Appendix A – Acid Rain Permit Application

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January 11, 2010

Morrie Lewis
Permit Writer
Idaho Department of Environmental Quality
Air Quality Division
1410 N. Hilton
Boise, ID 83706

Subject: Idaho Power Company – Langley Gulch Power Plant
Acid Rain Permit Application

Dear Mr. Lewis:

I am submitting this Acid Rain permit application in accordance with the requirements of 40 CFR 72.30 and 31. As stated in the above rule, the deadline for submittal of the application is at least 24 months before the date on which the unit commences operation. Langley Gulch is anticipated to commence commercial operation (CCO) on June 1, 2012. The monitor certification deadline will be the earlier of 90 unit operating days or 180 calendar days after the CCO date in accordance with 40 CFR 75.4(b)(2).

Langley Gulch will be subject to the permitting requirements of 40 CFR 72 through 40 CFR 75. The combustion turbine will be equipped with a continuous emissions monitoring system (CEMS) to monitor nitrogen oxide (NO_x) emissions from the exhaust stack to ensure compliance with 40 CFR 75. In addition, to ensure compliance with 40 CFR 72.9(c), the facility will hold sulfur dioxide (SO_2) allowances in excess of the total annual emissions of SO_2 for the previous calendar year. SO_2 allowances shall be tracked using the EPA's Clean Air Markets Division (CAMD) Business System. Langley Gulch is not subject to the requirements of 40 CFR 76 since it does not meet the applicability requirements of §76.1 as a "coal-fired utility unit".

If you have any questions regarding the Acid Rain Permit Application for the Langley Gulch Power Plant, please feel free to contact me at (208) 388-2426.

Sincerely,

Trevor Mahlum
Engineer – Power Production

Encl: Acid Rain Permit Application

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised ~ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Langley Gulch Power Plant	Idaho	57028

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
CT1	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the

submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd. **Recordkeeping and Reporting Requirements, Cont'd.**

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Dale Koger	
Signature Dale Koger	Date 1/11/10

Appendix B – Emission Inventories

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Combustion Turbine & Duct Burner (Maximum Emission Case)

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	2,375	Vendor Information
Fuel Heating Value	[Btu/ft^3]	994	PTC Application
F-Factor	[dscf/MMBtu]	8,710	40 CFR 75, Appendix F, Table 1
Ideal Gas Density	[scf/lb mol]	335.6	

NOx

NOx Concentration	[ppm]	2	PTC Limit, BACT
NOx Molecular Weight	[lb/lb mol]	46.01	
NOx Startup & Shutdown	[tons/yr]	18.4	PTC Application

$$NOx[\frac{lb}{hr}] = \frac{NOx[ppm] * NOx[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

NOx Emission Rate	[lb/hr]	20.1

$$NOx\left[\frac{ton}{yr}\right] = \frac{NOx\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\,\frac{lb}{ton}} + NOx\left[\frac{tons}{Startup\,\&\,Shutdown}\right]$$

NOx Emissions	[ton/yr]	87.7

CO

CO Concentration	[ppm]	2	PTC Limit, BACT
CO Molecular Weight	[lb/lb mol]	28.01	
CO Startup & Shutdown	[tons/yr]	235.9	PTC Application

$$CO[\frac{lb}{hr}] = \frac{CO[ppm] * CO[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

CO Emission Rate	[lb/hr]	12.2

$$CO\left[\frac{ton}{yr}\right] = \frac{CO\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\,\frac{lb}{ton}} + CO\left[\frac{tons}{Startup\,\&\,Shutdown}\right]$$

CO Emissions	[ton/yr]	278.1

VOC

VOC Concentration	[ppm]	2	PTC Limit, BACT
VOC Molecular Weight	[lb/lb mol]	16.04	
VOC Startup & Shutdown	[tons/yr]	50.7	PTC Application

$$VOC[\frac{lb}{hr}] = \frac{VOC[ppm] * VOC[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

VOC Emission Rate	[lb/hr]	7.0

$$VOC\left[\frac{ton}{yr}\right] = \frac{VOC\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + VOC\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

VOC Emissions	[ton/yr]	74.9

SO2

SO2 Concentration	[gr/hscf]	0.5	40 CFR 72.2; "Pipeline Natural Gas" Definition
SO2 Molecular Weight	[lb/lb mol]	64.04	
S Molecular Weight	[lb/lb mol]	32.07	
SO2 Startup & Shutdown	[tons/yr]	0.7	PTC Application

$$SO2\left[\frac{lb}{hr}\right] = \frac{Fuel\ Flow\left[\frac{100scf}{hr}\right] * Sulfur\ Content\left[\frac{gr}{100scf}\right]}{7000[\frac{gr}{lb}]} * \frac{SO2[MW]}{S[MW]}$$

SO2 Emission Rate	[lb/hr]	3.4

$$SO2\left[\frac{ton}{yr}\right] = \frac{SO2\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + SO2\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

SO2 Emissions	[ton/yr]	12.5

PM-10

PM-10 Concentration	[lb/hr]	12.55	PTC Limit; Vendor Guarantee
PM-10 Startup & Shutdowr	[tons/yr]	5.2	PTC Application

PM-10 Emission Rate	[lb/hr]	12.6

$$PM10\left[\frac{ton}{yr}\right] = \frac{PM10\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + PM10\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

PM-10 Emissions	[ton/yr]	48.5

CO2

CO2 Emission Factor	[kg/MMBtu]	53.02	40 CFR 98, Table C-1

$$CO_2\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	277,030

$$CO_2\left[\frac{ton}{yr}\right] = \frac{CO_2\left[\frac{lb}{hr}\right] * (6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right])}{2000\,\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	1,092,050

CH4

CH4 Emission Factor	[kg/MMBtu]	1.00E-03	40 CFR 98, Table C-1

$$CH_4\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	5.2

$$CH_4\left[\frac{ton}{yr}\right] = \frac{CH_4\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\,\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	20.6

N2O

N2O Emission Factor	[kg/MMBtu]	1.00E-04	40 CFR 98, Table C-1

$$N_2O\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	0.5

$$N_2O\left[\frac{ton}{yr}\right] = \frac{N_2O\left[\frac{lb}{hr}\right] * (6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right])}{2000\,\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	2.1

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Emergency Generator

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Engine Rating	[bhp]	1214	Vendor Advertised Maximum hp Rating
Annual Operation	[hrs]	60	PTC Application
Daily Operation	[hrs]	4	PTC Application
Heat Input	[gal/hr]	53.6	Vendor Information
Fuel Heating Value	[Btu/gal]	137,030	AP-42; Chapter 3
Fuel Sulfur Content	[% by weight]	0.0015	Ultra Low Sulfur Diesel (ULSD)

NOx

NOx Emission Factor	[g/hr hr]	4.8	EPA Tier 2 Standard

$$NOx\left[\frac{lb}{hr}\right] = Rating[hp] * NOx\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

NOx Emission Rate	[lb/hr]	12.8

$$NOx\left[\frac{ton}{yr}\right] = NOx\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

NOx Emissions	[ton/yr]	0.39

CO

CO Emission Factor	[g/hr hr]	2.6	EPA Tier 2 Standard

$$CO\left[\frac{lb}{hr}\right] = Rating[hp] * CO\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

CO Emission Rate	[lb/hr]	7.0

$$CO\left[\frac{ton}{yr}\right] = CO\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

CO Emissions	[ton/yr]	0.21

VOC

VOC Emission Factor	[g/hp hr]	0.3	EPA Tier 2 Standard (HC Emission Factor)

$$VOC\left[\frac{lb}{hr}\right] = Rating[hp] * VOC\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

VOC Emission Rate	[lb/hr]	0.8

$$VOC\left[\frac{ton}{yr}\right] = VOC\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

VOC Emissions	[ton/yr]	0.02

SO2

SO2 Emission Factor	[lb/hp hr]	0.000012	EPA AP-42, Table 3.4-1

$$SO2\left[\frac{lb}{hr}\right] = Rating[hp] * SO2\ EF\left[\frac{lb}{hp * hr}\right]$$

SO2 Emission Rate	[lb/hr]	0.01

$$SO2\left[\frac{ton}{yr}\right] = SO2\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

SO2 Emissions	[ton/yr]	0.00

PM-10

PM-10 Emission Factor	[g/hp hr]	0.15	EPA Tier 2 Standard

$$PM10\left[\frac{lb}{hr}\right] = Rating[hp] * PM10\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

PM-10 Emission Rate	[lb/hr]	0.4

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	0.01

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Fire Pump Engine

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Engine Rating	[bhp]	305	Vendor Advertised Maximum hp Rating
Annual Operation	[hrs]	30	PTC Application
Daily Operation	[hrs]	1	PTC Application
Heat Input	[gal/hr]	15.8	Vendor Information
Fuel Heating Value	[Btu/gal]	137,030	AP-42; Chapter 3
Fuel Sulfur Content	[% by weight]	0.0015	Ultra Low Sulfur Diesel (ULSD)

NOx

NOx Emission Factor	[g/hr hr]	3.0	EPA Tier 3 Standard

$$NOx\left[\frac{lb}{hr}\right] = Rating[hp] * NOx\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

NOx Emission Rate	[lb/hr]	2.0

$$NOx\left[\frac{ton}{yr}\right] = NOx\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

NOx Emissions	[ton/yr]	0.03

CO

CO Emission Factor	[g/hr hr]	2.6	EPA Tier 3 Standard

$$CO\left[\frac{lb}{hr}\right] = Rating[hp] * CO\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

CO Emission Rate	[lb/hr]	1.7

$$CO\left[\frac{ton}{yr}\right] = CO\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

CO Emissions	[ton/yr]	0.03

VOC

VOC Emission Factor	[g/hp hr]	0.14	EPA Tier 3 Standard (HC Emission Factor)

$$VOC\left[\frac{lb}{hr}\right] = Rating[hp] * VOC\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

VOC Emission Rate	[lb/hr]	0.1

$$VOC\left[\frac{ton}{yr}\right] = VOC\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

VOC Emissions	[ton/yr]	0.00

SO2

SO2 Emission Factor	[lb/hp hr]	0.000003	EPA AP-42, Table 3.4-1

$$SO2\left[\frac{lb}{hr}\right] = Rating[hp] * SO2\ EF\left[\frac{lb}{hp * hr}\right]$$

SO2 Emission Rate	[lb/hr]	0.00

$$SO2\left[\frac{ton}{yr}\right] = SO2\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

SO2 Emissions	[ton/yr]	0.00

PM-10

PM-10 Emission Factor	[g/hp hr]	0.15	EPA Tier 3 Standard

$$PM10\left[\frac{lb}{hr}\right] = Rating[hp] * PM10\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

PM-10 Emission Rate	[lb/hr]	0.1

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	0.00

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Cooling Tower

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Annual Operation	[hr]	8,760	PTC Application
Flow Rate	[gpm]	63,200	Equipment Design Parameter
TDS Concentration	[ppm]	5,000	PTC Application
TDS Flow	[lb/hr]	158,126	Calculation
Flow Producing PM 10	[%]	84%	"Calculating Realistic PM 10 Emissions from Cooling Towers"
Drift Eliminator Efficiency	[%]	0.0005%	Vendor Guarantee

PM-10 (Cooling Tower)

$$PM10\left[\frac{lb}{hr}\right] = TDS\ Flow\left[\frac{lb}{hr}\right] * Control\ Eff[\%] * PM10\ Factor[\%]$$

PM 10 Emission Rate	[lb/hr]	0.66

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM 10 Emissions	[ton/yr]	2.91

Dry Chemical Storage Silos

Inputs (Constants)	Units	Value	Source
Annual Operation	[hr/silo]	48	PTC Application
Daily Operation	[hr/silo]	2	PTC Application
Blower Flowrate	[cfm]	1,500	Equipment Design Parameter
Loading Emissions	[gr/scf]	0.01	Vendor Guarantee
Number of Silos		3	Contractor Design

PM-10 (Storage Silos)

$$PM10\left[\frac{lb}{hr}\right] = Blower\ Flow[cfm] * Loading\ Emissions[gr/scf] * \left[\frac{60min}{hr}\right] * \left[\frac{lb}{7000gr}\right]$$

PM 10 Emission Rate	[lb/hr]	0.13

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops\left[\frac{hr}{silo}\right] * 6[silos] * \frac{[ton]}{2000[lb]}$$

PM 10 Emissions	[ton/yr]	0.01

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Hazardous Air Pollutants

Pollutant	Facility Wide Ton/yr
1,3-Butadiene	3.62E-03
Acetaldehyde	3.37E-01
Acrolein	5.38E-02
Arsenic	1.91E-04
Benzene	1.03E-01
Beryllium	1.15E-05
Cadmium	1.05E-03
Chromium	1.34E-03
Cobalt	8.03E-05
Dichlorobenzene	1.15E-03
Ethyl Benzene	2.69E-01
Formaldehyde	6.04E+00
Hexane	1.72E+00
Manganese	3.63E-04
Mercury	2.48E-04
Naphthalene	1.15E-02
Nickel	2.01E-03
Propylene Oxide	2.44E-01
POM	1.61E-05
Selenium	2.29E-05
Toluene	1.10E+00
Xylenes	5.38E-01
Total	**10.4**

Combustion Turbine

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	2,134	Vendor Information
HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.1-3

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Heat\ Input\left[\frac{MMBtu}{hr}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
1,3-Butadiene	4.30E-07	3.62E-03
Acetaldehye	4.00E-05	3.36E-01
Acrolein	6.40E-06	5.38E-02
Benzene	1.20E-05	1.01E-01
Ethylbenzene	3.20E-05	2.69E-01
Formaldehyde	7.10E-04	5.97E+00
Naphthalene	1.30E-06	1.09E-02
Propylene Oxide	2.90E-05	2.44E-01
Toluene	1.30E-04	1.09E+00
Xylenes	6.40E-05	5.38E-01

Duct Burners

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	241	Vendor Information
Fuel Heating Value	[Btu/scf]	994	40 CFR 98, Table C-1
Organic HAP Emission Factors	[lb/10^6 scf]	See Below	EPA AP-42; Table 1.4-3
Metal HAP Emission Factors	[lb/10^6 scf]	See Below	EPA AP-42; Table 1.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{10^6 scf}\right] * HI\left[\frac{MMBtu}{hr}\right] * \left[\frac{10^6 scf}{994\ MMBtu}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
Arsenic	2.00E-04	1.91E-04
Benzene	2.10E-03	2.01E-03
Beryllium	1.20E-05	1.15E-05
Cadmium	1.10E-03	1.05E-03
Chromium	1.40E-03	1.34E-03
Cobalt	8.40E-05	8.03E-05
Dichlorobenzene	1.20E-03	1.15E-03
Formaldehyde	7.50E-02	7.17E-02
Hexane	1.80E+00	1.72E+00
Manganese	3.80E-04	3.63E-04
Mercury	2.60E-04	2.48E-04
Naphthalene	6.10E-04	5.83E-04
Nickel	2.10E-03	2.01E-03
POM*	1.14E-05	1.09E-05
Selenium	2.40E-05	2.29E-05
Toluene	3.40E-03	3.25E-03
Xylenes		

* POM Emission Factor is the sum of 7-PAH Group emission factors

Emergency Generator

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	60	PTC Application
Fuel Use	[gal/hr]	53.6	Vendor Information
Fuel Heating Value	[MMBtu/gal]	0.137	AP-42; Chapter 3
Organic HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-3
PAH HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Fuel\left[\frac{gal}{hr}\right] * \left[.137\frac{MMBtu}{gal}\right] * AnnualOps[\frac{hr}{yr}] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
Acetaldehye	2.52E-05	5.55E-06
Acrolein	7.88E-06	1.74E-06
Benzene	7.76E-04	1.71E-04
Formaldehyde	7.89E-05	1.74E-05
POM	4.50E-06	9.92E-07
Toluene	2.81E-04	6.19E-05
Xylenes	1.93E-04	4.25E-05

Fire Pump

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	30	PTC Application
Fuel Use	[gal/hr]	15.8	Vendor Information
Fuel Heating Value	[MMBtu/gal]	0.137	AP-42, Chapter 3
Organic HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-3
PAH HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Fuel\left[\frac{gal}{hr}\right] * \left[.137\frac{MMBtu}{gal}\right] * AnnualOps[\frac{hr}{yr}] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
1,3-Butadiene	3.91E-05	1.27E-06
Acetaldehye	7.67E-04	2.49E-05
Acrolein	9.25E-05	3.00E-06
Benzene	9.33E-04	3.03E-05
Formaldehyde	1.18E-03	3.83E-05
Naphthalene	8.48E-05	2.75E-06
POM	1.30E-04	4.22E-06
Toluene	4.09E-04	1.33E-05
Xylenes	2.85E-04	9.26E-06

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Toxic Air Pollutants

Pollutant	Category	Averaging Period	Screening Level [lb/hr]	Annual Average	24 Hour Average
1,3 Butadiene	HAP / TAP 586	Annual	2.40E 05	8.26E 04	9.21E 04
2 Methylnaphthalene	HAP / TAP 586	Annual	9.10E 05	5.24E 06	5.82E 06
3 Methylcholanthrene	HAP / TAP 586	Annual	2.50E 06	3.93E 07	4.36E 07
7,12 Dimethylbenz(a)anthracene	HAP / TAP 586	Annual	9.10E 05	3.49E 06	3.88E 06
Acenaphthene	HAP / TAP 586	Annual	9.10E 05	6.38E 07	6.29E 06
Acenaphthylene	HAP / TAP 586	Annual	9.10E 05	8.93E 07	1.22E 05
Acetaldehyde	HAP / TAP 586	Annual	3.00E 03	7.68E 02	8.55E 02
Acrolein	HAP / TAP 585	24 hour	1.70E 02	1.23E 02	1.37E 02
Ammonia	TAP 585	24 hour	1.20E+00	1.67E+01	1.86E+01
Anthracene	HAP / TAP 586	Annual	9.10E 05	5.99E 07	2.25E 06
Arsenic	HAP / TAP 586	Annual	1.50E 06	4.36E 05	4.85E 05
Barium	TAP 585	24 hour	3.30E 02	9.60E 04	1.07E 03
Benz(a)anthracene	TAP 586			4.36E 07	1.34E 06
Benzene	HAP / TAP 586	Annual	8.00E 04	2.36E 02	2.71E 02
Benzo(a)pyrene	HAP / TAP 586	Annual	2.00E 06	2.76E 07	6.22E 07
Benzo(b)fluoranthene				4.49E 07	1.80E 06
Benzo(g,h,l)perylene	HAP / TAP 586	Annual	9.10E 05	2.93E 07	1.01E 06
Benzo(k)fluoranthene				4.05E 07	7.17E 07
Beryllium	HAP / TAP 586	Annual	2.80E 05	2.62E 06	2.91E 06
Cadmium	HAP / TAP 586	Annual	3.70E 06	2.40E 04	2.67E 04
Chromium	HAP / TAP 585	24 hour	3.30E 02	3.05E 04	3.39E 04
Chrysene				4.72E 07	2.34E 06
Cobalt	HAP / TAP 585	24 hour	3.30E 03	1.83E 05	2.04E 05
Copper	TAP 585	24 hour	1.30E 02	1.85E 04	2.06E 04
Dibenzo(a,h)anthracene				2.83E 07	7.64E 07
Dichlorobenzene (o and 1,4)	HAP / TAP 585	24 hour	2.00E+01	2.62E 04	2.91E 04
Ethyl benzene	HAP / TAP 585	24 hour	2.90E+01	6.15E 02	6.83E 02
Fluoranthene	HAP / TAP 586	Annual	9.10E 05	7.08E 07	1.38E 06
Fluorene	HAP / TAP 586	Annual	9.10E 05	1.46E 06	1.88E 05
Formaldehyde	HAP / TAP 586	Annual	5.10E 04	1.38E+00	1.53E+00
Hexane	HAP / TAP 585	24 hour	1.20E+01	3.93E 01	4.36E 01
Indenol(1,2,3, cd)pyrene				4.16E 07	9.75E 07
Manganese	HAP / TAP 585	24 hour	6.70E 02	8.29E 05	9.21E 05
Mercury	HAP / TAP 585	24 hour	1.00E 03	5.67E 05	6.30E 05
Molybdenum	TAP 585	24 hour	3.33E 01	2.40E 04	2.67E 04
Naphthalene	TAP 585	24 hour	3.33E+00	2.64E 03	3.09E 03
Naphthalene (as PAH)	HAP / TAP 586	Annual	9.10E 05	0.00E+00	0.00E+00
Nickel	HAP / TAP 586	Annual	2.75E 05	4.58E 04	5.09E 04
Nitrous oxide	TAP 585	24 hour	6.00E+00	6.24E+00	6.94E+00
Pentane	TAP 585	24 hour	1.18E+02	5.67E 01	6.30E 01
Phenanthrene	HAP / TAP 586	Annual	9.10E 05	5.97E 06	5.66E 05
Propylene oxide	HAP / TAP 585	24 hour	3.20E+00	5.59E 02	6.55E 02
POM (7 PAH Group)	HAP / TAP 586	Annual	2.00E 06	2.56E 06	7.51E 06
Pyrene	HAP / TAP 586	Annual	9.10E 05	1.31E 06	6.16E 06
Selenium	HAP / TAP 585	24 hour	1.30E 02	5.24E 06	5.82E 06
Sulfuric acid mist	TAP 585	24 hour	6.70E 02	2.35E 01	2.61E 01
Toluene	HAP / TAP 585	24 hour	2.50E+01	2.50E 01	2.79E 01
Total PAH			2.60E+01	7.34E 03	7.64E 03
Vanadium	TAP 585	24 hour	2.70E+01	5.14E 04	8.32E 04
Xylenes	HAP / TAP 585	24 hour	2.80E+01	1.23E 01	1.37E 01
Zinc	TAP 585	24 hour	2.90E+01	6.33E 03	7.03E 03

Emission Source	Units	Value	Source
Combustion Turbine & Duct Burners			
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Turbine Heat Input	[MMBtu/hr]	2,134	Vendor Information
Duct Burner Heat Input	[MMBtu/hr]	241	Vendor Information

TAP-585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = CT\ EF\left[\frac{lb}{MMBtu}\right] * CT\ Fuel\ Use\left[\frac{MMBtu}{hr}\right] + \frac{DB\ EF\left[\frac{lb}{10^6 scf}\right] * DB\ Fuel\ Use\left[\frac{MMBtu}{hr}\right]}{Heating\ Value[994\frac{Btu}{scf}]}$$

Ammonia Equation

$$NH_3\left[\frac{lb}{hr}\right] = \frac{NH_3[ppm] * NH_3[MW] * FFactor\left[\frac{dscf}{MMBtu}\right] * Fuel\ Flow\left[\frac{MMBtu}{hr}\right]}{10^6 * 335.6} * \left(\frac{20.9}{20.9-15}\right)$$

Sulfuric Acid Equation

$$H_2SO_4\left[\frac{lb}{hr}\right] = \frac{\left(0.5\left[\frac{gr}{100scf}\right] * 5\%\right) * HI\left[\frac{MMBtu}{hr}\right] * \left[\frac{100scf}{.0994\ MMBtu}\right] * \frac{H_2SO_4[MW]}{S[MW]}}{7000\left[\frac{gr}{lb}\right]}$$

Pollutant	Category	Averaging Period	Combustion Turbine Emission Factor	Duct Burner Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24-Hour Average [lb/hr]	Annual Emissions [tpy]
1,3-Butadiene	HAP / TAP-586	Annual	4.30E-07		9.18E-04	**8.26E-04**	9.18E-04	3.62E-03
2-Methylnaphthalene	HAP / TAP-586	Annual		2.40E-05	5.82E-06	**5.24E-06**	5.82E-06	2.29E-05
3-Methylcholanthrene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
7,12-Dimethylbenz(a)anthracene	HAP / TAP-586	Annual		1.60E-05	3.88E-06	**3.49E-06**	3.88E-06	1.53E-05
Acenaphthene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
Acenaphthylene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
Acetaldehyde	HAP / TAP-586	Annual	4.00E-05	2.52E-05	8.54E-02	**7.68E-02**	8.54E-02	3.37E-01
Acrolein	HAP / TAP-585	24-hour	6.40E-06	7.88E-06	1.37E-02	1.23E-02	**1.37E-02**	5.38E-02
Ammonia	TAP-585	24-hour	5.0 [ppm]		1.86E+01	1.67E+01	**1.86E+01**	7.32E+01
Anthracene	HAP / TAP-586	Annual		2.40E-06	5.82E-07	**5.24E-07**	5.82E-07	2.29E-06
Arsenic	HAP / TAP-586	Annual		2.00E-04	4.85E-05	**4.36E-05**	4.85E-05	1.91E-04
Barium	TAP-585	24-hour		4.40E-03	1.07E-03	9.60E-04	**1.07E-03**	4.21E-03
Benz(a)anthracene	TAP-586			1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Benzene	HAP / TAP-586	Annual	1.20E-05	2.10E-03	2.61E-02	**2.35E-02**	2.61E-02	1.03E-01
Benzo(a)pyrene	HAP / TAP-586	Annual		1.20E-06	2.91E-07	**2.62E-07**	2.91E-07	1.15E-06
Benzo(b)fluoranthene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Benzo(g,h,l)perylene	HAP / TAP-586	Annual		1.20E-06	2.91E-07	**2.62E-07**	2.91E-07	1.15E-06
Benzo(k)fluoranthene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Beryllium	HAP / TAP-586	Annual		1.20E-05	2.91E-06	**2.62E-06**	2.91E-06	1.15E-05
Cadmium	HAP / TAP-586	Annual		1.10E-03	2.67E-04	**2.40E-04**	2.67E-04	1.05E-03
Chromium	HAP / TAP-585	24-hour		1.40E-03	3.39E-04	3.05E-04	**3.39E-04**	1.34E-03
Chrysene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Cobalt	HAP / TAP-585	24-hour		8.40E-05	2.04E-05	1.83E-05	**2.04E-05**	8.03E-05
Copper	TAP-585	24-hour		8.50E-04	2.06E-04	1.85E-04	**2.06E-04**	8.12E-04
Dibenzo(a,h)anthracene				1.20E-06	2.91E-07	2.62E-07	2.91E-07	1.15E-06
Dichlorobenzene (o-and 1,4-)	HAP / TAP-585	24-hour		1.20E-03	2.91E-04	2.62E-04	**2.91E-04**	1.15E-03
Ethyl benzene	HAP / TAP-585	24-hour	3.20E-05		6.83E-02	6.15E-02	**6.83E-02**	2.69E-01
Fluoranthene	HAP / TAP-586	Annual		3.00E-06	7.27E-07	**6.55E-07**	7.27E-07	2.87E-06
Fluorene	HAP / TAP-586	Annual		2.80E-06	6.79E-07	**6.11E-07**	6.79E-07	2.68E-06
Formaldehyde	HAP / TAP-586	Annual	7.10E-04	7.50E-02	1.53E+00	**1.38E+00**	1.53E+00	6.04E+00
Hexane	HAP / TAP-585	24-hour		1.80E+00	4.36E-01	3.93E-01	**4.36E-01**	1.72E+00
Indenol(1,2,3,-cd)pyrene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Manganese	HAP / TAP-585	24-hour		3.80E-04	9.21E-05	8.29E-05	**9.21E-05**	3.63E-04
Mercury	HAP / TAP-585	24-hour		2.60E-04	6.30E-05	5.67E-05	**6.30E-05**	2.48E-04
Molybdenum	TAP-585	24-hour		1.10E-03	2.67E-04	2.40E-04	**2.67E-04**	1.05E-03
Naphthalene	TAP-585	24-hour	1.30E-06	6.10E-04	2.92E-03	2.63E-03	**2.92E-03**	1.15E-02
Nickel	HAP / TAP-586	Annual		2.10E-03	5.09E-04	**4.58E-04**	5.09E-04	2.01E-03
Nitrous oxide	TAP-585	24-hour	3.00E-03	2.20E+00	6.94E+00	6.24E+00	**6.94E+00**	2.73E+01
Pentane	TAP-585	24-hour		2.60E+00	6.30E-01	5.67E-01	**6.30E-01**	2.48E+00
Phenanthrene	HAP / TAP-586	Annual		1.70E-05	4.12E-06	**3.71E-06**	4.12E-06	1.62E-05
Propylene oxide	HAP / TAP-585	24-hour	2.90E-05		6.19E-02	5.57E-02	**6.19E-02**	2.44E-01
POM (7-PAH Group)	HAP / TAP-586	Annual			2.62E-06	**2.36E-06**	2.62E-06	1.03E-05
Pyrene	HAP / TAP-586	Annual		5.00E-06	1.21E-06	**1.09E-06**	1.21E-06	4.78E-06
Selenium	HAP / TAP-585	24-hour		2.40E-05	5.82E-06	5.24E-06	**5.82E-06**	2.29E-05
Sulfuric acid mist	TAP-585	24-hour	5% of Fuel S Content		2.61E-01	2.35E-01	**2.61E-01**	1.03E+00
Toluene	HAP / TAP-585	24-hour	1.30E-04	3.40E-03	2.78E-01	2.50E-01	**2.78E-01**	1.10E+00
Total PAH			2.20E-06		7.64E-03	**7.34E-03**	7.64E-03	1.63E-02
Vanadium	TAP-585	24-hour		2.30E-03	5.58E-04	5.02E-04	**5.58E-04**	2.20E-03
Xylenes	HAP / TAP-585	24-hour	6.40E-05		1.37E-01	1.23E-01	**1.37E-01**	5.38E-01
Zinc	TAP-585	24-hour		2.90E-02	7.03E-03	6.33E-03	**7.03E-03**	2.77E-02

