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Gas-Fired Boiler and Turbine Air Toxics Summary Report

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REPORT SUMMARY

This document summarizes field measurements of toxic emissions from various gas-fired boilers and combustion turbines. The target analytes include the trace metals, formaldehyde, benzene, toluene, polycyclic aromatic hydrocarbons (PAHs), polychlorinated biphenyls (PCBs), and dioxin/furans. The results allow utilities to estimate emissions from gas-fired boilers and combustion turbines for permit applications, to inform the policy debate, and to help define benchmarks for improved operations.

Background

EPRI initiated the PISCES (Power Plant Integrated System: Chemical Emissions Study) project to collect and review data regarding the source, distribution, and fate of chemicals in fossil-fuel-fired power systems. While much of the EPRI PISCES field measurements focused on coal and oil-fired power plants, EPRI, Gas Research Institute (GRI), and various electric utilities sponsored a research program to characterize trace substance emissions from gas-fired boilers and combustion turbines. In addition, GRI conducted additional field studies on industrial turbines. Such information will help electric utilities meet permitting application requirements and effectively manage environmental emissions. Individual utilities can apply the EPRI field results to estimate plant-specific emissions.

Objectives

To characterize trace substance emissions from gas-fired boilers and combustion turbines.

Approach

Researchers conducted air toxic field measurements at two utility boilers, two utility combustion turbines, and seven industrial turbines. They measured trace metals, formaldehyde, benzene, toluene, PAHs, PCBs, dioxin/furans, and the criteria pollutants using sampling and analytical protocols consistent with previous PISCES air toxics field measurements. To evaluate the effect on formaldehyde, benzene, and toluene emissions, researchers also conducted parametric testing over a range of operating conditions.

Results

Trace metal emissions were consistently near or below the method detection limits. Organic emissions from utility boilers also were generally low and were not affected by varying load or excess air. However, the load at which a gas turbine operates can affect emissions of benzene, toluene, and formaldehyde, as well as hydrocarbons, CO, and NOx.

EPRI Perspective

The emission results from this study will help utilities estimate and manage the trace substance emissions from gas-fired boilers and combustion turbines. EPRI's Emission Factors Handbook (TR-105611) incorporates the various EPRI and DOE field studies and offers suggested emission factors for gas-fired boilers, as well as coal and oil-fired boilers.

EPRI is seeking to conduct additional PISCES field measurements at power plants employing advanced generation technologies such as gasification-combined-cycle and fluidized-bed combustion. Other EPRI PISCES measurements will focus on (1) mercury speciation measurements at conventional coal-fired power plants, (2) nickel speciation measurement at oil-fired power plants, (3) additional field testing to measure trace substances in power plant water and solid-waste streams, and (4) field measurements at power plants burning or co-firing alternative fuels such as biomass, petroleum coke, Orimulsion™, and refuse-derived fuels.

TR-105646

Interest Categories

Air toxics measurement & control
Combustion turbine/combined cycle plants

Keywords

Air toxics
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ABSTRACT

The Electric Power Research Institute, the Gas Research Institute, and various electric utilities sponsored a research program to characterize trace substances emissions from gas-fired boiler and combustion turbines. Field measurements were conducted at two utility boilers, two utility combustion turbines, and seven industrial turbines. The trace metals, formaldehyde, benzene, toluene, polycyclic aromatic hydrocarbons (PAHs), polychlorinated biphenyls (PCBs), and dioxin/furans were measured using sampling and analytical protocols consistent with previous EPRI PISCES air toxics field measurements. Parametric testing was conducted over a range of operating conditions to evaluate the effect on formaldehyde, benzene, and toluene emissions.

Trace metal emissions were consistently near or below the method detection limits. Organic emissions from utility boilers were also generally low, and were not affected by varying load or excess air. However, the load at which a gas turbine operates can affect emission of benzene, toluene, and formaldehyde, as well as hydrocarbons, CO, and No_x.

EXECUTIVE SUMMARY

In 1993 and 1994, Carnot conducted test programs to characterize hazardous air pollutant (HAP) emissions from a variety of gas-fired power generation units and industrial gas turbines. The power generation units that were tested included two utility boilers and two utility turbines. These test programs were funded by the Electric Power Research Institute (EPRI) and the Gas Research Institute (GRI) as part of the Power Plant Integrated Systems-Chemical Emissions Study (PISCES). In addition, Carnot conducted limited HAPs test programs on a number of industrial gas-fired turbines owned and operated by a natural gas transmission company. Testing at one of these sites was sponsored by GRI to support its investigation of air toxic emissions from gas-fired sources. Testing at the other industrial turbine sites was sponsored by the operator, and conducted in response to permitting requirements and compliance planning.

The key substances measured during the test programs are listed below:

• Trace Metals: cobalt, nickel,	Arsenic, barium, beryllium, cadmium, chromium, copper, lead, manganese, mercury, molybdenum, selenium, phosphorus, vanadium
• Semi-Volatile Organics:	Polycyclic aromatic hydrocarbons (PAH), polychlorinated biphenyls (PCB), polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF)
• Volatile Organics Compounds:	Formaldehyde, benzene, toluene
• Hydrocarbons:	CH_4, Total gaseous non-methane organics (TGNMO)
• Criteria Pollutants:	NO_x, CO

In addition to exhaust samples, Carnot also collected ambient air samples and fuel samples for analysis of selected compounds in an effort to determine the origins of the emissions. Some of the data that were collected from these test programs were then used to assess the public health risk through two independent studies.

Summaries of the NO_x emission factors (lb/10^{12}Btu or lb/MMBtu) along with mass emissions (tons/year) at maximum and minimum loads for each unit tested are presented in Tables S-1 through S-5 as follows:

Table S-1 Air Pollutant Summary for Two Gas-Fired Utility Boilers

Table S-2 Air Pollutant Summary for Two Gas-Fired Utility Turbines

Table S-3 Air Pollutant Summary for Two Gas-Fired GE Industrial Turbines

Table S-4 Air Pollutant Summary for Two Gas-Fired Rolls Royce Industrial Turbines

Table S-5 Air Pollutant Summary for Three Gas-Fired Solar Industrial Turbines

The mass emissions were calculated from the emissions factors and the unit heat input and assumed 8,670 hours of operation at each load condition per year. Thus, if the units are run continuously all year, the actual mass emissions would fall within the range of values indicated for maximum and minimum loads.

The results of the air toxics testing conducted at the utility sites was put into the context of public health risk through two independent health risk assessment (HRA) studies. One study was conducted by Carnot with GRI funding, and a separate study was conducted by EPRI. The study conducted by Carnot was a "screening" study that examined one unit from each of the following classes:

- Natural Gas-Fired Boiler
- Oil-Fired Boiler
- Coal-Fired Boiler
- Natural Gas-Fired Utility Turbine without NO_x Control
- Natural Gas-Fired Turbine with Water Injection for NO_x Control

The objective of the study performed by Carnot was to put natural gas-fired air toxic emissions into context relative to other fossil fuels with respect to overall health risk. The study was very conservative, as it was based on the Maximally Exposed Individual (MEI) experiencing exposure through inhalation, ingestion of soil and plants, and dermal uptake. EPRI's study was more extensive, in that it went beyond the use of health risk screening criteria and involved two investigations. The first investigation was an industry-wide evaluation of chronic risk associated with inhalation of substances for both the MEI and the Reasonably Exposed Individual (REI). The second investigation analyzed the risk associated with multimedia exposure: inhalation, ingestion, and dermal uptake.

The major conclusions drawn from the health risk assessment studies and the air toxics testing are summarized below:

- Emissions of hazardous air pollutants from gas-fired sources will not pose significant carcinogenic or non-carcinogenic public health risk.

- Barium, chromium, copper, lead, manganese, nickel, and vanadium are metals that were detected from some of the exhaust samples collected from the utility sources. It should be noted, however, that sampling and analytical variability, bias, and errors are a possible source of some of these measured emissions. As one example, the phosphorus field blank at Site 124 was 6.2 compared to 2.0 in the emissions. Thus, if sampling and analytical issues can lead to this level of variability from the field blank to the measured emissions, then any measurements within a factor of 3-5 could easily be due to sampling and analytical variability. At the indicated levels that metals were detected, the metals are not considered to pose a threat to public health. Potential sources of metal emissions are the unit heat transfer surfaces, the fuel, and the combustion air. Due to high detection limits associated with the fuel analyses, relative to the flue gas, the natural gas could not be ruled out as a potential source, albeit unlikely. The most likely source of the emissions for chromium, nickel and vanadium are previous boiler deposits from oil firing, although this fuel had not been fired for over one year.
- Emissions of semi-volatile organic compounds (PAH, PCB, PCDD, PCDF) from gas-fired utility sources were either not detected or were detected at levels less than 0.001 tons per year, which is several orders of magnitude lower than the 1990 Clean Air Act Amendments (CAAA) threshold of 10 or more tons per year for a single hazardous air pollutant, or 25 tons per year in aggregate, for determining major sources.
- VOC emissions from the utility boilers were less than 1.0 ton per year which is low from a health risk perspective and were not significantly impacted by unit load or excess air level.
- The load at which a given gas turbine is operated has a strong effect on the emissions of VOCs, hydrocarbons, CO and NO_x. Generally, NO_x increases with increasing load, and CO, benzene, toluene, formaldehyde, methane and TGNMO decrease with increasing load. This effect of load is primarily due to the design of a given turbine and its combustion characteristics.
- CO emissions may provide an indication of combustion conditions for a given turbine and turbine load. CO may be a suitable surrogate for estimating emissions of organic HAPs and other VOCs from gas turbines since conditions that reduce CO emissions (e.g., increased fuel/air mixing) generally reduce emissions of organic HAPs and other VOCs as well.

Table S-1

HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED UTILITY BOILERS

	B&W Opposed-Fired Boiler				**CE Tangentially-Fired Boiler**			
Compound	**Full Load** **330 Mwe** **3,300 MMBtu/hr**		**Minimum Load** **122 Mwe** **1,221 MMBtu/hr**		**Full Load** **750 Mwe** **7,500 MMBtu/hr**		**Minimum Load** **150 Mwe** **1,500 MMBtu/hr**	
Metals (1)								
•Barium	5.70 lb/10^{12}Btu	0.08 tpy	NT	NT	(2)	(2)	NT	NT
•Chromium	1.08 lb/10^{12}Btu	0.02 tpy	NT	NT	1.10 lb/10^{12}Btu	0.04 tpy	NT	NT
•Copper	1.20 lb/10^{12}Btu	0.02 tpy	NT	NT	(2)	(2)	NT	NT
•Nickel	1.19 lb/10^{12}Btu	0.02 tpy	NT	NT	3.60 lb/10^{12}Btu	0.12 tpy	NT	NT
•Vanadium	0.46 lb/10^{12}Btu	0.01 tpy	NT	NT	3.20 lb/10^{12}Btu	0.11 tpy	NT	NT
PAH (1)								
•Fluorene	ND	ND	NT	NT	0.003 lb/10^{12}Btu	0.0001 tpy	NT	NT
•Phenanthrene	0.016 lb/10^{12}Btu	0.0002 tpy	NT	NT	0.010 lb/10^{12}Btu	0.0003 tpy	NT	NT
•2-Methylnaphthalene	0.042 lb/10^{12}Btu	0.0006 tpy	NT	NT	0.009 lb/10^{12}Btu	0.0003 tpy	NT	NT
PCB	ND	ND	NT	NT	NT	NT	NT	NT
VOC								
•Formaldehyde	5.9 lb/10^{12}Btu	0.09 tpy	5.5 lb/10^{12}Btu	0.03 tpy	11.9 lb/10^{12}Btu	0.39 tpy	2.5 lb/10^{12}Btu	0.02 tpy
•Benzene	1.4 lb/10^{12}Btu	0.02 tpy	1.1 lb/10^{12}Btu	0.01 tpy	ND	ND	ND	ND
•Toluene	13.3 lb/10^{12}Btu	0.19 tpy	2.8 lb/10^{12}Btu	0.01 tpy	2.2 lb/10^{12}Btu	0.07 tpy	4.2 lb/10^{12}Btu	0.03 tpy
Hydrocarbons								
•Total HC as CH_4	2.0 x 10^4 lb/MMBtu	3 tpy	1.0 x 10^4 lb/MMBtu	1 tpy	NT	NT	NT	NT
•CH_4	NT	NT	NT	NT	ND	ND	ND	ND
•TGNMO	NT	NT	NT	NT	0.03 lb/MMBtu	821 tpy	0.02 lb/MMBtu	99 tpy
NO_x and CO								
•NO_x	0.12 lb/MMBtu	1,734 tpy	0.07 lb/MMBtu	369 tpy	0.13 lb/MMBtu	4,271 tpy	0.05 lb/MMBtu	296 tpy
•CO	0.06 lb/MMBtu	867 tpy	ND	ND	0.08 lb/MMBtu	2,628 tpy	ND	ND

