum loading operation: | 2 hr/day and 24 hr/yr per silo | | Exit temperatures: | 100 °F |

a) At higher heating value (HHV), 100 percent load, and 0 F.
b) For maintenance and testing activities.

## *Emission Inventories*

Emission inventories were provided in the application, including the emissions of federally-regulated criteria pollutants and hazardous air pollutants (HAP), and state-regulated toxic air pollutants (TAP). The emission inventories have been reviewed by DEQ and appear to accurately reflect the potential emissions from the facility.

Uncontrolled facility-wide emissions of $NO_X$, CO, VOC, and $PM_{10}$ were estimated to exceed 100 tons per year. Based upon the manufacturer's emission guarantees and the use of the control equipment, fuels, and operational schedules listed in Table 1, the facility-wide potential to emit criteria pollutants (controlled emissions) is provided in Table 2.

**Table 2 POTENTIAL TO EMIT CRITERIA POLLUTANTS[a]**

| Emissions Units | $NO_X$ | | CO | | VOC | | $PM_{10}$[b] | | $SO_2$ | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] |
| CT and duct burner[d] peak-load[e] | 20.10 | 88 | 12.24 | 278.1 | 7.01 | 74.9 | 12.55 | 49.46 | 3.41 | 13.44 | 0.02 | 0.05 |
| CT and duct burner[d] low-load[f] | 452.78 | | 70.35 | | 18.91 | | | | | | | |
| CT and duct burner[d] startup/shutdown[g] | 304.56 | | 2510.00 | | 186.60 | | | | | | | |
| Emergency generator engine[h] | 11.64 | 0.35 | 6.30 | 0.19 | 0.73 | 0.03 | 0.73 | 0.02 | 0.02 | 0.01 | | |
| Fire pump engine[i] | 2.08 | 0.04 | 1.80 | 0.03 | 0.10 | 0.01 | 0.11 | 0.01 | 0.01 | 0.01 | | |
| Cooling tower[j] | | | | | | | 0.67 | 2.91 | | | | |
| Dry chemical storage silos[k] | | | | | | | 0.05 | 0.01 | | | | |
| Paved roads[l] | | | | | | | 0.20 | 0.01 | | | | |
| Unpaved roads[l] | | | | | | | 0.27 | 0.01 | | | | |
| **Facility-Wide Totals** | **466.50** | **88.39** | **2518.10** | **278.32** | **187.43** | **74.95** | **14.59** | **52.43** | **3.44** | **13.47** | **0.02** | **0.05** |

a) Short-term (lb/hr) and annual (T/yr) emission estimates assume the use of BACT and are based on daily and annual limits on hours of operation.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Tons per any consecutive 12 calendar month period, calculated as a 12-month rolling total.
d) Annual totals assume a maximum of 7,884 hr/yr operation, continuous duct-firing at steady-state, and include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).
e) At steady-state and $\geq$ 60% of full-load operating conditions.
f) At steady-state and < 60% of full-load operating conditions.
g) At startup or shutdown operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).
h) Limited to 4 hr/day and 60 hr/yr operation for maintenance and testing purposes.
i) Limited to 1 hr/day and 30 hr/yr operation for maintenance and testing purposes.
j) Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 mg/L and a circulating flow rate of 63,200 gpm.
k) Total emissions from the dry chemical storage silos. Annual totals assume each silo is loaded once per month for up to 2 hours.
l) Fugitive emission sources.

A summary of the estimated emissions increase of toxic air pollutants (TAP) is provided in Table 3. The estimated emissions increases of TAP were below applicable screening emissions levels (EL), except for 1,3-butadiene, acetaldehyde, ammonia, arsenic, benzene, cadmium, formaldehyde, naphthalene (as PAH), nickel, nitrous oxide, the group of seven polycyclic aromatic hydrocarbons (7-PAH, or POM), and sulfuric acid mist. The estimated emissions increases of TAP that exceeded applicable EL were modeled to demonstrate preconstruction compliance with the applicable acceptable ambient concentrations (AAC); refer to the Ambient Air Quality Impact Analyses section and memorandum in Appendix C for additional information. The estimated emissions increases of TAP that did not exceed applicable EL demonstrated preconstruction compliance with TAP standards in accordance with IDAPA 58.01.01.210.05 for uncontrolled average emission rates, and in accordance with IDAPA 58.01.01.210.08 for controlled average emission rates. Modeling analyses conducted in the development of TAP rules indicates that if a controlled average emission rate is below the applicable EL, controlled ambient concentrations are expected to be below the applicable acceptable ambient concentration. Annual limits on hours of operation (Permit Conditions 50 and 77) were included in accordance with IDAPA 58.01.01.210.08.c to limit TAP emission from the CT, duct burner, emergency generator engine, and fire pump engine.

As provided in Table 3, the facility-wide potential to emit HAP was estimated at below the major source thresholds of 10 tons per year for any individual HAP and below 25 tons per year for any combination of HAP.

**Table 3 EMISSION ESTIMATES OF TAP AND HAP – PTE AND EMISSIONS INCREASES**

| Pollutant | Category TAP/HAP | Averaging Period | Screening Emission Level | Emissions Increase | PTE |
|---|---|---|---|---|---|
| | | | lb/hr | lb/hr[a] | T/yr[e] |
| 1,3-Butadiene | HAP, 586 TAP[d] | Annual [b] | 2.40E-05 | 8.26E-04 | 3.62E-03 |
| 2-Methylnaphthalene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 5.24E-06 | |
| 3-Methylcholanthrene | HAP, 586 TAP[d] | Annual [b] | 2.50E-06 | 3.93E-07 | |
| 7,12-Dimethylbenz(a)anthracene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 3.50E-06 | |
| Acenaphthene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 6.35E-07 | |
| Acenaphthylene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 8.85E-07 | |
| Acetaldehyde | HAP, 586 TAP[d] | Annual [b] | 3.00E-03 | 7.68E-02 | 3.36E-01 |
| Acrolein | HAP, 585 TAP[c] | 24-hour [a] | 1.70E-02 | 1.39E-02 | 5.38E-02 |
| Ammonia | 585 TAP[c] | 24-hour [a] | 1.20E+00 | 1.86E+01 | |
| Anthracene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 5.98E-07 | |
| Arsenic | HAP, 586 TAP[d] | Annual [b] | 1.50E-06 | 4.37E-05 | 1.91E-04 |
| Barium | 585 TAP[c] | 24-hour [a] | 3.30E-02 | 1.07E-03 | |
| Benzene | HAP, 586 TAP[d] | Annual [b] | 8.00E-04 | 2.35E-02 | 1.03E-01 |
| Benzo(a)pyrene | HAP, 586 TAP[d,f] | Annual [b] | 2.00E-06 | 2.76E-07 | |
| Benzo(g,h,i)perylene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 2.93E-07 | |
| Beryllium | HAP, 586 TAP[d] | Annual [b] | 2.80E-05 | 2.62E-06 | 1.15E-05 |
| Cadmium | HAP, 586 TAP[d] | Annual [b] | 3.70E-06 | 2.40E-04 | 1.05E-03 |
| Chromium | HAP, 585 TAP[c] | 24-hour [a] | 3.30E-02 | 3.40E-04 | 3.06E-04 |
| Cobalt | HAP, 585 TAP[c] | 24-hour [a] | 3.30E-03 | 2.04E-05 | 8.04E-05 |
| Copper | 585 TAP[c] | 24-hour [a] | 1.30E-02 | 2.06E-04 | |
| Dichlorobenzene (o- and 1,4-) | HAP, 585 TAP[c] | 24-hour [a] | 2.00E+01 | 2.91E-04 | 1.15E-03 |
| Ethyl benzene | HAP, 585 TAP[c] | 24-hour [a] | 2.90E+01 | 6.83E-02 | 2.69E-01 |
| Fluoranthene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 9.08E-07 | |
| Fluorene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.45E-06 | |
| Formaldehyde | HAP, 586 TAP[d] | Annual [b] | 5.10E-04 | 1.38E+00 | 6.04E+00 |
| Hexane | HAP, 585 TAP[c] | 24-hour [a] | 1.20E+01 | 4.37E-01 | 1.72E+00 |
| Manganese | HAP, 585 TAP[c] | 24-hour [a] | 6.70E-02 | 9.22E-05 | 3.64E-04 |
| Mercury | HAP, 585 TAP[c] | 24-hour [a] | 1.00E-03 | 6.31E-05 | 2.49E-04 |
| Molybdenum | 585 TAP[c] | 24-hour [a] | 3.33E-01 | 2.67E-04 | |
| Naphthalene | 585 TAP[c] | 24-hour [a] | 3.33E+00 | 4.03E-03 | |
| Naphthalene (as PAH) | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 2.93E-03 | |
| Nickel | HAP, 586 TAP[d] | Annual [b] | 2.75E-05 | 4.59E-04 | 2.01E-03 |
| Nitrous oxide | 585 TAP[c] | 24-hour [a] | 6.00E+00 | 6.93E+00 | |
| Pentane | 585 TAP[c] | 24-hour [a] | 1.18E+02 | 6.31E-01 | |
| Phenanthrene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 5.94E-06 | |
| Propylene oxide | HAP, 585 TAP[c] | 24-hour [a] | 3.20E+00 | 6.19E-02 | 2.44E-01 |
| POM (7-PAH Group) | HAP, 586 TAP[d,f] | Annual [b] | 2.00E-06 | 2.74E-06 | |
| Pyrene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.31E-06 | |
| Selenium | HAP, 585 TAP[c] | 24-hour [a] | 1.30E-02 | 5.83E-06 | 2.30E-05 |
| Sulfuric acid mist | 585 TAP[c] | 24-hour [a] | 6.70E-02 | 2.61E-01 | |
| Toluene | HAP, 585 TAP[c] | 24-hour [a] | 2.50E+01 | 2.81E-01 | 1.10E+00 |
| Vanadium | 585 TAP[c] | 24-hour [a] | 3.00E-03 | 5.58E-04 | |
| Xylenes | HAP, 585 TAP[c] | 24-hour [a] | 2.90E+01 | 1.39E-01 | 5.38E-01 |
| Zinc | 585 TAP[c] | 24-hour [a] | 3.33E-01 | 7.04E-03 | |
| Total POM | HAP | Annual [b] | see above[g] | 6.89E-03 | 3.02E-02 |
| **Individual HAP** | | | | | 6.04 |
| **Total HAP** | | | | | 12.25 |

a) Uncontrolled average emission rate in pounds per hour is the maximum estimated hourly average.
b) Controlled average emission rate in pounds per hour is an annual average, based on the proposed annual operating schedule and annual limits.
c) Non-carcinogenic substance listed in IDAPA 58.01.01.585.
d) Carcinogenic substance listed in IDAPA 58.01.01.586.
e) Tons per consecutive 12 calendar month period.
f) Polyaromatic hydrocarbons (PAH) and polycyclic organic matter (POM) are defined in IDAPA 58.01.01.586.

CT and duct burner potential to emit criteria pollutants

Criteria pollutant short-term emissions from the CT and the duct burner were conservatively estimated based upon the maximum pollutant estimates across all expected operational conditions on a pollutant-by-pollutant basis and based upon the manufacturer's performance guarantees. Operational conditions evaluated included peak load and startup, shutdown, and low-load events. "Hot" startup, "warm" startup, "cold" startup, and shutdown events were described in the application, and as provided in Table 4. Emissions from startup and shutdown events were estimated using manufacturer data and a startup profile developed by the engineering, procurement and construction contractor of the project. Maximum 1-hour CO, $NO_X$, and VOC emissions were estimated to occur during "cold" startup events. Maximum 1-hour $PM_{10}$ and $SO_2$ emissions were estimated to occur during steady-state operation at full-load, based on the maximum hourly emissions from over 20 operating condition cases. The steady-state operating condition case having the maximum estimated emissions of regulated pollutants was at conditions of maximum fuel flow rate to the CT and the duct burner (2,375 MMBtu/hr, HHV), peak load, ambient temperature 0°F, and with CT inlet air evaporative cooling off (Case "C" K-0F).

**Table 4 CT STARTUP AND SHUTDOWN EVENTS**

| Event | Time since shutdown | Duration |
|---|---|---|
| | hours | minutes |
| Hot | < 16 | 125 |
| Warm | 16-64 | 280 |
| Cold | > 64 | 310 |
| Shutdown | | 41 |

Short-term emissions from the CT and the duct burner during low-load events (at power outputs below 60% of base load, excluding periods defined as startup or shutdown) were not specifically estimated, because emission rates were expected to be lower, and best available control technology (BACT) control devices were expected to be more effective, during low-load events than during startup and shutdown events. Because the duct burner has been designed to generate supplemental power when needed during peak periods, it was not expected to be fired during startup, shutdown, and low-load events, and was not accounted for in these short-term emission estimates. Although emission reductions resulting from the use of BACT were also not specifically accounted for within startup and shutdown emission estimates, it has been assumed that BACT will be used at all times when possible in accordance with the manufacturer's specifications to minimize emissions (refer to Appendix A for additional information).

$NO_X$ and CO criteria pollutant annual emissions from the CT and the duct burner during startup and shutdown events were estimated based upon the proposed maximum number of "hot" startup (253), "warm" startup (45), "cold" startup (7), and shutdown (305) events (accounting for 982 hours out of 7,884 hr/yr of annual operation). Annual emissions from the CT and the duct burner during steady-state operation at full-load were conservatively estimated based on the maximum hourly emissions from over 20 operating condition cases as described above, and accounted for the remainder of the annual hours of operation (6,902 hours). Although $NO_X$ and CO annual emissions from the CT and the duct burner during low-load operation were not specifically estimated, the number and duration of startup, shutdown, and low-load events and associated emissions have been effectively limited by the $NO_X$ and CO annual emission limits, combined with continuous compliance monitoring using $NO_X$ and CO continuous emission monitoring systems (CEMS).

VOC, $PM_{10}$, and $SO_2$ criteria pollutant annual emissions from the CT and the duct burner during all expected operating conditions (peak load, low-load, startup, and shutdown) were estimated based upon the maximum of the short-term pollutant estimates assuming 7,884 hr/yr of annual operation, and the startup/shutdown event pollutant estimates assuming the maximum number of annual events (conservatively estimated at 305 annual events). For VOC, maximum emissions were estimated during a "cold" startup event. For $PM_{10}$ and $SO_2$, maximum emissions were estimated during conditions of maximum fuel flow rate (Case "C" K-0F) as described above.

$PM_{2.5}$ emissions were conservatively estimated, assuming 100% of $PM_{10}$ was $PM_{2.5}$. Refer to Appendix A for additional discussion.

CT and duct burner uncontrolled emissions of HAP and TAP

HAP and TAP short-term and annual emissions from the CT and the duct burner were estimated based upon AP-42 Sections 3.1 and 1.4 emission factors, sulfuric acid emission factors from manufacturer's literature,[1] and the annual hours of operation (7,884 hr/yr). While certain combustion HAP and TAP emissions were expected to increase during startup, shutdown, and low-load events, the use of the CatOx control device during such periods and during steady-state operation was expected to achieve an overall reduction in such emissions. It was therefore considered reasonable to use the uncontrolled emission factors from AP-42 (i.e., not accounting for emission reductions due to BACT). Annual TAP and HAP emissions also conservatively assumed continuous firing of the duct burner (7,884 hr/yr).

Ammonia emissions resulting from operation of the SCR system ("ammonia slip") were estimated based on the manufacturer's performance guarantees for the SCR system; refer to the BACT review and determinations in Appendix A for additional information concerning ammonia slip.

Ancillary equipment potential to emit criteria pollutants

Criteria pollutant short-term emissions from the emergency generator engine, diesel-fired fire pump engine, the cooling tower, and the dry chemical storage silos were estimated based upon the manufacturer's performance guarantees and assume the use of BACT (refer to Appendix A for additional information). Emissions from the emergency generator engine and the fire pump engine were estimated based upon compliance with Tier 2 and Tier 3 emission standards (respectively), the use of ultra-low sulfur diesel (ULSD), and daily maintenance and testing operation of up to 4 hours of operation and 1 hour of operation, respectively. Emissions from the cooling tower were estimated based upon the design cooling tower solids content and flow rate, estimation methods referenced from AP-42 Section 13.4, and a reference publication.[2] Emissions from loading of the dry chemical storage silos was based upon the expected amount of chemicals required for water treatment purposes, design flow rates, and up to 2 hours of loading per day per silo.

Criteria pollutant annual emissions from the emergency generator engine and the fire pump engine were estimated based upon the short-term emission estimates and annual maintenance and testing operation of up to 60 hours of operation and 30 hours of operation, respectively. It has been assumed that the sole function of the emergency generator engine is to provide back-up power when electric power from the local utility is interrupted, and that the sole function of the fire pump engine is to provide power to pump water for fire suppression or protection. Annual emissions from the cooling tower were estimated based upon the short-term emission estimates and continuous operation (8,760 hr/yr). Annual emissions from loading of the dry chemical storage silos were estimated based upon the short-term emission estimates and up to 24 hours of loading per year per silo.

Criteria pollutant short-term and annual fugitive dust emissions from paved and unpaved roads were estimated based upon the expected number of vehicles, average travel distances, average vehicle weight, and expected site conditions.

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[1] "Gas Turbine Emissions and Control," GE Reference Document GER-4211, R. Pavri and G. Moore, GE Energy Services, March 2001.

[2] "Calculating Realistic $PM_{10}$ Emissions from Cooling Towers," J. Reisman and G. Frisbie, Air and Waste Management Association annual meeting, 2001.

Ancillary equipment uncontrolled emissions of HAP and TAP

HAP and TAP short-term emissions from the emergency generator engine and the fire pump engine were estimated based upon unlimited daily operation (i.e., daily limits on operation were not accounted for within the emission estimates), and AP-42 Sections 3.4 and 3.3 emission factors. Annual emissions from the emergency generator engine and the fire pump engine were estimated based upon the short-term emission estimates and annual maintenance and testing operation of up to 60 hours of operation and 30 hours of operation, respectively. Emissions of HAP and TAP from the cooling tower were assumed to be negligible. Short-term and annual emissions from loading of the dry chemical storage silos were conservatively estimated assuming that each TAP (magnesium oxide and lime) were equivalent to 100% of estimated PM emissions, and up to 2 hours of loading per day of each TAP from the silos.

The emission inventories for this facility are included in Appendix B.

## *Ambient Air Quality Impact Analyses*

The applicant has demonstrated preconstruction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has demonstrated preconstruction compliance in accordance with 40 CFR 52.21(k) that emissions from this facility will not cause or significantly contribute to a violation of any NAAQS or any applicable maximum allowable increase over the baseline concentration as defined in IDAPA 58.01.01.581. The applicant has also demonstrated preconstruction compliance to DEQ's satisfaction that the emissions increases due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP).

An ambient air quality impact analyses memorandum has been crafted by DEQ based upon a review of the modeling analyses submitted in the application and has been included in Appendix C.

NAAQS ambient air quality impact analyses and significant impact analyses

As provided in the Emission Inventories section and in the Ambient Air Quality Impact Analyses memorandum in Appendix C, the estimated potential to emit $NO_X$, CO, $PM_{10}$, and $SO_2$ exceeded applicable DEQ modeling thresholds established in the State of Idaho Air Quality Modeling Guideline.[3]

Because the maximum modeled impacts of the proposed project were below the National Ambient Air Quality Standards (NAAQS), preconstruction compliance was demonstrated in accordance with IDAPA 58.01.01.210.06.

Because the maximum modeled impacts of the proposed project for pollutants that have increments were below applicable Significant Impact Levels (SIL), Class I and Class II area cumulative increment consumption analysis were not required.

Because the ambient air quality impact results from the significant impact analyses (SIA) were below the Class I and Class II area maximum allowable increments, preconstruction compliance was demonstrated in accordance with 40 CFR 52.21(k) and IDAPA 58.01.01.581.

The short-term and annual emission rates used in the significant impact analyses (SIA) and in the ambient air quality impact analyses were determined to be equivalent or conservative when compared to the potential to emit emission estimates for criteria pollutants. Refer to the Emission Inventories section for additional information concerning the potential to emit emission inventory (Table 2).

Toxic air pollutants ambient air quality impact analyses

As provided in the Emission Inventories section and in the Ambient Air Quality Impact Analyses in Appendix C, the estimated facility-wide uncontrolled emission rates of 1,3-butadiene, acetaldehyde, ammonia, arsenic, benzene, cadmium, formaldehyde, naphthalene (as PAH), nickel, nitrous oxide, the

[3] State of Idaho Air Quality Modeling Guideline, Doc ID AQ-011, rev. 1, Idaho DEQ, December 31, 2002.

group of seven polycyclic aromatic hydrocarbons (7-PAH, or POM), and sulfuric acid mist from the facility exceeded applicable screening emission levels (EL) established in IDAPA 58.01.01.585-586 and were modeled.

Because the ambient concentration results at the point of compliance were less than or equal to applicable AAC for modeled TAP, preconstruction compliance was demonstrated in accordance with IDAPA 58.01.01.210.06 for uncontrolled average emission rates and in accordance with IDAPA 58.01.01.210.08 for controlled average emission rates. The short-term and annual emission rates used in the ambient air quality impact analyses were determined to be equivalent or conservative when compared to the facility-wide emission estimates for TAP. Because the facility-wide emissions increases (Table 3) were estimated to be less than or equal to applicable screening emissions levels (EL) for TAP which were not modeled, preconstruction compliance for these TAP was demonstrated in accordance with IDAPA 58.01.01.210.05 and IDAPA 58.01.01.210.08. Refer to the Emission Inventories section for additional information.

Although it has been assumed that BACT will be used at all times when possible in accordance with the manufacturer's specifications to minimize emissions (refer to Appendix A for additional information), the facility-wide emission estimates used in the TAP preconstruction compliance demonstrations did not account for emission reductions resulting from operation of the control devices (e.g., CatOx).

## REGULATORY ANALYSIS

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

The facility is located in Payette County, which is designated as attainment or unclassifiable for $PM_{2.5}$, $PM_{10}$, $SO_2$, $NO_2$, CO, and ozone, and is located within Air Quality Control Region (AQCR) 63. There are no Class I areas within 10 km of the proposed facility. Refer to 40 CFR 81.313 for additional information.

### *Permit to Construct (IDAPA 58.01.01.201)*

An application was submitted requesting a permit to construct the proposed facility. Therefore, 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)*

An application was submitted for a permit to construct the proposed facility, and an optional Tier II operating permit was not requested. Therefore, the procedures of IDAPA 58.01.01.400-410 were not applicable to this permitting action.

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

The proposed facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because the facility has the potential to emit 100 tons per year or more of CO (278.32 T/yr).

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr, it is a designated facility as defined in IDAPA 58.01.01.006, and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

In accordance with IDAPA 58.01.01.313.01.b, the permittee must submit a complete application to DEQ for an initial Tier I operating permit within 12 months of becoming a Tier I source or commencing operation.

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

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input (designated facility) which has the potential to emit 100 tons per year or more of CO (278.32 T/yr), it is classified as a major stationary source as defined in §52.21(b)(1)(i)(a) and in accordance with IDAPA 58.01.01.205.01.

*IDAPA 58.01.01.205 ..... PERMIT REQUIREMENTS FOR NEW MAJOR FACILITIES OR MAJOR MODIFICATIONS IN ATTAINMENT OR UNCLASSIFIABLE AREAS.*

*40 CFR 52.21 ..... Prevention of significant deterioration of air quality.*

*40 CFR 52.21(a)(2) ..... Applicability procedures.*

In accordance with §52.21(a)(2)(i), because the proposed facility is a new major stationary source (as defined in paragraph (b)(1) of this section) in an area designated as attainment or unclassifiable for regulated New Source Review (NSR) pollutants (refer to the Attainment Designation (40 CFR 81.313) section), the requirements of this section apply.

In accordance with §52.21(a)(2)(iii), no new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements.

*40 CFR 52.21(b)..... Definitions.*

In accordance with §52.21(b)(1)(i)(a), the proposed facility is classified as a major stationary source of air pollutants because it is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input which has the potential to emit 100 tons per year or more of CO, a regulated NSR pollutant.

In accordance with §52.21(b)(1)(i)(c)(iii), because the facility is a fossil fuel-fired steam electric plant of more that 250 million British thermal units per hour heat input, fugitive emissions of the facility were included in determining whether it is a major stationary source.

*40 CFR 52.21(j)..... Control technology review.*

In accordance with §52.21(j)(1), a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan (SIP) and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61.

In accordance with §52.21(j)(2), a new major stationary source shall apply best available control technology (BACT) for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

Because the proposed facility has the potential to emit regulated NSR pollutants in significant amounts, best available control technology was required for each regulated pollutant emissions source (refer to Table 6 and Table 7 to Appendix A for additional information). A summary of BACT reviews and determinations has been provided in Appendix A.

In accordance with §52.21(j)(4), for phased construction projects, the determination of BACT shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of BACT for the source. This project has not been identified as a phased construction project.

*40 CFR 52.21(k) ..... Source impact analysis.*

In accordance with §52.21(k), the owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of: (1) Any national ambient air quality standard in any air quality control region; or (2) Any applicable maximum allowable increase over the baseline concentration in any area.

In accordance with IDAPA 58.01.01.579, baseline concentrations for PSD were established for Air Quality Control Region 63 (ACQR) on the dates specified in Table 5. In accordance with IDAPA 58.01.01.579.01.c.ii, because the facility-wide potential to emit $SO_2$ is below the significance threshold (refer to Table 6 in Appendix A for additional information), the minor source baseline date for $SO_2$ remains "not yet triggered" following submittal of the complete application for this project.

**Table 5 BASELINE DATES FOR AQCR 63[a]**

| Pollutant | Major Source Baseline Date | Minor Source Baseline Date |
|---|---|---|
| $NO_2$ | February 8, 1988 | October 25, 1991 |
| $PM_{10}$ | January 6, 1975 | December 11, 1978 |
| $SO_2$ | January 6, 1975 | Not yet triggered. |

a) As established in accordance with IDAPA 58.01.01.579.