Emission Source	Units	Value	Source
Emergency Diesel Generator			
Annual Operation	[hrs]	60	PTC Application
Daily Operations	[hrs]	4	PTC Application
Fuel Usage	[gph]	53.6	Vendor Information
Engine Rating	[bhp]	1214	Vendor Information
Fuel Heating Value	[btu/gal]	137030	AP 42; Chapter 3

TAP 585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = \frac{EF\left[\frac{lb}{MMBtu}\right] * Fuel\ Use\left[\frac{gal}{hr}\right] * Heating\ Value\left[\frac{Btu}{gal}\right]}{1e6\left[\frac{Btu}{MMBtu}\right]}$$

Pollutant	Category	Averaging Period	EDG Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24 Hour Average [lb/hr]	Annual Emissions [tpy]
Acenaphthene	HAP / TAP 586	Annual	4.68E 06	3.44E 05	**2.35E-07**	5.73E 06	1.03E 06
Acenaphthylene	HAP / TAP 586	Annual	9.23E 06	6.78E 05	**4.64E-07**	1.13E 05	2.03E 06
Acetaldehyde	HAP / TAP 586	Annual	2.52E 05	1.85E 04	**1.27E-06**	3.08E 05	5.55E 06
Acrolein	HAP / TAP 585	24 hour	7.88E 06	5.79E 05	3.96E 07	**9.65E-06**	1.74E 06
Anthracene	HAP / TAP 586	Annual	1.23E 06	9.03E 06	**6.19E-08**	1.51E 06	2.71E 07
Benz(a)anthracene	TAP 586		6.22E 07	4.57E 06	3.13E 08	7.61E 07	1.37E 07
Benzene	HAP / TAP 586	Annual	7.76E 04	5.70E 03	**3.90E-05**	9.50E 04	1.71E 04
Benzo(a)pyrene	HAP / TAP 586	Annual	2.57E 07	1.89E 06	**1.29E-08**	3.15E 07	5.66E 08
Benzo(b)fluoranthene			1.11E 06	8.15E 06	5.58E 08	1.36E 06	2.45E 07
Benzo(g,h,l)perylene	HAP / TAP 586	Annual	5.56E 07	4.08E 06	**2.80E-08**	6.81E 07	1.23E 07
Benzo(k)fluoranthene			2.18E 07	1.60E 06	1.10E 08	2.67E 07	4.80E 08
Chrysene			1.53E 06	1.12E 05	7.70E 08	1.87E 06	3.37E 07
Dibenzo(a,h)anthracene			3.46E 07	2.54E 06	1.74E 08	4.24E 07	7.62E 08
Fluorene	HAP / TAP 586	Annual	1.28E 05	9.40E 05	**6.44E-07**	1.57E 05	2.82E 06
Formaldehyde	HAP / TAP 586	Annual	7.89E 05	5.80E 04	**3.97E-06**	9.66E 05	1.74E 05
Indenol(1,2,3, cd)pyrene			4.14E 07	3.04E 06	2.08E 08	5.07E 07	9.12E 08
Naphthalene	TAP 585	24 hour	1.30E 04	9.55E 04	6.54E 06	**1.59E-04**	2.86E 05
Phenanthrene	HAP / TAP 586	Annual	4.08E 05	3.00E 04	**2.05E-06**	4.99E 05	8.99E 06
Propylene oxide	HAP / TAP 585	24 hour	2.79E 03	2.05E 02	1.40E 04	**3.42E-03**	6.15E 04
POM (7 PAH Group)	HAP / TAP 586	Annual		2.85E 05	**1.95E-07**	4.74E 06	8.54E 07
Pyrene	HAP / TAP 586	Annual	3.71E 06	2.72E 05	**1.87E-07**	4.54E 06	8.17E 07
Toluene	HAP / TAP 585	24 hour	2.81E 04	2.06E 03	1.41E 05	**3.44E-04**	6.19E 05
Total PAH			2.12E 04	1.56E 03	**1.07E-05**	2.60E 04	4.67E 05
Xylenes	HAP / TAP 585	24 hour	1.93E 04	1.42E 03	9.71E 06	**2.36E-04**	4.25E 05

Emission Source	Units	Value	Source
Fire Pump Engine			
Annual Operation	[hrs]	30	PTC Application
Daily Operations	[hrs]	1	PTC Application
Fuel Usage	[gph]	15	Vendor Information
Engine Rating	[bhp]	305	Vendor Information
Fuel Heating Value	[btu/gal]	137030	AP-42; Chapter 3

TAP-585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = \frac{EF\left[\frac{lb}{MMBtu}\right] * Fuel\ Use\left[\frac{gal}{hr}\right] * Heating\ Value\left[\frac{Btu}{gal}\right]}{1e6\ \left[\frac{Btu}{MMBtu}\right]}$$

Pollutant	Category	Averaging Period	FP Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24-Hour Average [lb/hr]	Annual Emissions [tpy]
1,3-Butadiene	HAP / TAP-586	Annual	3.91E-05	8.04E-05	**2.75E-07**	3.35E-06	1.21E-06
Acenaphthene	HAP / TAP-586	Annual	1.42E-06	2.92E-06	**1.00E-08**	1.22E-07	4.38E-08
Acenaphthylene	HAP / TAP-586	Annual	5.06E-06	1.04E-05	**3.56E-08**	4.33E-07	1.56E-07
Acetaldehyde	HAP / TAP-586	Annual	7.67E-04	1.58E-03	**5.40E-06**	6.57E-05	2.36E-05
Acrolein	HAP / TAP-585	24-hour	9.25E-05	1.90E-04	6.51E-07	**7.92E-06**	2.85E-06
Anthracene	HAP / TAP-586	Annual	1.87E-06	3.84E-06	**1.32E-08**	1.60E-07	5.77E-08
Benz(a)anthracene	TAP-586		1.68E-06	3.45E-06	1.18E-08	1.44E-07	5.18E-08
Benzene	HAP / TAP-586	Annual	9.33E-04	1.92E-03	**6.57E-06**	7.99E-05	2.88E-05
Benzo(a)pyrene	HAP / TAP-586	Annual	1.88E-07	3.86E-07	**1.32E-09**	1.61E-08	5.80E-09
Benzo(b)fluoranthene			9.91E-08	2.04E-07	6.98E-10	8.49E-09	3.06E-09
Benzo(g,h,l)perylene	HAP / TAP-586	Annual	4.89E-07	1.01E-06	**3.44E-09**	4.19E-08	1.51E-08
Benzo(k)fluoranthene			1.55E-07	3.19E-07	1.09E-09	1.33E-08	4.78E-09
Chrysene			3.53E-07	7.26E-07	2.48E-09	3.02E-08	1.09E-08
Dibenzo(a,h)anthracene			5.83E-07	1.20E-06	4.10E-09	4.99E-08	1.80E-08
Fluoranthene	HAP / TAP-586	Annual	7.61E-06	1.56E-05	**5.36E-08**	6.52E-07	2.35E-07
Fluorene	HAP / TAP-586	Annual	2.92E-05	6.00E-05	**2.06E-07**	2.50E-06	9.00E-07
Formaldehyde	HAP / TAP-586	Annual	1.18E-03	2.43E-03	**8.31E-06**	1.01E-04	3.64E-05
Indenol(1,2,3,-cd)pyrene			3.75E-07	7.71E-07	2.64E-09	3.21E-08	1.16E-08
Naphthalene	TAP-585	24-hour	8.48E-05	1.74E-04	5.97E-07	**7.26E-06**	2.61E-06
Phenanthrene	HAP / TAP-586	Annual	2.94E-05	6.04E-05	**2.07E-07**	2.52E-06	9.06E-07
Propylene oxide	HAP / TAP-585	24-hour	2.58E-03	5.30E-03	1.82E-05	**2.21E-04**	7.95E-05
POM (7-PAH Group)	HAP / TAP-586	Annual		3.60E-06	**1.23E-08**	1.50E-07	5.41E-08
Pyrene	HAP / TAP-586	Annual	4.78E-06	9.83E-06	**3.36E-08**	4.09E-07	1.47E-07
Toluene	HAP / TAP-585	24-hour	4.09E-04	8.41E-04	2.88E-06	**3.50E-05**	1.26E-05
Total PAH			1.68E-04	3.45E-04	**1.18E-06**	1.44E-05	5.18E-06
Xylenes	HAP / TAP-585	24-hour	2.85E-04	5.86E-04	2.01E-06	**2.44E-05**	8.79E-06

GHG Emission Calculations

The Langley Gulch facility has four (4) fuel burning emission sources onsite. The combustion turbine and duct burners, which emit through the HRSG stack, the diesel fired emergency generator, and the emergency diesel fire pump engine. The combustion turbine and duct burners are subject to the greenhouse gas (GHG) reporting requirements under 40 CFR 98 as a Source Category listed under Table A-3; Electricity generation unit that report CO_2 mass emissions year round through 40 CFR part 75. The emergency generator and the emergency diesel fire pump engine are exempt from the reporting requirements of 40 CFR 98 in accordance with 40 CFR 98.30(a)(2).

<u>Combustion Turbine GHG Emission Calculations</u>

$$\boldsymbol{CO2[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 53.02 kg/MMBtu [40 CFR 98; Subpart C, Table C-1]*
- *Global Warming Potential = 1 [40 CFR 98; Subpart A, Table A-1]*

*CO_2 [lb/hr] = 2,134 [MMBtu/hr] * 53.02 [kg/MMbtu[* 2.2 [lb/kg] = 248,918.3 [lb/hr]*

*CO_2 [ton/yr] = (248,918.3 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 981,235.9 [ton/yr]*

*CO_2 [metric ton/yr] = 981,235.9 [ton/yr] * 0.91 [metric ton/ton] = **922,361.8 [metric ton/yr]***

$$\boldsymbol{CH4[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-3 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 21 [40 CFR 98; Subpart A, Table A-1*

*CH_4 [lb/hr] = 2,134 [MMBtu/hr] * 1.0e-3 [kg/MMbtu[* 2.2 [lb/kg] = 4.695 [lb/hr]*

*CH_4 [ton/yr] = (4.695 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 18.51 [ton/yr]*

*CH_4 [metric ton/yr] = 18.51 [ton/yr] * 0.91 [metric ton/ton] = **16.84 [metric ton/yr]***

$$\boldsymbol{N2O[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-4 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 310 [40 CFR 98; Subpart A, Table A-1]*

*N_2O [lb/hr] = 2,134 [MMBtu/hr] * 1.0e-4 [kg/MMbtu[* 2.2 [lb/kg] = 0.4695 [lb/hr]*

*N_2O [ton/yr] = (.4695 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 1.851 [ton/yr]*

*N_2O [metric ton/yr] = 1.851 [ton/yr] * 0.91 [metric ton/ton] =* ***1.684 [metric ton/yr]***

$$\boldsymbol{CO2e[ton/yr] = CO2[metric\ ton/yr] + CH4[metric\ ton/yr] * 21[GWP] + N2O[metric\ ton/yr] * 310[GWP]}$$

*CO_2e [metric ton/yr] = 922,361.8[metric ton CO_2/yr] + (16.84 [metric ton CH_4/yr] * 21 [CH_4 GWP]) + (1.684 [metric ton N_2O] * 310 [N_2O GWP})*

CO_2e = 923,237.5 [metric ton/yr]

Duct Burner GHG Emission Calculations

$$\boldsymbol{CO2[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 241MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 53.02 kg/MMBtu [40 CFR 98; Subpart C, Table C-1]*
- *Global Warming Potential = 1 [40 CFR 98; Subpart A, Table A-1]*

*CO_2 [lb/hr] = 241 [MMBtu/hr] * 53.02 [kg/MMbtu[* 2.2 [lb/kg] = 28,111.2 [lb/hr]*

*CO_2 [ton/yr] = (28,111.2 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 110,814.4 [ton/yr]*

*CO_2 [metric ton/yr] = 110,814.4 [ton/yr] * 0.91 [metric ton/ton] =* ***100,841.1 [metric ton/yr]***

$$\boldsymbol{CH4[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 241 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-3 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 21 [40 CFR 98; Subpart A, Table A-1*

*CH_4 [lb/hr] = 241 [MMBtu/hr] * 1.0e-3 [kg/MMbtu[* 2.2 [lb/kg] = 0.53 [lb/hr]*

*CH_4 [ton/yr] = (0.53 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 2.09 [ton/yr]*

*CH_4 [metric ton/yr] = 2.09 [ton/yr] * 0.91 [metric ton/ton] =* ***1.90 [metric ton/yr]***

$$\boldsymbol{N2O[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 241 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-4 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 310 [40 CFR 98; Subpart A, Table A-1]*

*N_2O [lb/hr] = 241 [MMBtu/hr] * 1.0e-4 [kg/MMbtu[* 2.2 [lb/kg] = 0.05 [lb/hr]*

*N_2O [ton/yr] = (0.05 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 0.21 [ton/yr]*

*N_2O [metric ton/yr] = 0.21 [ton/yr] * 0.91 [metric ton/ton] =* ***0.19 [metric ton/yr]***

$$\boldsymbol{CO2e}[\boldsymbol{ton/yr}] = \boldsymbol{CO2}[\boldsymbol{metric\ ton/yr}] + \boldsymbol{CH4}[\boldsymbol{metric\ ton/yr}] * \mathbf{21}[\boldsymbol{GWP}] + \boldsymbol{N2O}[\boldsymbol{metric\ ton/yr}] * \mathbf{310}[\boldsymbol{GWP}]$$

*CO_2e [metric ton/yr] = 100,841 [metric ton CO_2/yr] + 1.90 [metric ton CH_4/yr] * 21 [CH_4 GWP] + 0.19 [metric ton N_2O] * 310 [N_2O GWP]*

CO_2e = 100,940 [metric ton/yr]

<u>Facility GHG Emissions Subject to 40 CFR 98</u>

$$\boldsymbol{CO2e}[\boldsymbol{metric\ ton/yr}] = \boldsymbol{CO2e}[\boldsymbol{Turbine}] + \boldsymbol{CO2e}[\boldsymbol{Duct\ Burners}]$$

CO_2e = 923,237.5 [metric tons/yr] + 100,940 [metric tons/yr]

CO_2e = 1,024,177.5 [metric tons/yr]

Appendix C – Limit Stringency Evaluation

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

Appendix D – Operation and Maintenance Manual

IDAHO POWER
An IDACORP Company

LANGLEY GULCH POWER PLANT

EMISSION SOURCE OPERATIONS AND MAINTENANCE MANUAL

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

Overview

The Langley Gulch Power Plant is a power generation facility, comprised of a natural gas-fired combustion turbine (CT) and a steam-driven steam turbine (ST). The combustion turbine burns natural gas as a fuel source which drives a 4-stage axial turbine for generating electricity. The waste heat from the turbine is exhausted through a heat recovery steam generator (HRSG), where the heat from the flue gas is transferred to the boiler feedwater to produce steam. The steam is routed to the ST where it drives the turbine blades to generate additional electricity.

The auxiliary equipment onsite which supports the gas and steam turbine operations include a water treatment facility, a cooling tower, a diesel-fired firewater pump, a diesel-fired emergency generator, as well as a duct burner which is integrated into the HRSG.

Operating Requirements

<u>Combustion Turbine</u>

Control Equipment

- **Dry Low NOx Combustors:** The dry low NOx (DLN) combustors are an integral part of Siemens' combustion system. The combustors are permanently installed in the turbine and do not have the capability to be turned off. The combustors achieve low NOx emissions through a 4-stage fuel supply system. The stages have varying degrees of fuel/air mixing prior to combustion. This staging of the fuel allows the turbine to operate at a lean fuel-to-air mixture, which reduces the NOx emissions.
- **Selective Catalytic Reduction:** The selective catalytic reduction (SCR) is a system installed within the HRSG which reacts with the CT exhaust NOx emissions. The CT exhaust passes through the HRSG and when it reaches the SCR, vaporized ammonia (NH3) is sprayed into the exhaust gas. The ammonia mixes with the exhaust and travels downstream into a catalyst grid. The ammonia/exhaust mixture reacts on the catalyst grid where the NOx and NH3 react forming nitrogen gas (N2) and water vapor (H2O) which is exhausted through the stack.
- **Catalytic Oxidation:** The oxidation catalyst is a system installed within the HRSG which reacts with the CT exhaust carbon monoxide (CO) and volatile organic compounds (VOCs). The catalyst grid is located in the HRSG and when the exhaust gases pass through it, the CO molecules are oxidized and exhaust as carbon dioxide (CO2) through the stack.
- **Good Combustion Practices:** The combustion turbine shall be operated in accordance with the recommended limits provided by the manufacturer. No control changes that will intentionally increase the emissions above the permitted levels shall be allowed. In addition, the CT and duct burners will be operated exclusively with pipeline quality natural gas.

Operational Procedures

- **CT BACT Emission Limits:** The combustion turbine shall be operated exclusively on natural gas, through the DLN combustion system. The DLN system shall be operated in accordance with the vendor's fuel fractioning schedules and recommendations. To meet the BACT emission levels, the CT exhaust gas shall pass through both the oxidation catalyst and the SCR during operations. These systems shall remain operable during normal operating conditions; however, during startup, shutdown, and low-load operations, these systems may have reduced effectiveness or may not be allowed to operate due to potential fouling/damage at low temperatures. During these conditions, the secondary BACT limits will be complied with.
- **Ammonia Flow:** The ammonia flow to the SCR shall be electronically archived at all times when the system is in service. The data shall be reduced to hourly averages to ensure the permit limit is not exceeded. A high flow alarm shall be programmed into the plant control system to alert the operations staff of abnormal conditions, in which case, action shall be taken to reduce the flow.
- **Control Equipment Maintenance & Operation:** The DLN combustion system will be inspected during each of the scheduled combustion turbine maintenance intervals. The oxidation catalyst and SCR will be inspected for fouling or physical damage no less than every two years. The CEMS and plant control system will be utilized to monitor for good combustion practices. Emissions above the permitted levels are indicative of either abnormal combustion practices or faulty equipment and will be investigated by the onsite operator. Any excess emissions will be reported in accordance with Permit Conditions 19-26.

<u>Emergency Diesel Generator</u>

Control Equipment

- **EPA Tier 2 Technologies:** The emergency engine was manufactured to the Tier 2 requirements and certified by the EPA under certificate #CPX-NRCI-10-03. Certificate available in generator O&M manual located in the plant control room.
- **Good Combustion Practices:** The emergency generator will be operated in accordance with the O&M manual distributed by the vendor. The engine shall be limited to 60 hrs/yr of operation for maintenance and readiness checks; operating no more than 4 hrs/day. Operation during emergency use is unlimited; however, excess emission evaluations may be required for operations in excess of permit limits. The engine will be operated exclusively on low sulfur diesel fuel. A non-resettable meter is installed on the engine and logs will be maintained of the operational hours.

Operational Procedures

- **Work Practices:** The emergency generator will be operated and maintained in accordance with prudent industry standards and applicable vendor instructions. No physical modifications which could increase emissions will be made to the engine without prior analysis.

Diesel Fire Pump

Control Equipment

- **EPA Tier 3 Technologies:** The diesel fire pump engine was manufactured to the Tier 3 requirements and certified by the EPA under the engine family #9CEXL0540AAB. Emission data sheet available in the fire pump O&M manual located in the plant control room.
- **Good Combustion Practices:** The diesel fire pump will be operated in accordance with the O&M manual distributed by the vendor. The engine shall be limited to 30 hrs/yr of operation for maintenance and readiness checks; operating no more than 1 hr/day. Operation during emergency use is unlimited; however, excess emission evaluations may be required for operations in excess of permit limits. The engine will be operated exclusively on low sulfur diesel fuel. A non-resettable hour meter is installed on the engine and logs will be maintained of the operational hours.

Operational Procedures

- **Work Practices:** The diesel fire pump will be operated and maintained in accordance with prudent industry standards and applicable vendor instructions. No physical modifications which could increase emissions will be made to the engine without prior analysis.

Cooling Tower

Control Equipment

- **Drift Eliminators:** The drift eliminators are installed above the water distribution sprayers and prevent water droplets from being carried airborne with the air passing through the fans. They are constructed of cellular PVC and force the air through direction changes which allow the entrained water droplets to coalesce on the surface and drop back into the tower basin.
- **Good Operating Practices:** The tower will be operated in accordance with prudent industry standards and applicable vendor instructions. The chemistry of the cooling tower will be maintained within the permitted levels.

Operational Procedures

- **Work Practices:** The drift eliminators are permanently installed in the cooling tower are in-service at all times the tower is operating. Along with maintaining the chemistry of the cooling water, the drift eliminators will be inspected for fouling and/or damage to ensure their effectiveness is not compromised.

Dry Chemical Storage Silos

Control Equipment

- **Bin Vent Filters:** The bin vent filters are installed on the roof of the storage silos. The vents have a filter installed which prevents the chemical from escaping into the atmosphere during loading operations. The bin vent filter is also equipped with an exhaust fan which pulls the air out of the silo and through the filter to maintain a vacuum within the silo. The fan pulls the air through the filter, which prevents air entrained with dry chemical from escaping through any other ports in the silo.
- **Good Operating Practices:** The storage silos will be operated in accordance with prudent industry standards and applicable vendor instructions. The bin vent filters will be operational during all loading operations.

Operational Procedures

- **Work Practices:** The bin vent filters will be installed and maintained in accordance with the written instructions included in the vendor's O&M manual. The filters and fan will be inspected and replaced as required.

Appendix E – Monitoring Plans & Protocols

LANGLEY GULCH POWER PLANT
NEW PLYMOUTH, IDAHO

CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) METHODOLOGY

PREPARED FOR: IDAHO POWER COMPANY

PREPARED BY: CUSTOM INSTRUMENTATION SERVICES CORPORATION

DATE: December 8, 2010
REVISION: 0

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1 INTRODUCTION

This document describes the Continuous Emissions Monitoring System (CEMS) being installed at the Langley Gulch Power Plant located near New Plymouth, Idaho. The CEMS includes oxide of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) analyzers on the combustion turbine exhaust stack. The CEMS instrumentation will be used to demonstrate continuous compliance with the allowable CO and NO_x limits set forth in the Idaho Department of Environmental Quality (IDEQ), Air Quality Permit to Construct (Permit Number P-2009.0092). The CEMS will also meet the monitoring and reporting requirements of the Acid Rain Program.

This document is designed to fulfill the requirement in Condition 52 the permit that the "permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval." A QA/QC Manual has been prepared and submitted under separate cover.

2 FACILITY DESCRIPTION

The Langley Gulch Power Plant is located near New Plymouth, Idaho. The site consists of a one-on-one combined-cycle plant, consisting of a natural gas-fired combustion turbine (CT) and a steam turbine. The CT is equipped with a heat recovery steam generator (HRSG) 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.

The unit is fired exclusively with pipeline quality natural gas and has an exhaust stack which discharges into the atmosphere approximately 160 feet above grade. The turbine has a maximum heat input of approximately 2134 mmBtu/hr at design conditions and generates 269 MW. The duct burner has a maximum heat input of approximately 241 mmBtu/hr at design conditions. The plant includes dry low NOx combustors and selective catalytic reduction (SCR) to control NOx emissions and a catalytic oxidation system to control CO emissions.

The NO_x and O_2 analyzers must meet the certification requirements of 40 CFR 75 and the CO analyzer must meet 40 CFR 60, Appendix B, Performance Specification 4/ 4A. As part of these requirements, CEMS certification testing will take place and a final test report will be submitted.