Notes: ND = not detected.
NT = not tested
All values are for baseline conditions. See the body of the report for selected "low NO_x" conditions.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
(1) Only those compounds that were measured at levels more than twice the field blank level are shown. See Section 3.1 for more information on data handling procedures.
(2) Detected at the field blank level

Table S-2
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED UTILITY BOILERS

	Westinghouse 501AA Turbine				GE Frame 7 Turbine			
Compound	**Full Load** 330 MWe 3,300 MMBtu/hr		**Minimum Load** 122 MWe 1,221 MMBtu/hr		**Full Load** 750 MWe 7,500 MMBtu/hr		**Minimum Load** 150 MWe 1,500 MMBtu/hr	
Metals (1)								
•Barium	6.62 lb/10^{12}Btu	0.023 tpy	NT	NT	3.80 lb/10^{12}Btu	0.027 tpy	NT	NT
•Chromium	1.85 lb/10^{12}Btu	0.006 tpy	NT	NT	1.90 lb/10^{12}Btu	0.014 tpy	NT	NT
•Copper	3.13 lb/10^{12}Btu	0.011 tpy	NT	NT	6.20 lb/10^{12}Btu	0.044 tpy	NT	NT
•Lead	(2)	(2)	NT	NT	0.53 lb/10^{12}Btu	0.004 tpy	NT	NT
•Manganese	3.47 lb/10^{12}Btu	0.012 tpy	NT	NT	(2)	(2)	NT	NT
•Nickel	1.60 lb/10^{12}Btu	0.006 tpy	NT	NT	1.20 lb/10^{12}Btu	0.009 tpy	NT	NT
PAH (1)								
•Phenanthrene	0.111 lb/10^{12}Btu	0.0004 tpy	NT	NT	(2)	(2)	NT	NT
•2-Methylnaphthalene	0.162 lb/10^{12}Btu	0.0006 tpy	NT	NT	(2)	(2)	NT	NT
PCB	ND	ND	NT	NT	ND	ND	NT	NT
PCDD/PCDF	(2)	(2)	NT	NT	(2)	(2)	NT	NT
VOC								
•Formaldehyde	87 lb/10^{12}Btu	0.30 tpy	985 lb/10^{12}Btu	1.02 tpy	15 lb/10^{12}Btu	0.11 tpy	7,539 lb/10^{12}Btu	16.09 tpy
•Benzene	6.4 lb/10^{12}Btu	0.02 tpy	10.1 lb/10^{12}Btu	0.01 tpy	1.3 lb/10^{12}Btu	0.01 tpy	9.9 lb/10^{12}Btu	0.02 tpy
•Toluene	60 lb/10^{12}Btu	0.21 tpy	86 lb/10^{12}Btu	0.09 tpy	21 lb/10^{12}Btu	0.15 tpy	206 lb/10^{12}Btu	0.44 tpy
Hydrocarbons								
•Total HC as CH_4	9.8 x 10^{-3}lb/MMBtu	34 tpy	1.6 x 10^{-2}lb/MMBtu	16 tpy	3.4 x 10^{-3}lb/MMBtu	24 tpy	5.2 x 10^{-2}lb/MMBtu	111 tpy
•CH_4	ND	ND	ND	ND	ND	ND	1.5 x 10^{-3}lb/MMBtu	3 tpy
•TGNMO	1.0 x 10^{-2}lb/MMBtu	35 tpy	1.6 x 10^{-2}lb/MMBtu	17 tpy	7.9 x 10^{-3}lb/MMBtu	56 tpy	1.1 x 10^{-2}lb/MMBtu	23 tpy
NO_x and CO								
•NO_x	0.45 lb/MMBtu	1,538 tpy	0.23 lb/MMBtu	235 tpy	0.13 lb/MMBtu	953 tpy	0.15 lb/MMBtu	316 tpy
•CO	0.005 lb/MMBtu	17 tpy	0.111 lb/MMBtu	115 tpy	0.002 lb/MMBtu	14 tpy	0.635 lb/MMBtu	1,355 tpy

Notes: ND = not detected.

NT = not tested.

Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.

(1) Only those compounds that were measured at levels more than twice the field blank level are shown. See Section 3.1 for more information on data handling procedures.

(2) Detected at the field blank level.

Table S-3
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED GE INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

	GE Frame 3				**GE LM1500**			
	Full Load **7.7 MWeq** **87 MMBtu/hr**		**Minimum Load** **3.9 MWeq** **44 MMBtu/hr**		**Full Load** **10.6 MWeq** **145 MMBtu/hr**		**Minimum Load** **2.7 MWeq** **36 MMBtu/hr**	
Compound								
VOC								
•Formaldehyde	260 lb/10^{12}Btu	0.10 tpy	419 lb/10^{12}Btu	0.08 tpy	4,189 lb/10^{12}Btu	2.66 tpy	25,450 lb/10^{12}Btu	4.04 tpy
•Benzene	3.4 lb/10^{12}Btu	0.001 tpy	4.2 lb/10^{12}Btu	0.001 tpy	39 lb/10^{12}Btu	0.025 tpy	2,359 lb/10^{12}Btu	0.375 tpy
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons								
•CH_4	ND	ND	0.012 lb/MMBtu	2 tpy	0.029 lb/MMBtu	18 tpy	2.17 lb/MMBtu	345 tpy
•TGNMO	0.008 lb/MMBtu	3 tpy	0.011 lb/MMBtu	2 tpy	0.013 lb/MMBtu	8 tpy	0.274 lb/MMBtu	44 tpy
NO_x, CO, SO_2, N_2O								
•NO_x	0.73 lb/MMBtu	278 tpy	0.51 lb/MMBtu	97 tpy	0.36 lb/MMBtu	229 tpy	0.07 lb/MMBtu	11 tpy
•CO	0.004 lb/MMBtu	2 tpy	0.018 lb/MMBtu	3 tpy	0.158 lb/MMBtu	100 tpy	3.57 lb/MMBtu	567 tpy
•SO_2	1.8 x 10^{-4}lb/MMBtu	0.07 tpy	2.3 x 10^{-4}lb/MMBtu	0.04 tpy	2.4 x 10^{-4}lb/MMBtu	0.15 tpy	1.8 x 10^{-4}lb/MMBtu	0.03 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
MWeq = 1,340 hp

Table S-4

HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED ROLLS ROYCE INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

	Rolls Royce Avon				**Rolls Royce Spey**			
Compound	**Full Load** **10.7 MWeq** **158 MMBtu/hr**		**Minimum Load** **2.7 MWeq** **40 MMBtu/hr**		**Full Load** **12.2 MWeq** **132 MMBtu/hr**		**Minimum Load** **3.1 MWeq** **33 MMBtu/hr**	
VOC								
•Formaldehyde	5,607 lb/10^{12}Btu	3.88 tpy	14,997 lb/10^{12}Btu	2.59 tpy	18.5 lb/10^{12}Btu	0.01 tpy	13,227 lb/10^{12}Btu	1.91 tpy
•Benzene	15.7 lb/10^{12}Btu	0.011 tpy	53 lb/10^{12}Btu	0.009 tpy	5.7 lb/10^{12}Btu	0.003 tpy	63 lb/10^{12}Btu	0.009 tpy
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons								
•CH_4	0.085 lb/MMBtu	ND	0.504 lb/MMBtu	87 tpy	0.012 lb/MMBtu	7 tpy	0.039 lb/MMBtu	6 tpy
•TGNMO	0.031 lb/MMBtu	21 tpy	0.110 lb/MMBtu	19 tpy	0.004 lb/MMBtu	2 tpy	0.076 lb/MMBtu	11 tpy
NO_x, CO, SO_2, N_2O								
•NO_x	0.237 lb/MMBtu	164 tpy	0.123 lb/MMBtu	21 tpy	0.575 lb/MMBtu	332 tpy	0.133 lb/MMBtu	77 tpy
•CO	0.410 lb/MMBtu	284 tpy	1.30 lb/MMBtu	225 tpy	0.20 lb/MMBtu	29 tpy	0.906 lb/MMBtu	131 tpy
•SO_2	3.0×10^{-4}lb/MMBtu	0.21 tpy	2.9×10^{-4}lb/MMBtu	0.05 tpy	2.8×10^{-4}lb/MMBtu	0.16 tpy	3.1×10^{-4}lb/MMBtu	0.05 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
MWeq = 1,340 hp

Table S-5
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR THREE GAS-FIRED SOLAR INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

	Mars T12000				Mars T14000				Mars T14000 SoLoNO$_x$			
	Full Load		Minimum Load		Full Load		Minimum Load		Full Load		Minimum Load	
	9.4 MWeq		2.4 MWeq		10.9 MWeq		2.7 MWeq		10.9 MWeq		3.8 MWeq	
Compound	100 MMBtu/hr		25 MMBtu/hr		110 MMBtu/hr		28 MMBtu/hr		110 MMBtu/hr		39 MMBtu/hr	
VOC												
•Formaldehyde	15.6	0.01 tpy	9,430 lb/10^{12}Btu	1.03 tpy	2.2 lb/10^{12}Btu	0.00 tpy	2,485	0.30 tpy	14.6 lb/10^{12}Btu	0.01 tpy	20,347	3.43 tpy
•Benzene	2.0 lb/10^{12}Btu	0.001	10.2 lb/10^{12}Btu	0.001 tpy	1.3 lb/10^{12}Btu	0.001 tpy	2.4 lb/10^{12}Btu	0.000 tpy	2.9 lb/10^{12}Btu	0.001 tpy	67 lb/10^{12}Btu	0.011
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons												
•CH_4	ND	ND	0.207 lb/MMBtu	23 tpy	ND	ND	0.019	2 tpy	0.003	1 tpy	2.66 lb/MMBtu	449 tpy
•TGNMO	0.010	4 tpy	0.043 lb/MMBtu	5 tpy	0.006	3 tpy	ND	ND	0.003	1 tpy	0.368	62 tpy
NO_x, CO, SO_2, N_2O												
•NO_x	0.517	226 tpy	0.121 lb/MMBtu	13 tpy	0.606	292 tpy	0.191	23 tpy	0.099	48 tpy	0.110	19 tpy
•CO	0.006	3 tpy	1.25 lb/MMBtu	137 tpy	0.005	2 tpy	0.220	26 tpy	0.015	7 tpy	4.90 lb/MMBtu	826 tpy
•SO_2	2.2x10	0.10 tpy	1.9x10	0.02 tpy	ND	ND	ND	ND	2.1x10	0.10 tpy	2.3x10	0.04 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT	0.004	2 tpy	0.587	99 tpy

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions are based on 8,760 hours of operation.
MWeq = 1,340 hp

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1

BACKGROUND

Title III of the 1990 Clean Air Act Amendments (CAAA) designates 189 chemicals or groups of chemicals as hazardous air pollutants (HAPs), and requires the Environmental Protection agency (EPA) to promulgate emission standards based upon maximum achievable control technology for all new and existing industrial major sources of HAPs. As part of Title V of the 1990 CAAA, each major source of regulated air pollutants must also characterize each regulated pollutant that it emits as part of its operating permit. As defined in the CAAA, a major source of HAPs is any single source, or group of sources, located within a contiguous area and under common control, that emits, or has the potential to emit, 10 tons per year (tpy) or more of any one listed HAP, or 25 tpy or more of any combination of listed HAPs. A major source of criteria pollutants emits, or has the potential to emit, 100 tpy of a single criteria pollutant (e.g., NO_x, CO, SO_2, VOCs, particulate matter). Under Title III, electric utility steam generating units are to be reviewed separately based upon utility reports which characterize air toxic emissions and health risks posed to the public. It should be noted that electric utility combustion turbines are not included within the definition of electric utility steam generating units.

As emissions of HAPs become more tightly regulated and incorporated into health risk assessment analyses, accurate measurement of these compounds becomes extremely important. In those cases where regulatory agencies ascribe one-half the detection limit to non-detected compounds, lower analytical detection limits may be necessary to insure appropriate assessments of health risk associated with a source. In addition, appropriate quantification of HAP emissions variation with load and other operating parameters must be made to fully understand the health risk associated with a given source.

This report presents a summary of the criteria pollutants and HAPs emitted from a variety of gas-fired stationary sources including utility boilers, utility turbines, and turbines used for natural gas transmission. All of the emissions data were compiled from previous reports prepared by Carnot from several emissions test programs performed in 1993 and 1994, including the Field Chemical Emissions Monitoring (FCEM) programs supporting the Power Plant Integrated Systems - Chemical Emissions Study (PISCES) sponsored by EPRI, GRI and several utilities. This report also includes a brief summary of two independent health risk assessments (one performed by Carnot under GRI funding and one performed by EPRI) which are used to place HAP emissions in the context of public health impacts. The documents used as the basis for this report are listed in Appendix A.