As provided in the Ambient Air Quality Impact Analyses section and in Appendix C, the applicant has demonstrated preconstruction compliance that emissions from this facility will not cause or significantly contribute to a violation of any NAAQS or any applicable maximum allowable increase over the baseline concentration as defined in IDAPA 58.01.01.581. Refer to the Ambient Air Quality Impact Analyses in Appendix C for additional information.

*40 CFR 52.21(r) ..... Source obligation.*

In accordance with §52.21(r)(1), any owner or operator who constructs or operates a source or modification not in accordance with the application submitted pursuant to this section or with the terms of any approval to construct, or any owner or operator of a source or modification subject to this section who commences construction after the effective date of these regulations without applying for and receiving approval hereunder, shall be subject to appropriate enforcement action.

In accordance with §52.21(r)(2), approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between constructions of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

In accordance with §52.21(r)(3), approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the State implementation plan and any other requirements under local, State, or Federal law.

These requirements are addressed within the permit authority section on the permit cover page.

## NSPS Applicability (40 CFR 60)

The facility is subject to 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and Subpart A – General Provisions.

The CT, HRSG, and HRSG duct burner are affected sources subject to Subpart KKKK, because the proposed construction date(s) are after February 18, 2005.

The emergency generator engine and the fire pump engine are affected sources subject to 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, because the proposed construction dates are after June 12, 2006.

In accordance with 40 CFR 60.4200(a)(2)(i), the CT is exempt from the requirements of Subpart GG, and the HRSG and duct burner are exempt from the requirements of 40 CFR 60, Subparts Da, Db, and Dc – Standards of Performance for Steam Generating Units, because the CT, HRSG, and duct burner are regulated under Subpart KKKK.

Refer to Table 1 for information concerning the proposed date of manufacture of each emissions unit.

NSPS Subpart KKKK

*40 CFR 60, Subpart KKKK ..... Standards of Performance for Stationary Combustion Turbines*

*40 CFR 60.4300 ..... What is the purpose of this subpart?*

*This subpart establishes emission standards and compliance schedules for the control of emissions from stationary CT that commenced construction, modification or reconstruction after February 18, 2005.*

Because commencement of construction of the stationary CT has been proposed after February 18, 2005, it will be subject to the requirements of this subpart.

*40 CFR 60.4305 ..... Does this subpart apply to my stationary combustion turbine?*

*(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.*

Because the stationary CT will have a heat input at peak load equal to or greater than 10 MMBtu per hour (2,134 MMBtu/hr) based on the higher heating value of the fuel, and will commence construction after February 18, 2005, the CT is subject to this subpart.

*(b) Stationary CT regulated under this subpart are exempt from the requirements of subpart GG of this part. HRSG and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.*

The stationary CT, HRSG, and duct burner are regulated under this subpart and are therefore exempted from the requirements specified.

*40 CFR 60.4310 ..... What types of operations are exempt from these standards of performance?*

*(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides ($NO_X$) emission limits in §60.4320.*

*(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the $NO_X$ emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.*

*(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.*

*(d) Combustion turbine test cells/stands are exempt from this subpart.*

Because the stationary CT has not been proposed to be operated as an emergency CT, engaged by manufacturers in research and development of equipment for both CT emission control techniques and CT efficiency improvements, located at an integrated gasification combined cycle electric utility steam generating unit subject to subpart Da, or operated as a CT test cell/stand, the requirements of §60.4310 are not applicable and were not included as a permit condition.

*40 CFR 60.4315 ..... What pollutants are regulated by this subpart?*

*The pollutants regulated by this subpart are $NO_X$ and $SO_2$.*

*40 CFR 60.4320 ..... What emission limits must I meet for $NO_X$?*

*(a) You must meet the emission limits for $NO_X$ specified in Table 1 to this subpart.*

*(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for $NO_X$.*

Because the CT is a new turbine firing natural gas, with a CT heat input at peak load (HHV) greater than 850 MMBtu/hr (2,134 MMBtu/hr) and greater than 30 MW output (269 MW), the applicable $NO_X$ standards from the table for each applicable combustion turbine type have been summarized in the table included in Permit Condition 37. As specified, the 96 ppm limit is applicable for operation at less than 75% of peak load. (The BACT limit for operation during periods of startup and shutdown is also 96 ppm; refer to the BACT discussion in Appendix A for additional information).

The requirements of §60.4320(b) are not applicable and were not included as a permit condition, because two or more turbines have not been proposed for this project (only one CT has been proposed).

**Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines**

| ***Combustion turbine type*** | ***Combustion turbine heat input at peak load (HHV)*** | ***$NO_X$ emission standard*** |
|---|---|---|
| *New turbine firing natural gas, electric generating* | *≤ 50 MMBtu/h* | *42 ppm at 15 percent $O_2$ or 290 ng/J of useful output (2.3 lb/MWh).* |
| *New turbine firing natural gas, mechanical drive* | *≤ 50 MMBtu/h* | *100 ppm at 15 percent $O_2$ or 690 ng/J of useful output (5.5 lb/MWh).* |
| *New turbine firing natural gas* | *> 50 MMBtu/h and ≤ 850 MMBtu/h* | *25 ppm at 15 percent $O_2$ or 150 ng/J of useful output (1.2 lb/MWh).* |
| *New, modified, or reconstructed turbine firing natural gas* | *> 850 MMBtu/h* | *15 ppm at 15 percent $O_2$ or 54 ng/J of useful output (0.43 lb/MWh)* |
| *New turbine firing fuels other than natural gas, electric generating* | *≤ 50 MMBtu/h* | *96 ppm at 15 percent $O_2$ or 700 ng/J of useful output (5.5 lb/MWh).* |
| *New turbine firing fuels other than natural gas, mechanical drive* | *≤ 50 MMBtu/h* | *150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh).* |
| *New turbine firing fuels other than natural gas* | *> 50 MMBtu/h and ≤ 850 MMBtu/h* | *74 ppm at 15 percent $O_2$ or 460 ng/J of useful output (3.6 lb/MWh).* |
| *New, modified, or reconstructed turbine firing fuels other than natural gas* | *> 850 MMBtu/h* | *42 ppm at 15 percent $O_2$ or 160 ng/J of useful output (1.3 lb/MWh).* |
| *Modified or reconstructed turbine* | *≤ 50 MMBtu/h* | *150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh).* |
| *Modified or reconstructed turbine firing natural gas* | *> 50 MMBtu/h and ≤ 850 MMBtu/h* | *42 ppm at 15 percent $O_2$ or 250 ng/J of useful output (2.0 lb/MWh).* |
| *Modified or reconstructed turbine firing fuels other than natural gas* | *> 50 MMBtu/h and ≤ 850 MMBtu/h* | *96 ppm at 15 percent $O_2$ or 590 ng/J of useful output (4.7 lb/MWh).* |
| *Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F* | *≤ 30 MW output* | *150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh).* |
| *Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F* | *> 30 MW output* | *96 ppm at 15 percent $O_2$ or 590 ng/J of useful output (4.7 lb/MWh).* |
| *Heat recovery units operating independent of the combustion turbine* | *All sizes* | *54 ppm at 15 percent $O_2$ or 110 ng/J of useful output (0.86 lb/MWh* |

Permit Condition 37 includes the requirements of this section.

*40 CFR 60.4325 ..... What emission limits must I meet for $NO_X$ if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?*

*You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.*

Because the permittee has not proposed burning of distillate oil or some other combination of fuels in the CT beyond that of pipeline quality natural gas, the requirements of §60.4325 are not applicable and were not included as a permit condition.

Permit Condition 47 includes the requirement to combust only pipeline quality natural gas.

*40 CFR 60.4330 ..... What emission limits must I meet for $SO_2$?*

*(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.*

Because the turbine is proposed to be located in a continental area, the permittee must comply with paragraph (a)(1), (a)(2), or (a)(3).

*(1) You must not cause to be discharged into the atmosphere from the subject stationary CT any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;*

*(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or*

*(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain $SO_2$ in excess of 65 ng $SO_2$/J (0.15 lb $SO_2$/MMBtu) heat input.*

Because the permittee has proposed that the CT will combust only pipeline quality natural gas as fuel, the requirements of §60.4330(a)(3) are not applicable and were not included as a permit condition.

*(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:*

*(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain $SO_2$ in excess of 780 ng/J (6.2 lb/MWh) gross output, or*

*(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.*

Because the turbine has not been proposed to be located in a noncontinental area or in a continental area that does not have access to natural gas, the requirements of §60.4330(b) are not applicable and were not included as a permit condition.

Permit Condition 38 includes the requirements of this section. Permit Condition 47 includes the requirement to combust only pipeline quality natural gas.

*40 CFR 60.4333 ..... What are my general requirements for complying with this subpart?*

*(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.*

*(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:*

*(1) Determine compliance with the applicable $NO_X$ emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or*

*(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.*

Because the proposed facility involves only one affected unit with heat recovery (one-on-one design configuration), methods for apportioning the combined gross energy output from the heat recovery unit in §60.4333(b) are not applicable and were not included as a permit condition.

Permit Condition 46 includes the requirements of this section.

*40 CFR 60.4335 ..... How do I demonstrate compliance for $NO_X$ if I use water or steam injection?*

*(a) If you are using water or steam injection to control $NO_X$ emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.*

*(b) Alternatively, you may use continuous emission monitoring, as follows:*

*(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a $NO_X$ monitor and a diluent gas (oxygen ($O_2$) or carbon dioxide ($CO_2$)) monitor, to determine the hourly $NO_X$ emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and*

*(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and*

*(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and*

*(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).*

Because the permittee has not proposed the use of water or steam injection for the control of $NO_X$ emissions, the requirements of §60.4335 were not applicable and were not included as a permit condition.

*40 CFR 60.4340 ..... How do I demonstrate continuous compliance for $NO_X$ if I do not use water or steam injection?*

*(a) If you are not using water or steam injection to control $NO_X$ emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the $NO_X$ emission result from the performance test is less than or equal to 75 percent of the $NO_X$ emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the $NO_X$ emission limit for the turbine, you must resume annual performance tests.*

Because the permittee has elected to use the CEMS compliance alternative to demonstrate continuous compliance for $NO_X$ in accordance with 40 CFR 60.4340(b), these requirements were not included as a permit condition.

*(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:*

*(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or*

*(2) Continuous parameter monitoring as follows:*

*(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's $NO_X$ formation characteristics, and you must monitor these parameters continuously.*

*(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-$NO_X$ mode.*

*(iii) For any turbine that uses SCR to reduce $NO_X$ emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.*

*(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the $NO_X$ emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).*

Because the CT is not a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, the requirements of §60.4340(b)(2)(i) are not applicable and were not included as a permit condition. §60.4340(b)(2) contains other applicable elective compliance options which were not included as a permit condition, because the permittee has elected to install and operate a $NO_X$ CEMS to demonstrate continuous compliance with $NO_X$ emission limits as described in §60.4345.

Permit Condition 54 includes the requirements of this section.

*40 CFR 60.4345 ..... What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?*

*If the option to use a $NO_X$ CEMS is chosen:*

*(a) Each $NO_X$ diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a $NO_X$ diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.*

*(b) As specified in §60.13(e)(2), during each full unit operating hour, both the $NO_X$ monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the $NO_X$ emission rate for the hour.*

*(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.*

*(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.*

*(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.*

The permittee has elected to install and operate a $NO_X$ CEMS to demonstrate continuous compliance with $NO_X$ emission limits in accordance with this section.

Permit Condition 55 includes the requirements of this section.

*40 CFR 60.4350 ..... How do I use data from the continuous emission monitoring equipment to identify excess emissions?*

*For purposes of identifying excess emissions:*

*(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).*

*(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both $NO_X$ and diluent monitors, the data acquisition and handling system must calculate and record the hourly $NO_X$ emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$ (or the hourly average $CO_2$ concentration is less than 1.0 percent $CO_2$), a diluent cap value of 19.0 percent $O_2$ or 1.0 percent $CO_2$ (as applicable) may be used in the emission calculations.*

*(c) Correction of measured $NO_X$ concentrations to 15 percent $O_2$ is not allowed.*

*(d) If you have installed and certified a $NO_X$ diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).*

*(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.*

*(f) Calculate the hourly average $NO_X$ emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:*

*(1) For simple-cycle operation:*

$$E = \frac{(NO_X)_h * (HI)_h}{P}$$

*Where:*

*E = hourly $NO_X$ emission rate, in lb/MWh,*

*$(NO_X)_h$= hourly $NO_X$ emission rate, in lb/MMBtu,*

*$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D–15a in appendix D to part 75 of this chapter, and*

*P = gross energy output of the CT in MW.*

*(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the CT, the additional electrical or mechanical energy (if any) generated by the steam turbine following the HRSG, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:*

$$P = (Pe)_t + (Pe)_c + P_s + P_o$$

*Where:*

*P = gross energy output of the stationary CT system in MW.*

*$(Pe)_t$ = electrical or mechanical energy output of the CT in MW,*

*$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and*

$$P_S = \frac{Q * H}{3.413 \times 10^6 \, Btu / MWh}$$

*Where:*

*$P_S$ = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,*

*Q = measured steam flow rate in lb/h,*

*H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x $10^6$ = conversion from Btu/h to MW.*

*$P_O$ = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the CT.*

*(3) For mechanical drive applications complying with the output-based standard, use the following equation:*

$$E = \frac{(NO_X)_m}{BL * AL}$$

*Where:*

*E = $NO_X$ emission rate in lb/MWh,*

*$(NO_X)_m$= $NO_X$ emission rate in lb/h,*

*BL = manufacturer's base load rating of turbine, in MW, and*

*AL = actual load as a percentage of the base load.*

Because the CT has not been proposed as part of a mechanical drive application (it has been proposed for electrical generation), the requirements of 40 CFR 60.4350(f)(3) are not applicable and were not included as a permit condition.

*(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).*

Because the CT is equipped with heat recovery, the requirements of 40 CFR 60.4350(g) are not applicable and were not included as a permit condition.

*(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).*

Permit Condition 56 includes the requirements of this section.

*40 CFR 60.4355 ..... How do I establish and document a proper parameter monitoring plan?*

*(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the $NO_X$ emission controls. The plan must:*

*(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the $NO_X$ emission controls,*

*(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,*

*(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),*

*(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,*

*(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and*

*(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:*

*(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.*

*(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.*

*(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the $NO_X$ emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.*

§60.4355 contains applicable elective and alternative compliance option requirements which were not included as a permit condition because the permittee has elected to install and operate a $NO_X$ CEMS to demonstrate continuous compliance with $NO_X$ emission limits.

*40 CFR 60.4360 ..... How do I determine the total sulfur content of the turbine's combustion fuel?*

*You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.*

§60.4360 contains applicable performance testing methodologies which were referenced but not included as a permit condition. In accordance with the permit general provisions, the permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing. The permittee has requested the use of the compliance option provided in §60.4365.

Permit Condition 59 includes the requirements of this section.

*40 CFR 60.4365 ..... How can I be exempted from monitoring the total sulfur content of the fuel?*

*You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for units located in continental areas and 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:*

*(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas and has potential sulfur emissions of less than 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for noncontinental areas; or*

*Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas or 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.*

The permittee has requested to use the compliance option provided in §60.4365.

Permit Condition 59 includes the requirements of this section.

*40 CFR 60.4370 ..... How often must I determine the sulfur content of the fuel?*

*The frequency of determining the sulfur content of the fuel must be as follows:*

*(a) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter ( i.e. , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).*

Because only pipeline quality natural gas has been proposed as a fuel source for the CT, the requirements of §60.4370(a) for fuel oil are not applicable and were not included as a permit condition.

*(b) Gaseous fuel. If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.*

*(c) Custom schedules. Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.*

*(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:*

*(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.*

*(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.*

*(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:*

*(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.*

*(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.*

*(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.*

*(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.*

*(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:*

*(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.*

*(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.*

*(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.*

*(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.*

§60.4370(c)(1)(i) through (iv) and (c)(2) contain applicable elective compliance options which were referenced but were not included as a permit condition.

Permit Condition 60 includes the requirements of this section.

*40 CFR 60.4375 ..... What reports must I submit?*

*(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.*

*(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.*

Permit Condition 69 includes the requirements of this section.

*40 CFR 60.4380 ..... How are excess emissions and monitor downtime defined for $NO_X$?*

*For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:*

*(a) For turbines using water or steam to fuel ratio monitoring:*

*(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for $NO_X$ control will also be considered an excess emission.*

*(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.*

*(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.*

Because the permittee has not proposed the use of water or steam to fuel ratio monitoring (or water or steam injection), the requirements of §60.4380(a) are not applicable and were not included as a permit condition.

*(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:*

*(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average $NO_X$ emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average $NO_X$ emission rate" is the arithmetic average of the average $NO_X$ emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average $NO_X$ emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid $NO_X$ emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average $NO_X$ emission rate" is the arithmetic average of all hourly $NO_X$ emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly $NO_X$ emissions rates for the preceding 30 unit operating days if a valid $NO_X$ emission rate is obtained for at least 75 percent of all operating hours.*

*(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: $NO_X$ concentration, $CO_2$ or $O_2$ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.*

*(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.*

Because the CT is equipped with heat recovery, the requirement in 40 CFR 60.4350(g) to assess excess emissions on a 4-hour rolling average basis is not applicable and was not included as a permit condition.

Permit Condition 70 includes the requirements of this section.

*(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the $NO_X$ emission controls:*

*(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.*

*(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.*

§60.4380(c) contains requirements which were not included as a permit condition because the permittee has elected to install and operate a $NO_X$ CEMS to demonstrate continuous compliance with $NO_X$ emission limits.

*40 CFR 60.4385 ..... How are excess emissions and monitoring downtime defined for $SO_2$?*

*If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:*

*(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the CT exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.*

*(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.*

*(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.*

Because only pipeline quality natural gas has been proposed as a fuel source for the CT, the requirements of §60.4385 pertaining to fuel oil are not applicable and were not included as a permit condition.

Permit Condition 71 includes the requirements of this section.

*40 CFR 60.4390 ..... What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?*

*(a) If you operate an emergency combustion turbine, you are exempt from the $NO_X$ limit and must submit an initial report to the Administrator stating your case.*

*(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the $NO_X$ limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.*

Because the stationary CT has not been proposed to operate as an emergency CT or to be engaged by manufacturers in research and development of equipment for both CT emission control techniques and CT efficiency improvements, the requirements of §60.4390 are not applicable and were not included as a permit condition.

*40 CFR 60.4395 ..... When must I submit my reports?*

*All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.*

Permit Condition 72 includes the requirements of this section.

*40 CFR 60.4400 ..... How do I conduct the initial and subsequent performance tests, regarding $NO_X$?*

*(a) You must conduct an initial performance test, as required in §60.8. Subsequent $NO_X$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).*

*(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:*

*(i) Measure the $NO_X$ concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the $NO_X$ emission rate:*

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P}$$

*Where:*

*E = $NO_X$ emission rate, in lb/MWh*

*$1.194 \times 10^{-7}$ = conversion constant, in lb/dscf-ppm*

*$(NO_X)_c$ = average $NO_X$ concentration for the run, in ppm*

*$Q_{std}$ = stack gas volumetric flow rate, in dscf/hr*

*P = gross electrical and mechanical energy output of the CT, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or*

*(ii) Measure the $NO_X$ and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the $NO_X$ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the $NO_X$ emission rate in lb/MWh.*

*(2) Sampling traverse points for $NO_X$ and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.*

*(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:*

*(i) You may perform a stratification test for $NO_X$ and diluent pursuant to*

*(A) [Reserved], or*

*(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.*

*(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:*

*(A) If each of the individual traverse point $NO_X$ concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent $CO_2$ (or $O_2$) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average $NO_X$ concentration during the stratification test; or*

*(B) For turbines with a $NO_X$ standard greater than 15 ppm @ 15% $O_2$, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point $NO_X$ concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent $CO_2$ (or $O_2$) from the mean for all traverse points; or*

*(C) For turbines with a $NO_X$ standard less than or equal to 15 ppm @ 15% $O_2$, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point $NO_X$ concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent $CO_2$ (or $O_2$) from the mean for all traverse points.*

*(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.*

*(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.*

*(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total $NO_X$ emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.*

*(3) If water or steam injection is used to control $NO_X$ with no additional post-combustion $NO_X$ control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 $NO_X$ emission limit.*

*(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average $NO_X$ emission rate at each tested level meets the applicable emission limit in §60.4320.*

*(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.*

*(6) The ambient temperature must be greater than 0°F during the performance test.*

Because the permittee has elected to use the CEMS compliance alternative (in lieu of performance testing as specified in 40 CFR 60.4340(a) and in this section) to demonstrate continuous compliance for $NO_X$ in accordance with 40 CFR 60.4340(b), these requirements were not included as a permit condition.

In accordance with the permit general provisions, the permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing.

*40 CFR 60.4405 ..... How do I perform the initial performance test if I have chosen to install a $NO_X$-diluent CEMS?*

*If you elect to install and certify a $NO_X$-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:*

*(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.*

*(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.*

*(c) Use the test data both to demonstrate compliance with the applicable $NO_X$ emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.*

*(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the $NO_X$ emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.*

Permit Condition 68 includes the requirements of this section.

*40 CFR 60.4410 ..... How do I establish a valid parameter range if I have chosen to continuously monitor parameters?*

*If you have chosen to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.*

§60.4410 contains an applicable elective compliance option which was not included as a permit condition because the permittee has elected to install and operate a $NO_X$ CEMS to demonstrate continuous compliance with $NO_X$ emission limits.

*40 CFR 60.4415 ..... How do I conduct the initial and subsequent performance tests for sulfur?*

*(a) You must conduct an initial performance test, as required in §60.8. Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.*

*(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:*

*(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or*

*(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).*

*(2) Measure the $SO_2$ concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the $SO_2$ emission rate:*

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P}$$

*Where:*

*E = $SO_2$ emission rate, in lb/MWh*

*$1.664 \times 10^{-7}$ = conversion constant, in lb/dscf-ppm*

*$(SO_2)_c$ = average $SO_2$ concentration for the run, in ppm*

*$Q_{std}$ = stack gas volumetric flow rate, in dscf/hr*

*P = gross electrical and mechanical energy output of the CT, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or*

*(3) Measure the $SO_2$ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the $SO_2$ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the $SO_2$ emission rate in lb/MWh.*

*(b) [Reserved]*

§60.4415(a) contains applicable performance testing methodologies which were referenced but not included as a permit condition. In accordance with the permit general provisions, the permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing.

Permit Condition 67 includes the requirements of this section.

*40 CFR 60.4420 ..... What definitions apply to this subpart?*

§60.4420 contains applicable definitions which were not included as a permit condition.

<u>NSPS Subpart IIII</u>

*40 CFR 60, Subpart IIII ..... Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

*40 CFR 60.4200 ..... Am I subject to this subpart?*

*(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.*

*(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:*

*(i) 2007 or later, for engines that are not fire pump engines,*

*(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.*

*(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:*

*(i) Manufactured after April 1, 2006 and are not fire pump engines, or*

*(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.*

*(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.*

Because commencement of construction (the date the engine is ordered) of the emergency generator engine has been proposed after July 11, 2005, and manufactured after April 1, 2006, the requirements of this subpart are applicable to the permittee.

Because commencement of construction (the date the engine is ordered) of the fire pump engine has been proposed after July 11, 2005, and manufactured as a certified NFPA fire pump engine after July 1, 2006, the requirements of this subpart are applicable to the permittee.

*(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.*

*(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.*

Because the emergency generator engine and the fire pump engine have not been proposed to be operated at a stationary CI ICE test cell/stand at the facility, and because the permittee will be required to obtain a permit for a reason other than the area source status of the stationary CI ICE (refer to the Title V Classification (IDAPA 58.01.01.300, 40 CFR 70) section for additional information), the requirements of §60.4200(b) through (c) are not applicable.

*(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.*

§60.4200(d) contains elective compliance exemption options which may require approval and which were not included as a permit condition. The permittee has not requested or qualified for exemption pursuant to the subparts provided.

*40 CFR 60.4201 ..... What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?*

Because the permittee has not proposed to manufacture stationary CI ICE, the requirements of §60.4201 are not applicable and were not included as a permit condition.

*40 CFR 60.4202 ..... What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?*

Because the permittee has not proposed to manufacture stationary CI ICE, the requirements of §60.4202 are not applicable to the permittee as a manufacturer and were not included as a permit condition. However in accordance with §60.4205, as an owner or operator the permittee must comply with the applicable emission standards for new nonroad CI engines, as discussed below:

*(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.*

*(1) For engines with a maximum engine power less than 37 kW (50 HP):*

*(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and*

*(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.*

*(2) For engines with a maximum engine power greater than or equal to 37 kW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.*

**Table 1 to 40 CFR 89.112–Emission Standards (g/kW-hr)**

| *Rated Power (kW)* | *Tier* | *Model Year*[1] | *$NO_X$* | *HC* | *NMHC + $NO_X$* | *CO* | *PM* |
|---|---|---|---|---|---|---|---|
| *kW<8* | *Tier 1* | *2000* | *—* | *—* | *10.5* | *8.0* | *1.0* |
| | *Tier 2* | *2005* | *—* | *—* | *7.5* | *8.0* | *0.80* |
| *8≤kW<19* | *Tier 1* | *2000* | *—* | *—* | *9.5* | *6.6* | *0.80* |
| | *Tier 2* | *2005* | *—* | *—* | *7.5* | *6.6* | *0.80* |
| *19≤kW<37* | *Tier 1* | *1999* | *—* | *—* | *9.5* | *5.5* | *0.80* |
| | *Tier 2* | *2004* | *—* | *—* | *7.5* | *5.5* | *0.60* |
| *37≤kW<75* | *Tier 1* | *1998* | *9.2* | *—* | *—* | *—* | *—* |
| | *Tier 2* | *2004* | *—* | *—* | *7.5* | *5.0* | *0.40* |
| | *Tier 3* | *2008* | *—* | *—* | *4.7* | *5.0* | |
| *75≤kW<130* | *Tier 1* | *1997* | *9.2* | *—* | *—* | *—* | *—* |
| | *Tier 2* | *2003* | *—* | *—* | *6.6* | *5.0* | *0.30* |
| | *Tier 3* | *2007* | *—* | *—* | *4.0* | *5.0* | |
| *130≤kW<225* | *Tier 1* | *1996* | *9.2* | *1.3* | *—* | *11.4* | *0.54* |
| | *Tier 2* | *2003* | *—* | *—* | *6.6* | *3.5* | *0.20* |
| | *Tier 3* | *2006* | *—* | *—* | *4.0* | *3.5* | |
| *225≤kW<450* | *Tier 1* | *1996* | *9.2* | *1.3* | *—* | *11.4* | *0.54* |
| | *Tier 2* | *2001* | *—* | *—* | *6.4* | *3.5* | *0.20* |
| | *Tier 3* | *2006* | *—* | *—* | *4.0* | *3.5* | |
| *450≤kW≤560* | *Tier 1* | *1996* | *9.2* | *1.3* | *—* | *11.4* | *0.54* |
| | *Tier 2* | *2002* | *—* | *—* | *6.4* | *3.5* | *0.20* |
| | *Tier 3* | *2006* | *—* | *—* | *4.0* | *3.5* | |
| *kW>560* | *Tier 1* | *2000* | *9.2* | *1.3* | *—* | *11.4* | *0.54* |
| | *Tier 2* | *2006* | *—* | *—* | *6.4* | *3.5* | *0.20* |

1. The model years listed indicate the model years for which the specified tier of standards takes effect.

- *In accordance with 40 CFR 89.113(a), exhaust opacity from compression-ignition nonroad engines shall not exceed:*
  - *20 percent during the acceleration mode;*
  - *15 percent during the lugging mode; and*
  - *50 percent during the peaks in either the acceleration or lugging modes.*

Because the proposed emergency generator engine is 2006 model year or later and greater than 560 kW, the applicable emission standards are Tier 2, as provided in §60.4202(a)(2).