3 CEMS AND PROCESS MONITOR DESCRIPTION

Custom Instrumentation Services Corporation of Englewood, Colorado, manufactured the extractive CEM system being supplied to the Langley Gulch Power Plant. All analyses are performed on a "dry" basis from undiluted samples and hourly results are reported in ppm, ppm corrected to 15% O_2, lb/mmBtu and pounds per hour. Technical information on the system is provided in Appendix 1.

The CEMS will be used to determine compliance with emission limits listed in the permit, as follows.

TABLE 1
AIR QUALITY PERMIT TO CONSTRUCT EMISSION LIMITS

Pollutant	Normal Operation	Low-Load Operation	Startup and Shutdown	Annual Emissions	Applicable Regulation
NO_x ppm @ 15% O_2, 3-hour rolling average	2.0	96	96	NA	PTC Section 33, 34, 35
NOx ppm @ 15% O_2, 30-day rolling average	15	96	NA	NA	PTC Section 37
NO_x Tons/Year	NA	NA	NA	88	PTC Section 36
CO ppm @ 15% O_2, 3-hour rolling average	2.0	24.5	NA	NA	PTC Section 33, 34
CO lb/hr	NA	NA	2510	NA	PTC Section 35
CO Tons/Year	NA	NA	NA	278.1	PTC Section 36
VOC ppm @ 15% O_2, 3-hour rolling average	2.0	11.5	NA	NA	PTC Section 33, 34

3.1 Analyzers

Oxides of Nitrogen (NO_X):
For the analysis of NO_x, a Teledyne (TAPI) Model 200EM analyzer is used. The Chemiluminescence detection method quantitatively converts NO to NO_2 by gas-phase oxidation with molecular ozone that is produced by the analyzer ozone generator in an environment, of system supplied dry instrument air. The Model 200EM converts NO_2 to NO by employing a converter cartridge filled with molybdenum (Mo, "moly") chips heated to a temperature of 600° F. The analyzer ranges are 10 ppm and 150 ppm and the analyzer will be calibrated daily on both ranges with cylinders of NO gas at approximately 9 and 135 ppm.

Carbon Monoxide Analyzer:
For the analysis of CO, a Teledyne (TAPI) Model 300EM analyzer is used. The Model 300EM Gas Filter Correlation Carbon Monoxide analyzer is a microprocessor-controlled analyzer that determines the concentration of carbon monoxide (CO) in a sample gas drawn through the instrument. It requires that sample and calibration gasses be supplied at ambient atmospheric pressure in order to establish a stable gas flow through the sample chamber where the gases ability to absorb infrared radiation is measured. The analyzer ranges are 10, 50 and 3000 ppm. The analyzer will be calibrated daily with cylinders of CO gas at approximately 8, 40 and 2400 ppm.

Oxygen Analyzer:
For the analysis of Oxygen, the O_2 channel of the Teledyne (TAPI) Model 200 EM analyzer is used. This type of analyzer is characteristically linear and is not sensitive to interference from moisture, combustibles, or physical vibrations. A true gross oxygen analysis is provided. The 0-

25% full-scale range will be configured into the system to allow for a span check daily with instrument air (20.9% O_2).

3.2 DATA ACQUISITION AND HANDLING SYSTEM DESCRIPTION

The Data Acquisition and Handling System (DAHS) provides historical data storage with review and complete editability. It generates all required reports in the format which is acceptable to IDEQ; hourly, daily, monthly summaries, and quarterly exceedance reports generated automatically or on demand. The electronic quarterly report required by EPA for 40 CFR 75 will be generated for submittal within 30 days after the end of the previous quarter. The DAHS is a passive system, receiving the majority of its information (data and control) from the CEM system. To acquire the balance of its information (i.e., fuel flow) interface is provided to the plant control systems.

Software provided for data acquisition is an integrated, user-friendly, menu-driven software package developed by CiSCO for data acquisition, analysis and reporting. Data acquisition will continue uninterrupted in the background while data manipulation and report generation is taking place in the foreground. The calculation of emissions in units of the applicable standards (ppm @ 15% O_2, lb/hr, lb/mmBtu) is accomplished by the DAHS. The calculations used are provided in Appendix 2.

3.3 Sample Handling

All components necessary to acquire a representative sample, condition that sample without loss of sample integrity and supply that sample to the analyzer for analysis are included in the system. All sample-wetted surfaces are Teflon, stainless steel or glass.

Sample Acquisition: A representative sample of gas from the stack is acquired with a CiSCO sample probe and is transported to the shelters via heated sample lines. The sample probes are designed to mount on a four-inch (4"), 150 pound ANSI flange. The probe assembly includes a 316L SS filter chamber located outside the flange in a NEMA 4 enclosure. This allows the filter to be periodically maintained safely without removing the probe from the gas stream. It also eliminates pluggage of the filter by direct impact of particulate or water droplets on the filter. The filter is rated at 15 microns and can be easily replaced or cleaned.

The heated sample line keeps the sample gas temperature above its acid dewpoint during transport to the shelter. A 5/16" OD stainless steel tube is traced with an electrical heater insulated with 1/2" of insulation and covered with a scuff-resistant jacket. The temperature-controlled heater is designed to maintain the sample temperature above 350°F. The probe and heated sample line are capable of accommodating flue gas with temperatures in excess of 400°F.

Sample Conditioning: The sample is conditioned by filtering out the particulate, and removing the sample gas moisture. Two stages of filtration are used; the coarse filter located in the sample probe will protect the heated sample line from plugging and a secondary fine filter located in the shelter will remove 99.99% of all particulate 0.1 micron and larger in size. This filter is located downstream of the refrigeration-cooled sample dryer. The clear shell of the filter housing simplifies visual inspection of the filter exterior conditions.

Drying of the sample is accomplished in two stages. First, the sample is passed through a refrigeration-cooled cold-water bath where the sample temperature and therefore its dewpoint, is lowered to approximately 35°F. All condensable moisture is separated from the sample gas and is continuously removed from the system with a peristaltic pump. To reduce the interference due to moisture and to prevent acid mist carryover, the sample dewpoint is lowered further with a membrane dryer. The remaining sample gas moisture permeates the membrane in the gaseous phase and is carried away in the ultra-dry purge air. The system includes a dual-column, regenerative air dryer to provide purge air to the membrane dryer at a nominal -80°F dewpoint. An effective sample dewpoint of 0°F to -20°F is obtained.

Sample Transport: The sample is drawn into the shelter with a Teflon-coated, Teflon diaphragm pump. A backpressure regulator on the output of the sample pump acts as a variable pressure relief valve, providing a sample bypass, which is vented. Adjustment of this bypass flow allows adjustment of the overall system response time. Fluctuations in process pressure and flow conditions are passed out of this bypass, rather than through the system, and therefore do not affect the analyzer. Pressure regulators with pressure gauges and flow control valves with flowmeters are used to set and regulate the pressure and flow of sample gas to each analyzer. These devices assure that calibration gas and sample gas is supplied to the analyzer at the same flow and pressure for an accurate analysis.

3.4 CEMS Calibration

The CEMS is equipped with the capability to initiate the automatic calibration routing on demand, and to call in the calibration solenoid valves to a completely manual calibration for maintenance. The automatic calibration routine will be performed every 24 hours on each of the analyzers under the programmed control system (PLC). The analyzers are zeroed on nitrogen, supplied from a high-pressure gas cylinder. The calibration span gases are also supplied from high-pressure gas cylinders.

In the manual calibration mode, calibration gas can either be injected directly into the analyzer for a diagnostic check only or injected into the sample probe via a 1/4" Teflon line in the probe support bundle, so that calibration gas flows through the entire sample handling system to verify the integrity of the total system. In the automatic calibration mode, calibration gas is injected into the sample probe on a daily basis.

CEMS Calibration Fail Alarms: To facilitate meeting applicable Federal and State regulations, the actual response of the analyzer during calibration is compared with a known absolute required response. If the error is larger than regulations allow, calibration fail alarms are activated, signaling a maintenance requirement and a readjustment of the analyzer.

CEMS Calibration Span & Zero Correction: If a calibration is conducted successfully, the PLC program calculates the amount of error in the readings, (zero and span) for the analyzer and generates a correction factor that corrects the slope and zero of the analyzer's response. This correction factor is applied to all subsequent sample readings to adjust the results to a "perfect" calibration.

3.5 SAMPLE LOCATION

The sample port for the CEMS sample probe is approximately 53 feet, 4 inches (2.9 diameters) from a downstream disturbance and is approximately 11 feet (0.6 diameters) upstream of the stack exhaust. The sample probe is 5 feet long, which will make the sample location at a representative point in the 18 foot, 7 inch diameter stack. Four EPA ports are located 6 inches above the CEMS ports. A sketch of the sampling locations is presented in Figure 1. The CEMS is housed in a ten by ten (10' x 10') metal shelter, located at the base of the stack. The shelter is climate controlled and provides a clean environment for the analyzers and associated equipment.

4 CERTIFICATION STRATEGY

The certification testing for the Langley Gulch Power Plant must meet the requirements of 40 CFR 60 and 40 CFR 75. To the extent possible, testing will be completed to meet all requirements concurrently. The performance specifications are presented in Table 1.

40 CFR 75: Testing to meet 40 CFR 75 requirements will be performed on the NO_x, and O_2 analyzers. The testing consists of a 7-day drift test, RATA, linearity and cycle response time. The results from the RATA testing will be presented in lb/mmBtu. The linearity test consists of three runs using three levels of calibration gas. The cycle response time test determines the upscale and downscale response of both the NO_x and O_2 analyzers.

40 CFR 60: The CO analyzer will be tested to meet the requirements of 40 CFR 60, Appendix B, Performance Specification 4/4A. The tests include a 7-day drift test, a response time test and a Relative Accuracy Test Audit (RATA). Calculations will be done for ppm @ 15% O_2 and lb/hr. All testing will be performed while the plant is operating at a minimum of 50 percent of normal load.

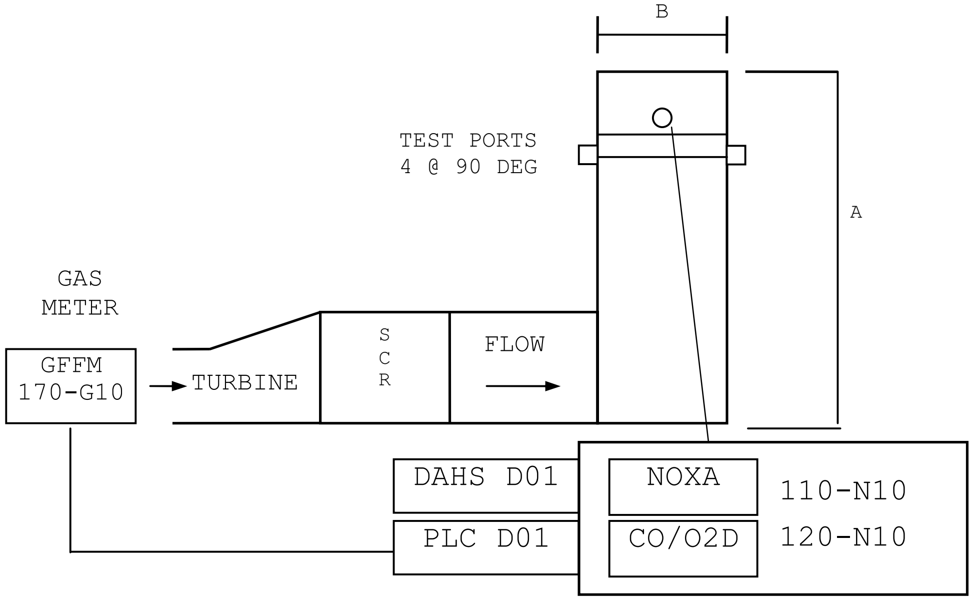
For both regulations, the RATA will involve verification by a third party test team, following 40 CFR 60, Appendix A test methods. Nine to twelve test runs will be performed. During these tests, the sample location will be tested for stratification. To perform the test, the DAHS will be placed in an "Audit Mode" and values will be recorded every minute and then averaged for the duration of the test period. These values are compared to the test team’s values for the same test period. The difference between the two sets of values must meet the requirements listed in Table 2.

TABLE 2: CEMS PERFORMANCE SPECIFICATIONS

	40 CFR 60	40 CFR 75
24-hr Drift – Zero and Span		
NO_x	• NA	2.5% of span of analyzer or 5 ppm
O_2	• NA	0.5% O_2
CO	• 5% of range of analyzer	NA
RESPONSE TIME TEST		
CO	• 1.5 minutes	NA
CYCLE RESPONSE TEST		
NO_x	• NA	15 minutes
O_2	• NA	15 minutes
LINEARITY		
NO_x	• NA	5% of gas value or 5 ppm
O_2	• NA	5% O_2
RATA		
NO_x lb/mmBtu	• NA	7.5% RA or $\underline{+}$0.015 lb/mmBtu [1]
O_2 %	• NA	NA
CO ppm @ 15% O_2 and lb/hr	• 10% RA, 5% of std, 5 ppm	NA
DAHS ACCURACY	Verify formulas	Verify formulas

1. Accuracy for annual Relative Accuracy (RA) frequency

FIGURE 1: CEMS SAMPLE PORT LOCATIONS



Monitor Location Information

A. Stack Height Above Grade - 160 feet
B. Stack Inside Diameter at Test Port - 18 feet, 7 inches
C. Inside Cross Sectional Area at CEMS Location 271.2 feet^2
D. CEMS Probe Elevation
   1. Above Grade 149 feet, 0 inches
   2. Above Last Disturbance
      a. Feet 53 feet, 4 inches
      b. Stack Diameters 2.9
   3. Prior to Stack Exit
      a. Feet 11 feet, 0 inches
      b. Stack Diameters 0.6

5 QUALITY ASSURANCE REQUIREMENTS

The CEMS for the Langley Gulch Power Plant is designed to meet the reporting, record keeping, certification, and quality assurance requirements of the requirements of 40 CFR 75, 40 CFR 60 and the IDEQ permit.

5.1 DATA VALIDATION REQUIREMENTS

Personnel at the Langley Gulch Power Plant strive to achieve 95% availability of the monitors under normal operating conditions. All reasonable and practical means are used to achieve this objective, including overtime corrective maintenance work, quarterly audits, routine preventative maintenance, and daily calibration checks. All pertinent regulations require the reduction of emissions to one-hour time-based emissions.

5.1.1 Invalid Data

Numerous conditions can render data invalid. If the correct numbers of valid data points are not collected for any reason, then the data collected is considered invalid. For 40 CFR 75 reporting, invalid data is automatically replaced by the DAHS. For 40 CFR 60 reporting, invalid data is reported as monitor downtime. The following are examples of conditions, which could result in invalid data:

- CEMS control power failure
- Analyzer malfunction
- Water in sample
- Back-flush cycle
- Last calibration fail (40 CFR 75) or out-of-control (for 40 CFR 60)
- Out-of-Service
- CEMS Off-line
- CEMS failed linearity test (out-of-control)
- CEMS failed relative accuracy (out-of-control)

5.1.2 Data Averaging

a) The CEMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. This is defined as a data point.

b) A valid hour of data is computed from four or more data points equally spaced over the one-hour period. Gaseous emissions data are reduced and recorded as one-hour averages. If one of the 15-minute periods (using four data points per hour) is invalid, the hour is considered invalid and the DAHS will replace the hourly data using the missing data procedures in 40 CFR 75 or will report the period as monitor downtime.

c) For 40 CFR 75 reporting, during periods of calibration, quality assurance or maintenance activities, a valid hour consists of at least two data points separated by a minimum of 15 minutes. If the CEMS does not collect valid data in accordance with this criteria, then the missing data procedures must be used to replace the data. In order to perform calibrations, quality assurance or maintenance, the "out-of-service" periods should begin more than 30 minutes into an hour and end less than 30 minutes into the next hour. In this way, nearly 60 minutes of service can be performed on the system without impacting availability.

d) For quarterly 40 CFR 75 reporting, all missing or invalid data is automatically replaced by the DAHS following the procedures contained in 40 CFR 75, Subpart D (for NO_x) and Appendix D (for fuel flow).

e) After determination of the emissions in the proper reporting parameters, the emissions data is rounded off to the same number of significant digits as the emission limit or the number of significant digits required by EPA.

5.2 CEMS GAS ANALYZER CALIBRATION

The CEMS is equipped with manual and automatic, zero and span calibration capabilities. The automatic calibration routine is performed every 24 hours on each of the analyzers under the programmed control of the system PLC. In addition, a calibration can be started manually at any time with the activation of the "Cal Start" button on the Operator Interface Terminal (OIT).

In either mode, a "Cal-at-Cabinet" valve allows the operator to select one of two modes of calibration. With the valve in the cabinet position, calibration gas is injected directly into the sample flow control components and then into the analyzers. With the valve in the probe position, calibration gas is injected into the sample probe via the 1/4" Teflon calibration line in the probe support bundle. The calibration gas is then pulled through the sample conditioning subsystem just as the sample is, and the integrity of the entire system is checked. This is the normal mode, which is used during the automatic calibration routine.

In the automatic calibration sequence, either manually or automatically initiated, the cal gas solenoid valves are automatically sequenced by the system PLC. The first four minutes of each five-minute period of gas flow is used for system stabilization. During the last minute, the analyzer response is interrogated by the PLC. Eleven values are read, five seconds apart, and are averaged for an average calibration reading. Initial programming has timed the calibration sequence, five minutes for zero and five minutes for each analyzer span.

If the calibration check passes, a new sample output correction factor is calculated for each analyzer and is stored to be used during sampling until the next calibration. If the calibration fails, the calibration fail alarm is activated and the subsequent sample output signal(s) will be uncorrected for each failed analyzer. Programming for 40 CFR 75 allows a maximum ±1% difference from reference gas for O_2 and ±5% of span for NO_x. Programming for the operating permit and 40 CFR 60 allows a maximum ±20% of range for CO out-of-control.

In order for the PLC to check the validity of a calibration and generate a fail or out-of-control signal if the analyzer response is outside of preset limits, it not only needs to know the actual analyzer response, it also must "know" a constant to compare it with. For zero, the constant is zero, and is stored in a register in the PLC. All analyzer span concentration values are input to the PLC via the OIT. These inputs are taken directly from the span gas cylinder labels.

The zero calibration gas should be zero grade nitrogen (N_2) as supplied by a specialty gas supplier. The nominal span gas concentrations required for the Langley Gulch Power Plant project are provided in Table 3.

TABLE 3: ANALYZER RANGES AND NOMINAL SPAN GAS CONCENTRATIONS

ANALYZER	FULL SCALE RANGES	40 CFR 75 SPAN	NOMINAL SPAN GAS
NO_x	0-10 and 0-150 ppm	0-10 and 0-150 ppm	9 and 135 ppm
CO	0-10, 0-50 and 0-3000 ppm	NA	8, 40 and 2400 ppm
O_2	0-25 %	0-21 ppm	20.9% (Inst. Air)

Calibration adjustment procedures for gas analyzers are provided in Appendix 2. The specific analyzer manufacturer's manuals are contained in the CEMS O&M Manual, which is incorporated here by reference.

APPENDIX 1

TECHNICAL INFORMATION

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL 200EH / 200EM

Chemiluminescene High & Medium Range $NO/NO_2/NO_X$ Analyzers

- 200EH: 0-5 ppm to 0-5000 ppm, user selectable
- 200EM: 0-1 to 0-200 ppm, user selectable
- Independent ranges for NO, NO_2, NO_X
- Auto ranging and remote range selection
- Microprocessor controlled for versatility
- NO_X-only or NO-only modes
- Multi-tasking software allows viewing of test variables while operating
- Continuous self checking with alarms
- Permeation drier on ozone generator
- Dual bi-directional RS-232 ports for remote operation (optional Ethernet or RS-485)
- Digital status outputs provide instrument condition
- Adaptive signal filtering optimizes response time
- Temperature & pressure compensation, automatic zero correction
- Converter efficiency correction software
- Minimum CO_2 and H_2O interference
- Catalytic ozone scrubber
- Internal data logging with 1 min to 365 day multiple averages (1 million records)

The Models 200EH and 200EM use the proven chemiluminescence measurement principle, coupled with state-of-the-art microprocessor technology for monitoring high and medium levels of nitrogen oxides. User-selectable analog output ranges and a linear response over the entire measurement range make them ideal for a wide variety of applications, including extractive and dilution CEM, stack testing, and process control.

A choice of NO_2 converters handles tough CEM and stack testing as well as combustion turbine startup and continuous operation applications. Selectable measurement modes (NO_X only, NO only, NO/NO_X switching), auto ranging (single range, dual range, auto-range, independent ranges, remote range control) enables to match the Models 200EH or 200EM to your needs. Modular instrument design offers top-mounted, quick access to all subassemblies and hinged front and rear panels to simplify module replacement and maintenance. A standard permeation dryer on the ozone generator provides dry air and excess ozone is removed by catalytic reaction, both eliminating the need for expendables.

All instruments in the Teledyne-API Model “E”-Series include built-in data acquisition capability with internal memory. This allows logging of multiple parameters in different pre-defined or customized data channels including averaged or instantaneous concentration values, calibration data, and operating parameters such as pressures and flow rates. Stored data are easily retrieved through the RS-232 port via APICOM or from the front panel, allowing predictive diagnostics and enhanced data analysis by tracking parameter trends.

The Models 200EH and 200EM combine rugged construction, light weight, ease of use, powerful diagnostics and outstanding performance for high and medium range applications.

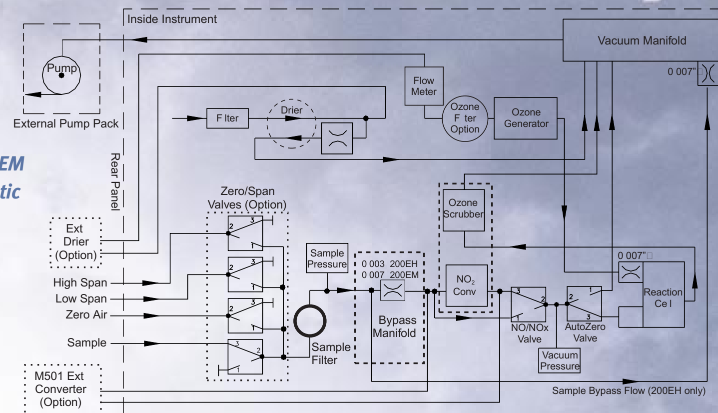
Approved - Returned: 12/14/2010

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL 200EH / 200EM

Chemiluminescence High & Medium Range $NO/NO_2/NO_X$ Analyzer

Model 200EH/EM schematic



SPECIFICATIONS

Ranges:	**200EH:** 0-5 ppm to 0-5000 ppm full scale, user selectable; independent NO, NO_2, NO_X ranges and auto-ranging supported **200EM:** 0-1 ppm to 0-200 ppm
Units:	ppm, mg/m^3
Zero Noise:	‹20 ppb (RMS)
Span Noise:	‹0.2% of reading above 20 ppm (RMS)
Lower Detectable Limit (LDL):	‹40 ppb (RMS)
Zero Drift:	‹20 ppb/24 hours
Span Drift:	‹1% reading/24 hours, ‹1% reading/7 days
Lag Time:	20 seconds switching mode; ‹6 seconds NO or NO_X only mode
Rise and Fall Time:	‹60 seconds to 95% (switching); 5 seconds NO only; 10 seconds NO_X only
Linearity:	1% full scale
Precision:	0.5% of reading
Sample Flow Rate:	250 cm^3/min (standard); 500 cm^3/min (optional)
Operating Temperature Range:	5 - 40˚C
Dimensions (HxWxD):	7” (178 mm) x 17” (432 mm) x 23.5” (597 mm)
Weight:	Analyzer 44 lbs (20 kg), External Pump 15 lbs (7 kg)
Power:	100V 50/60 Hz, 115V 60Hz, 220V 50/60Hz, 230V 50Hz, 240V 50Hz 250 Watts (analyzer), 250 Watts (pump)
Analog Outputs:	10V, 5V, 1V, 0.1V, selectable
Recorder Offset:	±10%
Serial Outputs:	Serial Port 1: RS-232, DB-9M Serial Port 2: standard RS-232 or optional RS-485, DB-9F
Status (Digital)	8 outputs, 6 inputs (opto-isolated), 6 alarm outputs (optional)
Current Output:	0-20 mA or 4-20 mA isolated outputs (optional)
Approvals:	CE

HOW TO ORDER

Model 200EH/EM Chemiluminescence $NO/NO_2/NO_X$ Analyzer includes:

- External pump
- Permeation ozone air dryer
- Independent NO, NO_2, NO_X ranges
- Auto ranging
- 47 mm particulate filter
- 12 isolated digital status outputs
- Dual bi-directional RS-232
- APICOM remote control software

Specify voltage/frequency:

- ☐ 100V/50Hz
- ☐ 220V/50Hz
- ☐ 230V/50Hz
- ☐ 240V/50Hz
- ☐ 100V/60Hz
- ☐ 115V/60Hz
- ☐ 220V/60Hz

Specify output voltage:

☐ 10V ☐ 5V ☐ 1V ☐ 0.1V

Additional Options:

- ☐ Rack mount brackets (19”) with chassis slides
- ☐ Rack mount brackets only
- ☐ Isolated 0-20 mA or 4-20 mA Output (specify up to 3 channels)
- ☐ Multi-drop serial interface
- ☐ Ethernet port includes 7 ft. CAT-5 cable (disables one serial port)
- ☐ Permeation dryer for sample gas
- ☐ Ozone air filter assembly

Calibration Valves:

- ☐ Dual-valve assembly for selection of customer-supplied zero and span gas (two gases)
- ☐ Triple-valve assembly for selection of customer-supplied zero and span gases (three gases or two gases and pressure vent)

NO_2 Converters:

- ☐ Mini-HICON Internal Converter (standard on 200EH)
- ☐ MOLYCON Converter (standard on 200EM)
- ☐ MODEL 501 External Converter (optional)

Accessories:

- ☐ RS-232 Cable
- ☐ Expendables Kit
- ☐ Spare Parts Kit
- ☐ Chassis carrying handle
- ☐ Zero Air Scrubber

For more information on Teledyne API’s family of monitoring instrumentation products, call us or visit our website at **www.teledyne-api.com**

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company
6565 Nancy Ridge Drive San Diego, CA 92121-2251
858-657-9800 Fax 858-657-9816
Email api-sales@teledyne.com

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL **300E**

Gas Filter Correlation CO Analyzer

EPA APPROVAL RFCA-1093-093
MCERTS certified Sira MC050069/00

- **Ranges, 0-1 ppm to 0-1000 ppm, user selectable**
- **Gas Filter Wheel for CO specific measurement**
- **14 meter path length for sensitivity**
- **Microprocessor controlled for versatility**
- **Multi-tasking software allows viewing of test variables during operation**
- **Continuous self checking with alarms**
- **Bi-directional RS-232 for remote operation**
- **Digital status outputs indicate instrument operating condition**
- **Adaptive signal filtering optimizes response time**
- **GFC wheel guaranteed against leaks for 5 years**
- **Temperature & Pressure compensation**
- **Internal data logging with 1 min to 365 day multiple averages**
- **APIcom remote operation software**

The Model 300E measures low ranges of carbon monoxide by comparing infrared energy absorbed by a sample to that absorbed by a reference gas according to the Beer-Lambert law. This is accomplished with a Gas Filter wheel which alternately allows a high energy light source to pass through a CO filled chamber and a chamber with no CO present. The light path then travels through the sample cell, which has a folded path of 14 meters.