2

TEST PROGRAM DESCRIPTIONS

During 1993 and 1994, Carnot conducted air toxic emissions measurement programs on a variety of units. Three categories of units tested were:

Category I:	Utility Boilers
Category II:	Gas Turbines used for electric generation
Category III:	Gas Turbines used at compressor stations for natural gas transmission

This section presents a description of the test program goals, descriptions of all units tested, and a brief summary of the test methodologies.

2.1 TEST PROGRAM OBJECTIVES

The testing on units in Categories I and II were Field Chemical Emissions Monitoring (FCEM) programs supporting the Power Plant Integrated Systems - Chemical Emissions Study (PISCES) and were funded by EPRI, GRI and several US utilities. FCEM Program Objectives for the Category I and Category II units were to:

1. Characterize emissions of hazardous air pollutants (HAPs) from various utility sources.
2. Provide a full set of data for EPRI's PISCES program on two natural gas-fired boilers and two natural gas-fired turbines that are fairly representative of the US population. The boilers included one wall-fired Babcock & Wilcox boiler and one tangentially-fired Combustion Engineering boiler. Both boilers are equipped with low NO_x combustion controls including flue gas recirculation (FGR), overfire air (OFA) and off-stoichiometric firing capability through burners-out-of-service (BOOS) operation. The turbines included a first generation Westinghouse design and a General Electric Frame 7 design. The Westinghouse turbine is not equipped with NO_x control while the GE Frame 7 utilizes water injection for NO_x reduction.
3. Perform additional tests to characterize the influence of operating parameters including load, excess air, flue gas recirculation and burner patterns, where applicable, on benzene, toluene, and formaldehyde emissions.
4. Obtain air toxic emissions data for use in responding to requests for emission inventory data from state and local regulatory agencies.

5. Analyze the natural gas fuel to characterize major constituents and trace compounds.

The gas turbine programs also included testing to obtain ambient air concentrations of trace metals, benzene, toluene, and formaldehyde with which to compare to turbine exhaust levels. These tests were performed to identify potential ambient contributions to exhaust measurements due to a large percentage of air that bypasses the primary combustion zone and is used for film cooling of the turbine can.

There were seven units in Category III that were tested representing designs by three manufacturers: General Electric, Rolls Royce, and Solar. All of these units are owned and operated by a US gas transmission company who funded the testing as part of their own internal regulatory efforts including:

- required compliance testing in accordance with local air district regulations
- engineering emissions to provide the sources with VOC data to support planning and permitting efforts in response to Title V of the 1990 Clean Air Act Amendments

The specific test objectives for these units included:

1. Evaluation of gaseous emissions (NO_x, CO, O_2, CO_2) and exhaust flow rate as a function of turbine load.
2. Evaluation of VOC emissions (benzene, toluene, formaldehyde) and methane/TGNMO emissions as a function of turbine load.
3. Evaluation of SO_2 emissions potential by evaluating sulfur content in the fuel.

One of the units manufactured by Solar is designed for low NO_x emissions. It is the Solar Mars T14000 SoLoNO_x turbine. GRI co-funded testing on this unit to supplement its own engineering emissions test programs to quantify gas toxics emissions from modern gas turbines designed for low-NO_x emissions. Thus, testing on this unit also included measurements to:

1. Evaluate gaseous emissions of N_2O as a function of turbine load.
2. Evaluate ambient VOC and methane/TGNMO levels concurrent with stack emissions analysis.

2.2 Unit Descriptions

The key design features of each of the units tested are summarized in Table 2-1. As shown, a wide variety of units is represented. Details regarding each category are presented below.

2.2.1 Utility Boilers

The two boilers represent two different designs by the two primary US boiler manufacturers: B&W opposed-fired unit and CE tangentially-fired unit. Both units use natural gas as a primary fuel, and both are capable of firing residual fuel oil if needed. Although neither unit fired oil within the year prior to testing, there may be residual ash on the boiler surfaces from oil firing that may be currently contributing to emissions from the units. Both units are equipped with low NO_x features including flue gas recirculation (FGR), overfire air (OFA) and burners-out-of-service (BOOS) capability.

In an effort to assess the representativeness of the units tested, the Utility Data Institute (UDI) database was screened for boilers with natural gas capability. The distribution of US utility boilers that use natural gas as either a primary fuel or a backup fuel is shown in Figure 2-1. As shown, boilers that fire gas as the primary fuel and oil as the back-up fuel represent 57% of the US firing capability for units that fire gas. The distribution of US utility boilers that fire this combination of fuels is shown in Figure 2-2 as a function of burner manufacturer, firing configuration, and steam design. As shown, Babcock and Wilcox represents 48% of the gas/oil boiler capacity in service today, and Combustion Engineering represents 32% of the gas/oil boiler capacity in service today. Together, these companies represent 80% of the gas/oil boiler capacity in service today. Most of the remaining boilers were built by Foster Wheeler and Riley-Stoker. Thus, the two boilers selected for the PISCES program are representative of the US gas-fired boiler population.

2.2.2 Electric Power Generation Turbine

The electric power generator turbines tested represent two different designs by US turbine manufacturers. One is manufactured by Westinghouse and one by General Electric. These turbines are fairly representative of gas turbine designs used for electric power generation as noted in Figures 2-3 and 2-4.

Table 2-1
GAS UNIT DESCRIPTIONS

Category	Site ID[1]	Unit Type	Use	Manufacturer	Model/Design	MCR[2]	Max Heat in[3] MMBtu/hr	NO_x Control[4]	Alternate Fuel
I	121	Boiler	elec generation	B&W	opposed fired	330 MWe	3,300	FGR, OFA, BOOS	res oil
	120	Boiler	elec generation	CE	tangential	750 MWe	7,500	FGR, OFA, BOOS	low S res oil
II	123	Turbine	elec generation	Westinghouse	501AA	55/73 MWe[5]	789	none	No. 2 oil
	124	Turbine	elec generation	GE	Frame 7	150 MWe	1,624	H_2O injection	none
III	NA	Turbine	gas trans	GE	Frame 3	7.7 MWeq	87	none	none
	NA	Turbine	gas trans	GE	LM1500	10.6 MWeq	145	none	none
	NA	Turbine	gas trans	Rolls Royce	Avon	10.7 MWeq	158	none	none
	NA	Turbine	gas trans	Rolls Royce	Spey	12.2 MWeq	132	none	none
	NA	Turbine	gas trans	Solar	Mars T12000	9.4 MWeq	100	none	none
	NA	Turbine	gas trans	Solar	Mars T14000	10.9 MWeq	110	none	none
	NA	Turbine	gas trans	Solar	Mars T14000, $SoLoNO_x$	10.9 MWeq	110	lean, pre-mixed combustion at >50% MCR	none

Notes:

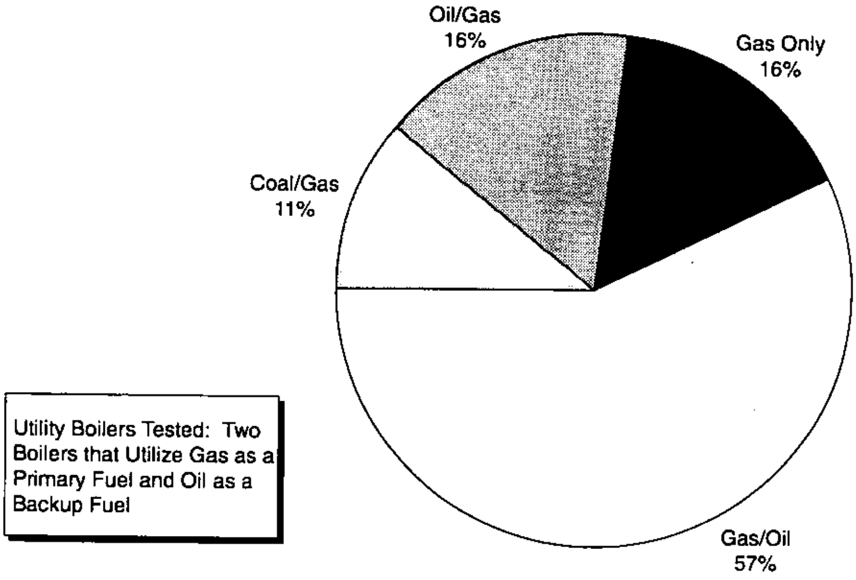
(1) Site ID for PISCES test reports submitted to the EPA.

(2) MWeq = 1,340 hp

(3) For the two boilers, this was determined based on a full-load heat rate of 10,000 Btu/kWh.

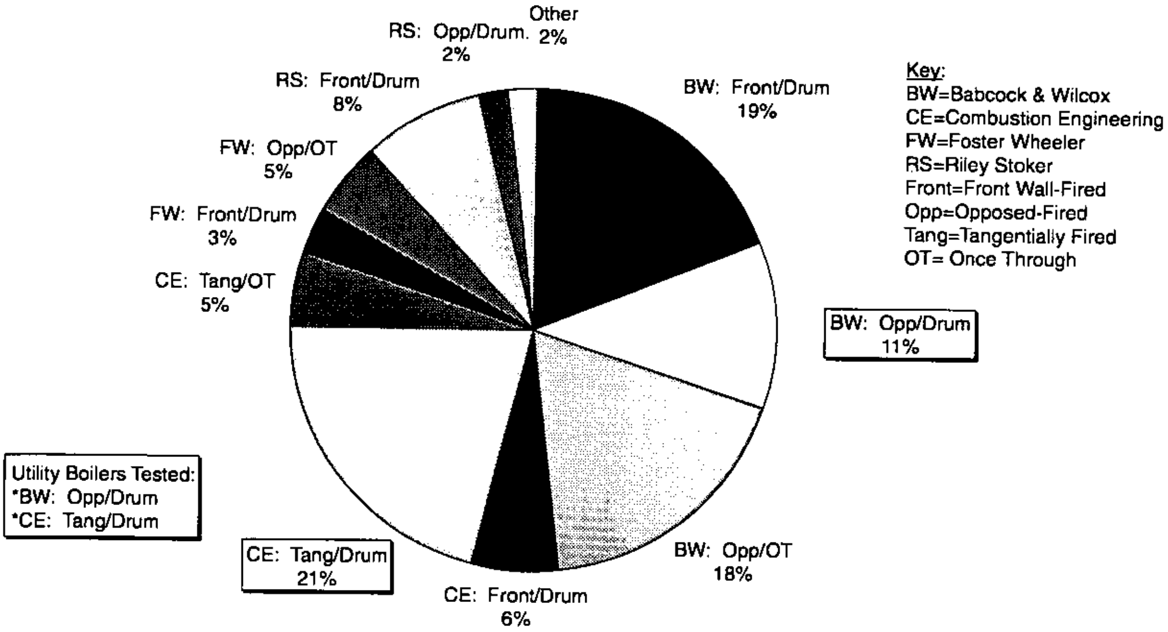
(4) FGR = Flue Gas Recirculation (to the hopper on the B&W unit and to the windbox on the CE unit)
OFA = Overfire Air
BOOS = Burners Out of Service

(5) During the summer, peak load is 55 MWe, and during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.



Utility Boilers Tested: Two Boilers that Utilize Gas as a Primary Fuel and Oil as a Backup Fuel

Figure 2-1 Distribution of US Utility Boilers that Use Natural Gas as Either a Primary Fuel or a Backup Fuel (from the UDI Database)
Based on capacity (MW)



Utility Boilers Tested:
*BW: Opp/Drum
*CE: Tang/Drum

Figure 2-2 Distribution of US Utility Boilers that Use Natural Gas as a Primary Fuel and Oil as a Backup Fuel (from the UDI Database)
Based on Capacity (MW)

The Westinghouse turbine is capable of generating up to 73 MW. However, it is usually only used at full capacity during the winter months. During the summer, maximum generation is typically 55 MW. Testing on this unit took place during the summer months. This unit fires No. 2 fuel oil as a back-up. This unit is not equipped with low NO_x controls

The distribution of US utility turbines that have dual fuel firing capability is shown in Figure 2-3. General Electric represents 48% of the firing capacity of these units while Westinghouse, Pratt and Whitney, and United Technologies represent 23%, 10%, and 10%, respectively. The Westinghouse turbine tested as part of the PISCES program is a Westinghouse Model 501AA. The 501 series turbine represents 16% of the dual fuel turbine capacity. Only the GE Frame 5 and 7 models represent more capacity. Thus, the Westinghouse 501 is fairly representative of the US dual fuel fired turbine capacity.