Permit Condition 75 includes the requirements of this section.

*(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 kW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.*

*(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.*

*(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.*

*(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.*

*(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.*

Because the proposed fire pump engine is 2009 model year or later with a maximum engine power greater than or equal to 225 kW (300 HP) and less than 450 kW (600 HP), the applicable emission standards for the fire pump engine are provided in Table 4 to Subpart IIII of Part 60, as provided in §60.4202(d). Refer to the discussion provided for 40 CFR 60.4205 for additional information.

*40 CFR 60.4203 ..... How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?*

*Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.*

Because the permittee has not proposed to manufacture stationary CI ICE, the requirements of §60.4203 are not applicable and were not included as a permit condition.

*40 CFR 60.4204 ..... What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?*

Because the permittee has not proposed the use of the stationary CI ICE for non-emergency purposes, the requirements of §60.4204 are not applicable and were not included as a permit condition.

*40 CFR 60.4205 ..... What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?*

*(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).*

Because the stationary CI ICE proposed will be post-2007 model year (2009 model year), the requirements of §60.4205(a) are not applicable and were not included as a permit condition.

*(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.*

Because the emergency generator engine proposed will be post-2007 model year, with a displacement of less than 30 liters per cylinder (2.54 L/cylinder), the permittee must comply with the applicable emission standards for new nonroad CI engines in §60.4202. Refer to §60.4202 for additional discussion regarding the referenced emission standards.

*(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.*

**Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines**

**[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]**

| *Maximum engine power* | *Model year(s)* | *NMHC + $NO_X$* | *CO* | *PM* |
|---|---|---|---|---|
| *kW<8 (HP<11)* | *2010 and earlier* | *10.5 (7.8)* | *8.0 (6.0)* | *1.0 (0.75)* |
| *8≤kW<19 (11≤HP<25)* | *2011+* | *7.5 (5.6)* | | *0.40 (0.30)* |
| | *2010 and earlier* | *9.5 (7.1)* | *6.6 (4.9)* | *0.80 (0.60)* |
| | *2011+* | *7.5 (5.6)* | | *0.40 (0.30)* |
| *19≤kW<37 (25≤HP<50)* | *2010 and earlier* | *9.5 (7.1)* | *5.5 (4.1)* | *0.80 (0.60)* |
| | *2011+* | *7.5 (5.6)* | | *0.30 (0.22)* |
| *37≤kW<56 (50≤HP<75)* | *2010 and earlier* | *10.5 (7.8)* | *5.0 (3.7)* | *0.80 (0.60)* |
| | *2011+*[1] | *4.7 (3.5)* | | *0.40 (0.30)* |
| *56≤kW<75 (75≤HP<100)* | *2010 and earlier* | *10.5 (7.8)* | *5.0 (3.7)* | *0.80 (0.60)* |
| | *2011+1* | *4.7 (3.5)* | | *0.40 (0.30)* |
| *75≤kW<130 (100≤HP<175)* | *2009 and earlier* | *10.5 (7.8)* | *5.0 (3.7)* | *0.80 (0.60)* |
| | *2010+*[2] | *4.0 (3.0)* | | *0.30 (0.22)* |
| *130≤kW<225 (175≤HP<300)* | *2008 and earlier* | *10.5 (7.8)* | *3.5 (2.6)* | *0.54 (0.40)* |
| | *2009+*[3] | *4.0 (3.0)* | | *0.20 (0.15)* |
| *225≤kW<450 (300≤HP<600)* | *2008 and earlier* | *10.5 (7.8)* | *3.5 (2.6)* | *0.54 (0.40)* |
| | *2009+*[3] | *4.0 (3.0)* | | *0.20 (0.15)* |
| *450≤kW≤560 (600≤HP≤750)* | *2008 and earlier* | *10.5 (7.8)* | *3.5 (2.6)* | *0.54 (0.40)* |
| | *2009+* | *4.0 (3.0)* | | *0.20 (0.15)* |
| *kW>560 (HP>750)* | *2007 and earlier* | *10.5 (7.8)* | *3.5 (2.6)* | *0.54 (0.40)* |
| | *2008+* | *6.4 (4.8)* | | *0.20 (0.15)* |

1) *For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.*
2) *For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.*
3) *In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.*

Because the fire pump engine proposed will have a displacement of less than 30 L/cylinder (1.13 L/cylinder), the permittee must comply with the emission standards in table 4 for all pollutants. Because the fire pump engine is rated at less than 2,650 rpm (1,760 rpm), the permittee must comply with the emission standards listed for model year 2009 and later (in reference to legend note 3 of Table 4 to Subpart IIII of Part 60).

*(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.*

*(1) Reduce $NO_X$ emissions by 90 percent or more, or limit the emissions of $NO_X$ in the stationary CI internal combustion engine exhaust to 1.6 grams per kW-hour (1.2 grams per HP-hour).*

*(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/kW-hr (0.11 g/HP-hr).*

Because the fire pump engine proposed will have a displacement of less than 30 L/cylinder (1.13 L/cylinder), the emission standards in §60.4205(d) were not applicable and were not included as a permit condition.

Permit Conditions 75 and 76 include the requirements of this section.

*40 CFR 60.4206 ..... How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?*

*Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.*

Permit Condition 80 includes the requirements of this section.

*40 CFR 60.4207 ..... What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?*

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

- In accordance with 40 CFR 80.510(b), all NR and LM diesel fuel is subject to the following per-gallon standards:

  (1) Sulfur content.

  (i) 15 ppm maximum for NR diesel fuel.

  (2) Cetane index or aromatic content, as follows:

  (i) A minimum cetane index of 40; or

  (ii) A maximum aromatic content of 35 volume percent.

Permit Condition 82 includes the requirements of this section. Because the fuel requirements of 40 CFR 80.510(b) are more stringent than 40 CFR 80.510(a) and will apply after October 2010, the standards of 40 CFR 80.510(a) were referenced but were not included as a permit condition.

*(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.*

*(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.*

*(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.*

§60.4207(c) and (e) include compliance options for which approval is required, and which were not included as permit conditions. Because the emergency generator engine and the fire pump engine will not be located in Alaska, the requirements of §60.4207(d) are not applicable and were not included as a permit condition.

*40 CFR 60.4208 ..... What is the deadline for importing or installing stationary CI ICE produced in the previous model year?*

*(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.*

Installation of stationary CI ICE that do not meet the applicable requirements for 2007 model year engines has not been proposed (the proposed stationary CI ICE are model year 2009). Because only the stationary CI ICE emissions units identified in Table 1 are permitted as a result of this permitting action, this requirement was not included as a permit condition.

*(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 kW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.*

Because the proposed emergency generator engine and the fire pump engine will each be greater than 25 HP (315 HP and 1,102 HP), the requirements of §60.4208(b) are not applicable and were not included as a permit condition.

*(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 kW (25 HP) and less than 56 kW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.*

*(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 kW (75 HP) and less than 130 kW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.*

*(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 kW (175 HP), including those above 560 kW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.*

*(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 kW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.*

*(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.*

Because the stationary CI ICE have not been proposed for non-emergency use, the requirements of §60.4208(c) through (f) are not applicable and were not included as a permit condition. Because the permittee has not proposed importation of CI ICE, §60.4208(g) was not included as a permit condition.

*(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.*

Because the proposed stationary CI ICE are not existing units which have been modified, reconstructed, or reinstalled, the requirements of §60.4208(h) are not applicable and were not included as a permit condition.

*40 CFR 60.4209 ..... What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?*

*If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.*

*(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.*

*(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.*

Permit Condition 81 includes the requirements of this section.

*40 CFR 60.4210 ..... What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?*

Because the permittee has not proposed to manufacture stationary CI ICE, the requirements of §60.4210 are not applicable and were not included as a permit condition.

*40 CFR 60.4211 ..... What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?*

*(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.*

In accordance with 40 CFR 94.1(d), 40 CFR 94 applies to the permittee as specified in NSPS Subpart IIII, to CI engines subject to the standards of NSPS Subpart IIII.

In accordance with 40 CFR 1068.1(a)(3), 40 CFR 1068 applies to the permittee with respect to stationary CI engines certified using the provisions of 40 CFR 1039, as indicated in NSPS Subpart IIII.

Because the permittee has not proposed the use of the emergency generator engine and the fire pump engine for nonroad use (as defined in 40 CFR 89.2), and the engines are regulated by NSPS Subpart IIII, the requirements of Part 89 are not applicable.

§60.4211(a) incorporates applicable requirements from 40 CFR parts 89, 94, and 1068 by reference. Permit Condition 78 references and includes the requirements of this section.

*(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.*

**Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines**

**[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]**

| *Engine power* | *Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)* |
|---|---|
| *kW<75 (HP<100)* | *2011* |
| *75≤kW<130 (100≤HP<175)* | *2010* |
| *130≤kW≤560 (175≤HP≤750)* | *2009* |
| *kW>560 (HP>750)* | *2008* |

*(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.*

*(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.*

*(3) Keeping records of engine manufacturer data indicating compliance with the standards.*

*(4) Keeping records of control device vendor data indicating compliance with the standards.*

*(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.*

Because the stationary CI ICE were proposed as model year 2009, the requirements of §60.4211(b) are not applicable and were not included as a permit condition.

*(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.*

*(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.*

*(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.*

*(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.*

*(i) Identification of the specific parameters you propose to monitor continuously;*

*(ii) A discussion of the relationship between these parameters and $NO_X$ and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_X$ and PM emissions;*

*(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;*

*(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and*

*(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.*

*(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.*

*(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.*

Because the emission standards specified in §60.4204(c) and §60.4205(d) were not applicable, the requirements of §60.4211(d) were not included as a permit condition.

Permit Condition 78 references and includes the requirements of this section.

*40 CFR 60.4212 ..... What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?*

*Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.*

Permit Condition 86 includes the requirements of this section.

*(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.*

*(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.*

*(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:*

*NTE requirement for each pollutant = (1.25) x (STD) (Eq. 1)*

*Where:*

*STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.*

*Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.*

*(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.*

*Where:*

*STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).*

*Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.*

§60.4212(a) through (d) contain applicable performance testing methodologies which were referenced but not included as a permit condition. In accordance with the permit general provisions, the permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing.

*40 CFR 60.4213 ..... What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?*

Because the permittee has not proposed the use of a stationary CI ICE with a displacement of greater than or equal to 30 L/cylinder, the requirements of §60.4213 are not applicable and were not included as a permit condition.

*40 CFR 60.4214 ..... What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?*

*(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 kW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 kW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.*

*(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.*

*(i) Name and address of the owner or operator;*

*(ii) The address of the affected source;*

*(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;*

*(iv) Emission control equipment; and*

*(v) Fuel used.*

*(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.*

*(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.*

*(ii) Maintenance conducted on the engine.*

*(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.*

*(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.*

Because the permittee has not proposed the use of the stationary CI ICE for non-emergency purposes, the requirements of §60.4214 are not applicable and were not included as a permit condition.

*(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.*

**Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines**

**[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]**

| *Engine power* | *Starting model year* |
|---|---|
| *19≤kW<56 (25≤HP<75)* | *2013* |
| *56≤kW<130 (75≤HP<175)* | *2012* |
| *kW≥130 (HP≥175)* | *2011* |

Because the stationary CI ICE were proposed as model year 2009, the requirements of §60.4214(b) are not applicable and were not included as a permit condition.

*(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.*

*40 CFR 60.4215 ..... What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?*

Because the facility will not be located in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands, the requirements of §60.4215 are not applicable and were not included as a permit condition.

*40 CFR 60.4216 ..... What requirements must I meet for engines used in Alaska?*

Because the facility will not be located in Alaska, the requirements of §60.4215 are not applicable and were not included as a permit condition.

*40 CFR 60.4217 ..... What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?*

*(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.*

*(b) [Reserved]*

§60.4217 contains alternative compliance options for special fuels which require approval and which were not included as a permit condition.

*40 CFR 60.4218 ..... What parts of the General Provisions apply to me?*

*Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.*

**Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII**

**[As stated in §60.4218, you must comply with the following applicable General Provisions:]**

| *General Provisions citation* | *Subject of citation* | *Applies to subpart* | *Explanation* |
|---|---|---|---|
| *§60.1* | *General applicability of the General Provisions* | *Yes* | |
| *§60.2* | *Definitions* | *Yes* | *Additional terms defined in §60.4219.* |
| *§60.3* | *Units and abbreviations* | *Yes* | |
| *§60.4* | *Address* | *Yes* | |
| *§60.5* | *Determination of construction or modification* | *Yes* | |
| *§60.6* | *Review of plans* | *Yes* | |
| *§60.7* | *Notification and Recordkeeping* | *Yes* | *Except that §60.7 only applies as specified in §60.4214(a).* |
| *§60.8* | *Performance tests* | *Yes* | *Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.* |
| *§60.9* | *Availability of information* | *Yes* | |
| *§60.10* | *State Authority* | *Yes* | |
| *§60.11* | *Compliance with standards and maintenance requirements* | *No* | *Requirements are specified in subpart IIII.* |
| *§60.12* | *Circumvention* | *Yes* | |
| *§60.13* | *Monitoring requirements* | *Yes* | *Except that §60.13 only applies to stationary CI ICE with a displacement of ≥30 liters per cylinder.* |
| *§60.14* | *Modification* | *Yes* | |
| *§60.15* | *Reconstruction* | *Yes* | |
| *§60.16* | *Priority list* | *Yes* | |
| *§60.17* | *Incorporations by reference* | *Yes* | |
| *§60.18* | *General control device requirements* | *No* | |
| *§60.19* | *General notification and reporting requirements* | *Yes* | |

§60.4218 contains a table identifying applicable and non-applicable general provisions. This table was referenced but not included as a permit condition.

Permit Condition 28 includes the requirements of this section.

*40 CFR 60.4219 ..... What definitions apply to this subpart?*

§60.4219 contains applicable definitions which were not included as a permit condition.

<u>NSPS Subpart A</u>

*40 CFR 60, Subpart A ..... General Provisions*

*40 CFR 60.1 ..... Applicability.*

*(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.*

*(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.*

Because the proposed facility contains affected facilities (the CT and the duct burner, the emergency generator engine, and the fire pump engine) which have been proposed to commence construction after the date of publication of the relevant applicable NSPS standards (Subparts KKKK and IIII), the general provisions in Subpart A are applicable.

40 CFR 60, Subpart A contains applicable requirements which have been summarized in the summary table provided in Permit Condition 28.

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

The proposed facility and emission sources are not subject to NESHAP requirements in 40 CFR 61.

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

The stationary RICE (emergency generator engine and fire pump engine) are area sources subject to 40 CFR 63, Subpart ZZZZ because they commenced construction on or after June 12, 2006 (2009). Because these sources are subject to regulation under 40 CFR 60, Subpart IIII, no further requirements are applicable under 40 CFR 63, Subpart ZZZZ.

The facility is not subject to 40 CFR 63, Subpart Q – NESHAP for Industrial Process Cooling Towers or to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines, because the facility was not proposed as a major source of HAP emissions.

<u>Subpart ZZZZ</u>

*40 CFR 63, Subpart ZZZZ..... National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

*40 CFR 63.6580 ..... What is the purpose of subpart ZZZZ?*

*Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.*

*40 CFR 63.6585 ..... Am I subject to this subpart?*

*You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.*

*(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.*

*(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.*

*(c) An area source of HAP emissions is a source that is not a major source.*

*(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.*

*(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.*

Because the permittee has proposed to operate the emergency generator engine and fire pump engine at an area source of HAP emissions (the facility is not major for HAP emissions), the permittee is subject to this subpart.

§63.6585(e) contains elective compliance exemption options which may require approval and which were not included as a permit condition.

*40 CFR 63.6590 ..... What parts of my plant does this subpart cover?*

*This subpart applies to each affected source.*

*(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.*

*(1) Existing stationary RICE.*

*(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.*

*(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.*

*(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.*

*(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.*

*(2) New stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.*

*(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.*

*(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.*

*(3) Reconstructed stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.*

*(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.*

*(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.*

*(b) Stationary RICE subject to limited requirements. (1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(h).*

*(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; or*

*(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.*

*(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(h) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.*

*(3) A stationary RICE which is an existing spark ignition 4 stroke rich burn (4SRB) stationary RICE located at an area source of HAP emissions; an existing spark ignition 4SRB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions; an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE; an existing spark ignition 4 stroke lean burn (4SLB) stationary RICE; an existing compression ignition emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; an existing spark ignition emergency or limited use stationary RICE; an existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; or an existing stationary residential, commercial, or institutional emergency stationary RICE located at an area source of HAP emissions, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.*

*(c) Stationary RICE subject to Regulations under 40 CFR part 60. An affected source that is a new or reconstructed stationary RICE located at an area source, or is a new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP, or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP, must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.*

The stationary RICE were classified as new affected sources, because the emergency generator engine and fire pump engine have been proposed to commence construction on or after June 12, 2006 (2009). Because the proposed stationary RICE have been proposed at an area source, and subject to regulations under 40 CFR 60, Subpart IIII, no further requirements apply for the emergency generator engine and fire pump engine under 40 CFR 63, Subpart ZZZZ.

<u>Subpart YYYY</u>

*40 CFR 63, Subpart YYYY..... National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*

*40 CFR 63.6080 ..... What is the purpose of subpart YYYY?*

*Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.*

*40 CFR 63.6085 ..... Am I subject to this subpart?*

*You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.*

Because the facility-wide potential to emit was estimated at below the major source thresholds of 10 tons/yr for individual HAP and below 25 tons/yr for any combination of HAP, this subpart is not applicable (refer to the Emission Inventories section for additional information).

Subpart Q

*40 CFR 63, Subpart Q..... National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers*

*40 CFR 63.400 ..... Applicability.*

*(a) The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in §63.401.*

Because the facility-wide potential to emit HAP was estimated at below the major source thresholds of 10 tons/yr for individual HAP and below 25 tons/yr for any combination of HAP, this subpart was not applicable (refer to the Emission Inventories section for additional information).

## *Permit Conditions Review*

This section describes the permit conditions for this initial PTC.

Initial Permit Conditions 1 and 2

These permit conditions describe the purpose of this permitting action and the emission sources and the control equipment regulated by this permit. The information included reflects design, equipment, and operational information presented in the application.

Initial Permit Conditions 3, 4, 5, and 6

Permit Condition 3 incorporates fugitive dust emission limits in accordance with IDAPA 58.01.01.650-651.

Compliance with this limit is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 4 through 6, and 103), including facility-wide inspections and corrective action when appropriate.

Initial Permit Conditions 7 and 8

Permit Condition 7 incorporates odorous emission limits in accordance with IDAPA 58.01.01.776.01.

Compliance with this limit is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 8 and 103), including corrective action when appropriate.

Initial Permit Conditions 9, 10, and 11

Permit Condition 9 incorporates visible emission limits in accordance with IDAPA 58.01.01.625.

Compliance with this limit is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 10, 11, and 103), including facility-wide inspection (or continuous opacity monitoring systems) and corrective action and opacity testing when appropriate.

Initial Permit Condition 12

This permit condition incorporates PM emission limits for process equipment as defined in IDAPA 58.01.01.006, in accordance with IDAPA 58.01.01.700-703, which includes the cooling tower and dry chemical storage silos.

Compliance with the requirement to use bin vent filters (Permit Condition 92) was considered adequate to ensure compliance with the process weight-based PM emission limitation for the dry chemical storage silos; the PM emission estimates provided (less than 0.086 lb/hr per silo loaded) and compliance with this requirement have been determined to be more stringent than the minimum allowable process weight-based PM emission limitation (1 lb/hr) as required by IDAPA 58.01.01.700.02.

Compliance with the requirement to use drift eliminators (Permit Condition 88) and solids content and flow rate limits (Permit Condition 90) were considered adequate to ensure compliance with the process weight-based PM emission limitation for the cooling tower; the PM emission estimates provided (less than 0.791 lb/hr) and compliance with these requirements have been determined to be more stringent than the minimum allowable process weight-based PM emission limitation (1 lb/hr) as required by IDAPA 58.01.01.700.02.

Initial Permit Condition 13

This permit condition incorporates PM emission limits from fuel-burning equipment as defined in IDAPA 58.01.01.006, in accordance with IDAPA 58.01.01.676. The duct burner is used for the primary purpose of producing heat and power by indirect heat transfer when operating as a combined cycle.

Compliance with the $PM_{10}$ emission limit (Permit Condition 39) is considered adequate to ensure compliance with this limit; the $PM_{10}$ emission limit for the CT and the duct burner (combined) has been determined to be more stringent based upon information provided in the application. Refer to the associated stringency evaluation included in Appendix B for additional information.

Initial Permit Condition 14 and 15

Permit Condition 14 incorporates sulfur content limits for distillate fuel oil, in accordance with IDAPA 58.01.01.725.

Compliance with this limit is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 15 and 103).

For the emergency generator engine and the fire pump engine, compliance with the requirement to use ultra-low sulfur diesel (ULSD) fuels (Permit Condition 82) ensures compliance with this limit; the ULSD sulfur content limit of 15 ppm has been determined to be more stringent (0.0015% by weight).

Initial Permit Conditions 16, 17, and 18

Permit Conditions 16 and 17 require developing and complying with the requirements of an O&M manual to ensure compliance with BACT emission limits (Permit Conditions 33 through 35), BACT work practices (Permit Conditions 43, 79, 89, and 94), the ammonia injection flow rate limit (Permit Condition 49), and control equipment maintenance and operation general provisions (Permit Condition 96).

Compliance with these requirements is ensured by complying with monitoring and recordkeeping requirements (Permit Condition 18).

Initial Permit Conditions 19, 20, 21, 22, 23, 24, 25, and 26

Permit Conditions 19 through 26 require compliance with excess emission procedures and requirements in accordance with IDAPA 58.01.01.130-136.

Compliance with these limits is ensured by complying with recordkeeping, notification, and reporting requirements (Permit Condition 21, 23, 25, 26, and 103).

Excess emissions include (but are not limited to) any excess emissions assessed according to CEMS monitoring requirements and any excess emissions assessed according to NSPS $NO_X$ CEMS Monitoring Excess Emissions requirements (Permit Conditions 53, 56, 58, 70, and 71).

Initial Permit Condition 27

This permit condition provides recommended test methods to be used if performance testing is required, unless otherwise approved by DEQ.

The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing in accordance with the performance testing general provision (Permit Condition 100).

Initial Permit Condition 28

This permit condition incorporates a summary of general provisions from NSPS Subpart A and as required by NSPS Subparts KKKK and IIII. Refer to NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Conditions 29 and 30

These permit conditions specify that with regard to permit conditions referenced in accordance with federal requirements (i.e., NSPS requirements), or with regard to incorporation of requirements by reference, should there be a conflict between the language of the permit condition and the language of the requirement, the language of the requirement shall govern. Federal requirements are incorporated by reference in accordance with IDAPA 58.01.01.107.

Initial Permit Condition 31

This permit condition provides DEQ agency contact information.

Initial Permit Condition 32

This permit condition defines startup, shutdown, and low-load events for the purposes of determining for each operating hour whether the BACT emission limits (Permit Condition 33), the BACT secondary emission limits for low-load events (Permit Condition 34), or the BACT secondary emission limits for startup and shutdown events (Permit Condition 35) are applicable to the CT and the duct burner.

Percentage of full load and maximum event duration are included in the event definitions. For general applicability across all startup events (“cold”, “warm”, and “hot”), the maximum event duration of 5.5 hours was included in the startup event definition.

A maximum event duration was not defined for low-load events. Operation at low-load was determined to be effectively limited as a result of the annual $NO_X$ and CO emission limits (Permit Condition 36), and annual VOC, $PM_{10}$, and $SO_2$ emission estimates based on the maximum hourly VOC, $PM_{10}$, and $SO_2$ emission estimates provided (including low-load) and assuming 7,884 hr/yr of annual operation (Permit Condition 50) were estimated at below the annual VOC, $PM_{10}$, and $SO_2$ emissions estimates provided and used in modeling analyses. Refer to the Response to Comments document for additional information.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Condition 51).

Initial Permit Condition 33

This permit condition establishes BACT emission limits for the CT and the duct burner (combined).

Refer to Appendix A for additional information concerning BACT determinations. These emission limits are applicable during all expected operating conditions excluding during startup, shutdown, and low-load events.

Compliance with these limits is ensured by complying with continuous monitoring and recordkeeping (Permit Conditions 51, 52, 53, 57, 58, and 103), performance testing (Permit Condition 64), and work practice requirements (Permit Condition 43).