The energy loss through the sample cell is compared with the span reference signal provided by the gas filter to produce a signal proportional to concentration, with little effect from interfering gases within the sample. This design produces excellent zero and span stability and a high signal to noise ratio allowing extreme sensitivity.

Multi-tasking software gives real time indication of numerous operating parameters and provides automatic alarms if diagnostic limits are exceeded. Built-in data acquisition and internal memory allows logging multiple parameters including average and instantaneous values, calibration data and operating parameters. Stored data are easily retrieved through the serial port or optional Ethernet port via our APIcom software or from the front panel, allowing operators to perform predictive diagnostics and enhanced data analysis by tracking parameter trends.

The Model 300E features rugged construction and is designed to perform with a minimum of attention. In the event maintenance is required, modular construction makes service a simple operation.

MODEL **300E**

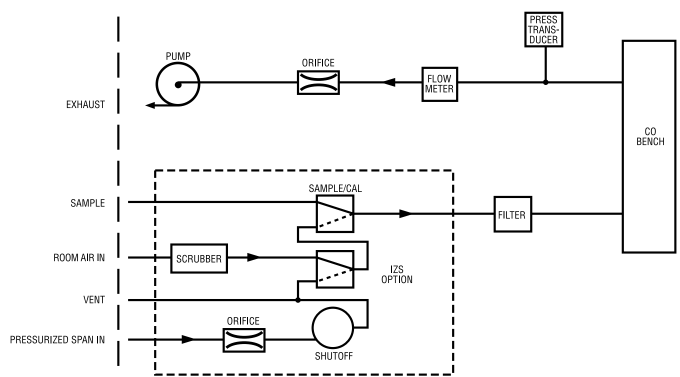
Gas Filter Correlation CO Analyzer

Specifications

Ranges:	0-1 ppm to 0-1,000 ppm full scale, user selectable. Dual ranges and auto ranging supported
Units:	ppb, ppm, µg/m³, mg/m³
Zero Noise:	< 0.02 ppm
Span Noise:	< 0.5% of reading above 5 ppm (RMS)
Lower Detectable Limit (LDL):	0.04 ppm
Zero Drift:	< 0.1 ppm/24 hours, 0.2 ppm/7 days
Span Drift:	< 0.5% of reading/24 hours, 1% of reading/7 days
Lag Time:	10 seconds
Rise and Fall Time:	< 60 seconds to 95%
Linearity:	1% of full scale
Precision:	0.5% of reading
Sample Flow Rate:	800 cm³/min ±10%
Operating Temperature Range:	5 - 40°C (with EPA Equivalency)
Dimensions (HxWxD):	7" (178 mm) x 17" (432 mm) x 23.5" (597 mm)
Weight:	40 lbs
Power:	100V - 120V, 220V - 240V, 50/60 Hz, 250W
Analog Outputs:	10V, 5V, 1V, 0.1V, selectable
Recorder Offset:	±10%
Serial Outputs:	Serial Port 1: RS-232 (DB-9M) Serial Port 2: standard RS-232 or optional RS-485 (DB-9F), Ethernet
Status (Digital)	8 outputs, 6 inputs (opto-isolated), 4 alarm outputs (optional)
Current Output:	Optional 4-20mA, select up to three channels
Approvals:	USEPA RFCA-1093-093, MCERTS certified Sira MC050069/00

NOTE: The values expressed above are in accordance with EPA definitions. All error specifications are based on constant conditions. Specifications exceed US EPA and Eignungsgeprüft requirements.

Schematic



How to Order

Model 300E Gas Filter Correlation CO Analyzer includes:

- Internal pump
- Auto ranging and dual ranges
- 47mm diameter particulate filter
- 8 isolated digital status outputs
- 6 isolated digital inputs
- Bi-directional RS-232
- APIcom remote control software

Specify input AC voltage & frequency:

☐ 100V - 115V ☐ 50Hz
☐ 220V - 240V ☐ 60Hz

Specify output DC voltage:

☐ 10V ☐ 5V ☐ 1V ☐ 0.1V

Calibration Options:

☐ TFE valves for selection of customer-supplied zero and span gas
☐ Internal zero air scrubber

Additional Options:

☐ Rack mount brackets (19") with chassis slides
☐ Rack mount brackets only
☐ 4-20mA outputs (specify up to three channels)
☐ Multi-drop RS-232 connection
☐ RS-485 communications
☐ Ethernet

Calibration Valves:

☐ Stainless steel valves for selection of customer-supplied zero and span gas
☐ Shut-off valve and flow control for external span gas cylinder
☐ Internal zero air scrubber

Accessories:

☐ RS-232 Cable
☐ Expendables Kit
☐ Spare Parts Kit

Specifications subject to change without notice. M300E/01.06

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company
9480 Carroll Park Drive ■ San Diego, CA 92121-5201
Ph. 858-657-9800 Fax 858-657-9816
Email api-sales@teledyne.com

For more information about the Teledyne API family of monitoring instrumentation products, call us or visit our website at

www.teledyne-api.com

CERTIFIED QUALITY MANAGEMENT SYSTEM ISO 9001:2000 ANAB DNV

Approved - Returned: 12/14/2010

190-RE-0005-001 - Packet 190-014 - Langley Gulch Power Plant - 2008044 - Received: 12/10/2010

2. SPECIFICATIONS, APPROVALS AND WARRANTY

2.1. SPECIFICATIONS

Table 2-1: Model 300E/300EM Basic Unit Specifications

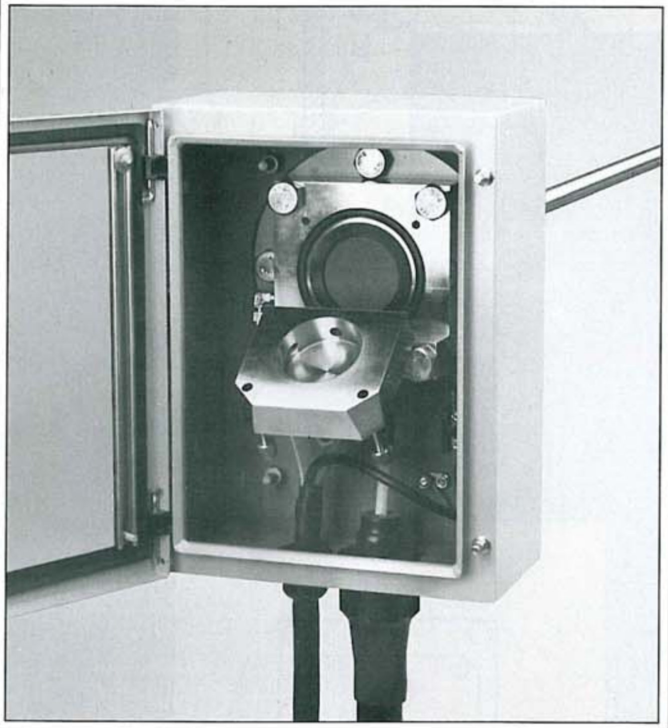
Ranges	M300E: Min: 0 1ppm; Max: 0 1000 ppm (User selectable) M300EM: Min: 0 1 ppm; Max: 0 5000 ppm (User selectable)
Measurement Units	M300E: ppb, ppm, $\mu g/m^3$, mg/m^3 (user selectable) M300EM: ppm, mg/m^3 (user selectable)
Zero Noise	M300E: ≤ 0.02 ppm RMS[1]; M300EM: ≤ 0.1 ppm RMS[1]
Span Noise	M300E:<0.5% of rdg RMS over 5ppm[1, 3]; M300EM:>0.5% of rdg RMS over 20ppm
Lower Detectable Limit	M300E: < 0.04 ppm[1]; M300EM: 0.2 ppm
Zero Drift (24 hours)	M300E: < 0.1 ppm[2]; M300EM: <0.5 ppm
Zero Drift (7 days)	M300E: < 0.2 ppm[2]; M300EM: <1.0ppm
Span Drift (24 hours)	< 0.5% of reading[2,4]
Span Drift (7 days)	< 1% of reading[2, 4]
Linearity	M300E: Better than 1% full scale[5]; M300EM: 0 3000 ppm: 1% full scale; 3000 5000 ppm: 2% full scale
Precision	0.5% reading[1,5]
Lag Time	<10 sec[1]
Rise/Fall Time	<60 sec to 95%[1]
Sample Flow Rate	$800 cm^3$/min. ±10% O_2 Sensor option adds 120 cm^3/min to total flow though when installed;
Temperature Range	5 40 C operating, 10 40 C EPA Equivalency
Humidity Range	0 95% RH, Non Condensing
Temp Coefficient	< 0.05 % per C (minimum 50 ppb/ C)
Voltage Coefficient	< 0.05 % per V
Dimensions (HxWxD)	7" x 17" x 23.5" (178 mm x 432 mm x 597 mm)
Weight	50 b (22.7 kg)
AC Power	100V 50/60 Hz (3.25A), 115 V 60 Hz (3.0A), 220 240 V 50/60 Hz (2.5A)
Environmental Conditions	Installation Category (Over voltage Category) II Pollution Degree 2
Analog Outputs	4 user configurable outputs
Analog Output Ranges	All Outputs: 0.1 V, 1 V, 5 V or 10 V Three outputs convertible to 4 20 mA isolated current loop. All Ranges with 5% under/over range
Analog Output Resolution	1 part in 4096 of selected full scale voltage
Status Outputs	8 Status outputs from opto isolators
Control Inputs	6 Control Inputs, 2 defined, 4 spare
Serial I/O	One (1) RS 232; One (1) RS 485 (2 connecters in parallel) Baud Rate : 300 115200
Alarm outputs (M300EM only)	2 opto-isolated alarms outputs with user settable alarm limits
Certifications	USEPA: Reference Method Number EQOA 0992 087 CE: EN61010 1:90 + A1:92 + A2:95, EN61326 Class A

[1] As defined by the USEPA
[2] At constant temperature and voltage
[3] Or 0.2 ppm, whichever is greater
[4] Or 0.1 ppm, whichever is greater
[5] Above 10 ppm range, otherwise 0.2 ppm for lower ranges

CiSCO

CUSTOM INSTRUMENTATION SERVICES CORPORATION

Stack Gas Sample Probe - Model EP750



Features

- Time-tested, field-proven design with backflush
- Cal gas injection on inlet side of filter
- A simple, easily maintained probe with no welded parts
- Can be built in any machinable material, typically 316L stainless steel or Hastelloy C-276
- Insertion tube can be any length and can be field shortened; it threads into body and is easily replaced
- Designed to mount on 4 inch 150 pound ANSI flange
- Heated filter chamber located outside of flange allows safe, easy filter change
- Electrical heater standard, or optional steam heater suitable for Class 1 Division 2 installation
- Filtration 5 to 25 microns with reusable non-reactive filters
- No active components at sample probe location
- No plant utilities required at sample probe location; sample probe completely supported from analysis enclosure
- High temperature model also available

Design Description

The CiSCO sample probe is designed to mount on a 4 inch 150 pound ANSI flange. It can be fabricated out of any machinable material. The probe is also available in a high temperature configuration and an explosion proof model. The probe assembly includes a heated filter chamber, located outside the flange in a NEMA 4 enclosure, which allows the filter to be periodically maintained safely without removing the probe from the gas stream. This eliminates filter clogging due to the direct impact of particulate or water droplets. The heater prevents the sample temperature from cooling to inhibit condensation of the sample gas moisture.

Filter easily cleaned or replaced

The filter, which is application-specific, is rated at 5 to 25 microns and can be easily replaced or cleaned. It is safely accessed via a hinged assembly, secured with two captive screws. Separate gas connections for sample extraction and backflush are incorporated into the filter chamber design. The calibration gas is injected on the stack side of the filter.

Simple maintenance

The insertion tube, which penetrates the stack, is easily maintained. If an obstruction occurs, the straight through design of the tube allows the blockage to be cleared with a ramrod without removing the probe from the gas stream.

Utilities not required at probe location

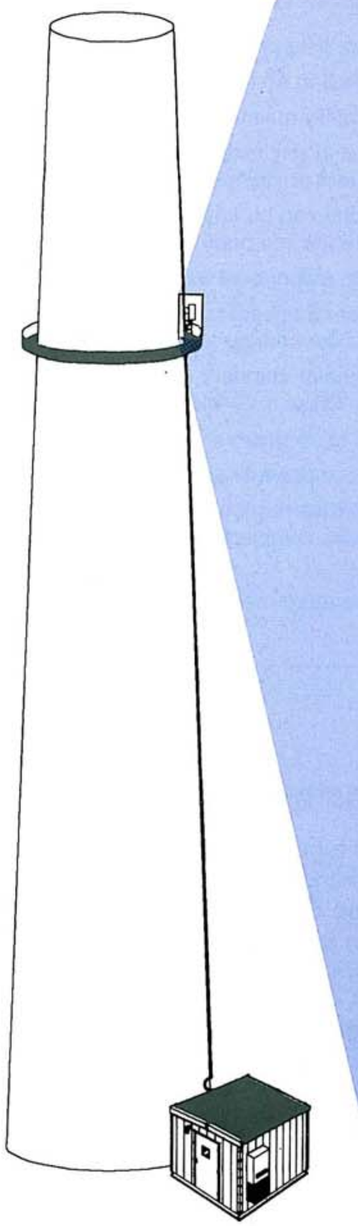
No active components are located at the sample probe. Plant utilities are not required at the sample probe location. The CiSCO sample probe is completely supported from the analysis enclosure.

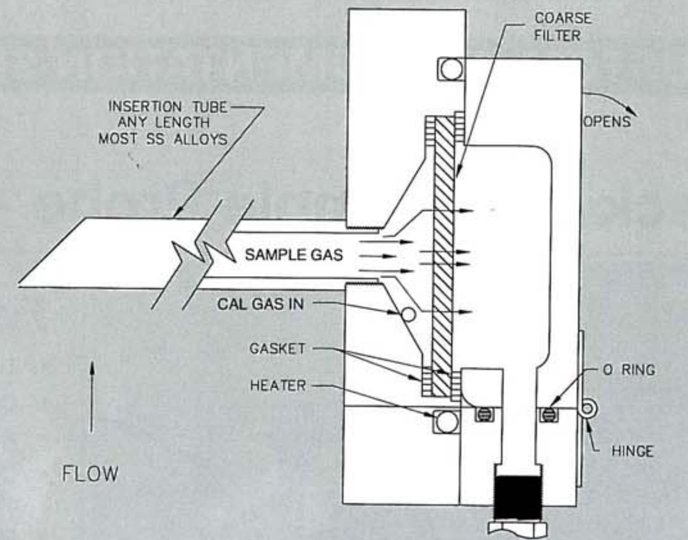
Meets regulatory requirements

CiSCO's sample probe is specially designed to meet federal and local environmental regulatory agency requirements for Continuous Emission Monitoring Systems (CEMS).

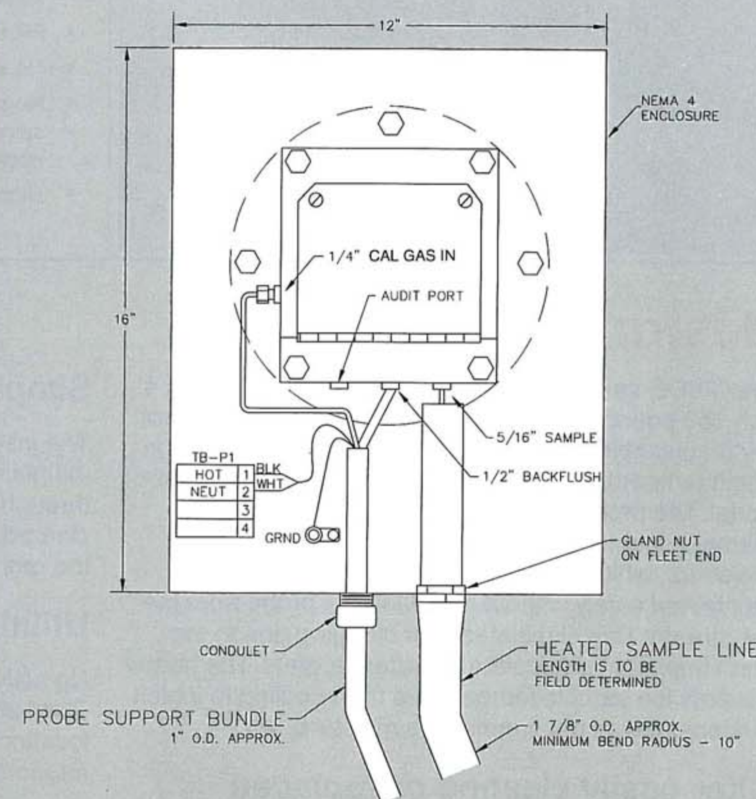
Typical Applications

- Simple cycle turbines
- Combined cycle turbines
- Coal fired boilers
- Bio-mass FBBs
- Waste incinerators
- Process measurements
- All CEMS applications





Probe Installation — Sectional View



Front View of Probe and Connectors

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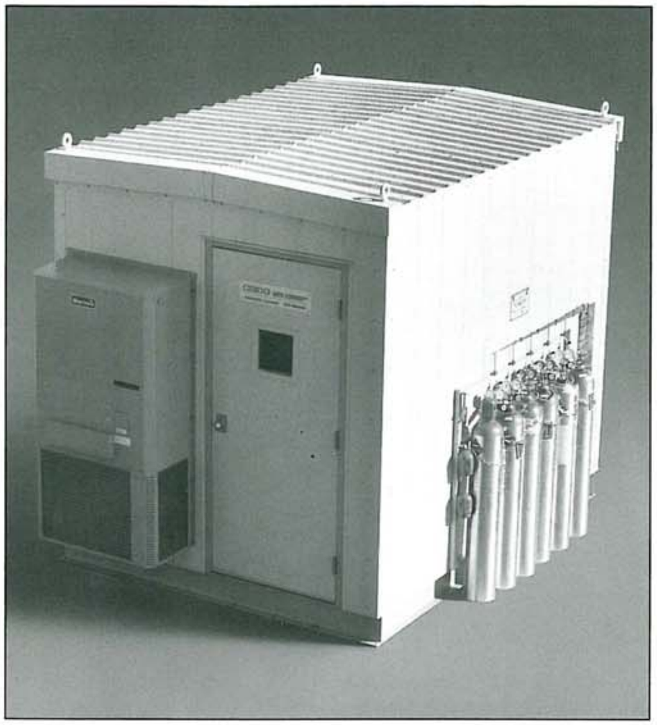
Custom CEMS Shelters



Features

- Custom built for your exact size and application
- Rugged welded steel frame with dust-tight interlocking steel side panels
- Twenty year exterior paint protection
- Climate controlled — industrial heating, air-conditioning, and R22 insulation provide stable environment
- Peaked roof promotes complete drainage
- Lifting "eyes" at all four corners facilitate handling
- No wooden or flammable materials
- Panic exit hardware on all doors and insulated, non-conductive, slip-resistant floor
- Bulkheads included for sample and calibration lines
- External junction box for plant wiring
- Class 1 Division 2 configurations available
- Meets or exceeds all applicable OSHA/NFPA/NEC and UL508 codes
- Easy, time saving site installation — ready to set on your slab or pad!

Design Description

CiSCO manufactures custom shelters to exacting standards to insure the proper environment for Continuous Emission Monitoring System (CEMS) equipment. Built of rugged, durable materials to meet size and application needs, CiSCO shelters provide a stable, clean, environmentally-controlled atmosphere for the operation and maintenance of the analysis system.

Unlike suppliers who use prefabricated housings, CiSCO designs and builds its own. This enables strict control of quality and consistency, while allowing CiSCO to offer many customized features that may not be available in other enclosures.

Improved CEMS performance

Every CiSCO shelter is designed to provide the perfect operating environment for analysis equipment and for the technicians who must maintain that equipment. CEMS housed in the proper setting are typically more predicable and trouble-free.

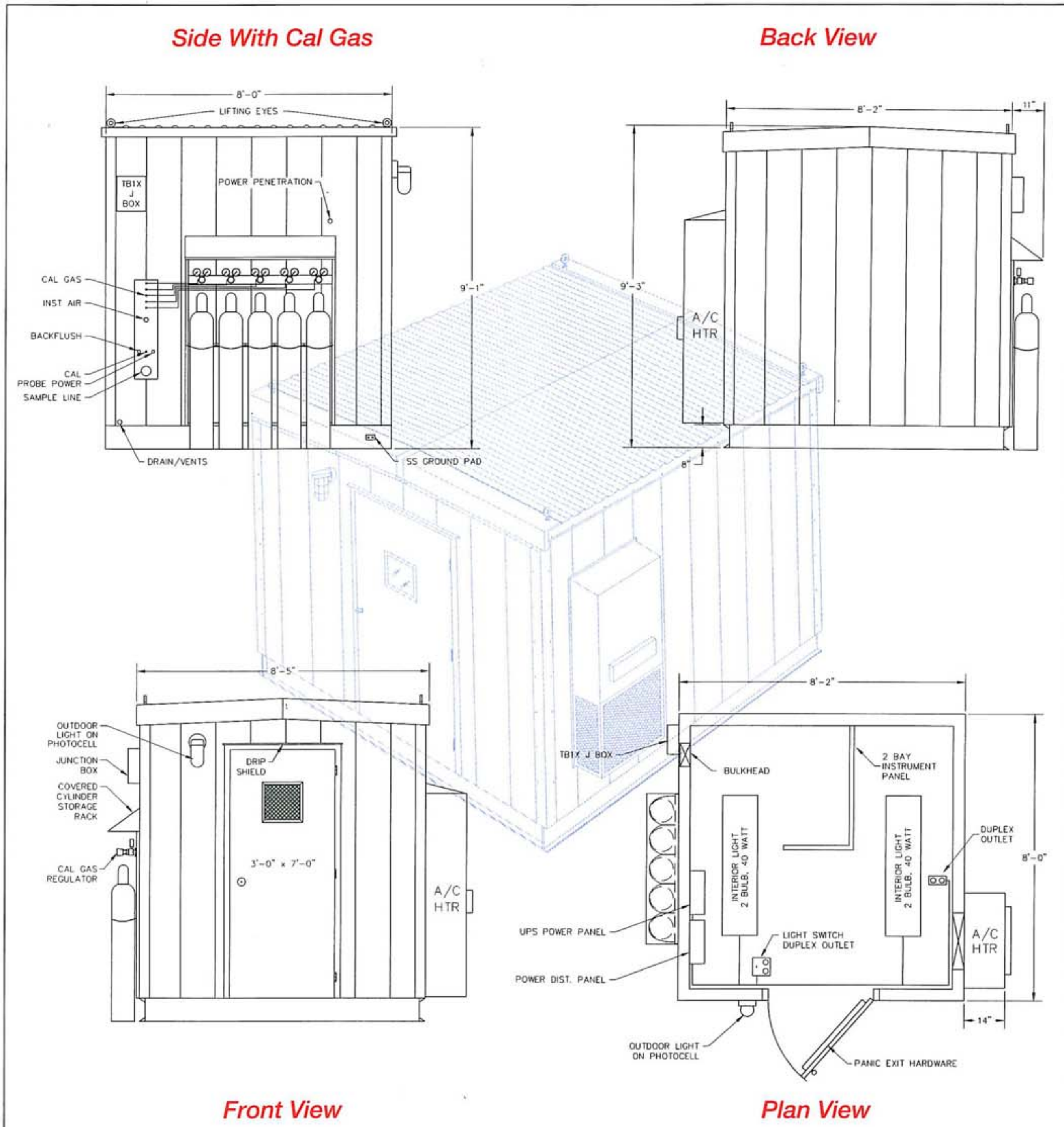
A convenient, temperature-stable, and pleasant working environment makes it easier for technicians to do their job. And, when CEMS get the care they need, maintenance costs are lower and uptime is higher.

Easy installation

Minimal field work is required to install a CiSCO shelter and startup the CEMS equipment. Each shelter is shipped on an open air-ride flatbed truck ready to hoist and place on a slab, pad, or other mounting. Typically, all that's needed to startup a system is to attach the heated sample line and probe support bundle. Then, connect utilities and a condensate drain. All necessary equipment is provided so a system can be ready to operate without delay. A hooded gas cylinder rack, complete with regulators and all connection hardware, is also included.

Made to last

CiSCO's shelters include a variety of useful features and rugged construction. The floors are 3/16" solid steel plate. Steel channels frame the bottom of the shelter and 3" square, 11 gauge corner posts support the side panels. Typical designs range from 8' x 8' (shown below) to 8' x 24'. Different heights, longer lengths and larger widths, up to 11', are also available. Safety features include panic exit hardware on the doors, non-conductive, slip-resistant flooring and smoke detectors. All shelters are complete with lighting, heating, air conditioning and utility connections. R22 insulation shields the walls, ceiling and floor, for all around protection.



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CiSCO

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CeDAR by
Custom Instrumentation Services Corporation
Configurable Emissions Data Acquisition and Reporting

Benefits

- ***Broad Scope* -** CeDAR handles a wide variety of CEMS data, including multiple sources and fuels.
- ***Customized Screens*** - CeDAR displays data and trends from multiple sources and fuels, simultaneously.
- ***Flexible Reporting*** - CeDAR generates both standard and user-created customized reports.
- ***Security Options* -** CeDAR has several user configurable levels of security.
- ***Federal, State and Local Compliance*** - Complies with all (40CFR 60, 75, 51, 266, CAIR, NJ EER, PADEP, SJVAQMD and RECLAIM) data acquisition and reporting requirements.
- ***Wide Interface Capabilities*** – Compatible with PLCs (GE9030, Allen-Bradley PLC5, Control & CompactLogix, SLC500), MODBUS and OSI's PI Historian.
- ***Modifiable Database* -** CeDAR's database can be modified to meet new report generation requirements.
- **EPA Electronic Data Reporting (EDR) –** The ***breez75X*** software is compatible with ECMPS reporting requirements.
- ***Rapid Trouble Shooting*** - CeDAR systems allow for remote access with either VPN's or modems.
- ***Quality*** - CeDAR is built by CiSCO - building quality CEM systems is CiSCO's only business.