The GE Frame 7 unit can generate up to 150 MW and is equipped with a water injection system to reduce NO_x emissions. It does not have back-up fuel firing capability.

The distribution of US utility turbines that have natural gas firing capability only is shown in Figure 2-4. Again, GE represents a large percentage of total firing capacity for these units at 47%. Westinghouse, Pratt and Whitney, and United Technology are also fairly well represented at 20%, 13%, and 7%, respectively. The GE turbine tested during the PISCES program is a GE Frame 7, the single most popular model (based on capacity) firing natural gas in the US today. It represents 29% of the US firing capacity in this turbine category.

2.2.3 Compressor Station Gas Turbines

As shown in Table 2-1, seven industrial size gas turbines used at compressor stations for natural gas transmission were tested. For these units, Maximum Continuous Rating (MCR) is expressed in units of MWeq or power delivered to the pipeline compressor. The distribution of US gas turbines used for natural gas transmission based on power capacity is shown in Figure 2-5. The gas turbine models tested by Carnot represent 42% of the US capacity. In addition, models manufactured by both GE and Rolls Royce, the two most popular manufacturers, were included.

Only one of these units is equipped with low NO_x features. It is the Solar Mars T14000 "SoLoNO$_x$". This unit employs lean, pre-mixed combustion at loads above 50% MCR. At lower loads, the combustor operates in a turbulent diffusion mode. A schematic of emissions performed based upon SoloNO$_x$ turbine operation as a function of load is shown in Figure 2-6. Dry low NO_x combustion has recently emerged as an effective method of NO_x reduction for gas turbines, particularly for turbines used for gas transmission. These turbines utilize a premixed flame. Although the overall fuel to air ratio is the same for a diffusion flame and a premixed flame in this application, the stoichiometric ratio for the premixed flame is less than 1.0. Lean combustion yields a lower flame temperature which, in turn, reduces thermal NO_x emissions.

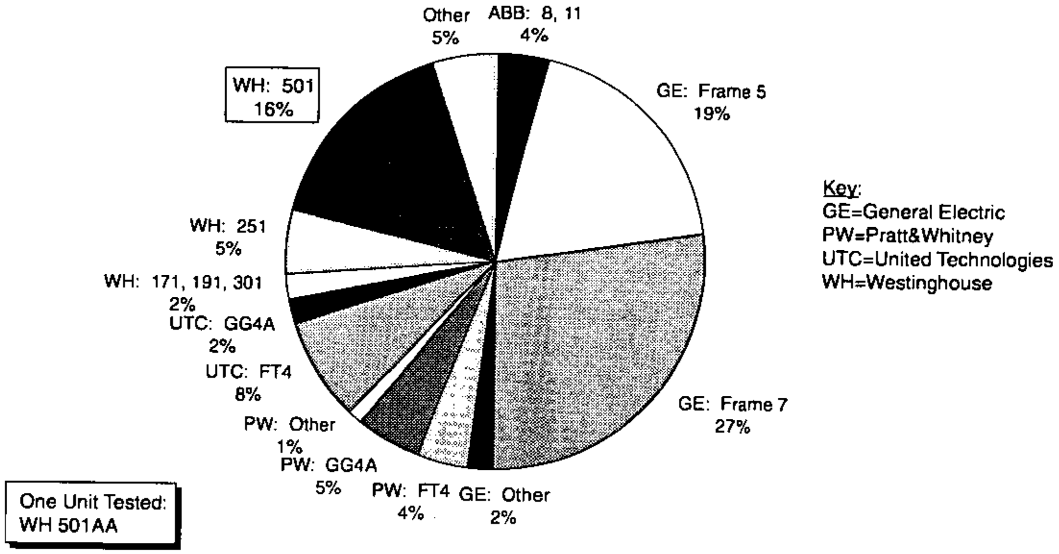


Figure 2-3 Distribution of US Utility Turbines that Have Dual Firing Capability (from the INTURB Database) Based on Capacity (MW)

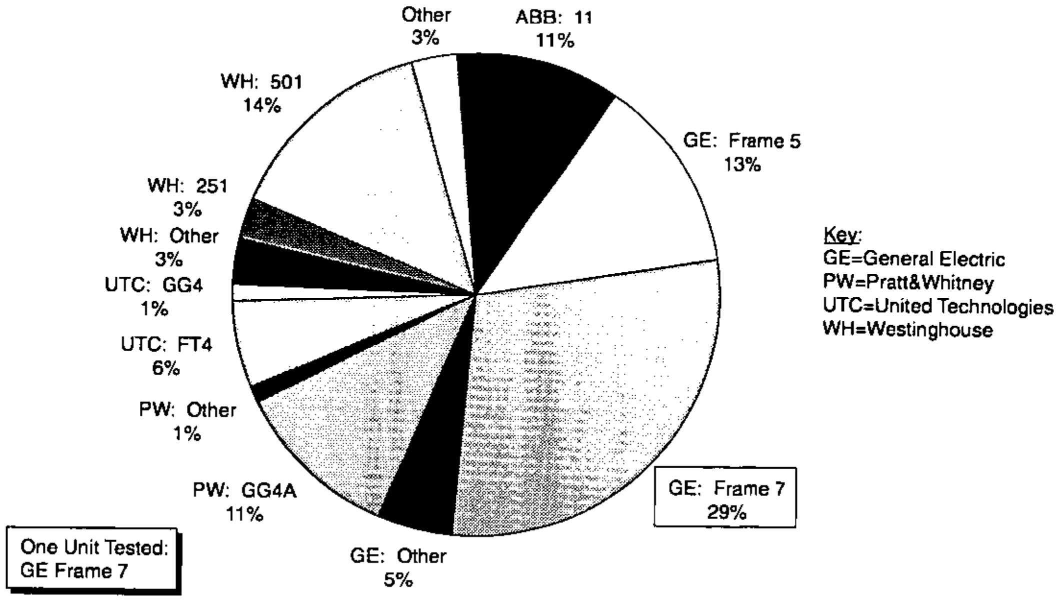


Figure 2-4 Distribution of US Utility Turbines that Fire Natural Gas Only (from the INTURB Database) Based on Capacity (MW)

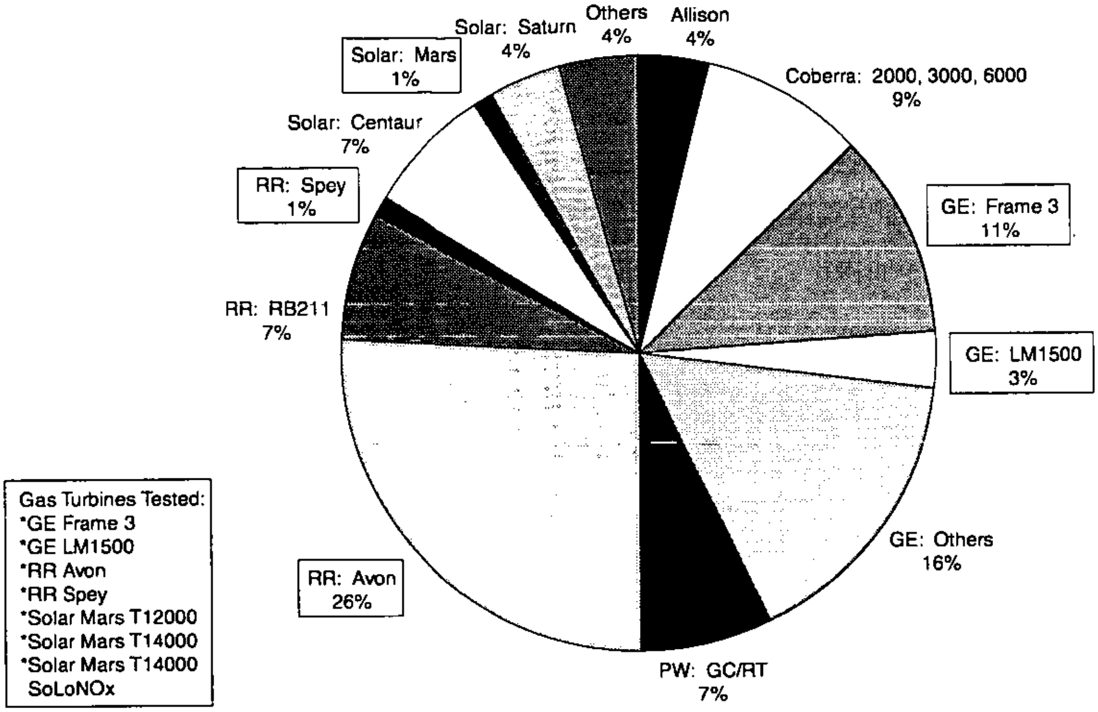


Figure 2-5 Distribution of US Gas Turbines Used for Natural Gas Transmission Based on Power Capacity (bhp)

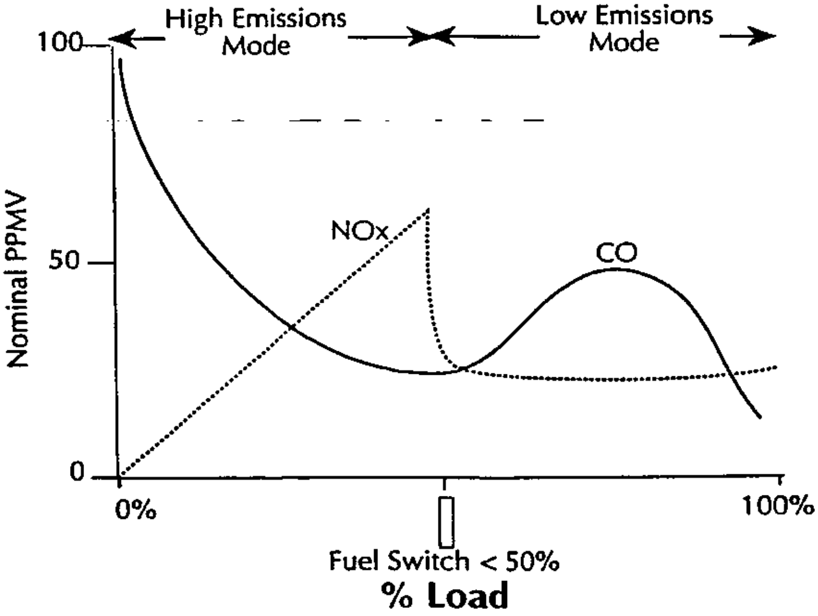


Figure 2-6 Solar Mars SoloNO$_x$ Emissions Characteristics (Indicative only)

2.2.4 Natural Gas Fuel Characteristics

Analyses for the natural gas fuels used at each site are summarized in Table 2-2. Methane percentage was fairly consistent among the natural gas samples taken with a standard deviation of only 1%. Nitrogen content was less than 1.75% for all sites. Sulfur content at levels detected is primarily attributable to addition of chemicals for odor and ranged from <0.10 ppm as H_2S at the utility sites to ≤ 1.7 ppm as H_2S at the gas transmission turbines. Heating values averaged 1,016 Btu/scf with a standard deviation of 13 Btu/scf (1.3% of the average). The gas samples for the utility units were also analyzed for trace compounds; however, most of these were not detected.

2.3 Test Conditions

The load conditions, operating parameters, compounds tested, and number of replicates for each compound are summarized in Table 2-3 for each of the units tested. The units are taken to be representative of their respective populations, although it should be noted that potential impacts can arise from variability in a source's condition or maintenance history. It was beyond the scope of the current study to document these impacts either qualitatively or quantitatively. Key features of the test program are noted below:

- All units were tested at 100% MCR with normal (or as-found) operating conditions. Full load testing on all units included measurements of:
  - NO_x, CO, O_2, CO_2
  - VOCs: formaldehyde, benzene, toluene
  - Methane/TGNMO and/or total hydrocarbons
- Full load tests on the utility boilers and the turbines used for electric generation also included:
  - metals
  - PAHs
- In addition, the B&W boiler and the GE Frame 7 electric generation turbine included measurements of PCBs. Both electric generation turbines included measurements for PCDD/PCDFs.
  - All of the industrial-sized turbines also included SO_2 evaluation via fuel samples.