Initial Permit Condition 34

This permit condition establishes BACT secondary emission limits for the CT and the duct burner (combined) for low-load events.

Refer to Appendix A for additional information concerning BACT determinations. The short-term emission rate estimates associated with the VOC emission limit was used as the basis for determining potential to emit to allow the flexibility to operate continuously at low-load (if necessary). Refer to the Emission Inventories section for additional information.

Compliance with these limits is ensured by complying with continuous monitoring and recordkeeping (Permit Conditions 51, 52, 53, 57, 58, and 103), performance testing (Permit Condition 65), and work practice requirements (Permit Condition 43).

Initial Permit Condition 35

This permit condition establishes BACT secondary emission limits for the CT and the duct burner (combined) for startup and shutdown events.

Refer to Appendix A for additional information concerning BACT determinations. The short-term emission rate estimates associated with these emission limits were used as the basis for preconstruction modeling compliance demonstrations (SIA and NAAQS) involving short-term averaging periods. Refer to the Emission Inventories and the Ambient Air Quality Impact Analyses sections for additional information.

Compliance with these limits is ensured by complying with continuous monitoring and recordkeeping (Permit Conditions 51, 52, 53, 57, 58, and 103) and work practice requirements (Permit Condition 43).

Initial Permit Condition 36

This permit condition establishes annual emission limits for the CT and the duct burner.

The annual emission rate estimates associated with these limits were the maximum estimates across all expected operating conditions, including peak load and startup, shutdown, and low-load events. The annual emission rate estimates were also used as the basis for preconstruction modeling compliance demonstrations (NAAQS) involving annual averaging periods. Refer to the Emission Inventories and the Ambient Air Quality Impact Analyses sections for additional information.

Annual VOC, $PM_{10}$, and $SO_2$ emission limits were not required. Annual VOC, $PM_{10}$, and $SO_2$ emission estimates based upon the short-term VOC, $PM_{10}$, and $SO_2$ emission estimates and assuming continuous operation were estimated at below the annual VOC, $PM_{10}$, and $SO_2$ emission estimates provided and used in the annual modeling analyses.

Compliance with this limit is ensured by complying with continuous monitoring, recordkeeping, and reporting requirements (Permit Conditions 52, 53, 57, 58, and 103).

Initial Permit Condition 37

This permit condition incorporates $NO_X$ emission limits for the CT and the duct burner from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 38

This permit condition incorporates $SO_2$ emission limits from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 39

This permit condition establishes a short-term $PM_{10}$ emission limit for the CT and the duct burner.

The short-term emission rate estimate associated with the $PM_{10}$ emission limit was the maximum estimate across all expected operating conditions and based upon the manufacturer's performance guarantee, including peak load and startup, shutdown, and low-load events. This short-term emission rate estimate was also used as the basis for preconstruction modeling compliance demonstrations (SIA and NAAQS) involving short-term averaging periods, and was the basis for calculating annual potential to emit. Refer to the Emission Inventories and the Ambient Air Quality Impact Analyses sections for additional information.

Compliance with this limit is ensured by complying with the performance testing requirement (Permit Condition 64).

Initial Permit Condition 40

This permit condition establishes a short-term ammonia emission limit for the CT and the duct burner, based on the manufacturer's emission guarantee for ammonia slip, which was the basis for calculating short-term and annual emission estimates and the TAP preconstruction compliance demonstration for ammonia.

This emission limit was considered reasonable and appropriate because ammonia emissions were not inherently limited by maximum equipment capacity or other permit limits, and to ensure proper SCR control equipment maintenance and operation (Permit Condition 96).

Compliance with this limit is ensured by complying with the monitoring and recordkeeping (Permit Condition 49), and performance testing requirement (Permit Condition 64).

Initial Permit Conditions 41 and 42

These permit conditions require the installation, operation, and maintenance of BACT control devices.

Refer to Appendix A for additional information concerning BACT determinations.

Corresponding emission limits for these BACT were established in Permit Conditions 33, 34, and 35.

Initial Permit Condition 43

This permit condition requires BACT work practices for minimizing emissions from the CT and the duct burner. Refer to Appendix A for additional information concerning BACT determinations.

Compliance with this requirement is ensured by developing and complying with the O&M manual requirements (Permit Conditions 16, 17, and 18).

Initial Permit Condition 44

This permit condition requires the installation, certification, operation, and maintenance of a $NO_X$ CEMS for continuous monitoring of $NO_X$ emissions to demonstrate compliance with the $NO_X$ BACT emission limit (Permit Condition 33), the $NO_X$ BACT secondary emission limits (Permit Conditions 34 and 35), and the $NO_X$ annual emission limit (Permit Condition 36).

Compliance with this requirement is ensured by complying with continuous monitoring and recordkeeping requirements (Permit Conditions 51, 52, and 53).

Initial Permit Condition 45

This permit condition requires the installation, certification, operation, and maintenance of a CO CEMS for continuous monitoring of CO emissions to demonstrate compliance with the CO BACT emission limit (Permit Condition 33), the CO BACT secondary emission limits (Permit Conditions 34 and 35), and the CO annual emission limit (Permit Condition 36).

Compliance with these requirements is ensured by complying with continuous monitoring and recordkeeping requirements (Permit Conditions 51, 57, and 58).

Initial Permit Condition 46

This permit condition incorporates general compliance requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 47

This permit condition specifies the fuel to be used in the CT and the duct burner and limits the fuel sulfur content.

These were voluntary limits proposed by the permittee, and BACT determinations assumed the use of fuel meeting these specifications. Refer to Appendix A for additional information concerning BACT determinations. The short-term and annual $SO_2$ emission rate estimates associated with the sulfur content limit were also used as the basis for preconstruction modeling compliance demonstrations (NAAQS) involving short-term and annual averaging periods.

Compliance with this requirement is ensured by complying with monitoring requirements (Permit Condition 61).

Initial Permit Condition 48

This permit condition requires the installation, calibration, operation, and maintenance of an ammonia injection flow meter.

Corresponding ammonia flow rate limits for the flow meter were established in Permit Condition 49.

Initial Permit Condition 49

This permit condition establishes an ammonia injection flow rate limit.

The short-term emission rate estimates associated with the maximum estimated ammonia injection flow rate to the SCR were used as the basis for preconstruction modeling compliance demonstrations (TAP) involving short-term averaging periods. Refer to the Emission Inventories and Ambient Air Quality Impact Analyses sections for additional information.

Compliance with this limit is ensured by complying with the ammonia injection flow rate monitoring requirement (Permit Condition 62).

Initial Permit Condition 50

This permit condition establishes annual limits on hours of operation for the CT and the duct burner.

The annual emission rate estimates (PTE) were calculated based upon these limits, and were used as the basis for preconstruction modeling compliance demonstrations (SIA, NAAQS, and TAP) involving annual averaging periods.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Condition 63).

Initial Permit Condition 51

This permit condition requires monitoring and recordkeeping of the occurrence of startup, shutdown, and low-load events, to ensure compliance with BACT emission limits (Permit Conditions 32, 33, 34, 35, and 36).

Initial Permit Conditions 52 and 53

These permit conditions require continuous monitoring and recordkeeping of $NO_X$ CEMS data for the CT and the duct burner and calculation of emissions to ensure compliance with the $NO_X$ BACT emission limit (Permit Condition 33), the $NO_X$ BACT secondary emission limits (Permit Conditions 34 and 35), and the $NO_X$ annual emission limit (Permit Condition 36).

Recordkeeping (electronic archiving) of each calculation and assessment of excess emissions is required on an hourly basis for short-term emission limits, and on a monthly basis for annual emission limits.

For additional guidance and policy concerning “blending” of emission limits when appropriate (Permit Condition 53), refer to the $NO_X$ Hourly Limit Determination & Correspondence information provided in the appendices to the application (email correspondence dated June 30, 2009).[4]

Compliance with this requirement is ensured by complying with monitoring and recordkeeping (Permit Conditions 51, 53, and 103), and reporting requirements (Permit Conditions 19 through 26).

Initial Permit Conditions 54, 55, and 56

These permit conditions incorporate $NO_X$ CEMS monitoring requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

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[4] "NSPS - KKKK Clarification, $NO_X$ blended average" email correspondence, H. Valdez, EPA Region X, June 30, 2009 (response to May 29, 2009 letter requesting clarification).

Initial Permit Conditions 57 and 58

These permit conditions require continuous monitoring and recordkeeping of CO CEMS data for the CT and the duct burner, to ensure compliance with the CO BACT emission limit (Permit Condition 33), the CO BACT secondary emission limits (Permit Conditions 34 and 35), and the CO annual emission limit (Permit Condition 36).

Recordkeeping (electronic archiving) of each calculation and assessment of excess emissions is required on an hourly basis for short-term emission limits, and on a monthly basis for annual emission limits.

For additional guidance and policy concerning "blending" of emission limits when appropriate (Permit Condition 58), refer to the $NO_X$ Hourly Limit Determination & Correspondence information provided in the appendices to the application (email correspondence dated June 30, 2009).[4]

Compliance with this requirement is ensured by complying with monitoring and recordkeeping (Permit Conditions 51, 58, and 103), and reporting requirements (Permit Conditions 19 through 26).

Initial Permit Conditions 59 and 60

These permit conditions incorporate sulfur content monitoring requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 61

This permit condition requires monitoring and recordkeeping of fuel total sulfur content, to ensure compliance with fuel specifications (Permit Condition 47).

Initial Permit Condition 62

This permit condition requires monitoring and recordkeeping of the SCR ammonia injection flow rate on at least a daily basis, to ensure compliance with the ammonia injection flow rate limit (Permit Condition 49).

At this time the permittee has not determined whether a CMS will be installed for monitoring of the ammonia injection flow rate. If installed, continuous monitoring data is required to be used for monitoring of the ammonia injection flow rate. The monitoring and calculation methodologies (e.g., the number of measurements per day, method of calculating averages, and methods for ensuring data quality) are required to be described in the O&M manual (Permit Conditions 16, 17, and 18).

Initial Permit Condition 63

This permit condition requires monitoring and recordkeeping of annual hours of operation of the CT and the duct burner on a monthly basis, to ensure compliance with annual hours of operation limits (Permit Condition 50).

Initial Permit Conditions 64, 65, and 66

Permit Conditions 64 and 65 require performance testing to demonstrate compliance with $NO_X$, CO, and VOC BACT emission limits (Permit Condition 33), the VOC BACT secondary emission limit for low-load events (Permit Condition 34), the $PM_{10}$ emission limit (Permit Condition 39), the ammonia emission limit (Permit Condition 40), and the visible emission limit (Permit Condition 9), in accordance with IDAPA 58.01.01.211.04.

Test conditions are specified and test methods are referenced (Permit Condition 27). Alternative test conditions or methods may be approved by DEQ, in accordance with IDAPA 58.01.01.157. The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing in accordance with the performance testing general provision (Permit Condition 100).

Compliance with this requirement is ensured by complying with monitoring, recordkeeping, notification, and reporting requirements (Permit Conditions 66, and 100 through 102).

Initial Permit Condition 67

This permit condition incorporates $SO_2$ performance test requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 68

This permit condition incorporates $NO_X$ CEMS performance test requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 69, 70, 71, and 72

These permit conditions incorporate excess emissions reporting and report submittal requirements from NSPS Subpart KKKK. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

For additional guidance and policy concerning "blending" of emission limits when appropriate (Permit Condition 70), refer to the $NO_X$ Hourly Limit Determination & Correspondence information provided in the appendices to the application (email correspondence dated June 30, 2009).[4]

Initial Permit Conditions 73 and 74

These permit conditions establish BACT emission limits for the emergency generator engine and the fire pump engine.

Refer to Appendix A for additional information concerning BACT determinations. The short-term emission rate estimates associated with these emission limits were used as the basis for preconstruction modeling compliance demonstrations (SIA and NAAQS) involving short-term averaging periods. Refer to the Emission Inventories and the Ambient Air Quality Impact Analyses sections for additional information.

Compliance with these limits is ensured by complying with the monitoring, recordkeeping, and other requirements set forth in NSPS Subpart IIII.

Initial Permit Condition 75

This permit condition incorporates emission standards for the emergency generator engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 76

This permit condition incorporates emission standards for the fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 77

This permit condition establishes annual limits on hours of operation for the emergency generator engine and fire pump engine.

The annual emission rate estimates (PTE) were calculated based upon these limits, and were used as the basis for preconstruction modeling compliance demonstrations (SIA, NAAQS, and TAP) involving annual averaging periods.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 83 and 84).

Initial Permit Condition 78

This permit condition incorporates compliance requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 79

This permit condition requires BACT work practices for minimizing emissions from the emergency generator engine and the fire pump engine. Refer to Appendix A for additional information concerning BACT determinations.

Compliance with this requirement is ensured by developing and complying with the requirements in the O&M manual (Permit Conditions 16, 17, and 18).

Initial Permit Condition 80

This permit condition incorporates operating and maintenance requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 81

This permit condition incorporates monitoring requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 82

This permit condition incorporates fuel requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

BACT determinations assumed the use of fuel meeting these specifications. Refer to Appendix A for additional information concerning BACT determinations. The short-term and annual $SO_2$ emission rate estimates associated with the sulfur content limit were also used as the basis for preconstruction modeling compliance demonstrations (NAAQS) involving short-term and annual averaging periods.

Initial Permit Condition 83 and 84

These permit conditions require monitoring and recordkeeping of daily and annual hours of operation of the emergency generator engine and the fire pump engine on a daily and on a monthly basis, to ensure compliance with daily and annual hours of operation for maintenance and testing limits (Permit Condition 77).

Initial Permit Condition 85

This permit condition incorporates notification, reporting, and recordkeeping requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 86

This permit condition incorporates testing requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Initial Permit Condition 87

This permit condition requires the installation, operation, and maintenance of BACT.

Work practices for this BACT were established in Permit Condition 89.

Initial Permit Condition 88

This permit condition requires operation of the drift eliminators to ensure compliance with the process weight rate limit (Permit Condition 12).

Initial Permit Condition 89

This permit condition requires BACT work practices for minimizing emissions from the cooling tower.

Refer to Appendix A for additional information concerning BACT determinations.

Compliance with this requirement is ensured by developing and complying with the requirements in the O&M manual (Permit Conditions 16, 17, and 18).

Initial Permit Condition 90 and 91

Permit Condition 90 establishes total dissolved solids (TDS) content and circulating flow rate limits for the cooling tower water.

BACT determinations assumed the use of cooling tower water meeting these specifications. Refer to Appendix A for additional information concerning BACT determinations. The short-term and annual $PM_{10}$ emission rate estimates associated with the TDS content limit were also used as the basis for preconstruction modeling compliance demonstrations (SIA and NAAQS) involving short-term and annual averaging periods. Recordkeeping (electronic archiving) is required on a daily basis.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Condition 91).

Initial Permit Condition 92

This permit condition requires the installation, operation, and maintenance of BACT control devices.

Work practices for this BACT were established in Permit Condition 94.

Initial Permit Condition 93

This permit condition requires operation of the bin vent filters to ensure compliance with the process weight rate limit (Permit Condition 12).

Initial Permit Condition 94

This permit condition requires BACT work practices for minimizing emissions from loading of the dry chemical storage silos.

Refer to Appendix A for additional information concerning BACT determinations.

Compliance with this requirement is ensured by developing and complying with the requirements in the O&M manual (Permit Conditions 16, 17, 18).

Initial Permit Condition 95

The duty to comply general provision requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Initial Permit Condition 96

The control equipment maintenance and operation general provision requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 97

The obligation to comply general provision specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Initial Permit Condition 98

The inspection and entry general provision requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Initial Permit Condition 99

The construction and operation notification general provision requires that the permittee notify DEQ of the dates of construction, initial startup, and achieving the maximum production rate, in accordance with IDAPA 58.01.01.211.

Initial Permit Conditions 100, 101, and 102

The performance testing general provisions require notification of intent to test, testing in accordance with the procedures of IDAPA 58.01.0.157, and reporting of test results in accordance with IDAPA 58.01.01.157.

The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing in accordance with the performance testing general provision (Permit Condition 100).

Initial Permit Condition 103

The monitoring and recordkeeping general provision requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 104

The certification general provision requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Initial Permit Condition 105

The false statements general provision requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Initial Permit Condition 106

The tampering general provision requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Initial Permit Condition 107

The transferability general provision specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Initial Permit Condition 108

The severability general provision specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

## PUBLIC REVIEW

### *Public Comment Period*

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.01.c and 40 CFR 52.21(q). During this period, comments were submitted in response to DEQ's proposed action. Refer to the Application Chronology section for public comment period dates.

In accordance with IDAPA 58.01.01.209.02.a.i, the public notice issued pursuant to IDAPA 58.01.01.209.01.c.ii addressed the degree of increment consumption expected from the new major facility. In accordance with IDAPA 58.01.01.209.02.a.ii and IDAPA 58.01.01.209.02.b.iv, the public notice issued pursuant to IDAPA 58.01.01.209.01.c.ii provided notification of the opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality effects of the new major facility, alternatives to it, the control technology required, and other appropriate considerations.

A response to comments document has been crafted by DEQ based on the comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

### *Public Hearing*

In addition to the public comment period, DEQ also provided a public hearing at New Plymouth High School in New Plymouth for persons interested to appear and submit written or oral comments. During this hearing, comments were not submitted in response to DEQ's proposed action. Refer to the Application Chronology section for the public hearing date. No differences between visibility analyses were provided to DEQ pursuant to IDAPA 58.01.01.209.02.b.ii.

# APPENDIX A

# BEST AVAILABLE CONTROL TECHNOLOGY REVIEWS AND DETERMINATIONS

### *Regulatory Analysis*

In accordance with §52.21(j)(2), a new major stationary source shall apply best available control technology (BACT) for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

As defined in §52.21(b)(12), BACT means an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act (CAA) which would be emitted from any proposed major stationary source or major modification which DEQ, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard in 40 CFR parts 60 and 61. If DEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

EPA recommends that BACT review follow a five-step process:[5]

1) Identify all control technologies
2) Eliminate technically infeasible options
3) Rank remaining control technologies by control effectiveness
4) Evaluate most effective controls and document results
5) Select BACT

The recommended “top-down” approach provides that all available control technologies be ranked in descending order of control effectiveness. The applicant first examines the most stringent, or "top" alternative. That alternative is established as BACT unless the applicant demonstrates, and DEQ determines, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. Although EPA and DEQ regulations do not specifically require application of this process to meet PSD regulatory requirements, this top-down analysis ensures that a defensible BACT determination, including consideration of all requisite statutory and regulatory criteria, is reached.

The BACT reviews submitted in the application adhered to the recommended five-step process (refer to the application for the BACT reviews in full detail).

Potential to emit from the facility has been estimated to be above the significance level threshold for the emissions of $NO_X$, CO, VOC, $PM_{2.5}$, $PM_{10}$, and PM, as summarized in Table 6 (refer to the Emission Inventories section for information concerning estimates of potential to emit). As a result, the BACT review included the emissions units and pollutants identified in Table 7.

[5] “New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting,” EPA Office of Air Quality Planning and Standards, Draft, October 1990.

**Table 6 NSR POLLUTANTS EMITTED IN SIGNIFICANT AMOUNTS**

| NSR Pollutant[a] | | Facility-Wide Potential to Emit (T/yr) | NSR Pollutant Significance Level[b] (T/yr) | Subject to PSD? |
|---|---|---|---|---|
| CO | | 279 | 100 | Yes |
| $NO_X$ | | 88 | 40 | Yes |
| $SO_2$ | | 14 | 40 | No |
| PM | | 53 | 25 | Yes |
| $PM_{10}$ | | 53 | 15 | Yes |
| $PM_{2.5}$[c] | direct | 53 | 10 | Yes |
| | as $SO_2$ | 14 | 40 | |
| | as $NO_X$ | 88 | 40 | |
| $O_3$ | as $NO_X$ | 88 | 40 | Yes |
| | as VOC | 75 | 40 | |
| Lead | | 0.05 | 0.6 | No |
| Fluorides | | <3 [d] | 3 | No |
| Sulfuric acid mist | | 2 | 7 | No |
| Hydrogen sulfide | | <10 [d] | 10 | No |
| Total reduced sulfur (including $H_2S$) | | <10 [d] | 10 | No |
| Reduced sulfur compounds (including $H_2S$) | | <10 [d] | 10 | No |
| Other NSR pollutant[d] | | <any [d] | any | No |

a) Significance levels which were not determined to be applicable are not listed; the permittee has not proposed operation of a municipal waste combustor or a municipal waste landfill.
b) "Significant" as defined in 40 CFR 52.21(b)(23).
c) DEQ continues to use the existing interim approach of relying on $PM_{10}$ as surrogate for $PM_{2.5}$ in accordance with EPA guidance until a revised SIP is adopted.[6]
d) Emission rates are estimated at less than significance levels.

**Table 7 EMISSION SOURCES APPLICABLE TO BACT REVIEW**

| Emissions Units | NSR Pollutants Emitted Applicable to BACT |
|---|---|
| Combustion turbine | $NO_X$, CO, VOC, $PM_{10}$, PM |
| Duct burner | $NO_X$, CO, VOC, $PM_{10}$, PM |
| Emergency generator engine | $NO_X$, CO, VOC, $PM_{10}$, PM |
| Fire pump engine | $NO_X$, CO, VOC, $PM_{10}$, PM |
| Cooling tower | $PM_{10}$, PM |
| Dry chemical storage silos | $PM_{10}$, PM |

BACT reviews were provided in the application for each regulated pollutant emissions unit identified in Table 7. Additional BACT reviews were also provided in the application for the control of $PM_{2.5}$ and $SO_2$ emissions. BACT determinations for $SO_2$ were not required and were not made by DEQ because the facility-wide potential to emit $SO_2$ was not estimated to exceed the corresponding significance level as provided in Table 7. $PM_{2.5}$ standards have not been adopted into a revised state implementation plan (SIP), and DEQ continues to rely on the use of $PM_{10}$ as surrogate for $PM_{2.5}$ in accordance with EPA guidance until a revised SIP is adopted.[6] Direct $PM_{2.5}$ emissions were conservatively estimated assuming that 100% of $PM_{10}$ emissions were $PM_{2.5}$ emissions, in lieu of estimating individual fractions or component concentrations. DEQ has considered this to be a reasonable and appropriate assumption, and that implementation of the $PM_{10}$ program as a surrogate with regard to meeting $PM_{2.5}$ NSR program requirements was reasonable and appropriate for this project.[7]

BACT determinations (or emission limits) for greenhouse gases were not required and were not made by DEQ. EPA does not currently consider greenhouse gases to be "regulated NSR pollutants" as defined in 40 CFR 52.21(b)(50),[8] and DEQ does not currently consider greenhouse gases to be "regulated air pollutants" as defined in IDAPA 58.01.01.006. DEQ is cognizant that EPA has recently issued a final ruling to tailor the major source applicability thresholds for greenhouse gas emissions.[9] However, EPA guidance has confirmed that addressing greenhouse gas emissions is not a requirement at this time.[10] Although not required, discussion has been provided concerning greenhouse gas emissions in terms of collateral impacts within BACT determinations where relevant, which ultimately did not affect the outcome of any BACT determinations. Current NSR permitting policy and guidance can be found on the EPA website at http://www.epa.gov/nsr/guidance.html.

### *Considerations*

Discussion relating to references; fuel selection; work practices; and startup, shutdown, and low-load events has been provided in this section.

References reviewed during the BACT reviews and determinations included but were not limited to:

- PSD PTC Application – Langley Gulch Power Plant (Revision 4)
- EPA RBLC, NSR policy and guidance, and technical bulletins
- National Combustion Turbine Spreadsheet, compiled by EPA Region 4 staff
- NSR permits (federal, state, and local) and associated test reports
- Technical journals and publications, including trade organization and professional societies
- Control technology manufacturers and environmental consultants
- Rule and implementation information for NSPS Subpart KKKK and NSPS Subpart IIII

With regard to fuel selection, because the permittee has requested to limit fuels combusted in the CT and the duct burner to only pipeline quality natural gas, and fuel combusted in the emergency generator engine and fire pump engine to only ultra-low sulfur diesel, consideration of further fuel cleaning or treatment were not considered as part of the BACT reviews and determinations.

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[6] "Final Rule on the Implementation of the New Source Review Provisions for Particulate Matter Less Than 2.5 microns ($PM_{2.5}$) Fact Sheet," Raj Rao, Office of Air Quality Planning & Standards, May 08, 2008.

[7] "Interim Implementation of New Source Review Requirements for $PM_{2.5}$," John S. Seitz, Director Office of Air Quality Planning & Standards, October 23, 1997.

[8] "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program," Stephen L. Johnson, Administrator, December 18, 2008.

[9] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 FR 31513-31608, Final, June 3, 2010.

[10] "Letter on the Endangerment Finding Action for 2010," Lisa P. Jackson, Administrator, February 22, 2010.

With regard to BACT work practices, good combustion practices or good operating practices were uniformly included in each BACT determination. The requirement to minimize emissions is referenced in both federal and state regulations; including 40 CFR 60.11(d) (Permit Condition 28), 40 CFR 60.4333(a) (Permit Condition 46), IDAPA 58.01.01.134 (Permit Conditions 19 through 26), and the control equipment maintenance and operation general provision (Permit Condition 96). Although work practices were evaluated on a pollutant-by-pollutant basis as part of the BACT review, it was interpreted that the intent of such requirements was to minimize emissions of all NSR regulated pollutants. These work practices were determined to be available, feasible, and effective and did not introduce significant collateral energy, environmental, or economic impacts.