The CeDAR Solution, from CiSCO's Software Division

CeDAR is your best solution for data acquisition, display, storage and reporting of Continuous Emission Monitoring System (CEMS) data. Since CeDAR's 1998 launch, it has proven to be a highly configurable, user-friendly product, which will meet present and future data acquisition and reporting needs.

CeDAR's applications are broad in scope. Whether you have turbines, incinerators, boilers, smelters or furnaces, CeDAR can handle it. Whether your system is a multi-unit installation with multiple fuels and multiple combustion sources, or a single-fueled source, CeDAR can be configured to meet your needs.

CeDAR is versatile. CeDAR offers a wide variety of real-time user interface screens. It is built on a Windows® based platform and allows for multiple screen displays to be open and viewable at the same time. CeDAR can display quantitative numerical data simultaneously with trends, from multiple sources at the same time - in real-time. CeDAR is expandable. It comes with an array of standard reports and the ability to configure custom reports to meet your individual needs. The Report Design Wizard allows users to design, configure and store their own report designs and formats, as well as use the standard reports, provided with their system.

CeDAR has a comprehensive trending package that allows users to graph multiple parameters

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on a 10-second, one-minute, hourly or daily basis. The Value Editor allows operators to view, verify and edit a wide variety of data.

CeDAR provides three levels of security to limit access to different parts of the program. Security levels can be tailored to allow all users to change some settings or data, but limit other settings or data editing to only a select few.

Data can be archived to any mass storage device automatically or manually. Additionally, CeDAR is provided with an easy to use installation program so that if anything ever did go wrong with a DAHS computer, CeDAR can be reinstalled on another computer in minutes.

CeDAR complies with all federal, state and local (40CFR60, 75, 51, 266 and 503) data acquisition and reporting requirements, including RECLAIM, NJEER, PADEP and SJVAQMD. It can interface with popular PLCs including the GE9030, Allen-Bradley PLC's, (SLC 500, ControlLogix & CompactLogix), as well as MODBUS and PI Historians.

The Configurable Advantage

CeDAR provides distinct benefits to the end-user because of its flexible design. When permit requirements change or alterations to the site occur, simply contact CiSCO with your needs. CeDAR's configurable database can be altered to provide the data required for the site reporting needs. CeDAR's flexibility allows these changes to be completed in a short time.

Expansion Capabilities

CiSCO makes a continuous effort to satisfy customers with specialized applications. CiSCO satisfies these needs with compatible add-on modules such as the ***breez75X*** EDR reporting software compatible with ECMPS. Modules are simple to install and generally access data already provided by CeDAR.

CeDAR also provides users the ability to enter CGA/linearity data directly into the database.

Data can be viewed and analyzed. Reports can be printed and data exported to EDRs (or other reporting modules). Data can also be exported to any off the shelf spreadsheet, such as Microsoft Excel.

CiSCO is able to rapidly respond to upcoming needs because CeDAR is written using the latest Microsoft® development tools, making CeDAR's design more flexible and extensible.

Service, Support and Training

Because the best service is service you never need, CiSCO has developed CeDAR to be problem free. If you ever have a problem, a built-in modem or VPN connection allows CiSCO to diagnose and solve problems remotely. CeDAR was designed and built by CiSCO, not third party suppliers. Our 20+ years of CEMS experience means we build just what customers need today, with the flexibility to expand and change to meet their future needs.

The CeDAR software team teaches CeDAR from the ground up, at your site, or ours. Training is customized to the site's needs. Training can cover the basics of daily operation of the system or also include EDR reporting.

System Requirements

CeDAR operates on any PC using a Pentium®IV (or newer) CPU with Windows® 2000/XP/Vista operating systems. CeDAR performs well with 1 GB, or higher, of RAM.

Warranty

CeDAR software is warranted to be error free. If an error is found, we will fix it at no charge.

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APPENDIX 2

CALCULATIONS

Emissions corrected to 15% oxygen

To calculate emission concentration to a particular Oxygen concentration. $C_{adj} = C_d \times \frac{20.9 - XO_2}{20.9 - \%O_2}$ Units: ppmvd Reference: 40CFR60 Appendix A, Method 20, Eq. 20-4 CiSCO Formula ID 0010	• C_{adj} Emission concentration corrected to C percent O_2 • C_d Emission concentration measured dry, ppmvd • X_{O2} Desired O_2% correction value. Typically 15% for turbines and 3% or 7% for boilers • $\%O_2$ Oxygen percentage in flue gas, for $0 < O_2$ $\% < 20.0\%$

Emission Rate lb/mmBtu

To calculate emissions rate in lb/mmBtu from ppmvd. $E = C_d \times F_{d,gen} \times K \times MW \times \left(\frac{20.9}{20.9 - O_2\%} \right)$ Units: lb/mmBtu Reference: 40CFR60 Appendix A Method 19, Eq. 19-1 CiSCO Formula ID 0050	• E Emissions expressed as lb/mmBtu • C_d Concentration measured, ppmvd • $F_{d,gen}$ General Dry Fuel Factor, dscf/mmBtu (see formula F-7, F-7a, or prorating using Formula F-8) • K Constant, 2.59E-9 (lb-mol/(dscf ppmvd)) • MW Molecular Wt (SO_2 64 lb/lb-mol, NO_2 46 lb/lb-mol, CO 28 lb/lb-mol, NH_3 17 lb/lb-mol)

Unmeasured Parameter Calculation

To calculate an unmeasured parameter based on user input values. $M_l = A \times HI$	• M_I Mass emissions of pollutant, lb/hr • HI Heat input to unit, mmBtu/hr • A Emissions Factor, lb/mmBtu

SO_2 Mass Emission Rate Using 0.0006 lb/mmBtu

Use the following equation to calculate the SO_2 emission using the 0.0006 lb/mmBtu emission rate in 40CFR75 Appendix D 2.3.2 (7/1/97). $SO2_{rate} = ER \times HI_{rate}$ Units: lb/hr Reference: 40CFR75 Appendix D 3.3.2 CiSCO Formula ID D-5	• $SO2_{rate}$ Hourly mass emission rate of SO_2 from combustion of pipeline natural gas, lb/hr • HI_{rate} Hourly heat input rate from combustion of a gaseous fuel, mmBtu/hr • ER SO_2 emission rate from 40CFR75 Appendix D 2.3.1.1 and 2.3.2.1.1 lb/mmBtu ***Notes:*** Use the Gas Emission Factor (GEF) when calculating SO_2 lb/hr from fuel flow rate of "pipeline quality" natural gas. For pipeline natural gas. 0.0006 GEF, lb/mmBtu. HI_{rate} derived in Formula F-20

Natural Gas Hourly Heat Input Rate mmBtu/hr

When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each period. $$HI_g = \frac{Q_g \times GCV_g}{10^4}$$ Units: mmBtu/hr Reference: 40CFR75 Appendix F 5.5.2 CiSCO Formula ID F-20	• HI_g Hourly heat input from gaseous fuel, mmBtu/hour • Q_g Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet/hr. • GCV_g Gross calorific value of gaseous fuel, using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 or GPA Standard 2261-90, Btu/scf (incorporated by reference under 40CFR75 §75.6) • 10^4 Conversion of Btu to mmBtu and hundred standard cubic feet to standard cubic feet

CO_2 Mass Emission, Part 72 Method

In lieu of using the procedures, methods, and equations in 40CFR75 Appendix G 2.1, the owner or operator of an affected gas-fired unit as defined under 40CFR §72.2 may use the following equation and records of hourly heat input to estimate daily CO_2 mass emissions (in tons). $$W_{CO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000}\right)$$ Units: tons/hr Reference: 40CFR75 Appendix G 2.3 CiSCO Formula ID G-4	• WCO_2 CO_2 emitted from combustion, tons/hour. • F_c Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1420 scf/mmBtu for crude, residual, or distillate oil and calculated according to the procedures in 40CFR75 Appendix F 3 3 5 • H Hourly heat input in mmBtu as reported in company records, see F-20. • U_f 1/385 scf CO_2/lb-mol at 14.7 psia and 68 F. • MW_{CO2} Molecular weight of carbon dioxide (44.0).

Calibration Correction

Calibration Correction	Corrected Concentration= Slope Factor * Raw concentration + Intercept Factor Slope Factor = $\frac{\text{Span Gas Value}}{\text{Span Response-Zero Response}}$ Intercept Factor = Actual Zero Response * Slope Factor

CUSTOM INSTRUMENTATION SERVICES CORPORATION

LANGLEY GULCH POWER PLANT
NEW PLYMOUTH, IDAHO

CONTINUOUS EMISSIONS MONITORING SYSTEM QUALITY ASSURANCE MANUAL

CiSCO CEMS SYSTEM NO. 10009150

PREPARED BY:
CUSTOM INSTRUMENTATION SERVICES CORPORATION

PREPARED FOR:
IDAHO POWER COMPANY

November 8, 2010

Revision B

7841 SOUTH WHEELING COURT • ENGLEWOOD, COLORADO 80112
TEL: (303) 790-1000 FAX (303) 790-7292

QUALITY ASSURANCE MANUAL UPDATE LOG

DATE OF UPDATE	PAGES AFFECTED	INITIALS

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APPENDICES

LIST OF TABLES, FIGURES AND FORMS

1. GENERAL PROVISIONS

1.1. INTRODUCTION

1.1.1. CEMS Quality Assurance Policy

Langley Gulch Power Plant, located in New Plymouth, Idaho, is committed to operate in accordance with applicable federal and state environmental regulatory requirements and to ensure that environmental measurements are of high quality and reliability. For these reasons, this Quality Assurance (QA) Plan provides plant personnel, involved with the Continuous Emissions Monitoring System (CEMS) compliance program, with the procedures and guidance necessary to report accurate, precise, and reliable data.

This document is designed to fulfill the requirement in Condition 52 of the permit that the "permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval." A CEMS methodology has been prepared and submitted under separate cover.

This document is intended to remain dynamic and responsive to program improvements and regulatory changes occurring over time. For this reason, provisions for the maintenance of this QA Plan as a functional instrument are incorporated herein.

1.1.2. Purpose and Functions of the QA Plan

- Provide quality control (QC) procedures necessary to ensure maximum CEMS data capture, minimum instrument downtime, and high data quality.
- Provide the QC procedures necessary to assure compliance with applicable CEMS installation, operation and maintenance requirements, and the applicable requirements for the quarterly reporting of information to regulatory agencies.
- Define the data acceptance criteria and data quality requirements for the Langley Gulch Power Plant.
- Evaluate the adequacy of the QC procedures and data acceptance criteria through the use of periodic audits.
- Provide an effective mechanism to document and implement QA Plan revisions, as necessary, in response to audit findings, system improvements or changes to compliance program objectives.
- Serve as a resource for the overall coordination of the Langley Gulch Power Plant compliance program.

1.2. REFERENCES

Code of Federal Regulations, Title 40 Part 60, Subpart A (General Provisions)

Code of Federal Regulations, Title 40 Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines

Code of Federal Regulations, Title 40 Part 60, Appendix A (Test Methods)

Code of Federal Regulations, Title 40 Part 60, Appendix B (Performance Specifications)

Code of Federal Regulations, Title 40 Part 60, Appendix F, Procedure 1 (Quality Assurance Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix A (Specifications and Test Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix B (Quality Assurance and Quality Control Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix D (Optional SO_2 Emissions Data Protocol for Gas-Fired Units and Oil-Fired Units)

Code of Federal Regulations, Title 40 Part 75, Appendix F (Conversion Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix G (Determination of CO_2 Emissions)

Code of Federal Regulations, Title 40 Part 98, (Mandatory Greenhouse Gas Reporting)

Custom Instrumentation Services Corporation (CiSCO) Continuous Emission Monitoring System (CEMS) Operations and Maintenance Manual, for the Langley Gulch Power Plant

Idaho Department of Environmental Quality, Air Quality Permit to Construct, Permit Number P-2009.0092.

Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I: Principles: (EPA 600/9-76-0276)

Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III: Stationary Source Specific Methods; (EPA-600/4-77-027b)

1.3. DEFINITIONS

Bias - Systematic error, resulting in measurements that will be either consistently low or high relative to the reference value. A bias test following each 40 CFR 75 RATA (Relative Accuracy Test Audit) determines if a CEMS is biased.

Calibration Drift - The difference between the analyzer reading and a reference value after a period of normal operation (i.e., 24 hours) during which no unscheduled maintenance work took place.

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination and permanent recording of stack emissions at the Langley Gulch Power Plant.

Cylinder Gas Audit (CGA) - This test is required by 40 CFR Part 60 for the CO analyzer. It is a 2-point [low (20-30%) and mid (50-60%) of range] test using protocol gases. The test is run while the unit is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during the test. The test is conducted within three (3) trials. The difference between the reference gas and the analyzer measurement shall not vary more than ± 5% or 15 ppm, whichever is less restrictive.

Data Acquisition and Reporting System (DAHS) - The portion of the CEMS (software and hardware) that permanently records all monitored emission data (including CEMS analyzers, and plant signals).

Fuel Flowmeter Accuracy Test This test is required by 40 CFR Part 75 for fuel flowmeter is listed in 40 CFR 75 Appendix D Section 2.1.5. It is a 3-point [low (minimum), mid (approximately equally spaced between the minimum and the full range), and high scale (maximum) ranges] using and independent source as a comparison. The test is conducted within 3 trials. The difference between the reference and the fuel flowmeter measurement shall not vary more than ± 2%

IDEQ Idaho Department of Environmental Quality

Linearity Test - This test is required by 40 CFR Part 75 for NO_x and O_2 analyzers. It is a 3-point [low (20-30%), mid (50-60%), and high (80-100%) of range] test using protocol gases. The test is run while the unit is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during the test. The test is conducted within three (3) trials. The difference between the reference gas and the analyzer measurement shall not vary more than ± 5% or 5 ppm, whichever is less restrictive.

O&M Manual - CiSCO CEMS Operations and Maintenance Manual

Out-of-Control for CEMS

(1) Calibration Error (drift). A CEMS is out-of-control when calibration drift exceeds the limit of the applicable standard for any calibration. The out-of-control period begins with the hour of completion of the failed calibration error test and ends at the time of completion of an effective re-calibration.

(2) Linearity Check/CGA. A CEMS is out-of-control when the error in linearity or CGA at any of the gas concentrations in a quarterly linearity check or CGA exceeds the applicable standard. The out-of-control period begins with the hour of the failed check and ends with the hour of a satisfactory linearity check following corrective action. For NO_x CEMS, the

out-of-control designation applies if either of the component analyzers (NO_x or O_2) exceeds the applicable specification.

(3) RATA (Relative Accuracy Test Audit). An out-of-control period occurs if the relative accuracy results from a RATA exceed the applicable standard. The out-of-control period begins with the hour of completion of the failed RATA and ends with the hour of completion of a successful RATA, following corrective action.

Out-of-Control for Fuel Flowmeter

(1) Fuel Flowmeter Calibration - A fuel flowmeter is out-of-control when an accuracy test drift exceeds ± 2%. The out-of-control period begins with the hour of completion of the failed accuracy test and ends with the hour of completion following an effective re-calibration.

(2) Fuel Flowmeter Calibration - A fuel flowmeter is out-of-control when an accuracy test has expired. The out-of-control period begins with the hour within the quarter that the test was required and ends with the hour of completion of a successful accuracy test. The out-of-control period begins with the hour within the quarter that the test was required and ends with the hour of completion of a successful accuracy test.

Quality Assurance (QA) - The activities and procedures that are performed by or on behalf of the Langley Gulch Power Plant, to ensure that CEMS data meets USEPA and state criteria with respect to accuracy, precision, availability, and representation after the successful completion of the initial performance specification testing.

Relative Accuracy (RA) - A comparison of CEMS measurements and reference method test results. The CEMS measurements are compared to the results of EPA reference method testing performed in accordance with the procedures and criteria established in 40 CFR 60, Appendix A.

Span Value for 40 CFR 75 - Between 100% and 125% of the Maximum Potential Concentration (MPC) or the Maximum Expected Concentration (MEC).

USEPA or EPA - The United States Environmental Protection Agency.

1.4. SUMMARY OF APPLICABLE CEMS REGULATIONS

Langley Gulch Power Plant falls under the regulatory requirements listed in Section 1.2. The NO_x and O_2 analyzers fall nder the QA/QC requirements of 40 CFR 75. Appendix A of 40 CFR 75 requires an initial evaluation of the CEMS accuracy. This includes a Relative Accuracy Test Audit (RATA), 7-day Calibration Error Test, Cycle Time Test and Linearity Check. Appendix B of 40 CFR 75 requires periodic CEMS performance evaluations. This includes quarterly Linearity Checks and a semi-annual or annual Relative Accuracy Test Audit (RATA).

The CO analyzer falls under the requirements in 40 CFR 60, Appendix B and F and the Construction Permit. This includes an initial Relative Accuracy Test Audit (RATA) and 7-day Calibration Drift Test, quarterly Cylinder Gas audits (CGA) and annual Relative Accuracy Test Audit (RATA).

For 40 CFR 75, quarterly reports in the latest version of the electronic reporting format are due to EPA within 30 days of the end of the quarter. For 40 CFR 60, semiannual reports summarizing all recorded excess emission events and periods of monitor downtime must be prepared and submitted to the IDEQ. The results of all performance tests and audits conducted during the quarter must be included in both reports. All CEMS records, including raw, reduced and validated data, maintenance records, audit findings and written QA procedures must be maintained for a minimum of five years.

This quality assurance plan must be maintained in accordance with 40 CFR 75, Appendix B and 40 CFR 60, Appendix F. Specifically, the CEMS is designed to meet the regulations listed in Table 1.

TABLE 1 APPLICABLE PERFORMANCE SPECIFICATIONS

Pollutant	Regulation
NO_x	40 CFR 75, Appendix A, Section §3
O_2	40 CFR 75, Appendix A, Section §3
CO	40 CFR 60, Appendix B, Performance Specification 4/4a
Fuel Flowmeter	40 CFR 75, Appendix D, Section §2.15

The CEMS is used to determine compliance with the limits listed in the Air Quality Permit as shown in Table 2.

TABLE 2
AIR QUALITY PERMIT TO CONSTRUCT EMISSION LIMITS

Pollutant	Normal Operation	Low-Load Operation	Startup and Shutdown	Annual Emissions	Applicable Regulation
NO_x ppm @ 15% O_2, 3-hour rolling average	2.0	96	96	NA	PTC Section 33, 34, 35
NOx ppm @ 15% O_2, 30-day rolling average	15	96	NA	NA	PTC Section 37
NO_x Tons/Year	NA	NA	NA	88	PTC Section 36
CO ppm @ 15% O_2, 3-hour rolling average	2.0	24.5	NA	NA	PTC Section 33, 34
CO lb/hr	NA	NA	2510	NA	PTC Section 35
CO Tons/Year	NA	NA	NA	278.1	PTC Section 36
VOC ppm @ 15% O_2, 3-hour rolling average	2.0	11.5	NA	NA	PTC Section 33, 34

2. DESCRIPTION OF CEMS PROGRAM

2.1. PLANT DESCRIPTION

The Langley Gulch Power Plant is located near New Plymouth, Idaho. The site consists of a one-on-one combined-cycle plant, consisting of a natural gas-fired combustion turbine (CT) and a steam turbine. The CT is equipped with a heat recovery steam generator (HRSG) 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.

The unit is fired exclusively with pipeline quality natural gas and has an exhaust stack which discharges into the atmosphere approximately 160 feet above grade. The turbine has a maximum heat input of approximately 2134 mmBtu/hr at design conditions and generates 269 MW. The duct burner has a maximum heat input of approximately 241 mmBtu/hr at design conditions. The plant includes dry low NO_x combustors and selective catalytic reduction (SCR) to control NO_x emissions and a catalytic oxidation system to control CO emissions.

2.2. CEMS EQUIPMENT DESCRIPTION AND MEASURED PARAMETERS

The extractive CEMS supplied to the Langley Gulch Power Plant was manufactured by Custom Instrumentation Services Corporation of Englewood, Colorado. The CEMS is housed in a 10' x 10' metal shelter, located at the base of the stack. The shelter is climate controlled and provides a clean environment for the analyzers, system PLCs (programmable logic controllers) and other supporting equipment. The DAHS is located in the plant control room.

Table 3 shows the parameters measured by the CEMS. All analyses are performed on a "dry" basis from undiluted samples and are reported in lb/mmBtu, lb/hr, tons/year and ppm @ 15% O_2. Emissions are measured at the HRSG stack and at the catalyst inlet. The catalyst inlet analyzers are used for plant operations. The analyzers used in the CEMS are described in the following sections.

TABLE 3 MEASURED PARAMETERS

CT/HRSG	Units
NO_x	ppm, ppm @ 15% O_2, lb/mmBtu, lb/hr, tons/yr
CO	ppm, ppm @ 15% O_2, lb/mmBtu, lb/hr, tons/yr
O2	dry %
Natural Gas Flow Rate	hscf/hr
Catalyst Inlet*	**Units**
NO_x	ppm, ppm @ 15% O_2
CO	ppm, ppm @ 15% O_2
O2	dry %

* For plant use only

2.2.1. Data Acquisition and Reporting System (DAHS)

The Data Acquisition and Reporting System (DAHS) used at the Langley Gulch Power Plant provides historical data storage with access to data for review and editing. It generates all required reports in the formats, which are acceptable to the EPA and the state. This includes hourly, daily, and monthly summaries, plus daily and quarterly exceedences data, automatically or on demand. The semi-annual report required by the state is generated and submitted within 30 days after the end of period. 40 CFR 75 quarterly reports in the most current electronic data reporting format are also generated by the DAHS. Sample reports are provided in Appendix 1.

The DAHS is designed to be placed in a Control Room environment. An IBM compatible desktop computer will store, manipulate, format, and archive the data. A color monitor, keyboard, printer, and modem are also included.

CeDAR™ software provided for data acquisition is an integrated, user-friendly, menu-driven software package developed by CiSCO for data acquisition, analysis, and reporting. Data acquisition will continue uninterrupted in the background while data manipulation and report generation is taking place in the foreground. Other software packages include the following:

- Windows for multitasking
- PCAnywhere for phone modem communications

The calculations of emissions in units of the applicable standards (See Table 3) are accomplished by the DAHS. The calculations used are provided in Appendix 2. The calculation to correct for calibration drift is also included in Appendix 2.

2.2.2. Oxides of Nitrogen Analyzer

For the analysis of NO_x, Teledyne (TAPI) Model 200EM analyzers are used. The Chemiluminescence detection method quantitatively converts NO to NO_2 by gas-phase oxidation with molecular ozone that is produced by the analyzer ozone generator in an environment, of system supplied dry instrument air. The Model 200EM converts NO_2 to NO by employing a converter cartridge filled with molybdenum (Mo, "moly") chips heated to a temperature of 600° F. The analyzer ranges configured into the system are given in Table 4.

2.2.3. Carbon Monoxide Analyzer

For the analysis of CO, Teledyne (TAPI) Model 300EM analyzers are used. The Model 300EM Gas Filter Correlation Carbon Monoxide analyzer is a microprocessor-controlled analyzer that determines the concentration of carbon monoxide (CO) in a sample gas drawn through the instrument. It requires that sample and calibration gasses be supplied at ambient atmospheric pressure in order to establish a stable gas flow through the sample chamber where the gases ability to absorb infrared radiation is measured.

The microprocessor uses the calibration values, the IR absorption measurements made on the sample gas along with data regarding the current temperature and pressure of the gas to calculate a final CO concentration. The analyzer ranges configured into the system are given in Table 4. Automatic range change is dependent upon concentration. All ranges are linearized within 0.1% with the microprocessor controlled electronics.

2.2.4. Oxygen Analyzer

For the analysis of Oxygen, the O_2 channel of the Teledyne (TAPI) Model 200 EM analyzer is used. This type of analyzer is characteristically linear and is not sensitive to interference from moisture, combustibles, or physical vibrations. A true gross oxygen analysis is provided. The analyzer ranges configured into the system are given in Table 4.

2.2.5. Fuel Flowmeter

The duct burner fuel flow meter will be a Rosemount compact orifice mass flowmeter model 3095MFCCS040N065T33CA1AQ4M5. The combustion turbine fuel flow meter will be a Triad (or equal) orifice plate meter tube with a Rosemount 2051 transmitter.

2.3. REPORTS

The reports generated for the Langley Gulch Power Plant are generated by the DAHS. Sample reports can be found in Appendix 1. All reporting is done in accordance with the requirements of 40 CFR 75 and the Air Quality Permit.

To meet the 40 CFR 75 requirements a quarterly report must be submitted to the EPA in electronic format. The file generated by the DAHS is in a prescribed format and includes emission and plant data for every hour in the quarter. Periods of missing data are substituted using EPA missing data procedures. The quarterly data is provided to the EPA electronically. The accuracy of the data being submitted is verified using Emissions Collection and Monitoring Plan System (ECMPS). This program verifies that all data is entered in the proper location and is in the proper format.

The Air Quality Permit requires that quarterly reports are submitted to summarize excess emissions and monitor information following the format in 40 CFR 60, Subpart KKKK. The information provided includes a summary of excess emissions, monitor downtime, and quarterly quality assurance test results. All monitoring data shall be kept on file for a period of at least five years and made available to agency personnel upon request.

- Unit Hourly Emissions Report - Summarizes minute totals/averages of mass emission and operating parameters for each hour.
- Unit Daily Emissions Report - Summarizes hourly totals/averages of mass emission and operating parameters for each hour in a 24-hour period.
- Unit Monthly Emissions Report - Summarizes daily emission rates and operating parameters for each month.
- Daily Fuel Report - Summarizes hourly fuel flow rates and usage for each hour in a 24-hour period.
- CEMS Downtime Report (daily, monthly, quarterly, or for a specified duration) - For each reported parameter, shows time and duration when plant is on-line and the CEMS is off-line.
- Excess Emissions Report (daily, monthly, quarterly, or for a specified duration) - Shows all parameter limit exceedences.
- CEMS Performance Summary - Summarizes downtime by reason and calculates excess emissions as a percentage of total source operating time.
- Emissions Data Summary - Summarizes exceedences by reason and calculates downtime as a percentage of total source operating time.
- Audit Report - Shows values for several parameters during a specified period of time.

- Raw Values Report - Shows raw values and monitor codes (in text and code number) for one parameter during a specified period of time.
- Calibration Reports   Summarizes calibration results and calculates out-of-control conditions for each analyzer for each day.