Table 2-2
NATURAL GAS ANALYSIS SUMMARY

Unit Type	Use	Manufacturer	Model/Design	CH_4 mole, %	C_2H_6 mole, %	N_2 mole, %	Sulfur as H_2S, ppm	HHV Btu/scf
Boiler	elec generation	B&W	opposed fired	95.5	1.68	0.49	0.02	998
Boiler	elec generation	CE	tangential	96.2	1.85	1.00	0.02	1,002
Turbine	elec generation	Westinghouse	501AA	95.7	2.01	0.58	0.02	1,014
Turbine	elec generation	GE	Frame 7	95.7	2.12	0.54	0.07	1,014
Turbine	gas trans	GE	Frame 3	95.73	3.04	0.12	1.4	1,038
Turbine	gas trans	GE	LM1500	94.41	2.62	1.73	1.4	1,013
Turbine	gas trans	Rolls Royce	Avon	93.07	4.18	1.39	1.7	1,030
Turbine	gas trans	Rolls Royce	Spey	93.07	4.18	1.39	1.7	1,030
Turbine	gas trans	Solar	Mars T12000	95.73	3.04	0.12	1.4	1,038
Turbine	gas trans	Solar	Mars T14000	94.79	2.92	1.27	1.4	1,020
Turbine	gas trans	Solar	Mars T14000,	94.41	2.62	1.73	1.4	1,013
Mean(1),(2)				95.14	2.55	0.89	0.75	1,016
Standard Deviation(1),(2)				1.01	0.82	0.55	0.78	13

Notes:
(1) Analyses for turbines located at the same site were only counted once.
(2) One half of non-detects used.

Table 2-3 GAS TOXICS TEST MATRICES

Units Tested	% MCR	O_2 Level	FGR Level	BOOS	Number of Replicates												
					NO_x, CO, O_2, CO_2 (2)	SO_2	N_2O (2)	Metals	PAH	PCB	PCDD/ PCDF	Formal- dehyde	Benzene	Toluene	Methane	TGNMO	Total HC as C1(2)
1 Unit Tested:	100%	Norm	Norm	10	3	-	-	3	3	3	-	3	3	3	-	-	1
•BW opposed-fired	37%	Norm	Norm	8	1	-	-	-	-	-	-	2	2	2	-	-	1
utility boiler.	37%	Min	Norm	8	1	-	-	-	-	-	-	2	2	2	-	-	1
	37%	Max	Norm	8	1	-	-	-	-	-	-	2	2	2	-	-	1
1 Unit Tested:	100%	Norm	Norm	1	3	-	-	3	3	-	-	3	3	3	-	-	-
•CE tangentially-fired	100%	Min	High	0	1	-	-	-	-	-	-	2	2	2	2	2	-
utility boiler.	100%	Min	Low	0	1	-	-	-	-	-	-	2	2	2	2	2	-
	100%	Min	Norm	2	1	-	-	-	-	-	-	2	2	2	2	2	-
	20%	Norm	Norm	8	1	-	-	-	-	-	-	2	2	2	2	2	-
	20%	Min	High	8	1	-	-	-	-	-	-	2	2	2	2	2	-
	20%	Norm	High	12	1	-	-	-	-	-	-	2	2	2	2	2	-
1 Unit Tested:	100%	Norm	NA	NA	5	-	-	3(3)	3	3	3	3(3)	3(3)	3(3)	3	3	4
•Westinghouse	80%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	1
electric generation	50%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	1
turbine.	30%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	1
1 Unit Tested:	100%	Norm	NA	NA	4	-	-	3(3)	3	3	3	3(3)	3(3)	3(3)	3	3	1
•GE Frame 7 electric	70%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	2
generation turbine.	50%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	2
	30%	Norm	NA	NA	2	-	-	-	-	-	-	2(3)	2(3)	2(3)	2	2	2
6 Units Tested(1):	100%	Norm	NA	NA	3	3	-	-	-	-	-	3	3	-	3	3	-
•GE Frame 3	75%	Norm	NA	NA	3	3	-	-	-	-	-	-	-	-	-	-	-
•GE LM1500	50%	Norm	NA	NA	3	3	-	-	-	-	-	-	-	-	-	-	-
•RR Avon	25%	Norm	NA	NA	3(4)	3(4)	-	-	-	-	-	3(4)	3(4)	-	3(4)	3(4)	-
•RR Spey																	
•Solar Mars T12000																	
•Solar Mars T14000																	
1 Unit Tested(1):	100%	Norm	NA	NA	3	3	3	-	-	-	-	3(3)	3(3)	3(3)	3(3)	3(3)	-
•Solar Mars T14000	75%	Norm	NA	NA	2	2	2	-	-	-	-	2(3)	2(3)	2(3)	2(3)	2(3)	-
SoLoNO$_x$.	50%	Norm	NA	NA	2	2	2	-	-	-	-	2(3)	2(3)	2(3)	2(3)	2(3)	-
	35%	Norm	NA	NA	2	2	2	-	-	-	-	2(3)	2(3)	2(3)	2(3)	2(3)	-

Notes:
(1) Compressor station turbines;
(2) Continuous measurements using Carnot's or site's CEMS;
(3) Ambient levels also measured;
(4) At the GE Frame 3, this load condition was not tested. "Low load" formaldehyde, toluene, benzene, methane and TGNMO tests were conducted at 50% MCR.

Additional information regarding the test conditions during individual tests can be found in the test reports referenced in Appendix A.

2.4 Test Methodology

The sampling methods and analytical procedures used for each compound group measured are summarized in Table 2-4. Information regarding sample rates and detection limits for each individual compound measured is provided in Appendix B.1 and key aspects of the sampling and analysis procedures are summarized in Appendix B.2 of this report. Each of the test reports listed in Appendix A includes detailed descriptions of the test methods, analytical procedures, and QA/QC practices used for all of the test programs.

Table 2-4
SAMPLING AND ANALYTICAL PROCEDURES SUMMARY GAS TOXICS TESTING

Parameter	Reference Method	Measurement Principle[1]	Comments
NO_x	EPA 7E	Chemiluminescence	Multi-point composite with Carnot CEMS.
CO	EPA 10	NDIR/Gas Filter Correlation	Multi-point composite with Carnot CEMS.
O_2	EPA 3A	Electrochemical Cell	Multi-point composite with Carnot CEMS.
CO_2	EPA 3A	NDIR	Multi-point composite with Carnot CEMS.
SO_2	ASTM D 3246	Fuel Analysis	Grab sample.
N_2O	None	NDIR	Multi-point composite with Carnot CEMS.
Metals[2]	EPA Draft 29	ICP, Graphite Furnace AA or CVAA	Isokinetic traverse.
PAH	CARB 429	HRGC/LRMS-SIM	Isokinetic traverse.
PCB	CARB 428	HRGC/LRMS-SIM	Analysis from PAH train.
PCDD/PCDF	EPA 23	HRGC/HRMS	Analysis from PAH train.
Formaldehyde	CARB 430	HPLC	Collected in midget impingers at a single point.
Benzene	CARB 410A/EPA TO-14	GC/MS	Collected in Tedlar bags.
Toluene	CARB 410A/EPA TO-14	GC/MS	Collected in Tedlar bags.
Methane	CARB 410A/EPA TO-14	FID/TCA	Collected in Tedlar bags.
TGNMO	CARB 410A/EPA TO-14	FID/TCA	Collected in Tedlar bags.
Total HC as CH_4	EPA 25A	FID	Continuous measurement at a single point.
Stack Gas Velocity	EPA 2A	S-type Pitot	With all isokinetic tests.
Stack Gas Moisture	EPA 4	Gravimetric	With all isokinetic tests.

Notes:

(1) See individual reports referenced in Appendix A for sample rate, detection limit, and sample volume information.

(2) Includes Arsenic, Barium, Beryllium, Cadmium, Chromium, Cobalt, Copper, Lead, Manganese, Mercury, Molybdenum, Nickel, Phosphorus, Selenium, Vanadium.

3

EMISSIONS FACTORS AND TEST RESULTS

This section presents emissions factors (lb/MMBtu) for each compound measured from the utility boilers, utility turbines, and gas transmission turbines tested. The emissions factors are shown as a function of load (% MCR) and general trends are described briefly in the text that follows.

3.1 DATA HANDLING PROCEDURES

Treatment of non-detects (analytical results for which the concentration of the species of interest is below the detection limit of the method) and blank values is of critical importance to this program because detection levels and blank concentrations are often of the same order of magnitude as sample values. When the results are then used for risk assessment or policy decisions, treatment of the data becomes important. Procedures were developed during the PISCES test programs to treat blank and non-detect values and are summarized below.

3.1.1 Non-Detect

The discussion presented below describes how to average, sum, and report emission values for various combinations of results that include detected and non-detected values.

All values detected. The average or sum is taken as appropriate. No special techniques are required.

All values below the detection limit. For individual test runs or species, the data are reported as "ND< (detection limit)." For cases where all three runs are below the detection limit, the average is reported as non-detect less than the average detection limit of the three runs. [Later, this convention was changed to presenting the largest reporting limit value expressed as "ND (the largest reporting limit value)." See References 5 and 6 for more information regarding this alternate data handling procedure. Because of this small difference in the way composite non-detected values were determined, there may be slight differences between the results presented in this report and the results presented in References 5 and 6 and Appendix C.2.]

Some values are detected and some are non-detects. As the best approximation, PISCES guidelines have settled on using half of the detection limit for non-detect values and the actual value for detects. As an example for averaging, an average for three test runs with the results 10, 8, and ND<6 would be 7. As an example for summing individual species values of 50, ND<1, and ND<2 would be summed to provide a value of 50+.5+1, or 51.5. In reporting these types of sums or average, no "<" sign is used. The only exception to this rule occurs when the average is less than the highest detection limit of the non-detected values. In this case, the average is reported as "ND<(the highest detection limit)." For example: 5, ND<4 and ND<3 would be reported as "ND<4."

Detection limit ratio. The methods described above may result in some loss of information in going from raw data to final values. Specifically, what is often lost is the amount of a final emission value that is attributable to detection limits and the amount that is attributable to measured values. In order to quantify and present this information, the "Detection Limit Component Ratio" was developed which is calculated as the ratio of the contribution of detection limit values to a final emission result to the emission result. For example, a set of three values of 12, ND<6, and 9 would be reported as 8, with a detection limit ratio of 13% ((3)/(12+3+9)). The different ratios provide insight as to the extent something is "really there," and hopefully can help provide better information to those making decisions on risk and policy issues. Lower detection limit ratios indicate a lower contribution to the average value from non-detects. The detection limit ratios were not included in this report but can be found in the PISCES reports listed in Appendix A.

3.1.2 Blank Values

The level and treatment of blank values is important in interpreting data, since in some cases species are detected but not at levels significantly higher than blanks. In these cases, measured values may not represent emissions, but rather just limitations of the method. However, most of the test methods used in this program either do not allow subtraction of blanks or are silent on how to treat blank values. In most cases, blanks are used as Quality Assurance indicators rather than to adjust the data.

With this in mind, the basic procedure followed in this program was not to subtract field blank values unless it was specifically called for or required in the method. In general, when reagent blank levels were found to contribute consistently to the field blank and sample values, they were subtracted. Both laboratory and Carnot reagent blanks were analyzed and subtracted from sample values when appropriate. In no case were blank results subtracted to levels below the analytical detection limit of the method. Detailed blank correction information is located in the references listed in Appendix A.

3.1.3 Data Segregation

The concentrations of the metals and semi-volatile organic compounds from the sources described in this report are extremely low and challenge the sampling and analytical (S&A) methods used. For the purposes of identifying potential "real" emissions levels of these trace compounds, the emissions were divided into three categories:

1. Detected concentrations at more than twice the field blank level.
2. Detected concentrations at less than twice the field blank level.
3. Concentrations below the analytical method detection limit.

The selection of twice the field blank value was based on the range of values measured and Carnot's past experience in air toxics evaluation. The reader should bear in mind that S&A variability, bias, error, etc. are possible sources of some of the "emissions" presented in this report. See the individual site reports listed in Appendix A for more information on S&A methods used during the PISCES program.

3.2 EMISSIONS FACTORS FOR GAS-FIRED UTILITY BOILERS

Air toxics emission programs were conducted on two gas-fired boilers as part of the PISCES FCEM programs. The units were a B&W opposed-fired boiler and a CE tangentially-fired boiler. Emissions factors for trace metals, organic compounds, NO_x and CO are presented in the following sections for these two boilers. The data are presented by boiler type to indicate the range of testing that was conducted. However, the data do not reveal significant differences in HAPs emissions between the two units. Furthermore, in Reference 10, EPRI reviewed the utility data and concluded that boiler design has little or no effect upon HAPs emissions.