With regard to CT startup, shutdown, and low-load events it was necessary to establish BACT secondary limits (in addition to GCP) for emissions of $NO_X$, CO, and VOC, because combustion and control device operational parameters were not expected to be optimal and emissions were expected to be greater during such events (refer to the Emission Inventories section for additional information concerning the emission estimates). As a result, compliance with the primary BACT limits was not considered feasible during such events. EPA has long held a policy that BACT emission limitations apply at all times, and that BACT limits may not be waived during periods of startup, shutdown, and maintenance. If compliance with normal BACT limits is not feasible, then BACT secondary limits for such periods should be established.[11] Maximum estimated hourly and annual emission rates used in modeling preconstruction compliance demonstrations formed the basis of the BACT secondary limits, and NSPS limits (legal "floor") were considered when appropriate. Startup, shutdown, and low-load events have been defined (Permit Condition 32) for the purposes of determining when primary or secondary limits apply.

A summary of BACT determinations follows for each regulated pollutant emissions unit identified in Table 7. Although separate reviews and determinations were made for each regulated pollutant emissions unit, the BACT determinations for both the CT and the duct burner, and similarly for the emergency generator engine and the fire pump engine, are presented together for the sake of discussion. Supporting testing, monitoring, recordkeeping, and/or reporting requirements to ensure compliance with BACT limits are presented and discussed within the Permit Conditions Review section.

[11] Prairie State Generation Company, PSD Appeal No. 05-05, slip op., EPA Environmental Appeals Board, August 24, 2006.

### *BACT Determinations Summary*

The BACT determinations have been summarized in Table 8. A description of each BACT review and determination follows.

**Table 8 BACT DETERMINATIONS SUMMARY**

| Emissions Units | NSR Pollutant | BACT Emission Limit | BACT Secondary Limit (Low-Load) | BACT Secondary Limit (Startup/Shutdown) | Selected Technology[c] |
|---|---|---|---|---|---|
| Combustion turbine and duct burner (combined) | $NO_X$ | 2.0 ppm[a] | 96 ppm[a] | 96 ppm[a] | SCR, DLN (CT only), and GCP |
| | CO | 2.0 ppm[a] | 24.5 ppm[a] | 2,510 lb/hr[b] | CatOx, DLN (CT only), and GCP |
| | VOC | 2.0 ppm[a] | 11.5 ppm[a] | | CatOx, DLN (CT only), and GCP |
| | PM and $PM_{10}$ | | | | NG[d] and GCP |
| Emergency generator engine | $NO_X$ + NMHC (VOC) | 6.4 g/kW-hr[e] | | | Tier 2 engine-based[f] and GCP |
| | CO | 3.5 g/kW-hr | | | Tier 2 engine-based[f] and GCP |
| | PM (and $PM_{10}$) | 0.20 g/kW-hr | | | ULSD[d] and GCP |
| Fire pump engine | $NO_X$ + NMHC (VOC) | 4.0 g/kW-hr[e] | | | Tier 3 engine-based[f] and GCP |
| | CO | -- | | | Tier 3 engine-based[f] and GCP |
| | PM (and $PM_{10}$) | 0.20 g/kW-hr | | | ULSD[d] and GCP |
| Cooling tower | PM and $PM_{10}$ | | | | Drift eliminators and good operating practices |
| Dry chemical storage silos | PM and $PM_{10}$ | | | | Bin vent filters/baghouse and good operating practices |

a) Parts of a gaseous contaminant per million parts of gas by volume, calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration.
b) Pounds per hour, calculated as a 1-hour average.
c) Technology abbreviations: SCR = selective catalytic reduction, DLN = dry low $NO_X$ combustors, CatOx = catalytic oxidation, GCP = good combustion practices. Refer to the acronyms, units, and chemical nomenclature section for a complete listing.
d) Pipeline natural gas (NG) was the only fuel proposed for use in the CT, and ultra-low sulfur diesel (ULSD) was the only fuel proposed for use in the emergency generator engine and the fire pump engine, and alternate fuels were not considered.
e) Emission limit is for both non-methane hydrocarbons (NMHC) and nitrogen oxides (combined).
f) Engine-based technologies capable of achieving applicable Tier 2 or Tier 3 emission standards.

## *Combustion Turbine and Duct Burner*

**Table 9 SUMMARIES OF BACT REVIEWS AND DETERMINATIONS, COMBUSTION TURBINE**

| NSR Pollutant | Technology[a] | Technically Feasible? | Control Effectiveness Ranking | Emissions Performance (ppm)[b] | Most effective based on impacts? |
|---|---|---|---|---|---|
| $NO_X$ | LNT, LEC, NSCR, catalytic combustion | No | | | |
| | SCR<br>DLN and GCP | Yes | 1 | < 2.0 | Yes |
| | DLN and GCP[c] | Yes | 2 | < 9 | No |
| | SCR, SNCR, and/or WC<br>and GCP | Yes | 3 | < 15 | No |
| | NSPS Subpart KKKK[d] and GCP | Yes | 4 | < 15 | No |
| CO | CatOx<br>DLN and GCP | Yes | 1 | < 2.0 | Yes |
| | DLN and GCP[c] | Yes | 2 | < 10 | No |
| | GCP | Yes | 3 | n/a[e] | No |
| VOC | CatOx<br>DLN and GCP | Yes | 1 | < 2.0 | Yes |
| | DLN and GCP | Yes | 2 | < 10 | No |
| | GCP | Yes | 3 | n/a[e] | No |
| $PM_{2.5}$, $PM_{10}$, and PM | LNT, catalytic combustion | No | | | |
| | NG[f] and GCP | Yes | 1 | n/a[e] | Yes |

a) Technology abbreviations: LNT = lean $NO_X$ trap, LEC = low emission combustors, DLN = dry low $NO_X$ combustors, SCR = selective catalytic reduction, NSCR = non-selective catalytic reduction, SNCR = selective non-catalytic reduction, WC = water controls, including steam injection and water injection, CatOx = catalytic oxidation, GCP = good combustion practices. Refer to the acronyms, units, and chemical nomenclature section for a complete listing.
b) Emission concentration performance from the CT and the duct burner combined.
c) Reference "Ultra Low $NO_X$ Combustion Technology," Power-Gen International 2008, Siemens Power Generation and Idaho Power, December, 2008.
d) Reference Table 1 to Subpart KKKK of Part 60.
e) An emission limit associated with the use of GCP was not evaluated for the purposes of this BACT determination.
f) Pipeline natural gas (NG) was the only fuel proposed for use in the CT, and alternate fuels were not considered.

**Table 10 SUMMARIES OF BACT REVIEWS AND DETERMINATIONS, DUCT BURNER**

| NSR Pollutant | Technology[a] | Technically Feasible? | Control Effectiveness Ranking | Emissions Performance (ppm)[b] | Most effective based on impacts? |
|---|---|---|---|---|---|
| $NO_X$ | SCR and GCP | Yes | 1 | < 2.0 | Yes |
| | SCR, SNCR, and GCP | Yes | 2 | < 15 | No |
| | NSPS Subpart KKKK[c] and GCP | Yes | 3 | < 15 | No |
| CO | CatOx and GCP | Yes | 1 | < 2.0 | Yes |
| | GCP | Yes | 2 | n/a[d] | No |
| VOC | CatOx and GCP | Yes | 1 | < 2.0 | Yes |
| | GCP | Yes | 2 | n/a[d] | No |
| $PM_{2.5}$, $PM_{10}$, and PM | NG[e] and GCP | Yes | 1 | n/a[d] | Yes |

a) Technology abbreviations: SCR = selective catalytic reduction, SNCR = selective non-catalytic reduction, CatOx = catalytic oxidation, GCP = good combustion practices. Refer to the acronyms, units, and chemical nomenclature section for a complete listing.
b) Emission concentration performance from the CT and the duct burner combined.
c) Reference Table 1 to Subpart KKKK of Part 60
d) An emission limit associated with the use of GCP was not evaluated for the purposes of this BACT determination.
e) Pipeline natural gas (NG) was the only fuel proposed for use in the CT, and alternate fuels were not considered.

## $NO_X$ BACT – Identify all control technologies

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 9 for the CT and in Table 10 for the duct burner. Detailed descriptions of each technology can be found within the references listed.

- Lean $NO_X$ trap (LNT) technologies use catalytic oxidation and reduction. A precious metal and chemically-modified (e.g., potassium carbonate) catalyst oxidizes NO to $NO_2$ and "traps" $NO_2$ to reduce $NO_X$ emissions. The catalyst is periodically regenerated by removing the adsorbed $NO_2$.
- Low emission combustors (LEC) use improved fuel and air premixing techniques (e.g., forward flowing venturi, effusion cooling technology, advanced secondary fuel nozzle) prior to combustion in order to reduce $NO_X$ and CO emissions.
- Catalytic combustion technologies use flameless catalytic combustion, which reduces combustion temperature in order to reduce $NO_X$ emissions.
- Dry low $NO_X$ combustors (DLN) use lean fuel-to-air mixtures, premixing techniques, and staged combustion, which reduce peak flame temperatures and oxygen concentration in the combustion zone in order to reduce $NO_X$ emissions.
- Selective catalytic reduction (SCR) uses a precious metal or zeolite catalyst and a reducing agent (e.g., ammonia or urea), which chemically reduces $NO_X$ to $N_2$ to reduce $NO_X$ emissions.
- Selective non-catalytic reduction (SNCR) technologies use a reducing agent (e.g., ammonia or urea), which chemically reduces $NO_X$ to $N_2$ to reduce $NO_X$ emissions.
- Non-selective catalytic reduction (NSCR) uses a precious metal catalyst in a stoichiometric or fuel-rich environment, which reduces oxygen concentration in order to reduce $NO_X$ emissions.
- Water controls (WC) include steam injection and water injection, which reduce combustion temperature in order to reduce $NO_X$ emissions.

**$NO_X$ BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

For the CT, the applicant documented that low emission combustors (LEC) and catalytic combustion technologies were not feasible control options. For the CT and the duct burner, the applicant documented that lean $NO_X$ trap (LNT, including $SCONO_X$) systems were not feasible control options. Available information supports that these control technologies have not been installed and commercially proven in large frame turbines, and were not considered demonstrated or available for this project. Combustion controls (e.g., LEC and catalytic combustion technologies) must be incorporated into the design of the turbine. Lean $NO_X$ trap technologies (LNT) have not been demonstrated in practice on turbines larger than 45 MW in size.

For the CT and the duct burner, the applicant has also documented that SNCR and NSCR were not technically feasible. Exhaust gas temperatures were expected to be below the minimum operating range of the SNCR of 1200 to 2000$^{o}$F and would require exhaust gas reheating. NSCR requires a stoichiometric or fuel-rich environment, which are not applicable to turbines using (more effective) dry low-$NO_X$ designs.

For the purposes of this determination, LNT, LEC, catalytic combustion, and NSCR were eliminated from review.

For the duct burner, because the burner fires fuel into the CT exhaust, the same add-on control devices available to the CT were considered available to the duct burner. None of the add-on control technologies identified for the duct burner were eliminated from review.

**$NO_X$ BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, the CT and the duct burner control technologies were ranked based upon emission rate performances (ppm) provided within the references listed.

For the CT, SCR combined with DLN and good combustion practices (GCP) was the top feasible control technology which has been demonstrated to effectively limit $NO_X$ emissions to 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

For the duct burner, SCR combined with GCP was the top control technology which has been demonstrated to effectively limit $NO_X$ emissions to 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

Other feasible control technologies were not determined to be as effective in limiting $NO_X$ emissions and were assigned a lower ranking.

**$NO_X$ BACT – Evaluate most effective controls and document results**

For the CT, the applicant has proposed to install and operate the most effective control technology available – SCR combined with DLN and GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

For the duct burner, the applicant has proposed to install and operate the most effective control technology available – SCR combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

Although collateral impacts were considered, they did not affect the outcome of the BACT determination. Collateral impacts associated with SCR include, but are not limited to:

- Environmental impacts associated with ammonia emissions. Ammonia is sprayed across the SCR catalyst to reduce $NO_X$ emissions, and as a normal part of this process, some ammonia passes beyond the catalyst and out of the stack without being reacted. Ammonia has been identified as a precursor to the formation of secondary particulate matter, and is regulated as a non-carcinogenic toxic air pollutant (TAP) as provided in IDAPA 58.01.01.585. The applicant has demonstrated preconstruction

compliance to DEQ's satisfaction that emissions of ammonia will not exceed the acceptable ambient concentration (AAC); refer to Appendix C for additional information. Although technologies determined infeasible are not evaluated, it has been noted that LNT and catalytic combustion technologies are capable of achieving equivalent or better $NO_X$, CO, and/or VOC emissions reductions without any associated ammonia emissions.

- Energy impacts and economic impacts associated with installation and operation of SCR and DLN. This includes a reduction in turbine efficiency associated with the SCR due to additional turbine backpressure resulting from placement of the control device within the exhaust stream.

**$NO_X$ BACT – Select BACT**

For the CT, the applicant has proposed and DEQ has determined that SCR combined with DLN and GCP constitutes BACT.

For the duct burner, the applicant has proposed and DEQ has determined that SCR combined with GCP constitutes BACT.

For both the CT and the duct burner, based upon the manufacturer's emission guarantees and the references listed, DEQ has determined that the corresponding $NO_X$ emission limit for the selected BACT is 2.0 ppm (Permit Condition 33) for the CT and the duct burner combined, calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration.

**$NO_X$ BACT – Startup, Shutdown, And Low-Load Events**

As discussed in the Considerations section, it was necessary to establish BACT secondary limits for $NO_X$ emissions from the CT and the duct burner for startup, shutdown, and low-load events.

For both the CT and the duct burner, based upon estimated emissions for startup, shutdown, and low-load events and considering applicable NSPS standards in accordance with 40 CFR 52.21(b)(12), DEQ has determined that the corresponding secondary $NO_X$ emission limit for the selected BACT is 96 ppm (Permit Conditions 34 and 35) during startup, shutdown, and low-load events for the CT and the duct burner combined, calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration.

Refer to the Emission Inventories section for additional information concerning estimated emissions.

**CO BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 9 for the CT and in Table 10 for the duct burner. Detailed descriptions of each technology can be found within the references listed.

- Catalytic oxidation (CatOx) systems use a precious metal catalyst, which oxidizes combustion products in order to reduce CO emissions.
- DLN use premixing techniques and staged combustion, which reduce incomplete combustion in order to reduce CO emissions.

**CO BACT – Eliminate technically infeasible options**

For the CT, none of the control technologies identified were eliminated from review.

For the duct burner, none of the control technologies identified were eliminated from review.

Available information supports that the control technologies identified have been installed and commercially proven for large frame turbines.

**CO BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, the CT and the duct burner control technologies were ranked based upon emission rate performances (ppm) provided within the references listed.

For the CT, a CatOx system combined with GCP was the top control technology which has been demonstrated to effectively limit CO emissions to 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

For the duct burner, a CatOx system combined with GCP was the top control technology which has been demonstrated to effectively limit CO emissions to 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

Other feasible control technologies were not determined to be as effective in limiting CO emissions and were assigned a lower ranking.

**CO BACT – Evaluate most effective controls and document results**

For the CT, the applicant has proposed to install and operate the most effective control technology available – a CatOx system combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

For the duct burner, the applicant has proposed to install and operate the most effective control technology available – a CatOx system combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

Although collateral impacts were considered, they did not affect the outcome of the BACT determination. Collateral impacts associated with CatOx include, but are not limited to:

- Environmental impacts associated with greenhouse gas emissions. The CatOx system converts CO to $CO_2$ emissions, and would therefore be expected to increase overall emissions of greenhouse gases. Greenhouse gases are not considered to be "regulated NSR pollutants;" refer to the Regulatory Analysis section for additional information.
- Energy impacts and economic impacts associated with installation and operation of a CatOx system. This includes a reduction in turbine efficiency associated with the CatOx system due to additional turbine backpressure resulting from placement of the control device within the exhaust stream.

**CO BACT – Select BACT**

For the CT, the applicant has proposed and DEQ has determined that a CatOx system combined with GCP constitutes BACT.

For the duct burner, the applicant has proposed and DEQ has determined that a CatOx system combined with GCP constitutes BACT.

For both the CT and the duct burner, based upon the manufacturer's emission guarantees and the references listed, DEQ has determined that the corresponding CO emission limit for the selected BACT is 2.0 ppm (Permit Condition 33) for the CT and the duct burner combined, calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration.

**CO BACT – Startup, Shutdown, And Low-Load Events**

As discussed in the Considerations section, it was necessary to establish BACT secondary limits for CO emissions from the CT and the duct burner for startup, shutdown, and low-load events.

For both the CT and the duct burner, based upon estimated emissions for low-load events and information provided by the applicant, DEQ has determined that the corresponding secondary CO emission limit for the selected BACT is 24.5 ppm (Permit Condition 34) during low-load events for the CT and the duct burner combined, calculated as a 3-hour rolling average.

For both the CT and the duct burner, based upon estimated emissions for startup and shutdown events which were also used as the basis for preconstruction ambient cumulative air quality impact analyses (CO NAAQS), DEQ has determined that the corresponding secondary CO emission limit for the selected BACT is 2,510 lb/hr (Permit Condition 35) during startup and shutdown events for the CT and the duct burner combined, calculated as a 1-hour average.

Refer to the Emission Inventories and the Ambient Air Quality Impact Analyses sections for additional information concerning estimated emissions and preconstruction ambient air quality impact analyses.

**VOC BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 9 for the CT and in Table 10 for the duct burner. Detailed descriptions of each technology can be found within the references listed.

- Catalytic oxidation (CatOx) systems use a precious metal catalyst, which oxidizes combustion products in order to reduce VOC emissions.
- DLN use premixing techniques and staged combustion, which reduce incomplete combustion in order to reduce VOC emissions.

**VOC BACT – Eliminate technically infeasible options**

For the CT, none of the control technologies identified were eliminated from review.

For the duct burner, none of the control technologies identified were eliminated from review.

Available information supports that the control technologies identified have been installed and commercially proven for large frame turbines.

**VOC BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, the CT and the duct burner control technologies were ranked based upon emission rate performances (ppm) provided within the references listed.

For the CT, a CatOx system combined with GCP was the top control technology which has been demonstrated to effectively limit VOC emissions to levels below 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

For the duct burner, a CatOx system combined with GCP was the top control technology which has been demonstrated to effectively limit VOC emissions to levels below 2.0 ppm in comparable projects using these technologies (for the CT and the duct burner combined).

Other feasible control technologies were not determined to be as effective in limiting VOC emissions and were assigned a lower ranking.

**VOC BACT – Evaluate most effective controls and document results**

For the CT, the applicant has proposed to install and operate the most effective control technology available – a CatOx system combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

For the duct burner, the applicant has proposed to install and operate the most effective control technology available – a CatOx system combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

Although collateral impacts were considered, they did not affect the outcome of the BACT determination. Descriptions of impacts associated with CatOx have been summarized in the CO BACT control effectiveness evaluation step.

**VOC BACT – Select BACT**

For the CT, the applicant has proposed and DEQ has determined that a CatOx system combined with GCP constitutes BACT.

For the duct burner, the applicant has proposed and DEQ has determined that a CatOx system combined with GCP constitutes BACT.

For both the CT and the duct burner, based upon the manufacturer's emission guarantees and the references listed, DEQ has determined that the corresponding VOC emission limit for the selected BACT is 2.0 ppm (Permit Condition 33) for the CT and the duct burner combined, calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration.

**VOC BACT – Low-Load Events**

As discussed in the Considerations section, it was necessary to establish BACT secondary limits for VOC emissions from the CT and the duct burner for low-load events.

For both the CT and the duct burner, based upon estimated emissions for low-load events, DEQ has determined that the corresponding secondary VOC emission limit for the selected BACT is 11.5 ppm (Permit Condition 34) for the CT and the duct burner combined, calculated as a 3-hour rolling average.

Refer to the Emission Inventories section for additional information concerning estimated emissions.

**$PM_{10}$ and PM BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 9 for the CT and in Table 10 for the duct burner. Detailed descriptions of each technology can be found within the references listed.

- Lean $NO_X$ trap (LNT) and catalytic combustion technologies use catalytic oxidation and reduction, which have been shown to reduce PM emissions.

**$PM_{10}$ and PM BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

For the CT, the applicant documented that LNT and catalytic combustion systems were not feasible control options, as discussed in the $NO_X$ technical feasibility evaluation step. Available information supports that a reduction in particulate emissions can be achieved with such controls.

**$PM_{10}$ and PM BACT – Rank remaining control technologies by control effectiveness**

For the CT and the duct burner, the use of clean fuel ("pipeline quality") and GCP was the top feasible control technology for minimizing PM emissions.

Control options were not eliminated based on energy, environmental, or economic impacts.

**$PM_{10}$ BACT – Evaluate most effective controls and document results**

For the CT, the applicant has proposed to install and operate the most effective control technology available – pipeline quality natural gas combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

For the duct burner, the applicant has proposed to install and operate the most effective control technology available – pipeline quality natural gas combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

**$PM_{10}$ and PM BACT – Select BACT**

For the CT, the applicant has proposed and DEQ has determined that pipeline quality natural gas combined with GCP constitutes BACT.

## *Emergency Generator Engine and Fire Pump Engine*

**Table 11 SUMMARIES OF BACT REVIEWS AND DETERMINATIONS**
**EMERGENCY GENERATOR ENGINE AND FIRE PUMP ENGINE**

| NSR Pollutant | Technology[a] | Technically Feasible? | Control Effectiveness Ranking | Generator Performance (g/kW-hr) | Fire Pump Performance (g/kW-hr) | Most effective based on impacts? |
|---|---|---|---|---|---|---|
| $NO_X$ | $NO_X$ adsorber or SCR (Tier 4)[b] and GCP | No | | | | |
| | NSPS Subpart IIII (Tier 2 to 3)[c] and GCP | Yes | 1 | < 6.4 [f] | < 4.0 [f] | Yes |
| CO | CDPF or CatOx (Tier 4)[b] and GCP | No | | | | |
| | NSPS Subpart IIII (Tier 2 to 3)[c] and GCP | Yes | 1 | < 3.5 | -- | Yes |
| VOC | CDPF or CatOx (Tier 4)[b] and GCP | No | | | | |
| | NSPS Subpart IIII (Tier 2 to 3)[c] and GCP | Yes | 1 | < 6.4 [f] | < 4.0 [f] | Yes |
| $PM_{2.5}$, $PM_{10}$, and PM | CDPF (Tier 4)[b] or dust collector[d] ULSD[d] and GCP | No | | | | |
| | CatOx (Tier 4)[b] ULSD[e] and GCP | No | | | | |
| | ULSD[e] and GCP | Yes | 1 | < 0.20 | < 0.20 | Yes |

a) Technology abbreviations: SCR = selective catalytic reduction, GCP = good combustion practices, CDPF = catalyzed diesel particulate filters, CatOx = catalytic oxidation system. Refer to the acronyms, units, and chemical nomenclature section for a complete listing.
b) Advanced emission control technologies capable of achieving Tier 4 emission standards, including aftertreatment and advanced engine design technologies.
c) Engine-based technologies capable of achieving applicable Tier 2 (emergency generator engine) or Tier 3 (fire pump engine) emission standards. Reference Table 1 to 40 CFR 89.112 (Tier 2) and Table 4 to Subpart IIII of Part 60 (Tier 3).[11]
d) Dust collectors include electrostatic precipitator, wet scrubber, or baghouse control devices.
e) Ultra-low sulfur diesel was the only fuel proposed for use in the emergency generator engine and the fire pump engine (also required by NSPS Subpart IIII), and alternate fuels were not considered.
f) Emission limit is for both non-methane hydrocarbons and nitrogen oxides (combined).

### Aftertreatment Control Technology Feasibility and Availability

The permittee has documented concerns regarding the availability and feasibility of aftertreatment control technologies in emergency and fire service applications. Concerns have been similarly documented by engine manufacturers and the NFPA, related to the long-term reliability and long-term performance of the engines and aftertreatment control devices used in these applications. Available information supports that aftertreatment control technologies have not been commercially proven in emergency generator engine and fire pump engine applications.

As discussed in the Standards of Performance for Stationary CI ICE Final Rule,[12] manufacturers have not been required at this time to certify engines in emergency or fire service applications to Tier 4 emission standards that require aftertreatment control technologies. Although specific technologies have been identified and discussed below, aftertreatment control technologies were not considered feasible or available for use with the emergency generator engine or with the fire pump engine.

[12] Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 FR 39154-39185, Final, July 11, 2006.

**$NO_X$ BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 11 for the emergency generator engine and for the fire pump engine. Detailed descriptions of each technology can be found within the references listed.

- Aftertreatment control technologies include $NO_X$ adsorbers and SCR.
- Advanced engine design technologies include exhaust gas recirculation (EGR), variable geometry turbo chargers, and improved fuel and air mixing prior to combustion.
- Engine-based technologies include injection timing retardation and lean burn combustion.

**$NO_X$ BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

- As discussed in the Aftertreatment Control Technology Feasibility and Availability section, aftertreatment control technologies such as $NO_X$ adsorbers and SCR were not considered feasible or available for this project.
- As discussed in the Aftertreatment Control Technology Feasibility and Availability section, advanced engine design technologies such as EGR, variable geometry turbo chargers, and improved fuel and air mixing prior to combustion were not considered feasible or available for this project.

**$NO_X$ BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, CI ICE control technologies were ranked based upon emission rate performances (g/kW-hr) provided within the references listed.

For the emergency generator engine and the fire pump engine, the use of engine-based technologies; operation limited to maintenance, testing, and emergency-use; and GCP was the top feasible control technology which has been demonstrated to effectively limit $NO_X$ emissions below EPA certification emission standards (refer to the NSPS Applicability (40 CFR 60) section for additional information concerning these emission standards).

**$NO_X$ BACT – Evaluate most effective controls and document results**

For the emergency generator engine and the fire pump engine, the applicant has proposed to install and operate the most effective control technology available – engine-based technologies capable of achieving applicable Tier 2 and Tier 3 emission standards combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

**$NO_X$ BACT – Select BACT**

For the emergency generator engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 2 emission standards (Permit Condition 73) combined with GCP (Permit Condition 79) constitutes BACT.

For the fire pump engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 3 emission standards (Permit Condition 74) combined with GCP (Permit Condition 79) constitutes BACT.

A summary of the corresponding emission limits (g/kW-hr) is provided in the BACT Determinations Summary Table (Table 8).