2.4. ORGANIZATIONAL RESPONSIBILITIES

The organizational chart for the Langley Gulch Power Plant (Figure 1) shows the personnel responsible for QA activities. All identified plant personnel have a shared responsibility for the day-to-day operation, maintenance and quality assurance of the CEMS. The responsibilities for QA activities can be summarized as follows:

Manager, Power Production
- 40 CFR 75 designated representative.

Facility Contact
- Administer the QA Manual to ensure compliance, including checking QA results periodically and reviewing/updating the QA Manual as needed, but at least once per year
- Responsible, along with Plant Technician, for overall maintenance and inspection program. This includes checking QA results and reviewing maintenance procedures.
- Responsible for compiling reports sent out under company letterhead to the appropriate regulatory agencies. Printed reports originate from the CEMS DAHS and are compiled by the Plant Engineer and are forwarded to the DR and the Regulatory Agency.
- Responsible for the overall program including maintaining complete files of CEMS data, including records, reports, alarm printouts, QA forms, etc. All required information is stored for five years and shall be made available for inspection upon request. DAHS printed reports with a software back-up copy are archived. Any forms or documents that are not computer generated will be archived onsite.
- Responsible for electronically storing and maintaining all CEMS files, which includes, but is not limited to all records, reports, and QA forms.

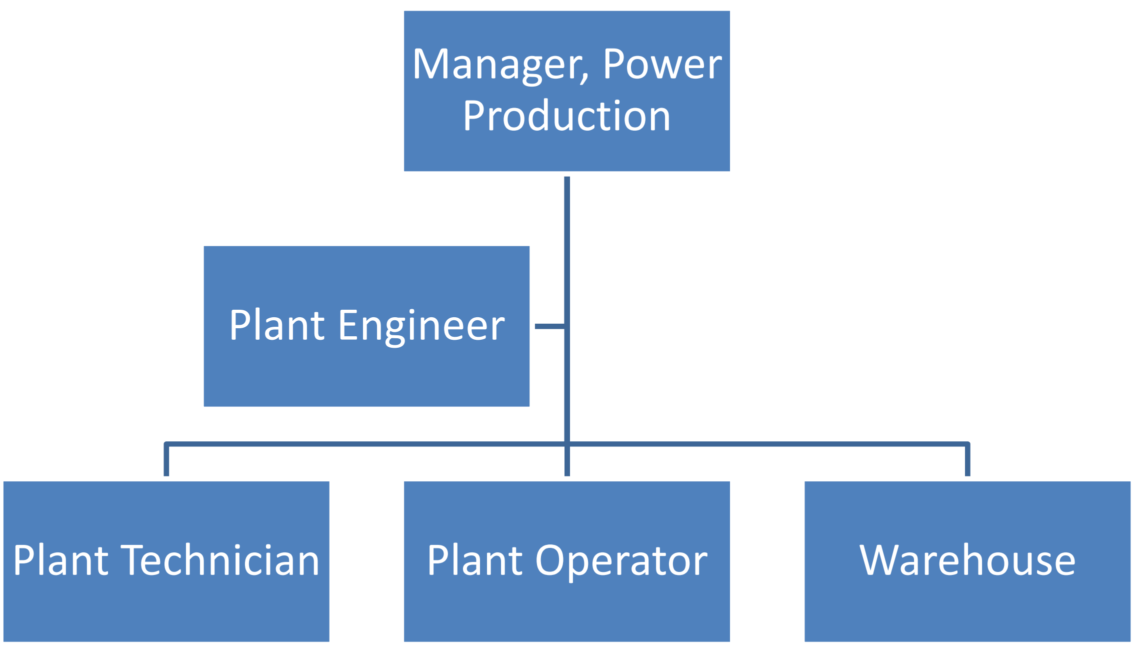
Plant Technician
- Schedule and perform daily, weekly, monthly, quarterly, and annual maintenance defined in the QA Manual.
- Perform all required corrective actions needed to keep the CEMS operating within specifications, including service to correct out-of-control conditions, service required as a result of preventative maintenance checks, service due to CEMS alarm conditions, and service due to malfunctioning components. If an alarm condition cannot be corrected, the Plant Engineer and CEMS Manufacturer are contacted.
- Ensure that all required CEMS accuracy audits, including Linearity Checks, Cylinder Gas Audits (CGAs) and Relative Accuracy Test Audits (RATAs) are performed as required by applicable regulations. This may include retaining the services of an outside stack testing company or initiating corrective maintenance if a Linearity Check or RATA fails.
- Maintain the CEMS spare parts inventory at required levels to minimize downtime and data loss. Parts are obtained from the onsite warehouse or ordered from the manufacturer.

Plant Operator

- Monitor for CEMS alarms in the control room on a 24-hour basis. Alarms are investigated, and the appropriatecorrective actions are taken as needed. The events are documented in the DAHS with both reason for the alarm and the actions taken to correct the problem.
- Trouble shoot and attempt to correct alarm conditions, and notify Plant Technician if an alarm condition is not corrected.
- Maintain the supply of cylinder gases required for daily calibration drift tests and periodic CEMS assessment audits. This includes maintaining a permanent file of all cylinder gas certification documentation from the cylinder gas supplier.

Figure 1

Langley Gulch Power Plant Organizational Chart



3. QUALITY ASSURANCE REQUIREMENTS

The CEMS for the Langley Gulch Power Plant is designed to meet the reporting, record keeping, certification, and quality assurance requirements of 40 CFR 75 and the state Air Quality Permit.

3.1. DATA VALIDATION REQUIREMENTS

Personnel at the Langley Gulch Power Plant strive to achieve 95% availability of the monitors under normal operating conditions. All reasonable and practical means are used to achieve this objective, including overtime-corrective maintenance work, quarterly audits, routine preventative maintenance, and daily calibration checks. All pertinent regulations require the reduction of emissions to one-hour time-based emissions.

3.1.1. Invalid Data

Numerous conditions can render data invalid. If the correct numbers of valid data points are not collected for any reason, then the data collected is considered invalid. For 40 CFR 75 reporting, invalid data is automatically replaced by the DAHS. For 40 CFR 60 reporting, invalid data is reported as monitor downtime. The following are examples of conditions that could result in invalid data:

- CEMS control power failure
- Analyzer malfunction
- Water in sample
- Back flush cycle
- Last calibration fail
- Out-of-Service
- CEMS Off-line
- CEMS failed linearity test (out-of-control)
- CEMS failed relative accuracy (out-of-control)

3.1.2. Hourly Data Validation

a) The CEMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. This is defined as a data point.

b) A valid hour of data is computed from four or more data points equally spaced over the one-hour period. Gaseous emissions data are reduced and recorded as one-hour averages. If one of the 15-minute periods (using four data points per hour) is invalid, the hour is considered invalid and the DAHS will replace the hourly data using the missing data procedures in 40 CFR 75 or will be recorded as monitor downtime.

c) For 40 CFR 75 reporting, during periods of calibration, quality assurance or maintenance activities, a valid hour consists of at least two data points separated by a minimum of 15 minutes. If the CEMS does not collect valid data in accordance with this criteria, then the missing data procedures must be used to replace the data. In order to perform calibrations, quality assurance or maintenance, the "out-of-service" periods should begin more than 30 minutes into an hour and end less than 30 minutes into the next hour. In this way, nearly 60 minutes of service can be performed on the system without impacting availability.

d) For quarterly 40 CFR 75 reporting, all missing or invalid data is automatically replaced by the DAHS following the procedures contained in 40 CFR 75, Subpart D (for NO_x) and Appendix D (for fuel flow).

e) After determination of the emissions in the proper reporting parameters, the emissions data is rounded off to the same number of significant digits as the emission limit or the number of significant digits required by EPA.

3.2. CEMS GAS ANALYZER CALIBRATION

The CEMS is equipped with manual and automatic, zero and span calibration capabilities. The automatic calibration routine is performed every 24 hours under the programmed control of the system PLC. In addition, a calibration can be started manually at any time with the activation of the "Cal Start" button provided on the Operator Interface Terminal (OIT).

In either mode, a "Cal-at-Cabinet" valve allows the operator to select one of two modes of calibration. With the valve in the cabinet position, calibration gas is injected directly into the sample flow control components and then into the analyzers. With the valve in the probe position, calibration gas is injected into the sample probe via the 1/4" Teflon calibration line in the probe support bundle. The calibration gas is then pulled through the sample conditioning subsystem just as the sample is, and the integrity of the entire system is checked. This is the normal mode that is used during the automatic calibration routine.

In the automatic calibration sequence, either manually or automatically initiated, the cal gas solenoid valves are automatically sequenced by the system PLC. The first four minutes of each five-minute period of gas flow is used for system stabilization. During the last minute, the analyzer response is interrogated by the PLC. Eleven values are read, five seconds apart, and are averaged for an average calibration reading. Initial programming has timed the calibration sequence, five minutes for zero and five minutes for each analyzer span.

If the calibration check passes, a new sample output correction factor is calculated for each analyzer at each sample point and is stored to be used during sampling until the next calibration. If the calibration fails, the calibration fail alarm is activated and the subsequent sample output signal(s) will be uncorrected for each failed analyzer. Programming for 40 CFR 75 allows a maximum ±1% difference from reference gas for O_2 and ±5% of span for NO_x. Programming for 40 CFR 60 allows a maximum ±20% of span for CO.

In order for the PLC to check the validity of a calibration and generate a fail or out-of-control signal if the analyzer response is outside of preset limits, it not only needs to know the actual analyzer response, it also must "know" a constant to compare it with. For zero, the constant is zero, and is stored in a register in the PLC. All analyzer span concentration values are input to the PLC via the OIT. The values are taken directly from the span gas cylinder certification sheets. The nominal span gas concentrations required for the Langley Gulch Power Plant are provided in Table 4.

TABLE 4 ANALYZER RANGES AND NOMINAL SPAN GAS CONCENTRATIONS

ANALYZER	FULL SCALE RANGE	40 CFR 75 SPAN	DAILY SPAN GAS
NO_x Low Range	0-10 ppm	0-10 ppm	8-10 ppm
NO_x High Range	0-150 ppm	0-150 ppm	120-150 ppm
CO Low Range	0-10 ppm	NA	5-10 ppm
CO Mid Range	0-50 ppm	NA	25-50 ppm
CO High Range	0-3000 ppm	NA	1500-3000 ppm
O_2	0-25 %	0-21 %	16.8-21 %

Calibration adjustment procedures for gas analyzers are provided in Appendix 3. The specific analyzer manufacturer's manuals are contained in the CEMS O&M Manual, which is incorporated here by reference.

3.3. CEMS INSTALLATION AND CERTIFICATION

The CEMS must meet the installation and initial certification criteria contained in the Air Quality Permit, 40 CFR 75, Appendix A, and 40 CFR 60, Appendix B. This includes a Relative Accuracy Test Audit (RATA) and 7-day calibration error tests on all analyzers. For 40 CFR 75 certification, linearity, response time, bias, and DAHS verification tests must also be performed.

Once certified, the CEMS is evaluated on a cyclical basis in accordance with the Quality Assurance and Quality Control Procedures under the following 40 CFR 75, Appendix B, 40 CFR 60, Appendix F and the Air Quality Permit.

3.3.1. Relative Accuracy Test Audit (RATA)

Relative Accuracy Test Audits (RATAs) are conducted on the CEMS as a part of an initial certification and as a semi-annual or annual quality assurance check. The test evaluates the accuracy of the CEMS. The RATA is performed by a third-party contractor stack sampling team that conducts reference method tests and data collection simultaneously with the CEMS. 40 CFR 75 Appendix A, Section 6.1.2 (a-c) requires, starting January 1, 2009, any Air Emission Test Body (AETB) conducting a RATA for Part 75 must adhere to the requirements of ASTMD D7036-04, and provide a credentialed "Qualified Individual" on-site for the duration of the testing. The reference method tests are performed in accordance with procedures in 40 CFR 60, Appendix A, Reference Method 3A (O_2), Method 7E (NO_x), and Method 10 (CO). Langley Gulch Power Plant is operated at the normal operating load during the RATA. The data from the CEMS DAHS is evaluated and compared with the data from the reference method test results as a part of the relative accuracy determination. A minimum of nine test runs are performed. A maximum of twelve runs may be performed. Three of the twelve runs may be rejected as only nine test runs are needed to determine relative accuracy. All relative accuracy test data is reported.

The relative accuracy (RA) specifications for each applicable regulation are in Table 5. The results of any RATA above the minimum standard result in the analyzer and CEMS being classified as out-of-control. In the event RATA results indicate an out-of-control period, the analyzers are re-calibrated, all problems are corrected, and another RATA is initiated immediately. Notice must be forwarded to the EPA and the state within 72 hours of the additional RATA test.

Under 40 CFR 75 , the results of the initial certification RATA determine if the next scheduled RATA must be conducted during the next six months or within 12 months. In the event the results from an initial or periodic RATA for the NO_x or O_2 CEMS are between 7.5% and 10.0% RA (relative accuracy), the next RATA test is required in the second quarter following the RATA per 40 CFR 75. In order to perform RATAs on an annual basis instead of a semiannual basis, the results from an initial or periodic NO_x or O_2 RATA must be less than or equal to 7.5% RA (relative accuracy).

For qualifying low NO_x emitters (<0.20 lb/mmBtu), the CEMS qualify for annual RATAs where the average analyzer value during a RATA is within 0.015 lb/mmBtu of the average reference method value (as per 40 CFR 75, Appendix B, 2.3.1).

TABLE 5 RELATIVE ACCURACY (RA) SPECIFICATIONS

Component	Regulation	Specification
NO_x lb/mmBtu	40 CFR 75 Appendix A 3.3.2 (semi-annual RATA)	≤10.0% RA of the mean value of reference method tests or ≤0.020 lb/mmBtu if level during RATA is ≤0.2 lb/mmBtu
	40 CFR 75 Appendix B § 2.3.1.2(f) (annual RATA)	≤7.5% RA of the mean value of reference method tests or ≤0.015 lb/mmBtu if level during RATA is ≤0.2 lb/mmBtu
CO ppm	40 CFR 60 Appendix B, Performance Specification 4/4a	10% RA 5% of emission standard +/- 5 ppm mean difference

3.3.1.1.RATA Calculations

The RATA is performed during initial certification or at least once a year, according to the Relative Accuracy Test procedure in the applicable Performance Specification. To evaluate RATA results, use the following procedure.

1. Calculate the arithmetic mean of the monitor or monitoring system measurement values.

2. Calculate the mean of the reference method values.

3. Using data from the automated DAHS, calculate the arithmetic differences between the reference method and monitor measurement data sets.

4. Calculate the arithmetic mean of the difference (Eq. A-7, 40 CFR 75, Appendix A, Section 7.5.1), the standard deviation (Eq. A-8 40 CFR 75, Section 7.3.2), the confidence coefficient (Eq. A-9), and the monitor or monitoring system relative accuracy (RA) using the equation below.

The relative accuracy for a RATA is defined as (Eq. A-10 40 CFR 75, Section 7.3.4):

$$RA \quad \frac{|\bar{d}| + |cc|}{RM} \times 100$$

Where:

RA	Relative accuracy of the CEMS, %
$\vert d\vert$	Absolute value of the mean difference between the RM values and the CEMS values
$\vert cc\vert$	Absolute value of the confidence coefficient
RM	Average reference method (Arithmetic mean) value or applicable standard in lb/hr, lb/mmBtu or ppm

If the RATA results exceed the RA performance criteria, the CEMS is considered out-of-control. The appropriate personnel, designated in the Organizational Responsibilities section, must initiate corrective maintenance and arrange prompt follow-up testing after the corrective maintenance is completed.

3.3.1.2. 40 CFR 75 Bias Factor and Adjustment Factor

Following a RATA, the NO_x CEMS is tested for bias. The bias test requires the comparison of the mean difference (d) and the confidence coefficient (cc) determined when calculating the relative accuracy results. If the mean difference (d) is greater than the confidence coefficient (cc), the monitor or monitoring system has failed the bias test.

If the monitor or monitoring system fails the bias test standard (d $\geq$ cc and RA $\leq$ 10%), a Bias Adjustment Factor (BAF) is calculated using equation (Eq.) A-12 in 40 CFR 75, Appendix A. If the RA is greater than 10% but less than 20%, then an adjustment factor of 1.111 is used. The BAF and adjustment factor are applied to the associated CEMS data until the next RATA test or a repeat bias test shows a different bias factor. The BAF and adjustment factor are manually keyed into the CEMS DAHS for CEMS data adjustment and reporting.

The BAF is determined using the following equation (Eq. A-12 40 CFR 75, Section 7.6.5):

$$BAF \quad 1 + [\,|\bar{d}| \div CEM]$$

Where:

BAF	Bias Adjustment Factor (to the nearest 1000^{th})
$\vert d\vert$	Arithmetic mean of the difference obtained during bias test using Equation A-7
CEM	Mean of the data values provided by the monitor during the bias test

3.3.2. 7-Day Calibration Error Test

The calibration error test verifies the ability of the CEMS to remain within calibration standards for a specified period of time without unscheduled maintenance, repair or adjustment. The calibration error test results are determined from the daily calibrations of the analyzers with two concentrations of calibration gas (zero-level and mid/high-level) performed approximately 24 hours apart for seven consecutive operating days. 40 CFR 75 defines an *operating day* as any day in which the unit combusts fuel. The calibration gases are injected at the CEMS extractive probe to verify the sample lines, sample conditioning, sample analysis, and data acquisition and handling system. The calibration error test is expressed as a percent of the span of the analyzer. The calibration error for the O_2 analyzers is expressed as the difference from the reference gas. The calibration error test performance specifications are listed in Table 6.

TABLE 6 7-DAY CALIBRATION ERROR TEST PERFORMANCE STANDARDS

GAS	FULL SCALE RANGE	40 CFR 75 SPAN	ZERO ERROR	SPAN ERROR
NO_x Low Range	10 ppm	10 ppm	≤ ±2.5%	≤ ±2.5%
NO_x High Range	150 ppm	150 ppm	≤ ±2.5%	≤ ±2.5%
CO Low Range	10 ppm	NA	≤ ±5%	≤ ±5%
CO Mid Range	50 ppm	NA	≤ ±5%	≤ ±5%
CO High Range	3000 ppm	NA	≤ ±5%	≤ ±5%
O_2	25%	21%	≤ ±0.5% O_2	≤ ±0.5% O_2

3.3.3. DAHS Verification Tests

The DAHS evaluation and certification include sample calculations to verify the following: (1) proper computation of all required emissions, (2) proper computation and application of the missing data substitution procedures, and (3) application of the bias adjustment factor. These tests are performed in accordance with EPA specifications.

3.3.4. 40 CFR 75 Cycle Time/40 CFR 60 Response Time Test

The cycle time/response time tests determine the time required for the CEMS to respond to a change in monitored gases. The response test includes the response through the entire sample transport, sample conditioning, analyzing and reporting system cycle of the CEMS. Tests are conducted with zero gas and high-level calibration cylinder gas.

While the source is operating and the CEMS is measuring and recording the stack concentrations, zero or high-level calibration gas is injected until a stable response is reached. The response time for the monitor to complete 95.0% of the concentration or emission rate step change at each gas concentration is recorded by the DAHS. Response times of less than 15 minutes are acceptable. The longer of the two cycle times (NO_x or O_2 analyzers) is the NO_x system response time.

Furthermore, to meet 40 CFR 60 Appendix B Performance Specification 4a requirements for ranges of 200 ppm or less, the CO analyzer is challenged with a zero gas and high level (50 to 100% of range) calibration gas. Both the upscale and down scale response time averages are determined. As stated in 40 CFR 60, Appendix B, PS 4a the response time to reach 95% of the respective reference gas values must be on average less than 1.5 minutes. The upscale and downscale time is the longer of the two analyzer response times.

3.3.5. Linearity Check

A linearity check is required on the NO_x and O_2 analyzers during the initial certification tests for 40 CFR 75. See section 3.6 Quarterly QA Assessments, for a description of the procedures.

3.4. FUEL METER INSTALLATION AND CERTIFICATION

The fuel flowmeter system must meet the installation and initial certification criteria contained in the operating permit and 40 CFR 75, Appendix D.

Once certified, the fuel flowmeter system is evaluated on a cyclical basis in accordance with the Quality Assurance and Quality Control Procedures under the following: 40 CFR 75, Appendix D and the operating permit.

3.4.1. Fuel Flowmeter Accuracy Test

The Fuel Flowmeter Accuracy Test (FFAT) is conducted on the fuel flowmeter as a part of an initial certification and at least once every four-calendar quarters for a quality assurance check. The test evaluates the accuracy of the meters.

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flowmeter) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined using 40 CFR 75 Appendix D Section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flowmeters, only) or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined using 40 CFR 75 Appendix D Section 2.1.5.2 by in-line comparison against a reference flowmeter.

TABLE 7: FUEL FLOWMETER TEST SPECIFICATION

Component	Regulation	Specification
FFAT	40 CFR 75 Appendix D Section 2.1.5	≤2% of full scale or upper range value

The accuracy for the FFAT is based on the reference value of the reference meter or device compared to the tested fuel flowmeter. The following equation is used:
Eq. D-1 (40 CFR 75, Appendix D)

$$ACC = \frac{|R - A|}{URV} \times 100$$

Where:

- ACC = Flowmeter accuracy at a particular load level, as a percentage of the upper range value.
- R=Average of the three flow measurements of the reference flowmeter.
- A=Average of the three measurements of the flowmeter being tested.
- URV=Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

The results must be forwarded in a timely manner to the regulatory agencies. The results can be submitted to the EPA electronically via the ECMPS Client Tool with the current quarterly emission submission or prior. Hardcopies are stored on-site for audit purposes.

TABLE 8: FUEL FLOWMETER TEST REQUIREMENTS

TEST	TEST REQUIREMENTS
FFAT	Report the date, hour, and minute that all test runs were completed.
	For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.
	It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

3.5. DAILY QA ASSESSMENT PLAN

3.5.1. Daily CEMS Calibration Error (Drift)

The daily calibration error (drift) test is used to evaluate the quality of the data collected by the CEMS. The CEMS is calibrated each day approximately 24-hours apart using zero-level and high-level concentration cylinder gases. Calibration error for the analyzers is determined as follows (Eq. A-5, 40 CFR 75, Appendix A).

$$CE = \frac{|R - A|}{S} \times 100$$

Where:

Where:	CE	Calibration error as a percentage of the span
	R	Reference value of the zero or high-level cylinder gas
	A	Actual monitoring system response
	S	Span of the instrument

Calibration error for the O_2 analyzer is determined by the following formula.

CE |R A|

CE	Calibration error as a percentage of the span
R	Reference value of the zero or high-level cylinder gas
A	Actual monitoring system response

The standards of performance for calibration error are summarized in Table 9. Reports of calibration error test results are printed daily. These reports must be filed for record keeping purposes. The calibration results are also archived by the CEMS data acquisition and handling system.

3.5.2. Daily Drift Requirements

For 40 CFR 75, the NOx and O2 analyzers are invalid when the calibration error exceeds the calibration fail limits in Table 9. The invalid period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. In addition, an analyzer is considered out of control if a daily calibration has not been performed within 26-clock hours (2-hour grace period). Units that have been offline for more than 26-clock hours prior to doing an online calibration are permitted an 8-hour grace period from startup to perform an online calibration. 40 CFR 75 Appendix B 2.1.4 permits the use of a mean difference between the analyzer response and the calibration gas of 5 ppm for NO_x analyzers with spans of $\leq$50 ppm.

For 40 CFR 60, the CO analyzers are out-of-control if either the zero (low level) or high level calibration drift exceeds twice the applicable drift specification for five consecutive daily periods. If either the low-level or the high-level calibration drift result exceeds four times the applicable drift specification, the CEMS is out-of-control. The out-of-control period begins at the time corresponding to the completion of the fifth consecutive daily check with a drift in excess of two times the allowable limit or the time corresponding to the completion of a daily check in excess of four times the allowable limit. The end of the out-of-control period is the time corresponding to the completion of a calibration drift check following corrective action that results in the drift at both low and high levels being within the allowable limit.

TABLE 9 Analyzer Drift Specifications

GAS	Regulation	CALIBRATION FAIL	OUT-OF-CONTROL
NO_x Low Range	40 CFR 75	5.0 ppm	NA
NO_x High Range	40 CFR 75	10.0 ppm	NA
CO Low Range	40 CFR 60	1.0 ppm	2.0 ppm
CO Mid Range	40 CFR 60	5.0 ppm	10.0 ppm
CO High Range	40 CFR 60	300.0 ppm	600.0 ppm
O_2 (diluent)	40 CFR 75	1.0% O_2	NA

3.6. QUARTERLY QA ASSESSMENT

The following CEMS quality assessment is completed on the pollutant and diluent analyzers on a quarterly basis. Quarterly linearity checks must not be performed less than two months apart.

3.6.1. Linearity Checks/Cylinder Gas Audits

Pollutant and diluent analyzers undergo a quarterly cylinder gas audit (CGA) in three of four quarters each calendar year. A linearity check is required in every quality assurance operating quarter. A QA operating quarter is one in which the plant operates for 168 hours. Linearity checks are not required on NO_x analyzers with span values of 30 ppm or less.

The CGA requirements in 40 CFR 60, Appendix F are similar to the 40 CFR 75 linearity requirements except that only two levels of calibration gas are required (low and mid). A CGA is performed on analyzers with gases at 20-30% and 50-60% of full scale. A linearity check is performed on analyzers with gases at 20-30%, 50-60%, and 80-100% of span. The cylinder gases are injected at the base of the sample probe on the stack to assess the complete sample train. The quarterly linearity check uses cylinder gases prepared in accordance with EPA Protocol No. 1 procedures when they are being used to meet the 40 CFR 75 requirements.The data is collected by the DAHS.

It is critically important to regularly record and track the expiration of all cylinder gases used for quality assurance purposes. These dates may be entered on the line next to the cylinder number in the linearity/CGA settings of CeDAR Database Editor. Using expired gases can result in invalidating a quality assurance test in certain circumstances.

The accuracy for a CGA is based on the reference value of the cylinder gas concentration; the following equation is used (Eq. 1-1, 40 CFR 60, Appendix F). :

$$A = \frac{|C_m - C_a|}{C_a} \times 100$$

Where:

A Accuracy of analyzer, percent

C_m Average analyzer response during audit in appropriate units.

C_a Average audit value (certified value) in appropriate units.