3.2.1 Metals

Testing for metals was conducted at full load only. Emissions factors for each metal are summarized in Table 3-1. For each boiler, stack emissions are presented in $lb/10^{12}Btu$ and have been divided into three categories: 1) emissions measured at more than twice the field blank (FB) levels, 2) emissions measured at less than twice the field blank levels, and 3) species that were not detected by the analytical method. For those species that were not detected, the analytical method detection limit is shown preceded by "ND<." In addition, for each unit, natural gas fuel analyses were conducted for selected trace compounds and the results are also shown in Table 3-1 for direct comparison with stack emissions. Only eight of the fifteen target metals were tested for in the natural gas fuel. Key results are noted below:

Table 3-1
FULL LOAD METALS EMISSIONS FACTORS (lb/1012 Btu) FOR TWO GAS-FIRED UTILITY BOILERS

Metal	Site 121 B&W Opposed-Fired 330 Mwe				Site 120 CE Tangentially-Fired 750 MWe			
	Stack Gas Emissions				Stack Gas Emissions			
	Detected >FB(1)	Detected ~FB(2)	ND	Fuel Analysis	Detected >FB(1)	Detected ~FB(2)	ND	Fuel Analysis
Arsenic	--	0.2	--	0.25	--	0.23	--	ND<0.12
Barium	5.7	--	--	(3)	--	2.4	--	(3)
Beryllium	--	--	ND<0.01	(3)	--	--	ND<0.01	(3)
Cadmium	--	0.05	--	(3)	--	--	ND<0.03	(3)
Chromium	1.08	--	--	(3)	1.1	--	--	(3)
Cobalt	--	--	ND<0.11	ND<15.3(4)	--	0.12	--	ND<15.3(4)
Copper	1.2	--	--	ND<8.3(4)	--	0.25	--	ND<8.2(4)
Lead	--	0.58	--	ND<53.9(4)	--	0.27	--	ND<53.7(4)
Manganese	--	0.44	--	(3)	--	0.38	--	(3)
Mercury	--	--	ND<0.35	0.0013	--	--	ND<0.34	ND<0.0006
Molybdenum	--	1.9	--	(3)	--	0.58	--	(3)
Nickel	1.19	--	--	ND<7.6	3.6	--	--	ND<7.6
Selenium	--	--	ND<0.03	ND<0.4	--	--	ND<0.03	ND<0.4
Phosphorus(5)	--	4.6	--	ND<0.8	--	--	ND<0.54	ND<0.8
Vanadium	0.46	--	--	(3)	3.2	--	--	(3)

Notes:
(1) More than twice the field blank level
(2) Less than twice and more than the field blank level.
(3) Not analyzed in the fuel.
(4) Only a qualitative or semi-quantitative analysis can be done on these elements.
(5) The analytical method cannot distinguish between phosphorus and phosphate. The value shown is most likely phosphate. Note that phosphorus is a HAP while phosphate is not.

- Combustion Air. Ambient air samples were not collected at the utility boiler sites. However, barium is a common component of wind-borne soil and may have contributed to the stack emissions measured from the B&W boiler.
- Unit Surfaces. Unit surfaces are a possible source of chromium and nickel, since both are present in stainless steel. In addition, vanadium is present in large concentrations in fuel oil which had been fired in both utility boilers in prior years. Although it had been over a year since oil had been burned in the utility boilers, the levels of vanadium emissions are low so it is possible that they result from residual ash from oil firing.

3.2.2 Semi-Volatile Organic Compounds

Sampling for Polycyclic Aromatic Hydrocarbons (PAH) and Polychlorinated Biphenyls (PCB) was conducted at both the utility boilers at full load-only. Only those species that were detected are presented in Table 3-2. More information regarding detection limits for all of the semi-volatile compounds can be found in the individual site reports listed in Appendix A.

Table 3-2
FULL LOAD SEMI-VOLATILE ORGANIC EMISSIONS FACTORS (lb/10^{12}Btu)
FOR TWO GAS-FIRED UTILITY BOILERS

	Site 121 **B&W Opposed-Fired Boiler** **330MWe**	**Site 120** **CE Tangentially-Fired Boiler** **750 MWe**
PAH (detected species only):		
•Naphthalene	1.1	0.24
•Fluorene	--	0.003$^{(3)}$
•Phenanthrene	0.016$^{(3)}$	0.010$^{(3)}$
•2-Methylnaphthalene	0.042$^{(3)}$	0.009$^{(3)}$
PCB:	(1)	(2)

Notes:
(1) All PCB isomers not detected.
(2) Not tested.
(3) More than twice the field blank level.

3.2.2.1 PAH

Only a few PAH species were detected:

- Naphthalene was detected in all samples but levels were on the same order as the field blanks. This result is common, since naphthalene is a decomposition product of the XAD-2 resin used in the CARB 429 sampling train.
- Fluorene was detected at more than twice the field blank level at Site 120.

- Chromium, nickel, and vanadium were the only metals detected from both units above the field blank level.
- Barium and copper were detected from the wall-fired boiler.

In all cases, metal mass emissions did not exceed 0.2 ton per year.

The possible sources of the trace metals are the fuel, the combustion air, and the unit surfaces. Each of these possible sources is addressed below:

- Fuel. Limited fuel analyses for trace metallic compounds were conducted during the test programs at both sites. As shown, most of the eight metals analyzed were not detected in the fuel samples. The analyses for trace species in the fuel were performed by IGT. Note that, except for arsenic and mercury, the fuel analysis detection limits were higher than the stack gas analysis detection limits. As emission characteristics did not follow definitive trends, the results are presented generically for each of the boiler test sites.
- Site 121. Only arsenic and mercury were detected in the gas fuel used in the B&W utility boiler. None of the metals were detected in the other fuel samples. A mass balance on the B&W boiler showed that arsenic stack emissions levels were 80% of the fuel input. At this time, there is not enough information available to determine if this result is statistically significant. Mercury was detected in the B&W fuel sample, but not in the stack gas. The fuel method was more sensitive than the stack method for mercury. As a result, the fuel level of 0.0013 lb/10^{12}Btu is considered more representative of unit emissions than the non-detect value obtained for the stack gas. Copper, lead, and mercury were detected in the stack gas but not in the fuel. However, the detection limit of the natural gas fuel analysis was high so it cannot be determined if the emissions originated from the fuel. Neither cobalt nor selenium were detected in either the stack gas or fuel samples, although the stack gas analysis method had a lower detection limit. Phosphorus was detected in the stack gas but not in the fuel. In this case, the measured emissions were much higher than the fuel detection limit indicating that the phosphorus probably did not originate from the fuel.
- Site 120. In this case, none of the metals were detected in the fuel samples. Arsenic was detected at the field blank level in the stack gas. This level was almost twice as high as the fuel analysis detection limit indicating that the arsenic probably did not originate from the fuel. Cobalt, copper, lead, and mercury were all detected in the stack gas but not the fuel. However, the detection limits of the natural gas fuel analysis for these metals were high so it cannot be determined if the emissions originated from the fuel. Mercury, selenium, and phosphorus were not detected in either the stack gas or the fuel.

Table 3-3
HYDROCARBONS AND OTHER VOLATILE ORGANIC COMPOUND EMISSIONS FACTORS FOR TWO GAS-FIRED UTILITY BOILERS

Test Conditions		**MCR:**	**100%**	**100%**	**100%**	**100%**	**37%**	**37%**	**37%**	**20%**	**20%**	**20%**
		O_2:	**AF**	**Min**	**Min**	**Min**	**AF**	**Min**	**Max**	**AF**	**Min**	**AF**
		FGR:	**AF**	**High**	**Low**	**AF**	**AF**	**AF**	**AF**	**AF**	**High**	**High**
		BOOS[3]:	**AF**	**0**	**0**	**2**	**AF**	**AF**	**AF**	**AF**	**AF**	**12**
Emissions Factors												
Boiler	Compound[1],[2]											
Site 121	Formaldehyde	lb/10^{12}Btu	5.9				5.5	4.4	6.3			
B&W Opposed-Fired	Benzene	lb/10^{12}Btu	1.4				1.1	0.7	1.3			
330 MWe	Toluene	lb/10^{12}Btu	13.3				2.8	1.7	2.5			
	Total HC as CH_4	lb/MMBtu	2×10^{-4}				1×10^{-4}	5×10^{-6}	6×10^{-6}			
Site 120	Formaldehyde	lb/10^{12}Btu	11.9	2.7	4.3	4.4				2.5	2.4	2.7
CE Tangentially-Fired	Benzene	lb/10^{12}Btu	ND<0.4	0.9	0.7	0.5				ND<0.7	2.0	1.1
750 MWe	Toluene[4]	lb/10^{12}Btu	2.2	1.6	1.3	0.8				4.2	1.4	1.9
	CH_4	lb/MMBtu	(5)	ND<4.1×10^{-4}	ND<4.2×10^{-4}	ND<4.3×10^{-4}				ND<7.1×10^{-4}	ND<6.1×10^{-4}	ND < 7.0×10^{-4}
	TGNMO	lb/MMBtu	(5)	0.025	0.011	0.010				0.015	0.008	0.011

Notes:

(1) Total hydrocarbons were measured with a continuous FID analyzer, while TGNMO and the other VOCs were measured from bag samples collected in Tedlar bags.

(2) TGNMO was not included in the test program on the B&W boiler.

(3) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8.

(4) High field blank measured at this site.

(5) Hydrocarbons were not tested at this condition.

- Phenanthrene was detected from both units at more than twice the field blank level.
- 2-Methylnaphthalene was detected from both units.

The mass emissions of detected PAH species are less than 0.001 tons per year.

3.2.2.2 PCB

The semi-vost sample train used for the B&W boiler was also analyzed for PCB species but none were detected.

3.2.3 Hydrocarbons and Other Volatile Organic Compounds

Hydrocarbons and other volatile organic compound emissions factors for the two utility boilers are shown in Table 3-3 for each of the operating conditions that were tested. These emissions are comparable to other gas- and oil-fired boilers and are low from a health risk perspective. Some of the key points regarding the emissions from gas-fired boilers are highlighted below:

- Formaldehyde and benzene emissions were fairly uniform with load and operating condition. Mass emissions for these compounds ranged from 0.1-0.4 tons per year.
- Toluene emissions were fairly uniform with operating condition at minimum load. However, on average, full load toluene emissions factors were six times higher than at minimum load. It is not clear if the higher levels at full load are a real impact of unit load or due to non-representative test results. One of the three full load sample results was not included in the average because it was significantly higher than other toluene measurements conducted during this program. Despite the higher emissions factor, full load mass emissions were only 0.20 tons per year.
- Total hydrocarbons at Site 121, which were measured with a continuous FID analyzer, were higher at full load than at minimum load which is consistent with the CO emissions factors presented in the next section. Methane at Site 120, as measured from bag samples, was not detected at any test condition. However, total gaseous non-methane organics were detected at all test conditions.

3.2.4 NO_x and CO

Although the test programs were not designed as NO_x reduction programs, it was of interest to study the effect of low NO_x operating conditions on emissions of VOCs as discussed above. During the test programs, extensive gaseous emissions sampling was conducted in the exhaust ducting of the boiler. This information is helpful in evaluating the effectiveness of NO_x reduction techniques as a side issue during the air toxics testing.

NO_x and CO emissions factors for all of the operating conditions tested on each utility boiler are presented in Table 3-4. As shown, there were several test conditions on each boiler that were designated as "minimum O_2" conditions. These O_2 levels were established by the individual boiler operators to minimize NO_x emissions and maintain boiler efficiency.

For the B&W boiler at minimum load, NO_x emissions were reduced from 0.069 lb/MMBtu to 0.055 lb/MMBtu (20% reduction) when excess O_2 was minimized. During testing of the CE boiler at full load, NO_x emissions were reduced from 0.125 lb/MMBtu to 0.083 lb/MMBtu (34% reduction) when excess O_2 was minimized, flue gas recirculation was increased to a relatively high level, and all of the burners were put in service. During testing of the CE boiler at minimum load, increasing the flue gas recirculation with either minimum excess O_2 or an additional four burners out of service decreased emissions from 0.045 lb/MMBtu to 0.030 lb/MMBtu (33% reduction).

For both units, CO emissions were higher at full load as compared to minimum load. In fact, for both units, the minimum load CO emissions were less than the detection limit. This is due to the large amounts of excess air used at low loads to maintain steam temperatures and abide by the NFPA minimum air flow guideline of 25% of full load air flow. The higher levels of excess air yield more complete combustion, and, consequently, lower CO emissions. Although, none of the CO emissions were excessive for these units. CO concentrations during all conditions were less than 400 ppmc and most were less than 150 ppmc.