**CO BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 11 for the emergency generator engine and for the fire pump engine. Detailed descriptions of each technology can be found within the references listed.

- Aftertreatment control technologies include catalyzed diesel particulate filters (CDPF), diesel oxidation catalyst systems (DOC), diesel particulate filters (DPF), and CatOx systems.
- Advanced engine design technologies include EGR, variable geometry turbo chargers, and improved fuel and air mixing prior to combustion.
- Examples of engine-based technologies include injection timing retardation and lean burn combustion.

**CO BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

- As discussed in the Aftertreatment Control Technology Feasibility and Availability section, aftertreatment control technologies such as CDPF, DOC, DPF, and CatOx systems were not considered feasible or available for this project. These aftertreatment systems contain media that could potentially plug, resulting in engine backpressure and long-term reliability issues. In addition, aftertreatment systems using CatOx must achieve a minimum operating temperature before becoming effective and before catalyst self-regeneration is possible, contributing to plugging concerns. For these reasons and because engines in emergency and fire service applications are limited to operation for emergency purposes and for maintenance and testing purposes only (maintenance and testing operation limited to less than 60 hr/yr and 30 hr/yr, respectively), aftertreatment control technologies have not been considered feasible for such applications.

**CO BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, CI ICE control technologies were ranked based upon emission rate performances (g/kW-hr) provided within the references listed.

For the emergency generator engine and the fire pump engine, the use of engine-based technologies; operation limited to maintenance, testing, and emergency-use; and GCP was the top feasible control technology which has been demonstrated to effectively limit CO emissions below EPA certification emission standards (refer to the NSPS Applicability (40 CFR 60) section for additional information concerning these emission standards).

**CO BACT – Evaluate most effective controls and document results**

For the emergency generator engine and the fire pump engine, the applicant has proposed to install and operate the most effective control technology available – engine-based technologies capable of achieving applicable Tier 2 and Tier 3 emission standards combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

**CO BACT – Select BACT**

For the emergency generator engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 2 emission standards (Permit Condition 73) combined with GCP (Permit Condition 79) constitutes BACT.

For the fire pump engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 3 emission standards (Permit Condition 74) combined with GCP (Permit Condition 79) constitutes BACT.

A summary of the corresponding emission limits (g/kW-hr) is provided in the BACT Determinations Summary Table (Table 8).

**VOC BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 11 for the emergency generator engine and for the fire pump engine. Detailed descriptions of each technology can be found within the references listed.

- Aftertreatment control technologies include CDPF, DOC, DPF, and CatOx systems.
- Advanced engine design technologies include EGR, variable geometry turbo chargers, and improved fuel and air mixing prior to combustion.
- Examples of engine-based technologies include injection timing retardation and lean burn combustion.

**VOC BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

- As discussed in the Aftertreatment Control Technology Feasibility and Availability and the CO BACT determination sections, aftertreatment control technologies such as CDPF, DOC, DPF, and CatOx systems were not considered feasible or available for this project.

**VOC BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, CI ICE control technologies were ranked based upon emission rate performances (g/kW-hr) provided within the references listed.

For the emergency generator engine and the fire pump engine, the use of engine-based technologies; operation limited to maintenance, testing, and emergency-use; and GCP was the top feasible control technology which has been demonstrated to effectively limit VOC emissions below EPA certification emission standards (refer to the NSPS Applicability (40 CFR 60) section for additional information concerning these emission standards).

**VOC BACT – Evaluate most effective controls and document results**

For the emergency generator engine and the fire pump engine, the applicant has proposed to install and operate the most effective control technology available – engine-based technologies capable of achieving applicable Tier 2 and Tier 3 emission standards combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

**VOC BACT – Select BACT**

For the emergency generator engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 2 emission standards (Permit Condition 73) combined with GCP (Permit Condition 79) constitutes BACT.

For the fire pump engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 3 emission standards (Permit Condition 74) combined with GCP (Permit Condition 79) constitutes BACT.

A summary of the corresponding emission limits (g/kW-hr) is provided in the BACT Determinations Summary Table (Table 8).

**$PM_{10}$ BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 11 for the emergency generator engine and for the fire pump engine. Detailed descriptions of each technology can be found within the references listed.

- Aftertreatment control technologies include CDPF, DOC, DPF, and CatOx systems.
- Advanced engine design technologies include EGR, variable geometry turbo chargers, and improved fuel and air mixing prior to combustion.

**$PM_{10}$ BACT – Eliminate technically infeasible options**

Based upon review of the references listed, technically infeasible control technologies which were not determined to be available and applicable to this project were eliminated from review.

- As discussed in the Aftertreatment Control Technology Feasibility and Availability and the CO BACT determination sections, aftertreatment control technologies such as CDPF, DOC, DPF, and CatOx systems were not considered feasible or available for this project.

**$PM_{10}$ BACT – Rank remaining control technologies by control effectiveness**

Based upon review of the references listed, CI ICE control technologies were ranked based upon emission rate performances (g/kW-hr) provided within the references listed.

For the emergency generator engine and the fire pump engine, the use of engine-based technologies; operation limited to maintenance, testing, and emergency-use; and GCP was the top feasible control technology which has been demonstrated to effectively limit $PM_{10}$ emissions below EPA certification emission standards (refer to the NSPS Applicability (40 CFR 60) section for additional information concerning these emission standards).

**$PM_{10}$ BACT – Evaluate most effective controls and document results**

For the emergency generator engine and the fire pump engine, the applicant has proposed to install and operate the most effective control technology available – engine-based technologies capable of achieving applicable Tier 2 and Tier 3 emission standards combined with GCP. Control options were not eliminated based on energy, environmental, or economic impacts.

**$PM_{10}$ BACT – Select BACT**

For the emergency generator engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 2 emission standards (Permit Condition 73) combined with GCP (Permit Condition 79) constitutes BACT.

For the fire pump engine, the applicant has proposed and DEQ has determined that engine-based technologies and corresponding Tier 3 emission standards (Permit Condition 74) combined with GCP (Permit Condition 79) constitutes BACT.

A summary of the corresponding emission limits (g/kW-hr) is provided in the BACT Determinations Summary Table (Table 8).

### *Cooling Tower*

**Table 12 SUMMARY OF BACT REVIEW, COOLING TOWER**

| NSR Pollutant | Technology | Technically Feasible? | Control Effectiveness Ranking | Control Efficiency (gal drift/gal flow) | Most effective based on impacts? |
|---|---|---|---|---|---|
| $PM_{2.5}$, $PM_{10}$, and PM | Drift eliminators and good operating practices | Yes | 1 | 0.0005% | Yes |

**$PM_{10}$ and PM BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. A list of the technologies identified and a summary of the BACT review and determination is provided in Table 12 for the cooling tower. Detailed descriptions of each technology can be found within the references listed.

- Drift eliminators mechanically capture and cause water droplets to coalesce in cooling tower stacks, preventing release to the atmosphere.

**$PM_{10}$ and PM BACT – Eliminate technically infeasible options**

For the cooling tower, none of the control technologies identified were eliminated from review. Drift eliminators have been installed in comparable projects and are a proven technology.

**$PM_{10}$ and PM BACT – Rank remaining control technologies by control effectiveness**

For the cooling tower, drift eliminators combined with good operating practices was the top control technology which has been demonstrated to effectively minimize $PM_{10}$ and PM emissions.

**$PM_{10}$ and PM BACT – Evaluate most effective controls and document results**

For the cooling tower, the applicant has proposed to install and operate the most effective control technology available – drift eliminators combined with good operating practices. Control options were not eliminated based on energy, environmental, or economic impacts.

**$PM_{10}$ and PM BACT – Select BACT**

For the cooling tower, the applicant has proposed and DEQ has determined that drift eliminators combined with good operating practices constitute BACT (Permit Conditions 87 and 89, respectively).

## *Dry Chemical Storage Silos*

**Table 13 SUMMARY OF BACT REVIEW, DRY CHEMICAL STORAGE SILOS**

| NSR Pollutant | Technology | Technically Feasible? | Control Effectiveness Ranking | Grain Loading Performance (gr/dscf) | Most effective based on impacts? |
|---|---|---|---|---|---|
| $PM_{2.5}$, $PM_{10}$, and PM | Bin vent filters/baghouse and good operating practices | Yes | 1 | 0.01 | Yes |

**$PM_{10}$ and PM BACT – Identify all control technologies**

Based upon review of the references listed, the top control technologies were identified. The technology identified and a summary of the BACT review and determination is provided in Table 13 for the dry chemical storage silos. Detailed descriptions of each technology can be found within the references listed.

- Baghouses and bin vent filters use fabric filtration to collect and reduce particulate emissions. Bin vent filters have the added advantage of being designed for direct use with silos.

**$PM_{10}$ and PM BACT – Eliminate technically infeasible options**

For the dry chemical storage silos, none of the control technologies identified were eliminated from review. Bin vent filters have been installed in comparable projects and are a proven technology.

**$PM_{10}$ and PM BACT – Rank remaining control technologies by control effectiveness**

For the dry chemical storage silos, bin vent filters combined with good operating practices was the top control technology which has been demonstrated to effectively minimize $PM_{10}$ and PM emissions.

**$PM_{10}$ and PM BACT – Evaluate most effective controls and document results**

For the dry chemical storage silos, the applicant has proposed to install and operate the most effective control technology available – bin vent filters combined with good operating practices. Control options were not eliminated based on energy, environmental, or economic impacts.

**$PM_{10}$ and PM BACT – Select BACT**

For the dry chemical storage silos, the applicant has proposed and DEQ has determined that bin vent filters combined with good operating practices constitute BACT (Permit Conditions 92 and 94, respectively).

# APPENDIX B

# EMISSION INVENTORIES AND LIMIT STRINGENCY EVALUATION

# IPC - Langley Gulch Power Plant

**Criteria Pollutant Emission Summary**

| Source | Emission Rate (ton/year) PM | PM-10 | $NO_x$ | $SO_2$ | CO | VOC |
|---|---|---|---|---|---|---|
| ***Point Source*** | | | | | | |
| Gas Turbine | 49.5 | 49.5 | 87.8 | 13.4 | 278.1 | 74.9 |
| 750 kW Genset | 0.011 | 0.011 | 0.35 | 0.00 | 0.19 | 0.02 |
| 315 HP Genset | 0.002 | 0.002 | 0.03 | 0.00 | 0.03 | 0.001 |
| Storage Silos | 0.01 | 0.01 | | | | |
| Cooling Tower | 3.46 | 2.91 | | | | |
| Sum | 52.94 | 52.38 | 88.18 | 13.44 | 278.31 | 74.93 |
| Modeling Threshold | na | 1.0 | 1.0 | 1.0 | na | na |
| Modeling Required | | **YES** | **YES** | **YES** | | |
| ***Fugitive Sources*** | | | | | | |
| Paved Roads | 0.0004 | 0.0004 | | | | |
| Unpaved Roads | 0.002 | 0.002 | | | | |
| **Total** | **52.94** | **52.39** | **88.18** | **13.44** | **278.31** | **74.93** |

NOTE: Turbine emissions from the turbine emission workbook

| Source | Emission Rate (lb/hr) PM | PM-10 | $NO_x$ | $SO_2$ | CO | VOC |
|---|---|---|---|---|---|---|
| ***Point Source*** | | | | | | |
| Gas Turbine | 12.55 | 12.55 | 452.78 | 3.41 | 2510.00 | 186.60 |
| 750 kW Genset | 0.36 | 0.36 | 11.64 | 0.01 | 6.30 | 0.73 |
| 315 HP Genset | 0.10 | 0.10 | 2.08 | 0.00 | 1.80 | 0.10 |
| Storage Silos | 0.04 | 0.04 | | | | |
| Cooling Tower | 0.79 | 0.664 | | | | |
| Sum | 13.85 | 13.72 | 466.50 | 3.42 | 2518.11 | 187.42 |
| Modeling Threshold | na | 0.2 | na | 0.2 | 14.0 | na |
| Modeling Required | | **YES** | | **YES** | **YES** | |
| ***Fugitive Sources*** | | | | | | |
| Paved Roads | | 0.20 | | | | |
| Unpaved Roads | | 0.27 | | | | |
| **Total** | **13.85** | **14.20** | **466.50** | **3.42** | **2518.11** | **187.42** |

## IPC - Langley Gulch Power Plant

Summary Combined TAP Emissions

| Toxic Air Pollutants[1] | Turbine TAPs Emissions (lb/hr) | Generator TAPs Emissions (lb/hr) | Fire Pump TAPs Emissions (lb/hr) | Total Combined TAPs Emissions (lb/hr) | IDAPA 58.01.01.585/586 EL (lb/hr) | Exceeds? |
|---|---|---|---|---|---|---|
| 1,3-Butadiene | 8.26E-04 | | 2.75E-07 | 8.26E-04 | 2.40E-05 | **Exceeds** |
| 2-Methylnaphthalene | 5.24E-06 | | | 5.24E-06 | 9.10E-05 | Below |
| 3-Methylcholanthrene | 3.93E-07 | | | 3.93E-07 | 2.50E-06 | Below |
| 7,12-Dimethylbenz(a)anthracene | 3.50E-06 | | | 3.50E-06 | 9.10E-05 | Below |
| Acenaphthene | 3.93E-07 | 2.31E-07 | 1.00E-08 | 6.35E-07 | 9.10E-05 | Below |
| Acenaphthylene | 3.93E-07 | 4.57E-07 | 3.56E-08 | 8.85E-07 | 9.10E-05 | Below |
| Acetaldehyde | 7.68E-02 | 1.25E-06 | 5.40E-06 | 7.68E-02 | 3.00E-03 | **Exceeds** |
| Acrolein | 1.37E-02 | 5.69E-05 | 1.90E-04 | 1.39E-02 | 1.70E-02 | Below |
| Ammonia | 1.86E+01 | | | 1.86E+01 | 1.20E+00 | **Exceeds** |
| Anthracene | 5.24E-07 | 6.08E-08 | 1.32E-08 | 5.98E-07 | 9.10E-05 | Below |
| Arsenic | 4.37E-05 | | | 4.37E-05 | 1.50E-06 | **Exceeds** |
| Barium | 1.07E-03 | | | 1.07E-03 | 3.30E-02 | Below |
| Benzene | 2.35E-02 | 3.84E-05 | 6.57E-06 | 2.35E-02 | 8.00E-04 | **Exceeds** |
| Benzo(a)pyrene | 2.62E-07 | 1.27E-08 | 1.32E-09 | 2.76E-07 | 2.00E-06 | Below |
| Benzo(g,h,i)perylene | 2.62E-07 | 2.75E-08 | 3.44E-09 | 2.93E-07 | 9.10E-05 | Below |
| Beryllium | 2.62E-06 | | | 2.62E-06 | 2.80E-05 | Below |
| Cadmium | 2.40E-04 | | | 2.40E-04 | 3.70E-06 | **Exceeds** |
| Chromium | 3.40E-04 | | | 3.40E-04 | 3.30E-02 | Below |
| Cobalt | 2.04E-05 | | | 2.04E-05 | 3.30E-03 | Below |
| Copper | 2.06E-04 | | | 2.06E-04 | 1.30E-02 | Below |
| Dichlorobenzene (o- and 1,4-) | 2.91E-04 | | | 2.91E-04 | 2.00E+01 | Below |
| Ethyl benzene | 6.83E-02 | | | 6.83E-02 | 2.90E+01 | Below |
| Fluoranthene | 6.55E-07 | 1.99E-07 | 5.36E-08 | 9.08E-07 | 9.10E-05 | Below |
| Fluorene | 6.12E-07 | 6.33E-07 | 2.06E-07 | 1.45E-06 | 9.10E-05 | Below |
| Formaldehyde | 1.38E+00 | 3.90E-06 | 8.31E-06 | 1.38E+00 | 5.10E-04 | **Exceeds** |
| Hexane | 4.37E-01 | | | 4.37E-01 | 1.20E+01 | Below |
| Manganese | 9.22E-05 | | | 9.22E-05 | 6.70E-02 | Below |
| Mercury | 6.31E-05 | | | 6.31E-05 | 1.00E-03 | Below |
| Molybdenum | 2.67E-04 | | | 2.67E-04 | 3.33E-01 | Below |
| Naphthalene (PAH)[2] | 2.92E-03 | 6.43E-06 | 5.97E-07 | 2.93E-03 | 9.10E-05 | **Exceeds** |
| Nickel | 4.59E-04 | | | 4.59E-04 | 2.75E-05 | **Exceeds** |
| Nitrous oxide | 6.93E+00 | | | 6.93E+00 | 6.00E+00 | **Exceeds** |
| Pentane | 6.31E-01 | | | 6.31E-01 | 1.18E+02 | Below |
| Phenanthrene | 3.71E-06 | 2.02E-06 | 2.07E-07 | 5.94E-06 | 9.10E-05 | Below |
| Propylene oxide | 6.19E-02 | | | 6.19E-02 | 3.20E+00 | Below |
| POM (7-PAH Group)[3] | 2.49E-06 | 2.22E-07 | 2.42E-08 | 2.74E-06 | 2.00E-06 | **Exceeds** |
| Pyrene | 1.09E-06 | 1.84E-07 | 3.36E-08 | 1.31E-06 | 9.10E-05 | Below |
| Selenium | 5.83E-06 | | | 5.83E-06 | 1.30E-02 | Below |
| Sulfuric acid mist | 2.61E-01 | | | 2.61E-01 | 6.70E-02 | **Exceeds** |
| Toluene | 2.78E-01 | 2.03E-03 | 8.41E-04 | 2.81E-01 | 2.50E+01 | Below |
| Total PAH[4] | 6.87E-03 | 1.05E-05 | 1.18E-06 | 6.89E-03 | | |
| Vanadium | 5.58E-04 | | | 5.58E-04 | 3.00E-03 | Below |
| Xylenes | 1.37E-01 | 1.39E-03 | 5.86E-04 | 1.39E-01 | 2.90E+01 | Below |
| Zinc | 7.04E-03 | | | 7.04E-03 | 3.33E-01 | Below |

Notes:

[1] Red font indicates annual averages, blue font indicates 24-hour averages.

[2] Naphthalene was the maximum individual PAH of the individual PAH compounds provided for each of the emissions units.

[3] POM (7-PAH Group) is the sum of benz(a)anthracene, chrysene, benzo(b)fluoranthene, benzo(k)anthracene, benzo(a)pyrene, indeno (1,2,3-cd)pyrene, dibenz(a,h)anthracene.

Total PAH is the sum of all PAH compounds, including 2-methylnaphthalene, 3-methylcholanthrene, 7,12-dimethylbenz(a)anthracene, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(g,h,l)perylene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene.

## IPC - Langley Gulch Power Plant

SGT6-5000F Gas Turbine in 1x1 Combined Cycle

| | Max Emission Case | | | | | | | Low Load Case | Startup Case |
|---|---|---|---|---|---|---|---|---|---|
| **CH2M HILL Case Number** | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** |
| CTG Load | BASE | BASE | BASE | BASE | BASE | 60% | 60% | 50% | 10% |
| CTG Inlet Air Cooling | Off | Evap. Cooler | Off | Off | Evap. Cooler | Off | Off | Off | Off |
| Ambient Temperature, F | 59 | 104 | 0 | 59 | 104 | 20 | 59 | 90 | 90 |
| HRSG Duct Firing | Unfired | Unfired | Fired | Fired | Fired | Unfired | Unfired | Unfired | Unfired |
| Fuel Flow Rate, MMBTU/hr (HHV) | 1,854 | 1,700 | 2,375 | 2,096 | 1,942 | 1,416 | 1,253 | 1,115 | 750 |
| Ideal Gas Density, scf/lb-mol | 335.6 | 335.6 | 335.6 | 335.6 | 335.6 | 335.6 | 335.6 | 335.6 | 335.6 |
| Method 19 F Factor, dscf/MMBTU | 8,710 | 8,710 | 8,710 | 8,710 | 8,710 | 8,710 | 8,710 | 8,710 | 8,710 |
| | | | | | | | | | |
| Emissions | | | | | | | | | |
| NOx, ppmvd (dry, 15% O2) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 96 | 96 |
| MW of NOx, lb/lb-mol | 46.01 | 46.01 | 46.01 | 46 01 | 46.01 | 46.01 | 46.01 | 46.01 | 46.01 |
| NOx, lb/hr | 15.7 | 14.4 | 20.1 | 17.7 | 16.4 | 12.0 | 10.6 | 452.8 | 452.8 |
| | | | | | | | | | |
| CO, ppmvd (dry, 15% O2) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 24.5 | 1300 |
| MW of CO, lb/lb-mol | 28.01 | 28.01 | 28.01 | 28 01 | 28.01 | 28.01 | 28.01 | 28.01 | 28.01 |
| CO, lb/hr | 9.6 | 8.8 | 12.2 | 10.8 | 10.0 | 7.3 | 6.5 | 70.3 | 2510.8 |
| | | | | | | | | | |
| Fuel Sulfur Concentration, gr/100dscf | 0.5 | 0.5 | 0.5 | 0 5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Fuel Heat Content, BTU/scf (LHV) | 994 | 994 | 994 | 994 | 994 | 994 | 994 | 994 | 994 |
| MW of S, lb/lb-mol | 32.07 | 32.07 | 32.07 | 32 07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 |
| MW of $SO_2$, lb/lb-mol | 64.04 | 64.04 | 64.04 | 64 04 | 64.04 | 64.04 | 64.04 | 64.04 | 64.04 |
| Natural Gas Flow, 100scf/hr | 18,655 | 17,106 | 23,893 | 21,083 | 19,533 | 14,248 | 12,608 | 11,217 | 7,545 |
| $SO_2$, lb/hr | 2.66 | 2.44 | 3.41 | 3.01 | 2.79 | 2.03 | 1.80 | 1.60 | 1.08 |
| $SO_2$, lb/MMBtu | 0.001 | 0.001 | 0.001 | 0.001 | 0.001 | 0 001 | 0.001 | 0.001 | 0.001 |
| | | | | | | | | | |
| VOC, ppmvd (dry, 15% O2) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 11.5 | 200 |
| MW of VOC, lb/lb-mol | 16.04 | 16.04 | 16.04 | 16 04 | 16.04 | 16.04 | 16.04 | 16.04 | 16.04 |
| VOC, lb/hr | 5.5 | 5.0 | 7.0 | 6 2 | 5.7 | 4.2 | 3.7 | 18.9 | 328.9 |
| | | | | | | | | | |
| Total PM10, lb/hr | 10.0 | 10.0 | 12.4 | 12.4 | 12.4 | 10.0 | 10.0 | 10.0 | 10.0 |
| | | | | | | | | | |
| Ammonia, ppmvd (dry, 15% O2) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| MW of Ammonia, lb/lb-mol | 17.0 | 17.0 | 17.0 | 17.0 | 17.0 | 17.0 | 17.0 | 17.0 | 17.0 |
| Ammonia, lb/hr | 14.5 | 13.3 | 18.6 | 16.4 | 15.2 | 11.1 | 9.8 | 8.7 | 8.7 |
| | | | | | | | | | |

Notes:

(1) All data at 55% Ambient Rela ive Humidity.

(2) For $NO_X$, CO and VOC: Emission Rate (lb/hr) = Concentration (lb/dscf) * F Factor (dscf/MMBtu) * Fuel Flow Rate (MMBtu/hr) * (20.9/(20 9-15))

(3) For $NO_X$, CO and VOC: Emission Rates in ppmvd based on determined BACT for the turbines.

(4) For $SO_2$: Emissions based on the sulfur content in the natural gas.

## IPC - Langley Gulch Power Plant

SGT6-5000F Gas Turbine in 1x1 Combined Cycle - Startup/Shutdown Emissions

| | Hot Start | Warm Start | Cold Start | Shutdown |
|---|---|---|---|---|
| Duration per Startup/Shutdown Event (min) | 125 | 280 | 310 | 41 |
| | | | | |
| Emissions per event | | | | |
| $NO_X$, lb | 88 | 154 | **172** | 21 |
| CO, lb | 1108 | 2792 | **4,476** | 113 |
| $SO_2$, lb | 3.2 | 6.1 | **6.7** | 1.2 |
| VOC, lb | 270 | 475 | **680** | 23 |
| Total $PM_{10}$, lb | 23 | 54 | **60** | 5.9 |
| | | | | |
| Hourly Emissions from Startup/Shutdown | | | | |
| $NO_X$, lb/hr | 75 | 100 | **124** | 31 |
| CO, lb/hr | 1,054 | 598 | **2,510** | 165 |
| $SO_2$, lb/hr | 2 | 1 | 1 | **2** |
| VOC, lb/hr | 130 | 141 | **186.6** | 34 |
| Total $PM_{10}$, lb/hr | 11 | 12 | **12** | 9 |
| | | | | |

Notes:

(1) Startup Shutdown emissions data obtained from Siemens sheet at 61.2 F (11/14/08).

(2) Hourly emissions for startup/shutdown estimated as total emissions divided by duration of the event.