Linearity error for the pollutant analyzers and diluent analyzers are determined as follows (Eq. A-4, 40 CFR 75, Appendix A, Section 7.1):

$$LE = \frac{|R - A|}{R} \times 100$$

Where:

LE Percent linearity error, based on the reference value

R Reference value of the cylinder gas (low, mid or high)

A Average of three monitoring system responses

The results must be forwarded in a timely manner to the regulatory agencies. The quarterly assessment report is due to the state and to the EPA not later than 30 days after the end of the quarter. The results of the three-point linearity check are provided in electronic format with the quarterly report. Documentation includes EPA Protocol No. 1 cylinder gas certifications that meet the concentration requirements. The gases required are listed in Table 10.

TABLE 10 AUDIT GASES

Analyzer	LOW	MID	HIGH
NO_x High Range	30-45 ppm	75-90 ppm	120-150 ppm
CO Low Range	2-3 ppm	5-6 ppm	8-10 ppm
CO Mid Range	10-15 ppm	25-30 ppm	40-50 ppm
CO High Range	600-900 ppm	1500-1800 ppm	2400-3000 ppm
O_2	4.2-6.3%	10.5-12.6%	16.8-21%

To perform the linearity check, each audit gas must take the same path as the sample gas. First the calibration gas bottles are put in place of the gases used for the daily zero and span check. Then, the manual calibration switch is pushed and the gas flows up the Teflon line in the probe support bundle and into the probe chamber. The gas is then drawn down the heated sample line and into the analyzers. The flow rates and pressures during the check should be the same as those during calibration. A detailed description of the linearity check procedures is located in the Langley Gulch Power Plant CEMS O&M Manual.

The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the monitoring data. The mean difference at all test points must meet the requirements listed below. Results of the check are kept on file at the plant and reported to the state and the EPA in the quarterly report.

3.6.2. Out-of-Control Linearity Error

An out-of-control period occurs when the error in linearity at any of the three concentrations exceeds the applicable standards as summarized below. The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following corrective action and/or monitor repair.

NO_x — Error in linearity results are acceptable if they do not exceed or deviate from the reference values by more than 5%. Linearity results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average reference values is less than or equal to 5 ppm.

O_2 — Error in linearity results are acceptable if they do not exceed or deviate from 5% of the reference value <u>or</u> the absolute value of the difference between the average of the monitor response values and the average reference values must be less than or equal to 0.5% O_2, whichever is less restrictive.

3.6.3. Out-of-Control CGA 40 CFR 60

According to 40 CFR 60, Appendix F, a CO analyzer is considered out-of-control if the CGA results exceed ±15% of the gas value or ±5 ppm. The out-of-control period begins at the time corresponding to the completion of sampling for the CGA and ends at the time corresponding to the completion of a subsequent successful CGA, following corrective action. During an out-of-control period, CEMS data cannot be used to calculate emission compliance or counted towards meeting minimum data availability.

3.7. CEMS ANNUAL QA ASSESSMENT

See 40 CFR 75, Appendix B, Section 2.3.1 for Relative Accuracy Test Audit and 40 CFR 75, Appendix B, 2.3.3 for Bias Adjustment Factor information.

3.8. FUEL FLOWMETER ANNUAL QA ASSESSMENT

3.8.1. Fuel Flowmeter Accuracy Test

See Section 3.4.1 for Fuel Flowmeter Accuracy Test.

4. MAINTENANCE

4.1. GENERAL

Langley Gulch Power Plant requires a certain level of maintenance to assure a high level of confidence in the validity of the data. A good maintenance program prevents major and costly equipment failures and is required by the applicable regulations.

4.2. DAILY CALIBRATION CHECK

Once every day, an automatic calibration check is performed. The zeros and spans of the gas analyzers are compared to known concentrations of calibration gas. The calibration routine is part of the system timing function programmed into the system PLC and therefore, the time and frequency of each calibration can be field set. Refer to the CiSCO CEMS Operations and Maintenance Manual for further details.

Evaluation Procedure for Daily Calibration Reports

1. At the same time each day, the PLC is programmed to initiate an automatic calibration check. The results of these checks are printed on the Daily Calibration Reports. All monitor values are printed. (See the sample reports in Appendix 1.)

2. Collect the daily calibration reports and alarm printouts (See Organizational Responsibilities section).

3. Analyze the Daily Calibration Reports and Alarm Printouts (See Organizational Responsibilities section). If the monitors or analyzers are operating within specifications, the Daily Preventative Maintenance Checklist (Form 1) is completed to indicate that the calibration check is acceptable. If any problems are noted in any step of the process, immediately initiate corrective action to repair the component or analyzer (See Organizational Responsibilities section). All corrective actions must be documented, including problem description, actions taken, and as-left condition.

4. An automatic calibration check is always required after CEMS maintenance to provide documentation that the CEMS calibration is within specifications.

Procedure: Daily Gas Analyzer Calibration Drift Determination

Step 1: The CEMS computer is programmed to initiate an automatic calibration check at a preset time each day. When necessary, plant personnel can manually initiate the automatic calibration check function by pressing the Auto Calibrate Mode Switch. This will start an automatic calibration test sequence. This test mode takes approximately 15 minutes.

Step 2: After the test sequence is completed, observe the analyzer values that were recorded on the computer printout. The calibration values should have two sets of readings, zero and span check values.

Step 3: Check the calibration result values to determine if any analyzer failed calibration. If the monitors or analyzers are operating within specifications, the Daily Preventative Maintenance Checklist (Form 1) is completed to indicate that the calibration check is acceptable. Check CeDAR alarm log for failed calibrations.

Step 4: If an analyzer failed calibration, troubleshooting procedures must start immediately to correct the problem (See Organizational Responsibilities section). All corrective actions must be documented, including problem description, actions taken, and as-left condition.

a. After completing the troubleshooting procedure, repair the analyzer as necessary to insure calibration performance within the acceptable range.

b. Initiate a parts order to replace the faulty equipment as soon as possible.

c. Initiate the automated calibration check function to obtain a new computer printout of calibration values to ensure that the problem has been corrected.

Step 5: Record all steps taken to bring the CEMS into proper operating condition, including problem description, actions taken, and as-left condition.

4.3. DAILY PREVENTATIVE MAINTENANCE

The daily preventative maintenance checks include a review of the calibration error (drift) test results, a check of the calibration gas cylinders, plus visual checks and verification of various general items. The CEMS Daily Preventative Maintenance Checklist (Form 1) must be completed each day. If an item on the checklist is verified as operating within normal parameters, use the designation OK. If an item does not check out as operating within normal parameters, corrective action must be initiated and the corrective actions must be documented, including problem description, actions taken, and as-left condition. CiSCO has provided a record book for the CEM System that should be used to document all maintenance.

NOTES: When checking the supply of calibration gases, new calibration gas bottles should be ordered when the cylinder gas pressure gauge reads approximately 1000 psig. <u>NOTE: All cylinder gas certification documentation must be filed for permanent reference when new cylinders are received at the plant.</u>

CEMS DAILY PREVENTATIVE MAINTENANCE CHECKLIST

DATE ________________________ INITIALS ___________________________

TIME STARTED _____________________ TIME COMPLETED ____________

UNIT # _____________________________

	MON	TUES	WED	THURS	FRI	SAT	SUN
Calibration Error (Drift) Checks							
NOx Analyzer	______	______	______	______	______	______	______
CO Analyzer	______	______	______	______	______	______	______
O2 Analyzer	______	______	______	______	______	______	______
CEM Visual Inspections							
Bath temp & water level	______	______	______	______	______	______	______
Sample pumps, temp.	______	______	______	______	______	______	______
Printer paper supply	______	______	______	______	______	______	______
Panel flows & pressures	______	______	______	______	______	______	______
Log in Cal & problems	______	______	______	______	______	______	______
System Alarms	______	______	______	______	______	______	______
Calibration Gas Bottle Checks (High pressure, psig)							
NO_x low/ CO low	______	______	______	______	______	______	______
NO_x high / CO mid	______	______	______	______	______	______	______
CO high	______	______	______	______	______	______	______
O_2	______	______	______	______	______	______	______

COMMENTS:

FORM 1

4.4. PERIODIC TEST AND PREVENTATIVE MAINTENANCE CHECKLISTS

The following Periodic Test and Preventative Maintenance Checklists (Forms 2 through 5) list the procedures that must be performed each month, every three months, every six months, and every year to complete the recommended maintenance. Some items on the maintenance sheets, such as filter checks, may not exhibit a failure condition until damage to other components has resulted. These items require caution in determining replacement frequency. Close and continuous observation of the operating characteristics of the system, with particular notation of any shift, either sudden or prolonged, in one direction, of any of the many visual indicators in the system should prompt a maintenance response to prevent loss of data and/or equipment damage.

CEMS alarms indicate that service is required. They <u>do not</u> necessarily indicate that data is invalid. They <u>do</u> announce that the system is operating outside of design tolerance and incorrect data and equipment damage <u>will</u> occur if the system is allowed to continue operation without corrective action. For this reason, the alarms should be exercised on a regular basis to assure that they are operational. All alarm conditions require correction in a timely manner.

One of the best indications of system performance is the validity of the data being generated. The CEMS is programmed to conduct a calibration error (drift) test once every 24 hours. Daily scrutiny of these results will dictate whether or not maintenance is needed. As part of a good maintenance program, a stock of spare parts must be kept on site and available at all times.

The Periodic Test and Preventative Maintenance Checklists (Form 2 through 5) are used to direct and record maintenance activities. Each one must be completely filled out and maintained as part of the CEMS records. Many maintenance items on the checklists have a corresponding Periodic Test Procedure (PTP) or Preventative Maintenance Procedure (PMP) that provides detailed instructions. The correct PTP or PMP numbers are referenced on the checklist for those items. Periodic Test Procedures (PTPs) and Preventative Maintenance Procedures (PMPs) are provided in Appendices 3 and 4.

4.5. CORRECTIVE ACTION FOR A MALFUNCTIONING CEMS

Due to the complexity of the CEMS, a detailed written procedure is not provided for a malfunctioning system, analyzer, monitor or component in this manual. Each problem must be evaluated by trained plant personnel utilizing the CEMS Operations and Maintenance Manual (which is incorporated here by reference) and/or factory assistance.

It is recommended that zero and span calibration error (drift) tests be conducted immediately prior to any maintenance and a calibration <u>must be performed after any maintenance.</u> If the post-maintenance zero or calibration error (drift) test shows excessive drift, corrective action and recalibration must be conducted to bring the CEMS within specifications. All corrective action activities will be documented and will include problem description, actions taken, and as-left condition. Data is out-of-control if the daily calibration drift is greater than limits shown in Table 9.

4.6. SPARE PARTS INVENTORY

A recommended spare parts inventory is listed in the CiSCO CEMS O&M Manual. Refer to the Organizational Responsibilities section for person responsible for maintaining spare parts inventory.

CEMS MONTHLY/PERIODIC TESTING CHECKLIST
FOR LANGLEY GULCH POWER PLANT

UNIT # ______________________________ DATE ______________________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
GENERAL:					
Check Water Bath Level					
EXERCISE ALARMS:					
Shelter Temp Transmitter Alarm Test (PTP# 2c, Rev 0)					
Sample Vacuum Alarm (PTP# 3, Rev 4)					
Water Alarm (PTP# 4, Rev 4)					
Air Pressure Alarm (PTP# 5, Rev 4)					
Heated Sample Line Temp Alarm (PLC controlled line) (PTP# 6c, Rev 1)					
Low Cylinder Pressure Alarm (PTP# 15, Rev 0)					

COMMENTS:

FORM 2

CEMS 3-MONTH PREVENTATIVE MAINTENANCE CHECKLIST
FOR LANGLEY GULCH POWER PLANT

UNIT #______________________________ DATE ______________________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Replace Fine Sample Filters (PMP #1)					
Exercise Flow Meters (PMP# 2)					
Exercise Pressure Regulators (PMP# 3)					
Change Primary and Secondary Air Filter (PMP# 6)					
Change AC Filters (PMP# 8b)					
Change Drain Pump Tubing (PMP# 11)					
Complete Monthly Checklist					
Complete CGA/Linearity Error Tests					

COMMENTS:

FORM 3

CEMS 6-MONTH PREVENTATIVE MAINTENANCE CHECKLIST
FOR LANGLEY GULCH POWER PLANT

UNIT #______________________________ DATE ________________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Check/Replace Filter Holder Seal (PMP# 12)					
System Leak Test (PMP# 21)					
Complete Monthly Checklist					
Complete 3-Month Checklist					
Complete RATA testing ***if a semiannual RATA is required***					

COMMENTS:

FORM 4

CEMS ONE-YEAR PREVENTATIVE MAINTENANCE CHECKLIST
FOR LANGLEY GULCH POWER PLANT

UNIT # ______________________________ DATE _________________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Change HRSG Probe Filter /Seals (PMP# 4)					
Clean Heated Sample Lines (PMP# 7)					
Change Membrane Dryer (PMP# 9)					
Replace Air Dryer Tower (PMP# 10)					
Rebuild Sample Vacuum Pump as needed (PMP# 13)					
Change SCR Inlet Probe Filter /Seals (PMP# 17)					
Change Ammonia Scrubber (PMP# 22)					
Calibrate fuel flow meters to 2% accuracy					
Complete Monthly Checklist					
Complete 3-Month Checklist					
Complete 6-Month Checklist					
Complete RATA testing					

COMMENTS:

FORM 5

APPENDICES

APPENDIX 1

DAHS REPORT FORMATS

Not currently available

APPENDIX 2

CALCULATIONS AND CALIBRATION PROCEDURES

FORMULAS

Correct ppm to 15% oxygen

To calculate emission concentration to a particular Oxygen concentration.

$$C_{adj} = C_d \times \frac{20.9 - XO_2}{20.9 - \%O_2}$$

Units: ppmvd

Reference: 40CFR60 Appendix A, Method 20, Eq. 20-4

CiSCO Formula ID 0010

- C_{adj} Emission concentration corrected to C percent O_2
- C_d Emission concentration measured dry, ppmvd
- X_{O2} Desired O_2% correction value. Typically 15% for turbines and 3% or 7% for boilers
- $\%O_2$ Oxygen percentage in flue gas, for 0 < O_2 % < 20.0%

Emission Rate lb/mmBtu

To calculate emissions rate in lb/mmBtu from ppmvd.

$$E = C_d \times F_{d,gen} \times K \times MW \times \left(\frac{20.9}{20.9 - O_2\,\%} \right)$$

Units: lb/mmBtu

Reference: 40CFR60 Appendix A Method 19, Eq. 19-1

CiSCO Formula ID 0050

- E Emissions expressed as lb/mmBtu
- C_d Concentration measured, ppmvd
- $F_{d,gen}$ General Dry Fuel Factor, dscf/mmBtu (see formula F-7, F-7a, or prorating using Formula F-8)
- K Constant, 2.59E-9 (lb-mol/(dscf ppmvd))
- MW Molecular Wt (SO_2 64 lb/lb-mol, NO_2 46 lb/lb-mol, CO 28 lb/lb-mol, NH_3 17 lb/lb-mol)

Unmeasured Parameter Calculation

To calculate an unmeasured parameter based on user input values.

$$M_l = A \times HI$$

- M_I Mass emissions of pollutant, lb/hr
- HI Heat input to unit, mmBtu/hr
- A Emissions Factor, lb/mmBtu

SO_2 Mass Emission Rate Using 0.0006 lb/mmBtu

Use the following equation to calculate the SO_2 emission using the 0.0006 lb/mmBtu emission rate in 40CFR75 Appendix D 2.3.2 (7/1/97).

$$SO2_{rate} = ER \times HI_{rate}$$

Units: lb/hr

Reference: 40CFR75 Appendix D 3.3.2

CiSCO Formula ID D-5

- $SO2_{rate}$ Hourly mass emission rate of SO_2 from combustion of pipeline natural gas, lb/hr
- HI_{rate} Hourly heat input rate from combustion of a gaseous fuel, mmBtu/hr
- ER SO_2 emission rate from 40CFR75 Appendix D 2 3 1 1 and 2.3.2.1.1 lb/mmBtu

Notes:

Use the Gas Emission Factor (GEF) when calculating SO_2 lb/hr from fuel flow rate of "pipeline quality" natural gas. For pipeline natural gas. 0.0006 GEF, lb/mmBtu.
HI_{rate} derived in Formula F-20

Natural Gas Hourly Heat Input Rate mmBtu/hr

When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each period. $$HI_g = \frac{Q_g \times GCV_g}{10^4}$$ Units: mmBtu/hr Reference: 40CFR75 Appendix F 5.5.2 CiSCO Formula ID F-20	• HI_g Hourly heat input from gaseous fuel, mmBtu/hour • Q_g Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet/hr. • GCV_g Gross calorific value of gaseous fuel, using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 or GPA Standard 2261-90, Btu/scf (incorporated by reference under 40CFR75 §75.6) • 10^4 Conversion of Btu to mmBtu and hundred standard cubic feet to standard cubic feet

CO_2 Mass Emission, Part 72 Method

In lieu of using the procedures, methods, and equations in 40CFR75 Appendix G 2 1, the owner or operator of an affected gas-fired unit as defined under 40CFR §72.2 may use the following equation and records of hourly heat input to estimate daily CO_2 mass emissions (in tons). $$W_{CO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000}\right)$$ Units: tons/hr Reference: 40CFR75 Appendix G 2.3 CiSCO Formula ID G-4	• WCO_2 CO_2 emitted from combustion, tons/hour. • F_c Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1420 scf/mmBtu for crude, residual, or distillate oil and calculated according to the procedures in 40CFR75 Appendix F 3.3.5 • H Hourly heat input in mmBtu as reported in company records, see F-20. • U_f 1/385 scf CO_2/lb-mol at 14.7 psia and 68 F. • MW_{CO2} Molecular weight of carbon dioxide (44.0).

Calibration Correction

Calibration Correction	Corrected Concentration= Slope Factor * Raw concentration + Intercept Factor Slope Factor = $\frac{\text{Span Gas Value}}{\text{Span Response-Zero Response}}$ Intercept Factor = Actual Zero Response * Slope Factor

CALIBRATION PROCEDURES

To calibrate the CEMS gas analyzer, use the following procedures.

1. Verify that the following system switches, pressures, and flows match the typical settings.

RANGE SWITCHES	TYPICAL SETTINGS
NO_x Analyzer	0-10/150 ppm
CO Analyzer	0-10/50/3000 ppm
O_2 Analyzer	0-25%

PRESSURES	TYPICAL SETTINGS
Bypass (Stack)	5-6 psi
$NO_x/CO/O_2$ Sample	2-4 psi
Dry Air	15 psi
Gas Cylinder Regulator	12 psi

FLOWS	TYPICAL SETTINGS
NO_x/ O_2 Sample (Stack)	3 L/M
Stack Calibration	5-9 L/M
Purge Air	9-10 L/M

2. Perform individual analyzer calibration adjustments using the procedures found in the CEMS Operations and Maintenance Manual, which are incorporated in this QA Manual by reference.

3. Initiate an automatic calibration check and verify that the calibration drift for each gas analyzer is within acceptable limits. If not, perform corrective maintenance as needed and repeat the calibration check until a satisfactory result is achieved.

APPENDIX 3

PERIODIC TEST PROCEDURES

PERIODIC TEST PROCEDURE

TITLE: Bath Temp Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

BATH TEMPERATURE ALARM-DESCRIPTION

A thermal switch mounted on the lid of the refrigeration-cooled cold-water bathtub monitors the temperature of the water. Should the temperature of the water rise too high, above 40°F (4°C) the "Bath Temp" alarm will be activated. This alarm will also come on should the level of the water in the tub drop, due to evaporation or leakage. The switch is normally open and is held closed when immersed in cool water. The switch will open at temperatures above 40°F (4°C). If the switch does not open above 40°F (4°C), please call CiSCO Field Service (303-790-1000).

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove water bath cover so the temperature sensor is out of the water, allow time to let the sensor acclimate. Keep the sensor in alarm status for at least 30 seconds.
3) Verify that the "Bath Temp" alarm appears on the local operator interface terminal.
4) Check water bath level before putting cover back on.
5) Place the CEM System back "in-service."
6) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
7) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Shelter Temperature Transmitter Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Heat Gun, Can Freeze Mist

SHELTER TEMPERATURE TRANSMITTER ALARM - DESCRIPTION

A thermocouple with a 4-20mA transmitter is used to monitor the temperature inside the rack. Temperature is transmitted to the PLC, which will compare it to coded set points of 50°F (10°C) and 95°F (35°C). Historical data is available in the DARS/DAHS.

TO TEST THIS ALARM:

1) Initiate the “out-of-service” mode to prevent collection of erroneous data in the DARS/DAHS and indicate maintenance.
2) Locate the thermocouple with temperature transmitter near top of the rack/cabinet (see Figure 2.3).
3) Using the heat gun, increase the temperature of the thermocouple above 95°F (35°C). Keep the sensor in alarm status for least 30 seconds.
4) Verify that the “High Shelter Temp” alarm appears on the local operator interface terminal.
5) Remove heat source.
6) Apply “Freeze Mist” or equivalent to thermocouple to reduce the temperature below 50°F (10°C). Keep sensor in alarm for at least 30 seconds.
7) Verify the “Low Shelter Temp” alarm on the local operator interface terminal.
8) Wait for alarm to clear after removal of cold temp source.
9) Place the CEM System back “in-service.”
10) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
11) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Sample Vacuum Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 9/16" wrench, ¼" plug

SAMPLE VACUUM ALARM-DESCRIPTION

A vacuum switch monitors the sample vacuum on the input to the sample pump. The vacuum switch is typically set to activate at 7 to 8 inches Hg (178 to 203 mm of Hg) and can be field adjusted. The switch is normally open and will close as the sample vacuum reaches its preset value. This alarm will activate on the operator interface terminal. If adjustment is required, please call CiSCO Field Service (303-790-1000).

Note: Each vacuum setting is system specific and the 7 to 8 inches of Hg (178 to 203 mm of Hg)may vary.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove ¼ flex tubing on inlet of fine sample filter assembly (see Figure 3.1)
3) Plug inlet fitting in filter assembly using ¼" tube plug. Keep in alarm status for at least 30 seconds.
4) Verify that the "Sample Vacuum" alarm appears on the local operator interface terminal.
5) Remove ¼" tube plug and reconnect the line.
6) Place CEM System "back in-service."
7) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
8) Perform PMP #21, System Leak Check.
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

¼" Flex Tubing

Figure 3.1

Fine Sample Filter Assembly

PERIODIC TEST PROCEDURE

TITLE: Water Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 10" jumper wire

WATER ALARM-DESCRIPTION

A sensor located in the fine sample filter will sense the presence of condensate through the conductivity to ground provided by the condensate. A "Water" alarm will be activated for the affected sample train if condensate is detected. This is given high priority to prevent damage to the system caused by allowing condensate to contaminate the sampling system. The sample pump will be automatically shut off if the water alarm is activated. To clear the water alarm and reactivate the sample pump, the alarm condition must be reviewed and the out-of-service button must be momentarily activated. Activation of this alarm is indicated on the interface terminal

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove the knurled lower flange and glass cylinder or fine sample filter assembly (see Figure 4.1).
3) Ground condensate probe for 10 seconds by using a jumper (see Figure 4.2).
4) After 10 seconds, the alarm will be verified in the PLC and the sample pump will shut off.
5) Verify that the "Water" alarm appears on the local operator interface terminal.
6) Remove jumper. Replace the knurled lower flange and glass cylinder. Be careful when tightening nut assembly. Excessive tightening can break glass filter assembly.
7) Perform PMP #21, System Leak Check.
8) Place CEM System back "in-service", back "out-of-service" and then back "in-service" to reactivate sample pump.
9) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

Note: This test just gives an indication that the circuit is functioning. Test procedure can be performed in conjunction with PMP #1. Refer to the Summarized Maintenance Schedule.

PERIODIC TEST PROCEDURE
(CONT'D)

Figure 4.1

Figure 4.2

PERIODIC TEST PROCEDURE

TITLE: Instrument Air Pressure Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

INSTRUMENT AIR PRESSURE ALARM-DESCRIPTION

A pressure switch monitors the instrument air pressure supplied to the cabinet/shelter. The pressure switch is set to activate at approximately 70 psi (480 KPa) decreasing and is field adjustable. Activation of this alarm is indicated on the operator interface terminal.

TO TEST THIS ALARM:

1) Initiate the “out-of-service” mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Shut off instrument air valve (see Figure 5.1).
3) Monitor air pressure on inlet gauge mounted on the inlet air filter block, assembly.
4) Release air pressure at drain valve on the bottom of the primary air filter down to 70 psi (±5 psi), (480 KPa, ±35 KPa). Keep the sensor in alarm status for at least 60 seconds for the built-in time delay to expire.
5) Verify that the “Air Press” alarm appears on the local operator interface terminal.
6) Turn on instrument air valve and verify that “Air Press” alarm is no longer active.
7) Place CEM System back “in-service.”
8) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

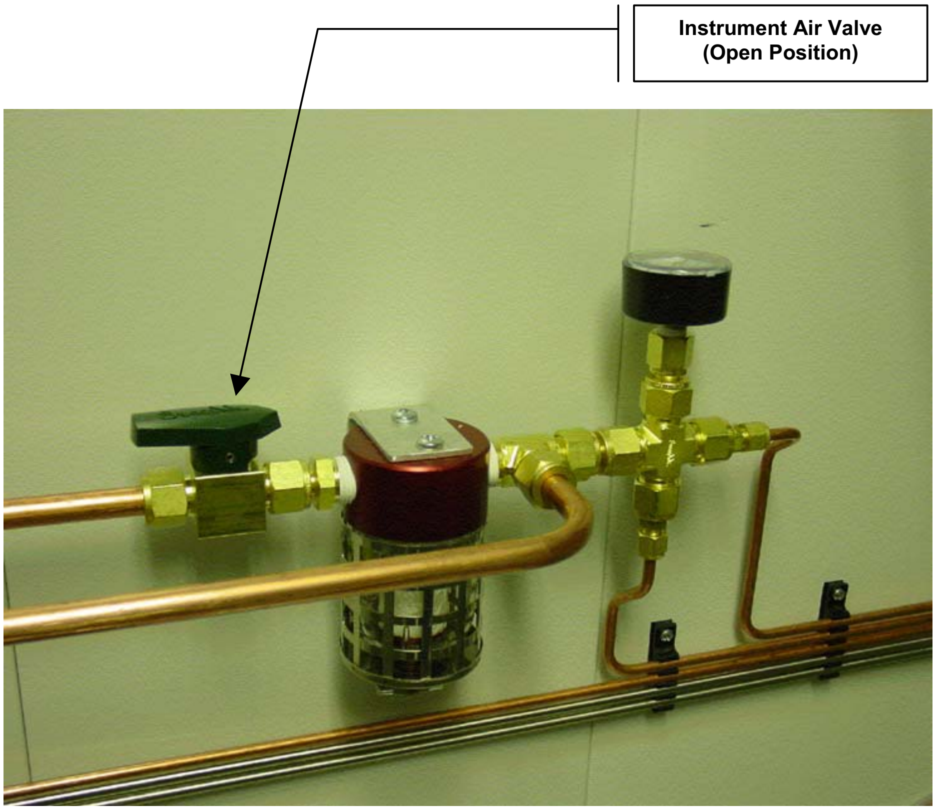


Figure 5.1

PERIODIC TEST PROCEDURE

TITLE: Heated Sample Line Temp Alarm Test (Controlled Line)

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

HEATED SAMPLE LINE TEMPERATURE ALARMS - DEVIATION VERIFICATION

A digital temperature controller maintains the sample line temperature (this device is usually mounted on the instrument rack). The controller monitors the temperature of the heated sample line via an input provided by a J-type thermocouple (T/C) imbedded in the heated sample line. The alarm is set to activate upon a predetermined deviation from the control set point temperature, refer to your manual for correct set point. If the heated sample line temperature drops 10°F below this set point or rises 15°F above the set point then the “Line Temp” alarm will be energized.