Table 3-4
NO_x AND CO EMISSIONS FACTORS FOR TWO GAS-FIRED UTILITY BOILERS

Test Conditions		**MCR** **O_2** **FGR** **BOOS**[1]	**100%** **AF** **AF** **AF**	**100%** **Min** **High** **0**	**100%** **Min** **Low** **0**	**100%** **Min** **AF** **2**	**37%** **AF** **AF** **AF**	**37%** **Min** **AF** **AF**	**37%** **Max** **AF** **AF**	**20%** **AF** **AF** **AF**	**20%** **Min** **High** **AF**	**20%** **AF** **High** **12**
Boiler	Emissions Factors Compound[1,2]											
Site 121 B&W	NO_x	lb/MMBtu	0.12				0.069	0.055	0.096			
Opposed-Fired 330 MWe	CO	lb/MMBtu	0.06				ND<3.7×10^{-3}	ND<3.7×10^{-3}	ND<3.7×10^{-3}			
Site 120 CE Tangentially-Fired 750 MWe	NO_x	lb/MMBtu	0.13	0.08	0.23	0.13				0.05	0.03	0.03
	CO	lb/MMBtu	0.08	0.08	0.30	0.11				ND<7.3×10^{-4}	ND<7.3×10^{-4}	ND<7.3×10^{-4}

Note:
(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8.

3.3 EMISSIONS FACTORS FOR GAS-FIRED UTILITY TURBINES

3.3.1 Metals

Testing for metals was conducted at full load only. Emissions factors for each metal are summarized in Table 3-5. Note that although the data have been segregated by unit type, metals emissions from the two units are very similar.

For each turbine, stack emissions are presented in lb/10^{12}Btu and have been divided into three categories: 1) emissions measured at more than twice the field blank (FB) levels, 2) emissions measured at less than twice the field blank levels, and 3) species that were not detected by the analytical method. For those species that were not detected, the analytical method detection limit is shown preceded by "ND<." In addition, for each unit, natural gas fuel analyses were conducted for trace compounds and the results are also shown in Table 3-1 for direct comparison with stack emissions. Only eight of the fifteen target metals were tested for in the natural gas fuel. Key results from the testing are addressed below:

- Barium, chromium, copper and nickel were detected from both turbines at levels greater than twice the field blank level.
- Manganese was detected at levels greater than twice the field blank level from the Westinghouse turbine only.
- Lead was detected at levels greater than twice the field blank level from the GE Frame 7 turbine only.

In no case did individual metal mass emissions exceed 0.02 tons per year.

The possible sources of the trace metals are the fuel, the combustion air, and the unit surfaces. Each of these possible sources is summarized below:

- <u>Fuel</u>. As shown in Table 3-5, none of the eight metals were detected in the fuel analyses from either unit. The analysis for trace species in the fuel was performed by IGT. Note that, except for arsenic and mercury, the fuel analysis detection limits were higher than the stack gas analysis detection limits. Comments regarding the metals analyzed follow below for each unit

Table 3-5

FULL LOAD METALS EMISSIONS FACTORS (lb/10^{12} Btu) FOR TWO GAS-FIRED UTILITY TURBINES

	Site 123 Westinghouse 501AA Turbine 55/73 MWe(1)				Site 124 GE Frame 7 Turbine 150 MWe			
	Stack Gas Emissions				Stack Gas Emissions			
Metal	**Detected >FB(1)**	**Detected ~FB(2)**	**ND**	**Fuel Analysis**	**Detected >FB(1)**	**Detected ~FB(2)**	**ND**	**Fuel Analysis**
Arsenic	--	--	ND<0.10	ND<0.12	--	0.18	--	ND<0.12
Barium	6.62	--		(4)	3.80	--	--	(4)
Beryllium	--	--	ND<0.03	(4)	--	--	ND<0.02	(4)
Cadmium	--	--	ND<0.01	(4)	--	--	ND<0.07	(4)
Chromium	1.85	--	--	(4)	1.90	--	--	(4)
Cobalt	--	0.50	--	ND<15.1(5)	--	--	ND<0.22	ND<15.1(5)
Copper	3.13	--	--	ND<8.1(5)	6.20	--	--	ND<8.1(5)
Lead	--	1.00	--	ND<53.0(5)	0.53	--	--	ND<53.0(5)
Manganese	3.47	--	--	(4)	--	4.50	--	(4)
Mercury	--	0.69	--	ND<0.0006	--	--	ND<0.55	ND<0.0006
Molybdenum	--	5.53	--	(4)	--	3.70	--	(4)
Nickel	1.6	--	--	ND<7.5	1.20	--	--	ND<7.5
Selenium	--	--	ND<0.09	ND<0.4	--	--	ND<0.06	ND<0.4
Phosphorus(6)	--	17.80	--	ND<0.8	--	11.90	--	ND<0.8
Vanadium	--	--	ND<0.20	(4)	--	--	ND<0.13	(4)

Notes:

(1) During the summer, peak load is 55 MW, and, during the winter, peak load is 73 MW. Testing on this unit was conducted during the summer.

(2) More than twice the field blank level.

(3) Less than twice and more than the field blank level.

(4) Not analyzed in the fuel.

(5) Only a qualitative or semi-quantitative analysis can be done on these elements.

(6) The analytical method cannot distinguish between phosphorus and phosphate. The value shown is most likely phosphate. Note that phosphorus is a HAP while phosphate is not.

Westinghouse 501AA Turbine. Arsenic and selenium were not detected in either the stack gas or the fuel samples. Cobalt, copper, lead, and nickel were detected at various levels in the stack gas, but, in all of these cases, the fuel detection limit was high so it cannot be determined if the emissions originated from the fuel. Mercury and phosphorus were detected in the stack gas at the field blank levels, and, in these cases, the fuel analysis detection limits were low enough to discern that these metals did not originate from the fuel.

GE Frame 7 Turbine. Arsenic was detected in the stack gas at the field blank level and only slightly above the fuel analysis detection limit. It cannot be determined if the emissions originated in the fuel. Cobalt, mercury and selenium were not detected in either the stack samples or the fuel samples. Copper, lead, and nickel were detected at various levels in the stack gas, but, in all of these cases, the fuel detection limit was high so it cannot be determined if the emissions originated from the fuel. Phosphorus was detected in the stack gas at the field blank level, but, in this case, the fuel analysis detection limit was low enough to discern that this metal did not originate from the fuel.

- Combustion Air. Ambient air samples were collected at the utility turbine sites and analyzed for trace metal constituents including arsenic, barium, chromium, cobalt, copper, nickel, phosphorous, and vanadium. For both utility turbine sites, the ambient air trace metals analysis results showed that the ambient air is not a contributor to emissions of the eight metals measured.
- Unit Surfaces. Unit surfaces are a possible source of chromium and nickel, since both are present in stainless steel. Both of these metals were detected above the field blank levels from both units.

3.3.2 Semi-Volatile Organic Compounds

Sampling for Polycyclic Aromatic Hydrocarbons (PAH), Polychlorinated Biphenyls (PCB), Polychlorinated Dibenzo-p-dioxins (PCDD) and Polychlorinated Dibenzofurans (PCDF) was conducted on both utility turbines at full load only. Emissions factors in lb/10^{12}Btu for detected species are presented in Table 3-6 with key points highlighted below.

3.3.2.1 PAH

For both of the units only a few species were detected:

- Naphthalene was detected from both units but levels were on the same order as the field blank. This is not uncommon since naphthalene is a decomposition product of the XAD-2 resin used in the test.

- Phenanthrene was detected in the samples taken from the Westinghouse turbine at levels less than 0.0005 tons per year.

Table 3-6
FULL LOAD SEMI-VOLATILE ORGANIC EMISSIONS FACTORS (lb/10^{12}Btu) FOR TWO GAS-FIRED UTILITY TURBINES

	Site 123 **Westinghouse 501AA Turbine** **55/73 MWe[(1)]**	**Site 124** **GE Frame 7 Turbine** **150 MWe**
PAH (detected species only):		
•Naphthalene	0.72	0.28
•Phenanthrene	0.111(2)	--
•2-Methylnaphthalene	0.162(2)	0.010
PCB:	(3)	(3)
PCDD/PCDF (detected species only)(4):		
•123478 HxCDD	$1.2x10^{-5}$	--
•123678 HxCDD	$3.9x10^{-6}$	--
•1234678 HpCDD	$4.3x10^{-6}$	--
•OCDD	$1.6x10^{-5}$	$1.8x10^{-5}$
•2378 TCDF	$7.7x10^{-6}$	--
•12378 PeCDF	$3.2x10^{-6}$	--
•23478 PeCDF	$3.3x10^{-6}$	--
•123478 HxCDF	$4.1x10^{-6}$	--
•Total HxCDD	$1.3x10^{-5}$	--
•Total HpCDD	$6.4x10^{6}$	--
•Total TCDF	$1.6x10^{-5}$	--
•Total PeCDF	$1.4x10^{-5}$	--
•Total HxCDF	$4.0x10^{-6}$	--

Notes:

(1) During the summer, peak load is 55 MW, and, during the winter, peak load is 73 MW. Testing on this unit was conducted during the summer.

(2) More than twice the field blank level; all other detected values are less than twice the field blank level.

(3) All PCB isomers not detected.

(4) For the Westinghouse turbine, these values are averages of the second two test runs. Measurements for the first test run were unusually high and not considered representative of the source. See site report listed in Appendix A for values from the first test run.

- 2-Methylnaphthalene was detected in the samples from both turbines Note that the average emissions factor for the Westinghouse turbine was 16 times higher than the emissions factor for the GE Frame 7 turbine despite the fact that the field blank levels were detected and were the same for both sites. Mass emissions of 2-methylnaphthalene were less than 0.0007 tons per year.

3.3.2.2 PCB

PCBs were not detected from either unit.

3.3.2.3 PCDD/PCDF

Only one homologue class was detected from the GE Frame 7 turbine and it is on the same order as the field blank level. Several isomers and homologue classes were detected from the Westinghouse turbine; however, all were at levels less than twice the field blank levels. The values shown for the Westinghouse turbine are the averages of the second two test runs. Measurements for the first test run were unusually high and not considered representative of the source. See the individual site report listed in Appendix A for values from the first test run.

3.3.3 Hydrocarbons and Other Volatile Organic Compounds

Emissions factors in units of lb/10^{12}Btu for formaldehyde, benzene, and toluene are presented as a function of MCR in Figures 3-1 and 3-2 for each utility turbine tested. Hydrocarbon emissions factors in units of lb/MMBtu for each of the units are summarized in Figures 3-3 and 3-4. Some of the key points are discussed below.

Westinghouse 501AA Utility Turbine

- Formaldehyde increased by an order of magnitude from 100% MCR to 30% MCR. On a mass basis, however, this increase only represents a change from 0.30 tons per year to 1.02 tons per year.
- Benzene and toluene emissions factors were fairly constant with load and were less than 0.25 tons per year.
- Total hydrocarbons (THC) were evaluated by continuous analyzer, and methane (CH_4) and total gaseous non-methane organics (TGNMO) were measured from bag samples collected on this unit. In theory, THC emissions should equal the sum of CH_4 and TGNMO emissions. Note that CH_4 was not detected from any of the samples, so the values shown represent the method detection limit. Therefore, in this case, TGNMO emissions should equal THC emissions. This is true at full and minimum loads. However, at 80% load, TGNMO emissions are higher than the THC emissions and at 50% load, THC emissions are higher than the TGNMO. The differences between the two sets of data are small enough to conclude that they are attributable to uncertainties associated with the sampling and analysis methods. In no case, did hydrocarbon emissions exceed 0.03 lb/MMBtu.