(3) Siemens emissions provided for a fast start configuration.
This is assumed to be worst case emissions for SU SD events.

| | Hot Start | Warm Start | Cold Start | Shutdown | |
|---|---|---|---|---|---|
| Duration per Startup/Shutdown Event (min) | 125 | 280 | 310 | 41 | |
| Number of Events per year | 253 | 45 | 7 | 305 | |
| Total Duration of event per year (hr) | 527 | 210 | 36 | 208 | |
| | | | | | |
| Emissions per event | | | | | |
| $NO_X$, lb | 88 | 154 | 172 | 21 | |
| CO, lb | 1108 | 2792 | 4476 | 113 | |
| $SO_2$, lb | 3 | 6 | 7 | 1 | |
| VOC, lb | 270 | 475 | 680 | 23 | |
| Total $PM_{10}$, lb | 23 | 54 | 60 | 6 | |
| | | | | | |
| Emissions from Startup/Shutdown | | | | | Total Emissions from Startup/Shutdown |
| $NO_X$, lb | 22,264 | 6,930 | 1,204 | 6,405 | 18.4 tpy |
| CO, lb | 280,324 | 125,640 | 31,332 | 34,465 | 235.9 tpy |
| $SO_2$, lb | 810 | 275 | 47 | 366 | 0.7 tpy |
| VOC, lb | 68,310 | 21,375 | 4,760 | 7,015 | 50.7 tpy |
| Total $PM_{10}$, lb | 5,819 | 2,430 | 420 | 1,800 | 5.2 tpy |

Power Generation

# Exhaust Emission Data Sheet
# 750DQFAA
## 60 Hz Diesel Generator Set

**Engine Information:**

| | | | |
|---|---|---|---|
| Model: | Cummins Inc. QST30-G5 NR2 | Bore: | 5.51 in. (139 mm) |
| Type: | 4 Cycle, 50°V, 12 Cylinder Diesel | Stroke: | 6.5 in. (165 mm) |
| Aspiration: | Turbocharged and Low Temperature aftercooled | Displacement: | 1860 cu. in. (30.4 liters) |
| Compression Ratio: | 14.7:1 | | |
| Emission Control Device: | Aftercooled (Air-to-Air) | | |

| | 1/4 | 1/2 | 3/4 | Full | Full | |
|---|---|---|---|---|---|---|
| **PERFORMANCE DATA** | **Standby** | **Standby** | **Standby** | **Standby** | **Prime** | |
| BHP @ 1800 RPM (60 Hz) | 276 | 551 | 827 | 1102 | 999 | |
| Fuel Consumption (gal/Hr) | 14.8 | 27.1 | 39.8 | 52.7 | 47.9 | |
| Exhaust Gas Flow (CFM) | 2350 | 3620 | 4930 | 6310 | 5880 | |
| Exhaust Gas Temperature (°F) | 553 | 686 | 770 | 816 | 798 | |
| | | | | | | |
| **EXHAUST EMISSION DATA** | | | | | | |
| | | | | | | |
| HC (Total Unburned Hydrocarbons) | 0.22 | 0.11 | 0.10 | 0.09 | 0.09 | |
| NOx (Oxides of Nitrogen as NO2) | 5.81 | 4.50 | 3.83 | 3.97 | 3.88 | |
| CO (carbon Monoxide) | 1.38 | 0.48 | 0.37 | 0.46 | 0.43 | |
| PM (Particular Matter) | 0.19 | 0.17 | 0.14 | 0.12 | 0.13 | |
| SO2 (Sulfur Dioxide) | 0.12 | 0.11 | 0.10 | 0.10 | 0.10 | |
| Smoke (Bosch) | 0.65 | 0.84 | 0.79 | 0.79 | 0.80 | |
| | | | | | | All Values are Grams/HP-Hour, Smoke is Bosch # |

## TEST CONDITIONS

Data was recorded during steady-state rated engine speed (± 25 RPM) with full load (±2%). Pressures, temperatures, and emission rates were stabilized.

| | |
|---|---|
| Fuel Specification: | 46.5 Cetane Number, 0.035 Wt.% Sulfur; Reference ISO8178-5, 40CFR86.1313-98 Type 2-D and ASTM D975 No. 2-D. |
| Fuel Temperature: | 99 ± 9 °F (at fuel pump inlet) |
| Intake Air Temperature: | 77 ± 9 °F |
| Barometric Pressure: | 29.6 ± 1 in. Hg |
| Humidity: | NOx measurement corrected to 75 grains H2O/lb dry air |
| Reference Standard: | ISO 8178 |

The NOx, HC, CO and PM emission data tabulated here were taken from a single engine under the test conditions shown above. Data for the other components are estimated. These data are subjected to instrumentation and engine-to-engine variability. Field emission test data are not guaranteed to these levels. Actual field test results may vary due to test site conditions, installation, fuel specification, test procedures and instrumentation. Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may results in elevated emission levels.

# Tier 3 Emissions Data - John Deere Power Systems

## Nameplate Rating Information

| | |
|---|---|
| Clarke Model | JU6H-UFAD98 |
| Power Rating (BHP / kW) | 315 / 235 |
| Certified Speed (RPM) | 1760 |

## Certificate Data

| | |
|---|---|
| John Deere Engine Rating | 6068HFC48A |
| Engine Model Year * | 2009 |
| EPA Family Name | 9JDXL06.8101 |
| EPA Certificate Number | JDX-NRCI-09-15 |
| CARB Executive Order Number | U-R-004-0361 |
| Emissions Label Part Number | R528920 |

* The Engine Model Year is listed on the emissions label.

## Emissions Data * *

| Units | g/hp-hr | g/kW-hr |
|---|---|---|
| CO | 0.45 | 0.61 |
| Pm | 0.055 | 0.074 |
| NOx | 2.69 | 3.61 |
| HC | 0.06 | 0.08 |
| NOx + HC | 2.75 | 3.69 |
| Test Engine | PE6068L000130 | |

* * The emission data listed is measured from the calibration engine under laboratory test conditions. It is intended to represent an "average" engine but is not a guarantee that all engines meet these values.

JOHN DEERE

John Deere Power Systems
3801 W. Ridgeway Ave., PO Box 5100
Waterloo, Iowa USA 50704 5100

## IDAPA 58.01.01.675-676
## Fuel Burning Equipment—Particulate Matter

This regulation establishes particulate matter emission standards for fuel burning equipment. Fuel burning equipment is defined in IDAPA 58.01.01…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.*

Emissions of particulate matter from fuel burning equipment that commence operation on or after October 1, 1979, with a maximum rated input of 10 MMBtu/hr or more, are subject to the emissions standards of IDAPA 58.01.01.675 and 676. Therefore, the combustion turbine will comply with the grain-loading standard for gas-fired sources when operating the duct burners. See Table 6-1.

*Table 6-1: IDAPA Rule 677 PM Standard for Fuel Burning Equipment*

| *Unit* | *Gas Turbine with Duct Firing* |
|---|---|
| Fuel | Natural Gas |
| Rated Heat Input (MM Btu/hr) | 2375.00 |
| PM Emission Rate (lb/hr) | 12.40 |
| ***Exit/Flue Gas Flowrate Calculation*** | |
| $F_d$ (Table 19-2, EPA Method 19) (dscf/MM Btu) [a,b] | 8,710 |
| Exit flowrate @ 0% $O_2$: (dscfm) | 344,771 |
| Exit flowrate @ 3% $O_2$: (dscfm) [c] | 402,554 |
| Calculated Grain Loading (gr/dscf @ 3% $O_2$) [d] | 0.003 |
| PM Loading Standard (IDAPA 58.01.01.677) (gr/dscf @ 3% 02) | 0.015 |
| Compliance w/ PM Loading Standard | **Yes** |

[a] Appendix A-7 to 40 CFR part 60, Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates, Table 19-2 (F Factors for Various Fuels)

[b] Fd, Volumes of combustion components per unit of heat content (scf/million Btu). Fd for natural gas and biogas is 8,710 dscf/106 Btu

[c] (Flow $_{3\%}$) = (Flow $_{0\%}$) x (20.9/(20.9 - 3)), where 20.9 = Oxygen concentration in ambient air

[d] (7,000 gr/lb) x (PM lb/hr) / (Flow (dscfm) x 60 (min/ hr)) = gr/dscf

## IDAPA 58.01.01.775-776
## Control of Odors

*"No person shall allow, suffer, cause or permit the emission of odorous gases, liquids or solids to the atmosphere in such quantities as to cause air pollution."*

LGPR will take all reasonable precautions to comply with this requirement by maintaining records of any odor complaint received and take action as expeditiously as practicable.

# APPENDIX C

# AMBIENT AIR QUALITY IMPACT ANALYSES

***M E M O R A N D U M***

**DATE:** June 25, 2010

**TO:** Morrie Lewis, Air Quality Analyst, Air Program

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

**PROJECT NUMBER:** P-2009.0092

**SUBJECT:** Modeling Review for the Idaho Power Company Permit to Construct Application for the Langley Gulch Power Plant Project, Located near New Plymouth, Idaho

## 1.0 Summary

Idaho Power Company (IPC) submitted a Permit to Construct (PTC) application for a new natural gas fired, combined-cycle power plant, the Langley Gulch Power Plant Project (LGPR), to be located near New Plymouth, Idaho. Air quality analyses involving atmospheric dispersion modeling of potential or allowable emissions associated with the proposed project were performed to demonstrate the new facility would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02 [Idaho Air Rules Section 203.02]) or Toxic Air Pollutant (TAP) increment (Idaho Air Rules Section 203.03). The LGPR is a major facility subject to requirements of the prevention of significant deterioration (PSD) program as specified in Idaho Air Rules Section 205, including PSD increment, effects on visibility, and other impact analyses.

A technical review of the submitted information and analyses was conducted by DEQ. The submitted information and analyses, in combination with DEQ's analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data; 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 were below significant contribution levels (SCLs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from emissions associated with the facility, when appropriately combined with background concentrations, were below applicable air quality standards at all ambient air locations; 5) demonstrated compliance with applicable PSD increments and other impact analysis requirements.

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, in combination with DEQ's analyses, demonstrated to the satisfaction of the Department that operation of the proposed facility or modification will not cause or significantly contribute to a violation of any ambient air quality standard, provided key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

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

| Table 1. KEY CONDITIONS USED IN MODELING ANALYSES | |
|---|---|
| **Criteria/Assumption/Result** | **Explanation/Consideration** |
| Maximum emissions rates for specified averaging periods do not exceed those listed in Table 5 and 6 of this memorandum. | Air impact modeling was performed using only these emissions rates. Impacts for emissions in excess of these rates have not been assessed. |
| Locations and stack parameters of emissions sources, and building dimensions and locations, as constructed and operated are identical to those modeled in the impact analyses. | These parameters may have a substantial affect on model results, and compliance with standards has not been demonstrated for configurations other than those used in the model and described in this memorandum. |

# 2.0 Background Information

## *2.1 Applicable Air Quality Impact Limits and Modeling Requirements*

This section identifies applicable ambient air quality limits and analyses used to demonstrate compliance.

### *2.1.1 Area Classification*

The LGPR facility will be located near New Plymouth, Idaho. The area is designated as an attainment or unclassifiable area for carbon monoxide (CO), lead (Pb), nitrogen dioxide ($NO_2$), ozone ($O_3$), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers ($PM_{10}$), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$), and sulfur dioxide ($SO_2$).

There are no Class I areas within 10 kilometers of the proposed site location.

### *2.1.2 Significant and Cumulative NAAQS Impact Analyses*

If estimated maximum pollutant impacts to ambient air from the emissions sources associated with the facility exceed the significant contribution levels (SCLs), referred to as Significant Impact Levels (SILs), of Idaho Air Rules Section 006.105, then a cumulative impact analysis is necessary to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Idaho Air Rules Section 203.02. A cumulative NAAQS impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions, and emissions from any nearby co-contributing sources, to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting maximum pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled value that must be used for comparison to the NAAQS.

| Table 2. APPLICABLE REGULATORY LIMITS | | | | |
|---|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Significant Impact Levels[a] ($\mu g/m^3$)[b]** | **Regulatory Limit [c] ($\mu g/m^3$)** | **Modeled Value Used[d]** |
| $PM_{10}$[e] | Annual[f] | 1.0 | 50[g] | Maximum 1st highest[h] |
| | 24-hour | 5.0 | 150[i] | Maximum 2nd highest[j] |
| $PM_{2.5}$[k] | Annual | Not established | 15[l] | Use $PM_{10}$ as surrogate |
| | 24-hour | Not established | 35[m] | Use $PM_{10}$ as surrogate |
| Carbon monoxide (CO) | 8-hour | 500 | 10,000[n] | Maximum 2nd highest[h] |
| | 1-hour | 2,000 | 40,000[n] | Maximum 2nd highest[h] |
| Sulfur Dioxide ($SO_2$) | Annual | 1.0 | 80[g] | Maximum 1st highest[h] |
| | 24-hour | 5 | 365[n] | Maximum 2nd highest[h] |
| | 3-hour | 25 | 1,300[n] | Maximum 2nd highest[h] |
| Nitrogen Dioxide ($NO_2$) | Annual | 1.0 | 100[g] | Maximum 1st highest[h] |
| | 1-hour | Not established | 188[o] | In development |
| Lead (Pb) | Quarterly | NA | 1.5[g] | Maximum 1st highest[h] |
| | 3-month[p] | NA | 0.15[g] | Maximum 1st highest[h] |

[a] Idaho Air Rules Section 006.105.
[b] Micrograms per cubic meter.
[c] Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.03.b.
[d] The maximum of 1st highest modeled value is always used for the significant impact analysis.
[e] Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers.
[f] The annual $PM_{10}$ standard was revoked in 2006. The standard is still listed because compliance with the annual $PM_{2.5}$ standard is demonstrated by a $PM_{10}$ analysis that demonstrates compliance with the revoked $PM_{10}$ standard.
[g] Not to be exceeded in any calendar year.
[h] Concentration at any modeled receptor.
[i] Not expected to be exceeded more than once in any calendar year.
[j] Concentration at any modeled receptor when using one year of meteorological data.
[k] Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
[l] Three-year mean of annual averages not to exceed standard.
[m] Three-year mean of 98th percentile not to exceed standard.
[n] Not to be exceeded more than once in any calendar year.
[o] Three-year mean of the 98th percentile of the annual distribution of 1-hour average daily maximum concentrations not to exceed standard.
[p] 3-month rolling average not to exceed standard.

New source review requirements for assuring compliance with $PM_{2.5}$ standards have not yet been completed and promulgated into Idaho Air Rules. At the time a complete application was received by DEQ, EPA had asserted through a policy memorandum that compliance with $PM_{2.5}$ standards will be assured through an air quality analysis for the corresponding $PM_{10}$ standard. Although the $PM_{10}$ annual standard was revoked in 2006, compliance with the revoked $PM_{10}$ annual standard must be demonstrated as a surrogate to the annual $PM_{2.5}$ standard. As stated in a recent Federal Register addressing implementation of $PM_{2.5}$ for PSD, "For States with SIP-approved PSD programs, the preamble to the May 2008 final rules stated that SIP-approved states may continue to implement a $PM_{10}$ program as a surrogate to meet the PSD program requirements for $PM_{2.5}$ pursuant to the 1997 $PM_{10}$ Surrogate Policy for up to three years (until May 2011) or until the individual revised State PSD programs for $PM_{2.5}$ are approved by EPA, whichever comes first. See 73FR28341."[1]

A 1-hour $NO_2$ standard of 188 $\mu g/mg^3$ was recently promulgated.[2] The standard has an effective date of April 12, 2010, as established by the Final Rule. NAAQS become applicable to permitting decisions in Idaho when such standards are incorporated by reference into Idaho Air Rules as per Idaho Air Rules Section 107. Impacts of 1-hour $NO_2$ were not assessed for the LGPR facility since the 1-hour $NO_2$ NAAQS will not be incorporated into Idaho Air Rules until spring of 2011.

[1] Federal Register/Vol. 75, No. 28/Thursday, February 11, 2010, Section II.C.

[2] Federal Register / Vol. 75, No. 26 / Tuesday, February 9, 2010.

### *2.1.3 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.*

Permit requirements for toxic air pollutants 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 a total project-wide emissions increase of a 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 TAPs requirements has been demonstrated.

### *2.1.4 PSD Impact Analyses*

Air impact analyses requirements for permits subject to the PSD program are specified in Idaho Air Rules Section 202.01.c.

## *2.2 Background Concentrations*

Background concentrations are used in the cumulative NAAQS impact analyses to account for impacts from sources not explicitly modeled. Table 3 lists appropriate background concentrations for rural Idaho areas.

Background concentrations were revised for all areas of Idaho by DEQ in March 2003.[3] Background concentrations in areas where no monitoring data are available were based on monitoring data from areas with similar population density, meteorology, and emissions sources. Background concentrations in these analyses were based on DEQ default values for rural/agricultural areas. Since modeled impacts were below SILs for all pollutants except 1-hour CO, background values for all other pollutants were not used in the analyses.

[3] Hardy, Rick and Schilling, Kevin. *Background Concentrations for Use in New Source Review Dispersion Modeling*. Memorandum to Mary Anderson, March 14, 2003.

| Table 3. BACKGROUND CONCENTRATIONS | | |
|---|---|---|
| **Pollutant** | **Averaging Period** | **Background Concentration ($\mu g/m^3$)[a]** |
| $PM_{10}$[b] | 24-hour | 73 |
| | Annual | 26 |
| Carbon monoxide (CO) | 1-hour | 3,600 |
| | 8-hour | 2,300 |
| Sulfur dioxide ($SO_2$) | 3-hour | 34 |
| | 24-hour | 26 |
| | Annual | 8 |
| Nitrogen dioxide ($NO_2$) | Annual | 17 |
| Lead (Pb) | Quarterly | 0.03 |

[a] Micrograms per cubic meter.
[b] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

# 3.0 Modeling Impact Assessment

## *3.1 Modeling Methodology*

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

### *3.1.1 Overview of Analyses*

Table 4 provides a brief description of parameters used in the modeling analyses.

| Table 4. MODELING PARAMETERS | | |
|---|---|---|
| **Parameter** | **Description/Values** | **Documentation/Additional Description** |
| General Location | Payette County | About 5 miles south of New Plymouth. |
| Model | AERMOD | AERMOD with the PRIME downwash algorithm, version 09292, was used for all air impact analyses except ozone. |
| Meteorological Data | Site-specific surface Boise upper air | 1 year of on-site data collected. |
| Terrain | Considered | Receptor, building, and emissions source elevations were determined using Digital Elevation Model (DEM) files. |
| Building downwash | Considered | Buildings present on the site that could reasonably cause plume downwash were included in the analyses through the use of the BPIP-PRIME program. |
| Receptor Grid | Grid 1 | 25-meter spacing along the ambient air boundary |
| | Grid 2 | 100-meter spacing out to 1,000 meters |
| | Grid 3 | 500-meter spacing out to 10,000 meters |
| | MaxGrid | 50-meter spacing centered on point of maximum impact. |

### *3.1.2 Modeling protocol and Methodology*

Refined air impact analyses were performed by CH2M Hill, Idaho Power's consultant. A modeling protocol was submitted to DEQ prior to the application, in June 2009, and DEQ provided conditional approval of the protocol to CH2M Hill on July 9, 2009. Modeling was generally conducted using data and methods described in the protocol and/or in the *State of Idaho Air Quality Modeling Guideline*.

CH2M Hill initially proposed to use SCREEN3 and the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) with a partial year of meteorological data, and the initial submittal included these analyses. In December of 2009 a full year of on-site meteorological data were available and the modeling was revised to include impacts associated with a full year of data. The

application was revised and resubmitted on December 15, 2009. Additional revisions were made in response to comments from DEQ and refinements in facility design/operations, and the final revised application was submitted on April 4, 2010.

### *3.1.3 Model Selection*

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. EPA provided a 1-year transition period during which either ISCST3 or AERMOD could be used at the discretion of the permitting agency. AERMOD must be used for all near-field air impact analyses, performed in support of air quality permitting, conducted after November 2006.

AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD offers the following improvements over ISCST3:

- Improved dispersion in the convective boundary layer and the stable boundary layer
- Improved plume rise and buoyancy calculations
- Improved treatment of terrain affects on dispersion
- New vertical profiles of wind, turbulence, and temperature

Site-specific analyses performed by CH2M Hill used AERMOD Version 09292.

### *3.1.4 Meteorological Data*

An on-site meteorological tower was erected to collect the following data: wind speed, wind direction, standard deviation of wind direction, vertical wind speed, and temperature, all at 10 meters; temperature, pressure, solar radiation, and relative humidity, all at 2 meters. The data were collected as per PSD monitoring guideline specifications. One year of data were collected, beginning December 3, 2008. Cloud cover observations used for determining mixing heights were obtained from the Ontario Municipal Airport, Oregon (WBAN 24162), about 18 miles northwest of the site. Upper air data were obtained from the Boise Air Terminal National Weather Service station (WBAN 24162).

Meteorological data were processed using AERMET version 06341. Month-specific surface characteristics were determined by using the program AERFURFACE (version 08009). Details on the meteorological data processing are presented in the submitted application.

### *3.1.5 Ambient Air Boundary*

A security fence around the immediate area of the LGPR was used as the boundary to ambient air, as this represents a highly secure physical barrier. The property boundary will also be fenced, but this was conservatively not used as the ambient air boundary.

### *3.1.6 Facility Layout*

DEQ checked locations specified in the model against those listed in the application, and reviewed the general location using Google Earth.

### *3.1.7 Building Downwash*

Downwash effects potentially caused by structures at the facility were accounted for in the dispersion modeling analyses. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific building dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and emissions release parameters for AERMOD.

### *3.1.8 Terrain Effects*

Terrain effects on dispersion were considered in the analyses. Receptor elevations and hill heights were obtained by CH2M Hill using AERMAP (version 09040) and Digital Elevation Model (DEM) 7.5-minute files.

Substantial site grading will be performed in preparation of construction. This will alter terrain in the area between the ambient air boundary and the property boundary. Elevations of modeling receptors were not altered according to site grading plans. This is not a critical inaccuracy of the analyses because these receptors are on IPC property and are in the immediate area of the plant. General public access will be precluded from this area even though the area will not be as secure as the area within the fence establishing the ambient air boundary.

### *3.1.9 Receptor Network*

A fenceline receptor grid with 25-meter spacing was used. Beyond the fenceline, a rectangular grid centered on the facility was used with 50-meter spacing, extending out to 1,000 meters, and 500-meter spacing, extending out to 10,000 meters.

The ambient air receptor network met the minimal requirements established in the *State of Idaho Air Quality Modeling Guideline*. DEQ also determined that the receptor spacing used was adequate to reasonably resolve maximum modeled concentrations.

## *3.2 Emission Rates*

Emissions rates used in the modeling analyses for the proposed project were equal to or greater than those presented in other sections of the permit application or the DEQ Statement of Basis. Emissions rates represent potential operations as limited by design or as limited by the permit.

### *3.2.1 Criteria Pollutant Emissions Rates*

Table 5 lists criteria pollutant emissions rates used in the Class II impact analyses for all averaging periods. Emissions rates from the turbine vary considerably with load and ambient air conditions. The emissions used in the modeling analyses represent the worst-case conditions for the specified averaging period.

| Table 5. EMISSIONS RATES USED FOR IMPACT MODELING | | | | | | |
|---|---|---|---|---|---|---|
| **Emissions Point** | **Description** | **Averaging Period** | **Emissions Rates (pounds/hour)** | | | |
| | | | **$PM_{10}$[a]** | **Carbon Monoxide** | **Sulfur Dioxide** | **Oxides of Nitrogen** |
| HRSG1 | main stack for turbine | 1-hr | | 2510 | | |
| | | 8-hr | | 186.6<br>564.6[b] | | |
| | | 3-hr | | | 3.408 | |
| | | 24-hr | 12.55 | | 3.408 | |
| | | annual | 10.981<br>11.29[b] | | 2.856<br>3.069[b] | 20.03<br>20.10[b] |
| CT1 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT2 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT3 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT4 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT5 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT6 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| CT7 | cooling tower cell | 24-hr, ann | 0.09488 | | | |
| FP[c] | fire water pump | 1-hr | | 1.800 | | |
| | | 8-hr | | 0.2252 | | |
| | | 3-hr | | | 1.070E-3 | |
| | | 24-hr | 4.300E-3 | | 1.329E-4 | |
| | | annual | 3.561E-4 | | 1.087E-5 | 6.849E-3<br>7.120E-3[b] |
| EG[d] | emergency generator | 1-hr | | 6.300 | | |
| | | 8-hr | | 3.152 | | |
| | | 3-hr | | | 0.01123 | |
| | | 24-hr | 0.06060 | | 1.871E-3 | |
| | | annual | 2.491E-3 | | 7.691E-5 | 0.07991 |
| SILO1[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |
| SILO2[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |
| SILO3[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |
| SILO4[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |
| SILO5[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |
| SILO6[e] | dry chemical silo loading | 24-hr | 7.140E-3 | | | |
| | | annual | 2.351E-4 | | | |

[a] Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers.
[b] DEQ revised worst-case emissions rate for averaging period.
[c] Emissions based on operation of 1.0 hour/day and 30 hour/year.
[d] Emissions based on operation of 4.0 hour/day and 60 hour/year.
[e] Emissions based on loading silos for 2.0 hour/day and 24 hour/year (loading each silo once per month).

### *3.2.2 TAP Emissions Rates*

Table 6 provides TAP emissions associated with operation of the proposed LGPR. The table only includes those TAPs where total emissions exceeded emissions screening levels (ELs) of Idaho Air Rules Section 585 and 586.

| Table 6. EMISSIONS RATES USED FOR TAPS IMPACT MODELING | | | |
|---|---|---|---|
| TAP | Emissions Rates[a] (pounds/hour) | | |
| | Turbine Stack (HRSG1) | Fire Water Pump (FP) | Emergency Generator (EG) |
| 1,3-Butadiene | 8.260E-04 | 2.750E-07 | |
| Acetaldehyde | 7.680E-02 | 5.400E-06 | 1.250E-6 |
| Ammonia[b] | 1.860E+01 | | |
| Arsenic | 4.357E-05 | | |
| Benzene | 2.352E-02 | 6.508E-06 | 3.833E-05 |
| Cadmium | 2.397E-04 | | |
| Formaldehyde | 1.379E+00 | 8.254E-06 | 3.889E-06 |
| Naphthalene | 2.922E-03 | 7.222E-06 | 1.560E-04 |
| Nickel | 4.589E-04 | | |
| Nitrous oxide[b] | 6.930E+00 | | |
| PAH | 4.224E-03 | 1.111E-06 | 1.024E-05 |
| POM (7-PAH) | 2.808E-04 | 2.420E-08 | 2.224E-07 |
| Sulfuric acid mist[b] | 2.610E-01 | | |

[a] Carcinogenic TAP – annual emissions were averaged over 8,760 hours per year.
[b] Non-carcinogenic TAP – maximum daily emissions are averaged over 24 hours.