TO TEST THIS ALARM:

1) Place the CEMS in the “out-of-service” mode to prevent collection of erroneous data in the data system.

2) Go to the “default parameter” view showing the Process Temperature and Process Set Point.

Alarm High - Deviation Verification

a) Change the set point using the ‘Down’ arrow key until the set point is 15 or more degrees below the thermocouple reading, i.e., Process Temperature. The deviation output LED on the controller will activate and an ***Alarm High*** will be indicated.
b) Verify that the “HSL Temp” alarm appears on the operator interface terminal. Review the data system alarm log to ensure that the data system recorded the alarm.

Alarm Low - Deviation Verification

a) Change the set point using the ‘Up’ arrow key until the set point is 10 degrees or more above the thermocouple reading, i.e., Process Temperature. The deviation output LED on the controller will activate and an ***Alarm Low*** will be indicated.

b) Verify that the “HSL Temp” alarm appears on the operator interface terminal. Review the data system alarm log to ensure that the data system recorded the alarm.

PERIODIC TEST PROCEDURE
(CONT'D)

3) Place the CEMS back in the "in-service" mode to re-establish valid data collection in the data system.

4) Record the completion of this procedure in the CEMS Log Book and the QA Manual checklist.

Note: This test just gives an indication that the circuit and controller are functioning. For sample lines greater than 200 feet (60 meters), there may be an additional T/C. To test the secondary T/C, disconnect the primary T/C at the connector located near the sample line, and then connect the secondary going to the temperature controller. Repeat the steps above.

PERIODIC TEST PROCEDURE

TITLE: Sample Flow Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

SAMPLE FLOW ALARM-DESCRIPTION

Each sample flow meter can be equipped with an optional sample flow switch. If the sample flow drops below the preset level, the switch contacts will close indicating the fault condition. The "Sample Flow" alarm will activate on the local operator interface terminal if this alarm is detected. These flow switches are field adjustable and should be set to alarm at approximately 50 to 75% of the normal sample flow rate. Since most analyzers are flow sensitive, this alarm prevents accumulating erroneous data due to low or nonexistent sample flow.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Note the setting on the analyzer flow meter.
3) Decrease the flow with the flow control valve until the "Sample Flow" alarm is activated on the local operator interface terminal.
4) Return the flow meter to its original setting and verify that the "Sample Flow" alarm is no longer active.
5) Place the CEM System back "in-service".
6) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
7) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Calibration Gas Flow Alarm Test

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

CALIBRATION GAS FLOW ALARM-DESCRIPTION

If the calibration gas flow drops below the preset level, the switch contacts will close indicating the fault condition. The "CAL FLOW" alarm will be activated on the operator panel in the shelter if a low flow condition is detected. The flow switch is field adjustable and should be set to deactivate on decreasing flow at about 50 to 75% of the normal calibration gas flow rate through the sample probe. This switch will probably deactivate during a calibration at cabinet due to reduced flow requirements.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.

2) Open a test gas valve using the functions in the local operator interface terminal. Make sure that the Cal-at Cabinet valve is in the Probe position. Wait 15 seconds for flow to stabilize. Note level of the calibration gas flow. Flow rate should be equal to the sum of all the sample flow rates to each analyzer plus the bypass flow rate plus 1 to 2 LPM. The "Cal Flow" alarm should not be activated.

3) Decrease the calibration gas flow rate slowly by adjusting the flow valve on the calibration gas flow meter until the PLC Digital Input deactivates. Note level of flow on flow meter.
   Keep the sensor in this state for 15 seconds, to allow the PLC time delay to expire.

4) If the flow rate at which the Input deactivated was about 50 to 75% of the calculated calibration gas flow rate, proceed to step 6. If the flow rate at which the Input was deactivated was not 50 to 75%, the flow switch may require adjustment. Follow directions in step 5.

5) To adjust the calibration flow switch, turn the adjustment screw on the body of the flow switch clockwise to increase the flow rate level at which the alarm is activated or turn the adjustment screw counter clockwise to decrease the flow rate at which the alarm is activated. Increase the flow until the PLC Input activates and then repeat steps 1 through 4 above until the Input is deactivated at the correct flow rate (see Figure 12.1)

6) Reset the calibration flow meter to the correct flow rate.

7) Turn off the gas valve and place the CEM System back "in-service."

8) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm

9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

Flow Switch

Figure 12.1

APPENDIX 4

PREVENTATIVE MAINTENANCE PROCEDURES

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change Fine Sample Filters

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 10" adjustable wrench and miscellaneous hand tools

Note: This PMP should be done in conjunction with PMP #12 when in accordance with the Maintenance Schedule.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

The fine sample filter will remove 99.9% of all particulates 0.1 micron or larger. Its purpose is to protect the downstream components, especially the membrane dryer, from particulate contamination.

1) Place the CEM System in "out-of-service" mode.
2) Turn off sample pump(s) by using circuit breaker or by pulling the power plug.
3) Remove the knurled lower flange and glass cylinder for each filter.
4) Remove internal knurled nut and filter.
5) Install new filter. Make sure the water alarm probe is resting against the filter without touching the knurled nut.
6) Reassemble the unit taking care that the o-rings are well in place. Be very careful when tightening the assembly. Excessive tightening can break glass filter cylinder.
7) Turn on the sample pump.
8) Perform system leak test using PMP #21.
9) Once the assembly is complete, place the CEM System "back-in-service".
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Exercise Flowmeter

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: N/A

MAINTENANCE INSTRUCTIONS:

Check for ability to vary flow rates for each flowmeter.

1) Place the CEM System in "out-of-service" mode.
2) Each flowmeter is adjustable. Adjustment is obtained either with a valve on the flowmeter or by a separate valve in series with the flowmeter. Identify each flow meter that will be tested during this procedure.
3) Note and record the setting of each flowmeter.
4) Turn flow control knob on each flowmeter (on flowmeters with knob on base) clockwise then counter clockwise, then back to original setting. The rotometer float should move accordingly.
5) On flowmeters without flow control knobs, (i.e., Siemens analyzer and bypass flow control meters) find the corresponding flow control knob and turn clockwise, then counter clockwise, then back to the original setting. The rotometer float should move accordingly.
6) On calibration gas flowmeter, activate the zero or span solenoids using the local operator interface terminal. Vary flow then reset to original setting recorded in 3 above.
7) Check the flowmeter settings. A marker should be present on the flowmeter to indicate its proper setting. The valve of this setting should match the recommended valve listed in the O&M Manual. Settings may also appear in the Shelter's Log Book.
8) Place the CEM System "back-in-service".
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Exercise Pressure Regulator

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: N/A

MAINTENANCE INSTRUCTIONS:

1) Each regulator is manually adjustable and has a corresponding gauge to indicate the regulator control setting. Identify each regulator that will be maintained during this procedure.

2) Note settings on gauges associated with each regulator and record.

3) Turn regulator control knobs clockwise then counter clockwise, then return to original settings on all sample, bypass and purge air regulators as recorded in step 2 above.

4) Flow must exist through all regulators. To test calibration gas regulators, activate zero and span solenoids using the local operator interface terminal. Exercise, adjust and set pressure while cal gases are flowing.

5) Check the regulator settings. A marker should be present on each regulator to indicate its proper setting. The value indicated by the marker should match the value recommended in the O&M Manual, or as recorded in the Shelter's Log Book.

6) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Primary and Secondary Instrument Air Filters

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: ½ hour, 1 person

TOOLS / MATERIAL REQUIRED: primary and secondary air filter, 8" crescent wrench.

Note: Refer to the Recommended Spare Parts List located in the Appendix of the O&M Manual for part numbers per system. Some systems do not include a secondary filter.

Safety Notes: Safety Glasses

CAUTION! ***Bleed off all instrument air prior to changing filters.***

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Shut off instrument air valve in cabinet/shelter.
3) Release instrument air pressure using drain valve on the primary air filter. Check instrument air pressure gauge for 0 psi (0 KPa).
4) Remove primary and secondary air filter housings. The secondary filter polycarbonate bowl unscrews from the bottom. The primary filter drain nut unscrews from the bottom to free the polycarbonate housing. Be careful to retain o-ring.
5) Inspect filter seals. Replace if seals show signs of wear or deformity.
6) Remove air filters and install new filters.
7) Reinstall filter housings. Make sure that the screws and o-ring are still in place.
8) Turn instrument air valve back on.
9) Check filter housings for leaks using leak detection fluid.
10) Place CEM System "back-in-service".
11) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Clean Heated Sample Line

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 2 persons

TOOLS / MATERIAL REQUIRED: 6” adjustable wrench, 8” adjustable wrench and service water. Utility gloves.

Safety Notes: Safety Glasses and Gloves

MAINTENANCE INSTRUCTIONS:

The sample line connecting the sample probe to the cabinet/shelter is heated to prevent the sample from dropping below its dew point. It contains a 5/16” and a 3/8” OD tube for a dual sample line and a 5/16” OD tube for a single sample line. The tubes are covered with ½” of insulation to form a line of about 1-¾” diameter. The heater is a series, self-limiting heater that will automatically reduce its power requirements as it approaches its design temperature. The line is designed to maintain a minimum sample gas temperature of 350°F (177°C) when ammonia is present in the sample or 250°F (121°C) when ammonia is not present.

TO CLEAN HEATED SAMPLE LINE:

1) Place the CEM System in “out-of-service” mode.
2) Switch “off” heated sample line circuit breaker and allow line to cool.
3) Turn off the sample pump at the breaker or by pulling the power plug.
4) Disconnect heated sample line at both ends.
5) Connect instrument air to the end of the heated sample line in the cabinet/shelter and turn air on for 5 minutes.
6) Connect clean service water to a line at the bottom and run for 5 minutes. Monitor the condition of the water at the probe end and ensure that it is clean.
7) Shut off water, disconnect the water line from the heated sample line and allow water to drain for approximately 10 minutes.
8) Connect instrument air back onto the heated sample line at the cabinet/shelter end and turn the air on for 10 minutes.
9) Switch “on” heated sample line circuit breaker.
10) Continue the flow of instrument air through the heated sample line for an additional 15 minutes or until HSL temperature is normal.
11) Using gloves connect the line back to the probe and cooler.
12) Turn on the sample pump.
13) Perform System Leak Test using PMP #21.
14) Place the CEM System “back-in-service”.
15) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

Note: If the heated sample line is still not clean, consult CiSCO.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Air Conditioner Filters on HVAC

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Air Filter, miscellaneous hand tools.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) To access the filters, remove the HVAC exterior panel that contains the variable intake damper (Reference HVAC manufacturers manual for details, Appendix J).

2 Remove the AC fresh air and return air filters.

3) Inspect both filters for dirt build-up and condition.

4) A dirty fresh air filter or return air filter must be replaced.

5) Install existing or new filters as required and replace the HVAC exterior panel.

6) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change Membrane Dryer

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 9/16 open-end wrench, membrane tube bundle, pressure gauge and a on/off valve and screw driver.

Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers per system.

To minimize maintenance downtime, it may be advisable to have a spare membrane dryer/housing assembly on site. The spare assembly can be installed and the replaced assembly can be rebuilt as time permits.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

Membrane Dryer

A membrane dryer is used to remove additional moisture from the sample to prevent acid mist carryover and further reduce any analysis interference due to water. The sample gas moisture is removed from the sample gas in the gas phase using dry air input provided by the heatless air dryer. A sample dew point of -80°F (-62°C) is achieved

The material used in the membrane dryer allows water, in the gas phase, to permeate through the membrane from the wet sample side to the dry purge side due to a difference in water vapor pressures. Dry purge air with an -80°F (-62°C) dew point is supplied by the instrument air dryer. Purge airflow should be higher than sample flow to assure sufficient drying capacity.

TO CHANGE MEMBRANE DRYER:

1) Place the CEM System in “out-of-service” mode.
2) Unplug the sample pump power cord.
3) Remove membrane dryer assembly and all tubing connections.
4) Remove the end cap at each end of membrane assembly and remove o-rings.
5) Loosen both black lock bushings on air purge housing and remove old tube bundle.
6) Inspect o-rings and replace if necessary.
7) Install new tube bundle and reassemble membrane assembly. Make sure the tube bundle o-ring seals are installed.
8) Leak check membrane dryer assembly. This can be accomplished by installing a pressure gauge with an on/off valve on the inlet of the membrane dryer and plugging the outlet. Pressurize the dryer to 15 psi (103 KPa), shut off the valve, and monitor the pressure. If the pressure holds for 5 minutes, the dryer is leak tight.
9) Install membrane dryer assembly back into the system and tighten the tubing connections.
10) Plug in sample pump power cord.
11) Place the CEM System “back-in-service”.
12) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Air Dryer Towers

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: small strap wrench or channel locks

Safety Notes: Safety Glasses

***CAUTION!* Bleed off all instrument air prior to changing towers out.**

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.

2) Shut off instrument air valve in cabinet/shelter.

3) Release instrument air pressure using drain on primary air filter. Check the instrument air gauge for 0 psi (0 KPa).

4) Remove air dryer towers using a strap wrench.

5) Install new air dryer towers. Tighten towers only hand tight.

6) Turn instrument air valve on.

7) Leak check the dryer with leak detector fluid.

8) Place CEM System "back-in-service".

9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Drain Pump Tubing

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: Tubing cutter, replacement tubing

Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers per system.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

Condensate removed from the sample cooler will contain Nitric and Sulfuric acids, which may corrode the flex tubes.

1) Place the CEM System in “out-of-service” mode.
2) Unplug drain pump power cord.
3) Remove tubing from refrigeration unit trap drain fitting and from drain vent manifold.
4) Remove four (4) wing nuts on multiple head pumps or four (4) knurled screws on a single head pump.
5) Separate pump head in half and remove tubing.
6) Reinstall new section of tubing in pump head.
7) Put head(s) back together on the pump.
8) Reattach tubing on the drain/vent manifold and refrigeration trap drain fitting. The pump motor turns clockwise when viewed from the pump head end. The tube on the right goes to the refrigerated cooler.
9) Plug in the drain pump power cord.
10 Perform system leak check using PMP #21.
11) Place the CEM System “back-in-service”.
12) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Fine Sample Filter Glass Cylinder Seal

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 6" adjustable wrench, filter gasket
Note: This PMP should be done in conjunction with PMP #1.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Turn off the sample pump at the breaker or by pulling the power plug.
3) Remove fine sample filter base with wrench. Be careful not to break filter glass cylinder.
4) Replace filter cylinder gaskets.
5) Reassemble filter unit insuring proper installation of gasket. Be careful not to over tighten the glass cylinder as it could break.
6) Turn on the sample pump.
7) Perform System Leak Test using PMP #21.
8) Place the CEM System "back-in-service".
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Sample Pump Head Rebuild (1 or 2 heads)

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 5/32” and 3/16” Allen head wrench, 9/16” open-end wrench, vacuum gauge with ¼” male npt. fitting, rebuild kit for single head pumps, or dual head pump.

Note: Stack sample pump and bypass stack pumps use—refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in “out-of-service” mode.
2) Note direction of flow on pump head. Label in and out lines.
3) Remove pump from system by pulling power cord and removing ¼” flex lines using 9/16” wrench.
4) Remove 4 pump head screws using 3/16” Allen head wrench.
5) Remove pump diaphragm plate using 5/16” Allen head wrench.
6) Remove and then replace Teflon coated diaphragm and small Teflon seal from kit.
7) Wipe any foreign particles from inside pump head area.
8) Remove valve plate by removing two (2) screws using 5/16” Allen head wrench.
9) Remove then replace 2-flapper valves and valve gasket from kit.
10) Reinstall valve plate onto head (note plate is keyed). Ensure valve disks are seated and do not pinch during assembly.
11) Reinstall head on pump in accordance with the direction labeled in Step 2.
12) Start up pump and check deadhead vacuum by attaching a vacuum gauge onto the inlet (vacuum range should be 18-22” hg depending on altitude).
13) Reinstall pump into system.
14) Check sample and bypass flows to see if they are in specs per O&M Manual or Log Book entry.
15) Perform System Leak Test using PMP #21.
16) Place the CEM System “back-in-service”.
17) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Probe Filter and Gasket Set on High Temperature Probe Assembly

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 6" adjustable wrench, $^{3}/_{16}$" Allen wrench, inlet sample probe filter element, gasket set, gasket scraper.

Note: Refer to the Recommended Spare Parts List or Probe Assembly drawings located in the Appendix of the O&M Manual for part numbers per system.

Safety Notes: Safety Glasses and Gloves

MAINTENANCE INSTRUCTIONS:

1) Make sure the probe is cool enough to work on (Unit not on-line).
2) Place CEMS in "Out-of-Service" mode.
3) Turn off the sample pump at the breaker.

At the Probe:

4) Loosen and remove two (2) socket cap screws from the bottom of the probe manifold. (Use $^{3}/_{16}$" Allen wrench.)
5) Loosen four (4) captive hex head screws and remove cover assembly. (Use 6" adjustable wrench.)
6) Remove outer gasket, filter element and inner gasket. Also remove the three (3) O-Ring manifold gaskets. Clean filter seat surfaces with gasket scraper and rag.
7) Install new inner gasket, filter element and outer gasket. Also install the three (3) new O-Ring (manifold) gaskets. (The three (3) O-Rings (manifold) gaskets are provided with the gasket set.)
8) Replace probe cover and securely and evenly tighten the four (4) captive hex head screws. (DO NOT over-tighten.) Ensure gasket o-rings are seated properly before tightening.
9) Replace socket cap screws (bottom of manifold) and securely tighten. (DO NOT over-tighten.)

Inside the Shelter:

10) Turn on the sample pump.
11) Perform the system leak test using PMP #21.
12) Place the CEMS "back-in-service".
13) Record the completion of this procedure in the CEMS Log Book and the QA Manual checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: TEI NO_X Analyzer Pump Rebuild

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 20 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Pump repair kit (part no. 5013) Allen wrench – 3mm, 4mm, 9/16" wrench, spanner wrench

Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

MAINTENANCE INSTRUCTIONS:

TO REBUILD PUMP:

1) Place CEMS "out-of-service".
2) Disconnect pump tubing.
3) Remove the eight (8) socket head screws and washers holding the top metal plate of the pump head (use a 3mm Allen wrench). Refer to Figure 1.

   IMPORTANT: Note the orientation of the plate for reassembly later on.
4) Remove and discard old Teflon gasket.
5) Remove main body of pump head by removing four (4) socket head screws (use 4mm Allen wrench).

   IMPORTANT: Note the correct orientation of the head so as to reassemble it correctly.
6) To remove Teflon diaphragm, loosen and remove the clamping disk by using the spanner wrench in the dimples of the claming disk.
7) Discard the old Teflon diaphragm.
8) Insert clamping disk into new Teflon diaphragm (consisting of three (3) pieces) and screw clamping disk back into pump head. Do not over-tighten.
9) To remove flapper valve(s), loosen and remove screw and nut holding the flapper valves in place. Replace the old flapper with the new flapper being sure that the flappers are lying completely flat and straight. Be sure the screw head and not the washer is on the smooth side of the pump head.
10) Replace main body of the pump with four socket head screws being sure to use correct orientation as noted in Step 5.
11) Place Teflon gasket over main body of the pump head. There is only one position that this gasket can be placed so that all eight screw holes in the pump headline up with the holes in the gasket.
12) Replace top plate of pump head with the eight (8) socket head screws and washers being sure the Teflon gasket stays in place.
13) Reattach tubing.
14) Start pump and check vacuum pressure by reading the valve in the service mode menu of the analyzer. Valve should be below 35 mmHg.
15) Place system "in-service" and record completion in System Log Book.

PREVENTATIVE MAINTENANCE PROCEDURE
(CONT'D)

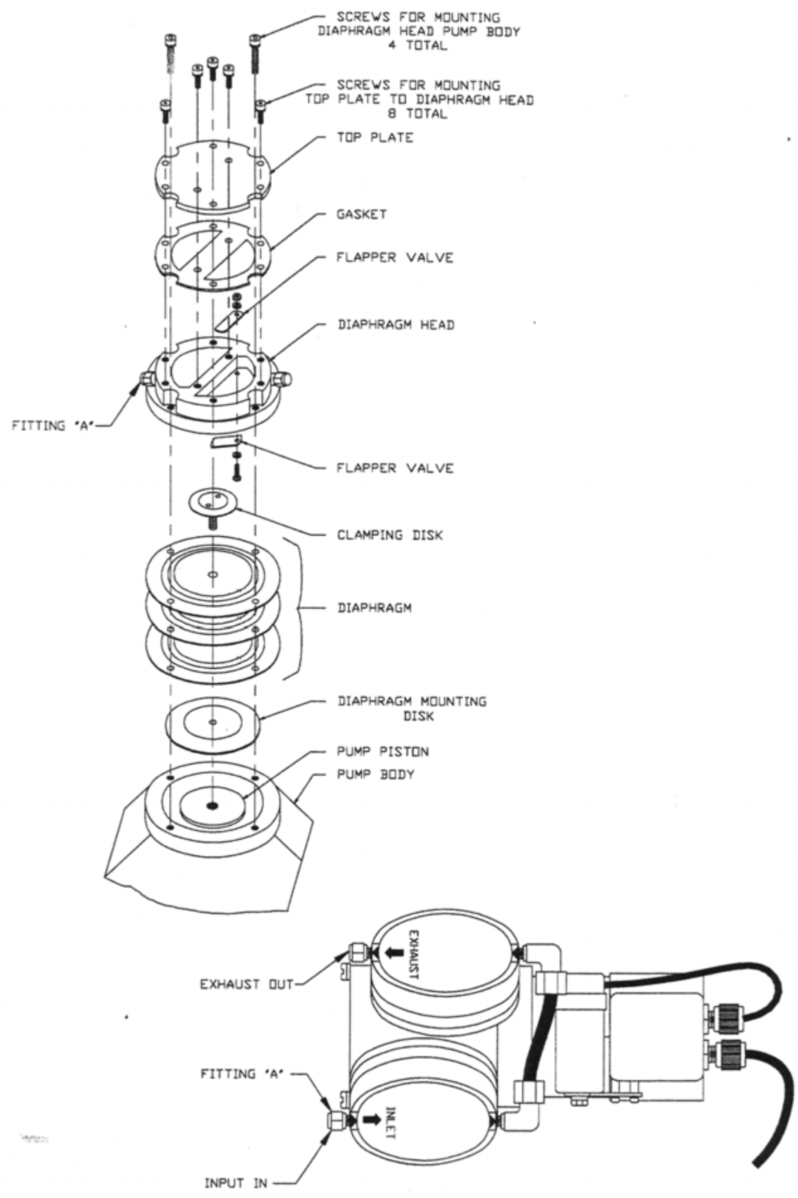


Figure 1 – KNF Pump Assembly

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: System Leak Test Procedure

MAINTENANCE FREQUENCY: See O&M, QA Manuals and Referenced PMPs

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 2 10” crescent wrenches or wrench set

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

System Leak Test

The System Leak Test is conducted to ensure that there are no leaks in the system that might impact the integrity of the sample and the sample analysis. This procedure tests for leaks in the vacuum portion of the CEMS. Leaks downstream of the vacuum pump are in a positive pressure environment and will not normally impact sample integrity, but could impact the ability to get an adequate sample volume and/or pressure.

1) Place the system in the “out-of-service” mode.
2) Select the zero gas by selecting it from the “Test Gas” screen on the OIT Panel.
3) Place the 4-way calibration valve in the “cabinet” position.
4) Allow the system to stabilize. Typically 3-4 minutes is adequate.
5) Adjust the oxygen analyzer to a zero value.
6) Place the 4-way calibration valve in the “probe” position.
7) Allow the system to stabilize. Typically 4-5 minutes is adequate.
8) Look at the oxygen analyzer output, a reading greater than 0.20 indicates an unacceptable leak. The leak can be anywhere from the probe through the vacuum pump inlet. All fittings and parts should be checked for tightness and tubing needs to be checked for leakage.
9) Once the assembly is complete, place the CEM System “back-in-service”.
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change NH_3 Scrubber

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 9/16" open-end wrench, 7/16" open-end wrench or 10" adjustable wrench, Teflon tape, and replacement scrubber.
Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

NH_3 Scrubber:

An NH_3 (ammonia) scrubber is installed inline on the sample inlet prior to a NO_x analyzer in a CEM System on a process, which utilizes NH_3 to reduce NO_x emissions.

TO CHANGE NH_3 SCRUBBER

1) Place the CEM System in "Out-of-Service" mode.

2) Loosen and remove the compression fittings (connected to tubing) from each end of the NH_3 scrubber housing.

3) Loosen and remove (Teflon taped) threaded fittings from each end of the NH_3 scrubber housing.

   Note: Take note that the NH_3 scrubber housing is marked with a "direction of flow arrow" which points towards the analyzer.

4) Remove old Teflon tape from housing fitting threads and replace with new Teflon tape.

   Note: Teflon tape threads that are inserted into the NH_3 scrubber (apply clockwise going with the threads) — the threads that insert into the compression fittings (on the tubes) do ***not*** get Teflon taped.

5) Install NH_3 scrubber housing fittings to the appropriate end of the ***new*** NH_3 scrubber housing.

   Note: Refer to the "direction of flow arrow" note.

6) Securely tighten the ***new*** NH_3 scrubber housing fittings to the compression fittings.

7) Once the assembly is complete, place the CEM System "Back-in-Service".

8) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.