### 3.3 Emission Release Parameters

Table 7 provides emissions release parameters for the analyses including stack height, stack diameter, exhaust temperature, and exhaust velocity. Stack gas temperatures and flow rates for the turbine vary considerably with load and atmospheric conditions. Modeling was performed conservatively using the lowest flow and temperatures expected over all operational scenarios, and combining these with maximum emissions predicted for any operational scenario.

| Table 7. EMISSIONS RELEASE PARAMETERS | | | | | |
|---|---|---|---|---|---|
| Release Point /Location | Source Type | Stack Height (m)[a] | Modeled Diameter (m) | Stack Gas Temp. (K)[b] | Stack Gas Flow Velocity (m/sec)[c] |
| Turbine Stack (HRSG1) | Point | 48.8 | 5.49 | 363 | 17.5 |
| Cooling Towers (CT1 - CT7) | Point | 14.2 | 10.0 | 298 | 10.0 |
| Fire Pump (FP) | Point | 6.1 | 0.128 | 789 | 52.4 |
| Emergency Gen. (EG) | Point | 6.1 | 0.152 | 709 | 163 |
| Silo Filling (SILO1 – SILO6) | Point | 11.0 | 0.610 | 311 | 1.62 |

[a] Meters.
[b] Kelvin.
[c] Meters per second.

### 3.4 Results for NAAQS Significant Impact Analyses

CH2M Hill performed a Significant Impact Analysis to evaluate whether operation of the proposed LGPR could have a significant contribution to air pollutant levels. Results of the Significant Impact Analyses are provided in Table 8.

| Table 8. RESULTS FOR SIGNIFICANT IMPACT ANALYSES | | | | |
|---|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Maximum Modeled Concentration ($\mu g/m^3$)[a]** | **SIL[b] ($\mu g/m^3$)** | **Cumulative Impact Analysis Required** |
| $PM_{10}$[c] | 24-hour | 1.9 | 5 | No |
| | Annual | 0.23<br>0.23[d] | 1 | No |
| Carbon monoxide (CO) | 1-hour | 4061 | 2000 | Yes |
| | 8-hour | 129.5<br>194.8[d] | 500 | No<br>No |
| Sulfur dioxide ($SO_2$) | 3-hour | 1.8 | 25 | No |
| | 24-hour | 0.34 | 5 | No |
| | Annual | 0.013<br>0.014[e] | 1 | No |
| Nitrogen dioxide ($NO_2$) | Annual | 0.21<br>0.22[e] | 1 | No |

[a] Micrograms per cubic meter.
[b] Significant Impact Levels.
[c] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
[d] DEQ modeled impacts resulting from revised emissions from the HRSG stack of 564.6 lb/hour for 8-hour CO and 11.29 lb/hour for annual $PM_{10}$.
[e] DEQ revised impacts resulting from revised emissions from the HRSG stack of 3.069 lb/hour for annual $SO_2$ and from the fire pump engine stack of 7.12E-3 lb/hour for annual $NO_X$.

Refinements in CO emissions estimates required remodeling of CO impacts by the applicant. DEQ also performed an 8-hour CO analysis for revised worst-case 8-hour CO emissions as estimated by DEQ. Resulting maximum impacts were below SILs except for 1-hour CO, where the SIL was exceeded at limited receptors very close to the facility. Cumulative impact analyses were required for CO. A cumulative impact analysis involves modeling facility-wide emissions along with co-contributing sources that could measurably contribute to concentrations within the radius of significant impact of the permitted facility. A background concentration is then added to modeled results to account for impacts from sources not specifically included in the modeling analyses.

DEQ revised potential annual $SO_2$ and $NO_X$ emissions as shown in Table 5. DEQ did not remodel for these changes; revised ambient impacts were estimated by multiplying the previous maximum impact levels by the ratio of the modified emissions rate of the specific source to the previous rate of the source, as shown in Table 8. The ratio was 1.075 for annual $SO_2$ emissions from the HRSG stack. NOx emissions were modified for both the HRSG stack and the fire water pump stack. The ratios were 1.003 for the HRSG stack and 1.04 for the fire water pump stack. Revised impacts were conservatively calculated by applying the 1.04 ratio to previously modeled results. Since the submitted annual modeling results were well below the SILs and the emissions ratios are near a value of 1.0, compliance with both the annual $SO_2$ and $NO_2$ standards was adequately demonstrated.

Maximum $PM_{10}$ 24-hour impacts were modeled at 1.9 $\mu g/m^3$, about 38 percent of the 5.0 $\mu g/m^3$ SIL. The maximum impact beyond the property boundary was modeled at 1.8 $\mu g/m^3$ at a location along the highway. Figure 1 shows a contour plot generated from the 1st highest modeled concentrations at each receptor. Concentrations quickly drop off to levels below 1.0 $\mu g/m^3$ at distances beyond one kilometer. This compares to the SIL of 5 $\mu g/m^3$ and the NAAQS of 150 $\mu g/m^3$. Annual $PM_{10}$ impacts of 0.2 $\mu g/m^3$ were also well below the SIL of 1.0 $\mu g/m^3$. Compliance with $PM_{2.5}$ standards has been demonstrated to the satisfaction of DEQ since compliance with $PM_{10}$ has been demonstrated, as prescribed by the EPA $PM_{10}$ surrogate policy.

### *3.5 Results for NAAQS Cumulative Impact Analyses*

Impacts of 1-hour CO exceeded the SIL out to a maximum distance of about 300 meters. The applicant, with assistance from Idaho DEQ and Oregon DEQ, assessed the area surrounding the proposed site location for co-contributing CO sources that could have a measurable impact within the CO significant impact area. There were no CO point sources indentified in the immediate area that could measurably contribute to CO impacts within the area of significant impact of the LGPR. The neighboring towns of New Plymouth, Idaho (about 5 miles from the proposed site), Fruitland, Idaho (about 9 miles from the proposed site), Nyssa, Oregon (about 15 miles from the proposed site), and Ontario, Oregon (about 10 miles from the proposed site) were also evaluated. The largest CO emissions source from a point source was identified as the Amalgamated Sugar Company (TASCO) in Nyssa, Oregon. The source is about 14.5 kilometers to the west, southwest of the proposed LGPR site. Five other sources permitted for CO emissions were identified in the Ontario area, with combined allowable CO emissions of 577 ton/year. The TASCO facility is permitted for 2,205 ton/year, far greater than the combined emissions of the other facilities.

DEQ determined the CO sources in Ontario and Nyssa were very unlikely to significantly contribute to CO concentrations within the area of significant impact for the LGPR; however, DEQ recommended the applicant conservatively perform an impact assessment for the TASCO facility and any large CO sources identified in Ontario. CH2M Hill modeled 2,074 pounds/hour from the TASCO facility, which is the permit-allowable rate for the TASCO facility.

There are multiple CO emissions sources at the TASCO facility and total allowable emissions were modeled conservatively from a single stack. Stack parameters were determined using the method for a "representative stack" in EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised*, EPA 454/R 92 019 (October 1992). In this method, the "representative" stack is the stack having the lowest value for a parameter identified as "M." M is calculated for each stack by the following:

$$M = \frac{h_s V T_s}{Q}$$

where:

| | | |
|---|---|---|
| M | = | merged stack parameter which accounts for the relative influence of stack height, plume rise, and emission rate on concentrations |
| $h_s$ | = | stack height (m) |
| V | = | $(\pi/4)\ d_s^2 v_s$ = stack gas volumetric flow rate ($m^3/s$) |
| $d_s$ | = | inside stack diameter (m) |
| $v_s$ | = | stack gas exit velocity (m/s) |
| $T_s$ | = | stack gas exit temperature (K) |
| Q | = | pollutant emission rate (g/s) |

The emissions were modeled using the following three scenarios to provide additional assurance that the 1-hour CO standard will be met:

1. Model the TASCO facility using a "worst-case representative stack" as per EPA Screening Model Guidance. Stack height = 21.3 meters (70 feet); stack diameter = 1.89 meters; stack gas temperature = 363 K (194$^o$ F); stack gas flow = 2,080 actual cubic feet per minute (acfm);

stack gas flow velocity = 0.35 meters/second.

2. Model the emissions from a stack with the same parameters as Scenario 1, except the source was placed along the primary wind direction (upwind) in Ontario, OR. This scenario was performed to demonstrate that any smaller source or collection of sources with CO emissions totaling 2,074 pounds/hour in Ontario would not cause an exceedance. Stack height = 21.3 meters (70 feet); stack diameter = 1.89 meters; stack gas temperature = 363 K (194$^o$ F); stack gas flow = 2,080 actual cubic feet per minute (acfm); stack gas flow velocity = 0.35 meters/second.

3. Model emissions as in Scenario 2, but use the average stack parameters rather than those of a "representative stack." Stack height = 33.8 meters (111 feet); stack diameter = 2.05 meters; stack gas temperature = 352 K (173$^o$ F); stack gas flow = 80,217 acfm; stack gas flow velocity = 37.9 meters/second.

CO impacts from all three scenarios are presented in Table 9. Maximum impacts from co-contributing sources to the impact area of LGPR (where emissions from LGPR have a maximum impact of greater than the SILs of 2,000 µg/m$^3$) are all less than 1,000 µg/m$^3$. Impacts on the design concentration, the maximum of highest modeled concentrations at each receptor, were much less. The influence of the co-contributing source on the maximum of 1$^{st}$ highest combined impacts, considering LGPR and the co-contributing source, was less than 1.0 µg/m$^3$ for all three scenarios. The results easily demonstrated compliance with the 1-hour CO NAAQS considering the maximum combined modeled impact for the LGPR, the impact from a large nearby source, and a reasonably conservative background concentration.

DEQ performed verification analyses for the CO cumulative impact analyses submitted. DEQ added a scenario that involved combined effects of the TASCO facility and an equivalent source in Ontario to account for other CO sources in the area (using the average stack parameters for the TASCO facility). The impact of both co-contributing sources on the maximum of 1$^{st}$ highest modeled concentrations from emissions of the LGPR facility was negligible, although the maximum impact from the co-contributing sources was modeled at 1,011 µg/m$^3$. This occurs because meteorological conditions that result in maximum impacts from the LGPR facility also result in minimal impacts of the co-contributing sources within the area of significant impact for the LGPR facility.

| Table 9. RESULTS FOR CO 1-HOUR CUMULATIVE IMPACT ANALYSES | | | | | | |
|---|---|---|---|---|---|---|
| **Co-Contributing Source Scenario** | **Maximum Modeled Concentration ($\mu g/m^3$)[a]** | | | **Total Ambient Impact ($\mu g/m^3$)** | **NAAQS[b] ($\mu g/m^3$)** | **Percent of NAAQS** |
| | **Co-Contributing** | **LGPR Facility** | **Combined** | | | |
| Scenario 1[c] | 320 | 4061 | 4,061 | 7,661[i] | 40,000 | 19 |
| Scenario 2[d] | 386 | 4061 | 4,061 | 7,661[i] | 40,000 | 19 |
| Scenario 3[e] | 916 | 4061 | 4,061 | 7,661[i] | 40,000 | 19 |
| Scenario 4[f] | 1,011[g] | 4061 | 4,061[h] | 7,661[i] | 40,000 | 19 |

[a] Micrograms per cubic meter.
[b] National ambient air quality standards.
[c] Representative stack at TASCO facility in Nyssa, OR, emitting at permit allowable rate.
[d] Modeled as Scenario 1 except facility was located in Ontario, OR.
[e] Average stack conditions at TASCO facility, but located in Ontario, OR.
[f] Conservative scenario combining Scenario 1 and Scenario 3.
[g] Maximum impacts from co-contributing sources for Scenario 1 (TASCO in Nyssa) and co-contributing for Scenario 3 (Ontario source with emissions equal to TASCO and average stack parameters).
[h] Maximum impacts from the Co-Contributing sources and the LGPR facility.
[i] Modeling results from combined impacts with a 3,600 $\mu g/m^3$ rural/agricultural default 1-hour CO background concentration.

## *3.6 AQRV Analyses for Class I Areas*

Seven Class I areas were identified within 300 kilometers of the proposed project, including the following:

- Eagle Cap Wilderness Area, Oregon – 125 km
- Sawtooth Wilderness Area Idaho – 126 km
- Hells Canyon Wilderness Area, Idaho – 130 km
- Strawberry Mountain Wilderness Area, Oregon – 144 km
- Jarbidge Wilderness Area, Nevada – 255 km
- Craters of the Moon National Monument, Idaho – 265 km
- Selway Bitterroot, Idaho – 275 km

Federal Land Managers (FLMs) use a Q/D screening approach to evaluate the need to perform a more refined Air Quality Related Values (AQRV) analysis, as established in the updated draft FLAG Guidance Document and consistently used throughout the US. This approach involves calculating a ratio (Q/D) of total combined emissions of PM, $NO_X$, $SO_2$, and $H_2SO_4$, in tons/year, to the distance from the Class I area. An AQRV analysis is generally not required if the Q/D value is less than 10. The total combined emissions of the listed pollutants were calculated by the applicant at 149.2 tons per year (155 tons per year as estimated by DEQ), giving a Q/D value of 1.2, far below the value of 10 used as criteria to trigger an AQRV analysis.

## *3.7 Increment Consumption*

Increment consumption was evaluated for both Class I and Class II areas.

### *3.7.1 Class II Area Increment Consumption*

Increment consumption must be evaluated for $PM_{10}$, $SO_2$, and $NO_2$. Because maximum modeled impacts of the proposed project for pollutants that have increments are all below Significant Impact Levels (SILs),

a cumulative increment consumption analysis was not required. The proposed project, operated as described in the submitted application, will not significantly contribute to an exceedance of a Class II PSD increment.

### *3.7.2 Class I Area Increment Consumption*

PSD increments have also been developed for Class I areas, and increment consumption must be assessed for proposed new major sources. Class I Area SILs have been proposed by both EPA and FLMs. As a screening level analysis, CH2M Hill modeled emissions using AERMOD with a ring of receptors 50 kilometers from the site. The location of the nearest Class I area is over 2.5 times the distance to the ring of receptors used as a screening approach.

Table 10 provides the results for the screening Class I increment assessment. Most modeled impacts are well below SILs. Impacts of 24-hour $PM_{10}$ and 3-hour $SO_2$ were the closest to SILs, with both at about 52 percent of the applicable SIL. DEQ is not contending this method, by itself, constitutes an acceptable screening level analysis for a Class I PSD increment assessment. However, DEQ is satisfied that impacts to any Class I area will not exceed SILs based on the following:

- Magnitude of emissions from the proposed facility.
- Distance to Class I areas.
- Predominant meteorology for the area.
- Results of the 50 kilometer AERMOD screening analyses.

**Table 10. RESULTS FOR CLASS I INCREMENT ANALYSES**

| Pollutant | Averaging Period | Maximum Modeled Concentration ($\mu g/m^3$)[a] | SIL[b] ($\mu g/m^3$) | | Cumulative Increment Analysis Required |
|---|---|---|---|---|---|
| | | | EPA | FLMs | |
| $PM_{10}$[c] | 24-hour | 0.141 | 0.3 | 0.27 | No |
| | Annual | 0.003 | 0.2 | 0.08 | No |
| Sulfur dioxide ($SO_2$) | 3-hour | 0.248 | 1 | 0.48 | No |
| | 24-hour | 0.038 | 0.2 | 0.07 | No |
| | Annual | 0.004 | 0.1 | 0.03 | No |
| Nitrogen dioxide ($NO_2$) | Annual | 0.006 | 0.1 | 0.03 | No |

[a] Micrograms per cubic meter.
[b] Significant Impact Levels.
[c] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

## *3.8 Visibility, Soils, and Vegetation Analysis*

Idaho Air Rules Section 202.01.c.v requires "an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the new major facility or major modification and general commercial, residential, industrial, and other growth associated with establishment of the new major facility or major modification. The owner or operator need not provide an analysis of the impact on vegetation or soils having no significant commercial or recreational value." Direct impacts of air pollutants from operations of the LGPR to the surrounding area, as indicated by AERMOD modeling results, are minimal. Impacts are only a fraction of applicable standards, and impacts only exceed Class II SILs for CO. Impacts of all other criteria pollutants were below SILs, and were substantially below SILs at most locations beyond the first few hundred meters of the facility. DEQ is satisfied that the project would not adversely affect soils and vegetation, since concentrations of pollutants are well below any standards and screening level criteria.

Operation of the LGPR facility results in emissions of visibility impairing pollutants, including $NO_X$, PM, and $SO_2$. Visibility impacts are expected to be negligible since modeled impacts of all visibility-impairing pollutants are below SILs. Total facility-wide emissions of $NO_X$ and PM are each less than 100 ton/year, and $SO_2$ emissions are less than 15 ton/year. Considering the type of sources and the magnitude of emissions, DEQ is satisfied that near-field visibility impacts will not be unacceptable. Idaho Air Rules Section 625 also requires that any pollutant discharged must have opacity less than 20 percent.

### *3.9 Growth Analyses and Associated Impacts*

Idaho Air Rules Section 202.01.c.iii requires "an analysis of the effect on air quality projected for the area as a result of general commercial, residential, industrial, and other growth associated with the new major facility or major modification." This analysis was submitted as a supplement to the application. The analysis explained that because of the low number of workers needed for construction and operation of the LGPR facility, there will be negligible growth to the area resulting from the project. Only about 18 full time employees will be added and expected to relocate to the area. This compares to a population of about 1,400 for New Plymouth, Idaho and 50,000 for the region extending from Ontario, Oregon to Caldwell, Idaho. DEQ concurs with this assessment and further analyses were not requested.

Idaho Air Rules Section 202.01.c.iv requires "a description of the nature, extent, and air quality effects of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the new major facility or major modification would affect." The area affected is taken to be the area within the radius of significant impact, which is 300 meters as defined by 1-hour CO modeling. The immediate area is BLM land that is open and used for grazing and recreational activities. Although there has been no growth within this area, the applicant conservatively assessed growth within the region, including New Plymouth, Idaho, Caldwell, Idaho (20 miles from the LGPR facility), and Ontario, Oregon. New Plymouth has grown by about 25 percent since 1977 and Caldwell has grown by about 56 percent. Air quality has generally improved in the region because of better emissions controls on vehicles and decreases in certain wide-spread emitting activities such as wood stove operations.

Highway I-84 borders the facility property along the northeastern side. Traffic has increased to the current level of over 10,000 vehicles per day. This increase in traffic is not expected to substantially impact air quality because of better emissions controls on newer vehicles and the traffic in this area is free-flowing and seldom subject to congestion.

### *3.10 Results for TAPs Analyses*

Facility-wide emissions of all TAPs were below applicable emissions screening levels (ELs) of Idaho Air Rules Section 585 and 586, except for 1,3-butadiene, acetaldehyde, arsenic, benzene, cadmium, formaldehyde, nickel, PAH (naphthalene), POM, ammonia, nitrous oxide, and sulfuric acid. Air impact modeling was performed for those TAPs having emissions exceeding the ELs, and results are presented in Table 11. Maximum modeled impacts are below AACs or AACCs for all TAPs assessed.

| Table 11. RESULTS FOR TAP IMPACT ANALYSES | | | |
|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Modeled Impact ($\mu g/m^3$)[a]** | **AAC/AACC[b] ($\mu g/m^3$)** |
| 1,3-Butadiene | Annual | <1.0E-5 | 3.6E-3 |
| Acetaldehyde | Annual | 3.1E-4 | 4.5E-1 |
| Arsenic | Annual | <1.0E-5 | 2.3E-4 |
| Benzene | Annual | 1.80E-4 | 1.2E-1 |
| Cadmium | Annual | <1.0E-5 | 5.6E-4 |
| Formaldehyde | Annual | 5.59E-3 | 7.7E-2 |
| Nickel | Annual | <1.0E-5 | 4.2E-3 |
| PAH (naphthalene) | Annual | 2.8E-4 | 1.4E-2 |
| POM | Annual | <1.0E-5 | 3.0E-4 |
| Ammonia | 24-hour | 1.81 | 900 |
| Nitrous oxide | 24-hour | 0.675 | 4,500 |
| Sulfuric acid | 24-hour | 0.0254 | 50 |

[a] Micrograms per cubic meter.
[b] Defined in Idaho Air Rules Section 585 and 586.

### *3.11 Ozone Impacts*

An ozone impact assessment was not specifically required for the proposed facility, as explained below. DEQ performed an ozone impact assessment because of elevated ozone levels monitored in northern Ada County. DEQ affirms that such action should not be considered precedent-setting and has not been adopted at this time as standard DEQ policy or procedure.

Ozone will not be emitted directly from the LGPR facility. Ozone is generated in the atmosphere through reactions involving $NO_X$ and VOC, which will be emitted from the facility. AERMOD cannot be used to assess ozone impacts since the quantity of ozone generated as a result of a given quantity of $NO_X$ or VOC emissions depends on a number of variables and mechanisms not accounted for in AERMOD. DEQ models ozone for airshed management purposes using the regional photochemical grid model Community Multiscale Air Quality (CMAQ).

PSD ozone assessment requirements are addressed in 40 CFR 51.166(i)(5)(*i*)(*e*) in footnote 1, indicating that any project with net emissions increase of 100 tons/year or more of VOC or $NO_X$ subject to PSD would be required to perform an ambient impact analysis. The LGPR facility is estimated to emit a maximum of 75 ton/year of VOC and 88 ton/year of $NO_X$, both below the 100 ton/year threshold requiring an ozone impact assessment.

Northern Ada County has experienced elevated ozone levels during summertime months, with concentrations very near to the applicable 75 ppb 8-hour standard. Potential ozone impacts in the Treasure Valley area were evaluated for increased emissions of VOC and $NO_X$ resulting from operation of the LGPR facility, even though PSD rules do not explicitly require such an analysis.

Impacts of the LGPR facility were determined by using a two-step process. First, Treasure Valley ozone concentrations were evaluated for each four-kilometer grid cell for a scenario that includes emissions from the LGPR facility. Next, ozone concentrations were evaluated for a scenario without emissions from the LGPR facility. Ozone impacts attributed to increased emissions from the LGPR were then calculated by subtracting impacts without the LGPR facility, on a grid cell – by – grid cell basis, from modeled impacts with the LGPR facility accounted for.

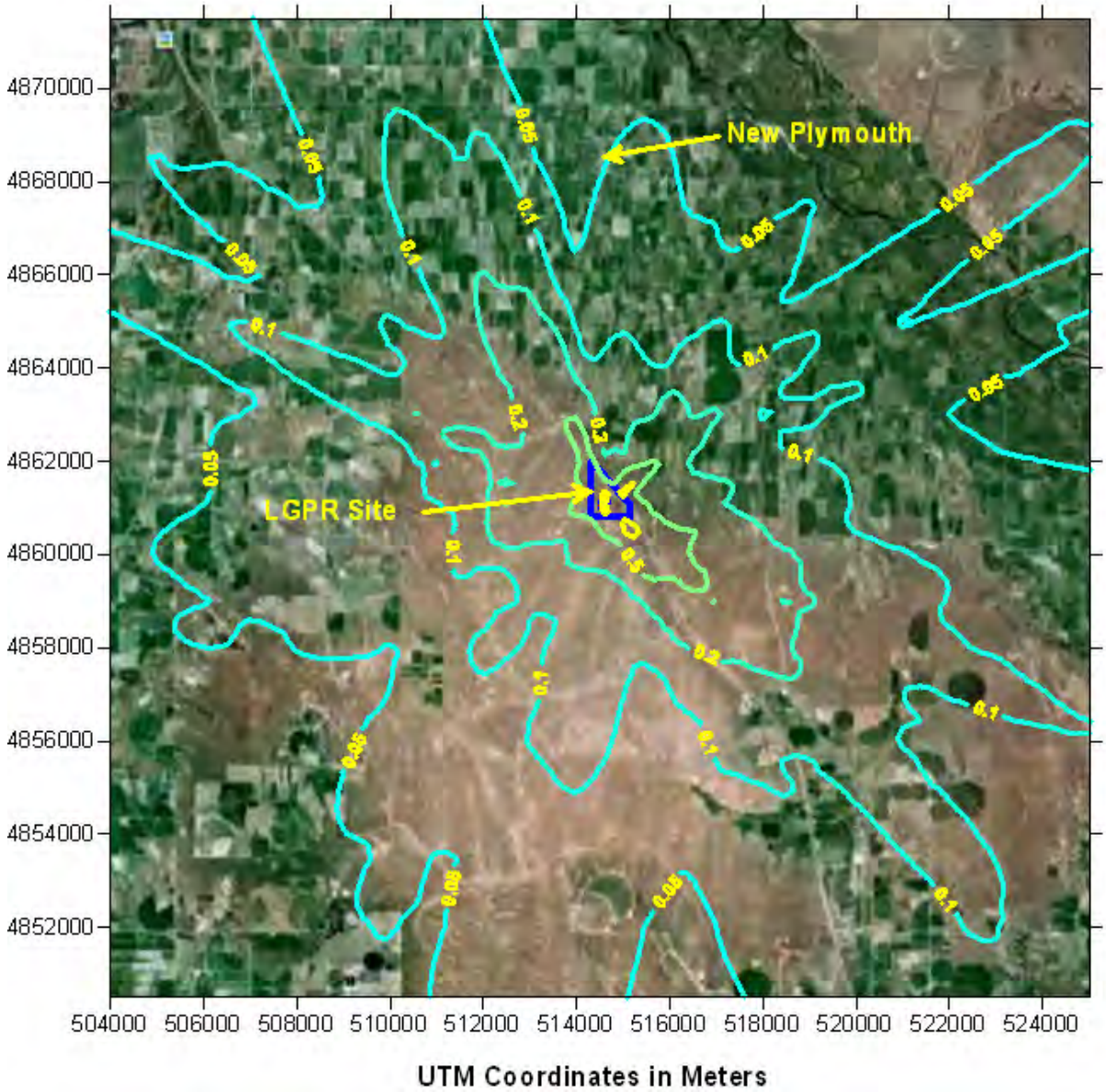
Maximum emissions expected under peak load, steady-state operation were modeled for 24 hours/day

during an identified summer ozone season (a 38 day period during 2007). Modeled impacts to northern Ada County were below 0.03 ppb, and were considered as negligible.

## 4.0 Conclusions

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the facility will not cause or significantly contribute to a violation of any air quality standard.

## Figure 1

### Contours of Maximum PM10 Concentrations Modeled for the LGPR Project

### Concentrations in Micrograms per Cubic Meter of Air