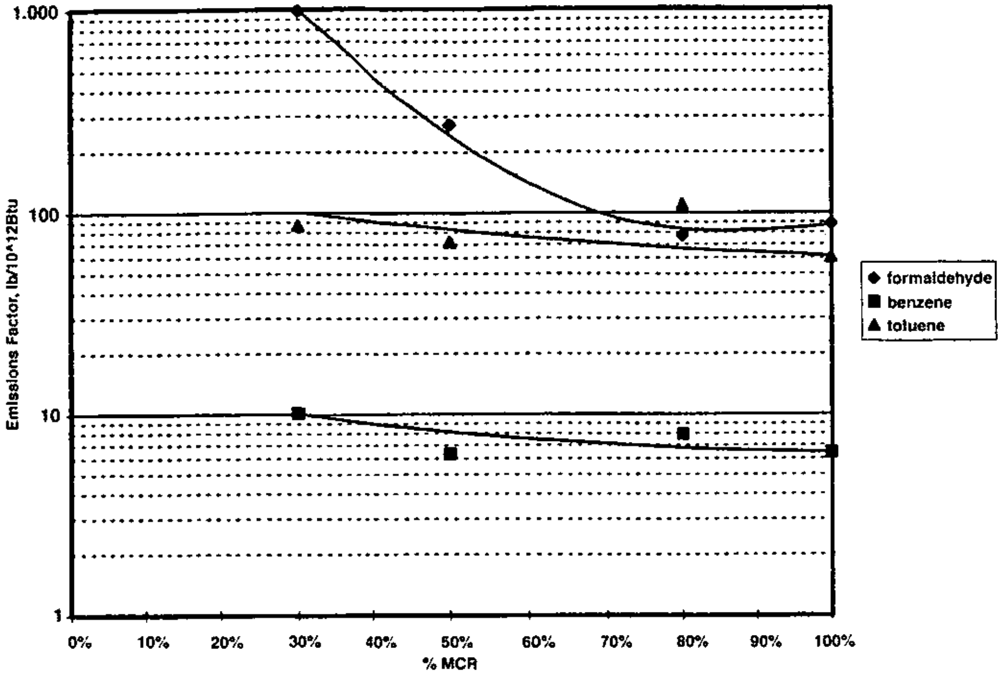


Figure 3-1 VOC Emissions Factors vs. MCR for a Westinghouse 501AA Utility Turbine

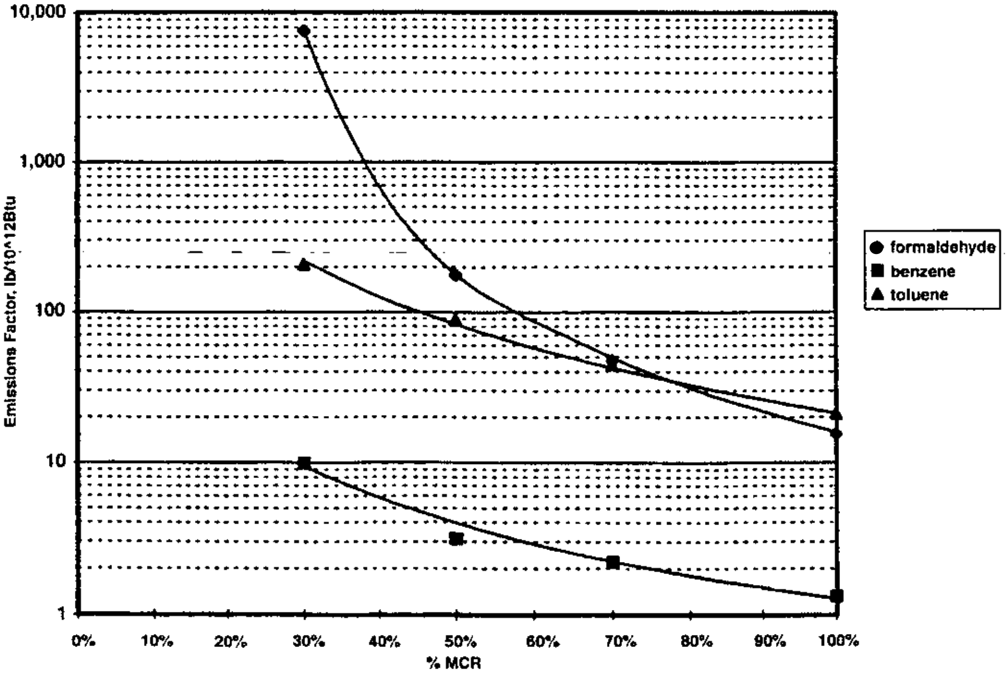


Figure 3-2 VOC Emissions Factors vs. MCR for a GE Frame 7 Utility Turbine

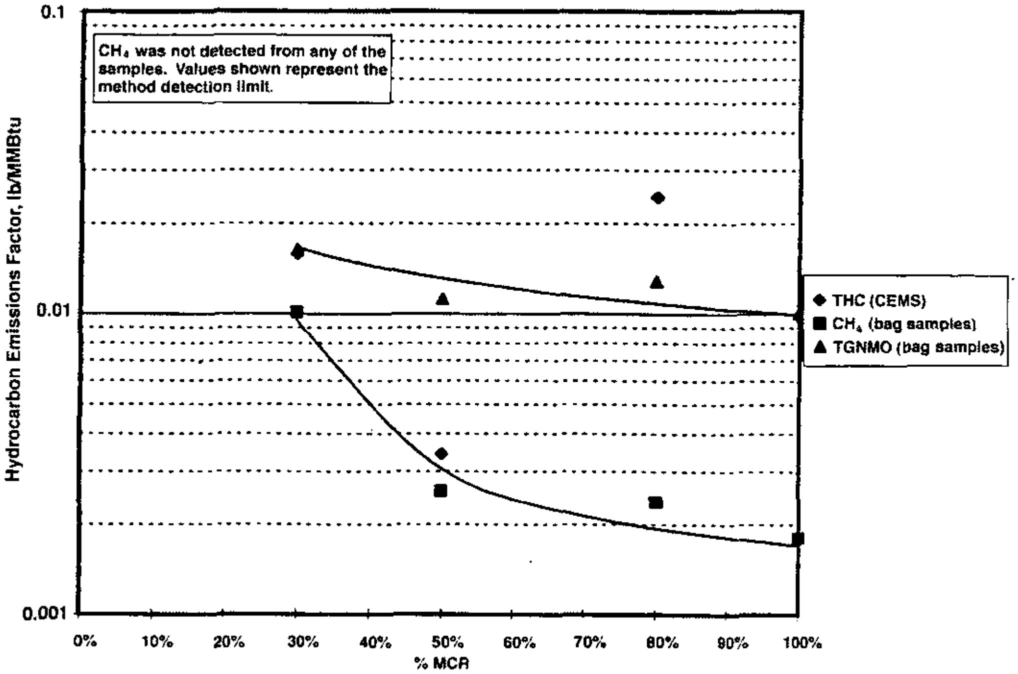


Figure 3-3 Hydrocarbon Emissions Summary Westinghouse 501AA Gas-Fired Utility Turbine

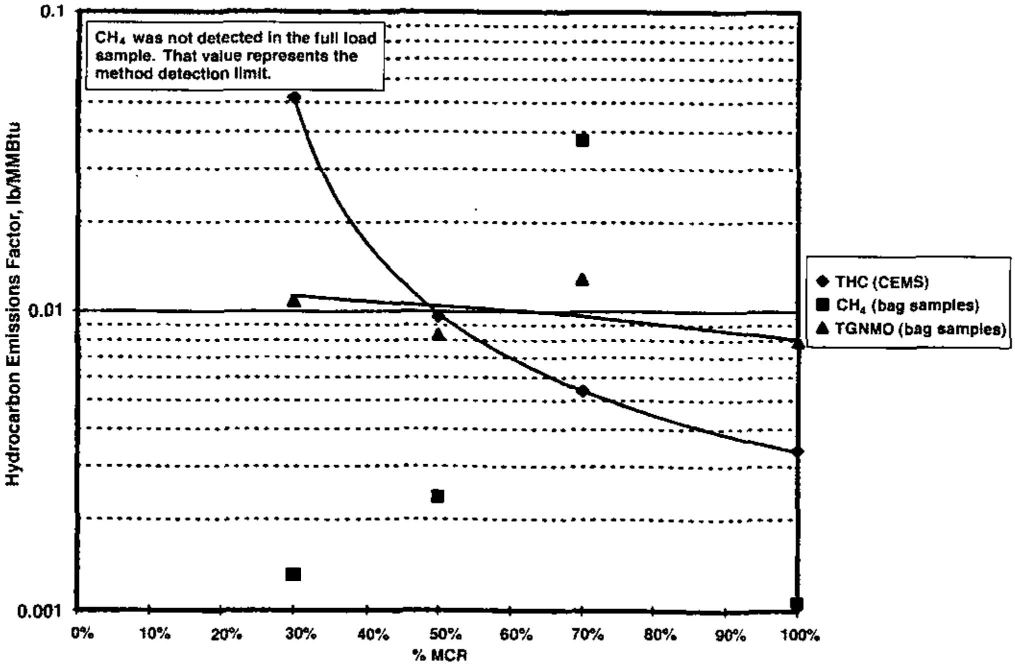


Figure 3-4 Hydrocarbon Emissions Summary for the GE Frame 7 Gas-Fired Utility Turbine

GE Frame 7 Utility Turbine

- Formaldehyde increases with decreasing load. This increase was fairly dramatic for the GE Frame 7 turbine with formaldehyde emissions factors ranging from 15 $lb/10^{12}Btu$ (0.11 tons per year) to 7,540 $lb/10^{12}Btu$ (16.1 tons per year).
- Benzene emissions increased slightly with decreasing load for the GE Frame 7 turbine with factors ranging between 1 $lb/10^{12}Btu$ (0.01 tons per year) and 10 $lb/10^{12}Btu$ (0.02 tons per year).
- Toluene emissions increased with decreasing load for the GE Frame 7 turbine with factors ranging from 10 $lb/10^{12}Btu$ (0.15 tons per year) to 200 $lb/^{12}Btu$ (0.44 tons per year).
- On this unit, THC were evaluated by continuous analyzer, and CH_4 and TGNMO were measured from bag samples collected on this unit. Note that CH_4 was not detected in the full load sample, so that value represents the method detection limit. In this case, the sum of CH_4 and TGNMO should equal THC emissions. At all load conditions except 70% MCR, THC are higher or nearly equal to the sum of TGNMO and THC. At 70% MCR, both CH_4 and TGNMO individually exceed THC. In no case, do the emissions factors for the hydrocarbons exceed 0.06 lb/MMBtu.

3.3.4 NO_x and CO

NO_x and CO emissions factors as a function of MCR are shown in Figures 3-5 and 3-6 for the Westinghouse turbine and the GE Frame 7 turbine, respectively.

The Westinghouse turbine is not equipped with any NO_x control features, and the NO_x and CO trends are characteristic of a conventional combustion system. NO_x peaks at full load at approximately 0.45 lb/MMBtu and drops off to less than 0.25 lb/MMBtu at minimum load. CO is fairly low across the load range. It is lowest at full load and peaks at minimum load at approximately 0.11 lb/MMBtu.

The GE Frame 7 turbine utilizes water injection for NO_x reduction. As shown in Figure 3-6, this method of NO_x reduction is effective. NO_x emissions are nearly constant across the load range at an average of 0.13 lb/MMBtu. CO emissions are negligible above 70% MCR and then rise dramatically at lower loads, reaching a peak value of 0.63 lb/MMBtu at 30% MCR.

CO emissions follow the same trends exhibited by formaldehyde, benzene, and toluene. Emissions factors as a percentage of minimum load emissions factors for these pollutants are plotted in Figure 3-7 as a function of MCR. Because of similar trends, CO may be a suitable surrogate for estimating VOC emissions from utility gas turbines. Furthermore, conditions that reduce CO emissions (e.g., increased fuel/air mixing) generally reduce emissions of VOCs as well.

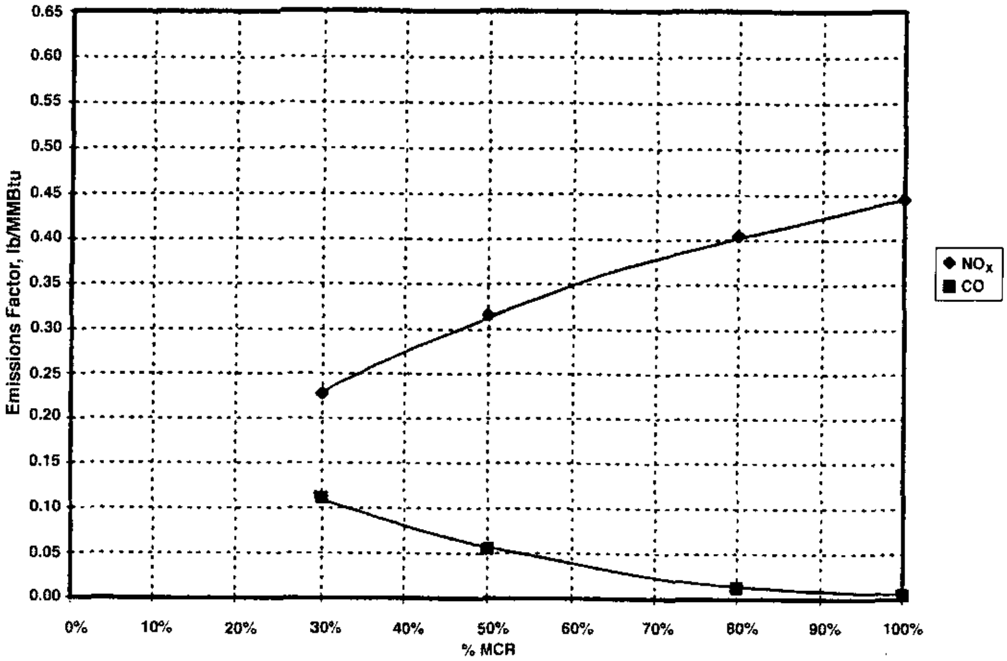


Figure 3-5 NO_x and CO Emissions Factors vs. MCR Westinghouse 501AA Utility Turbine

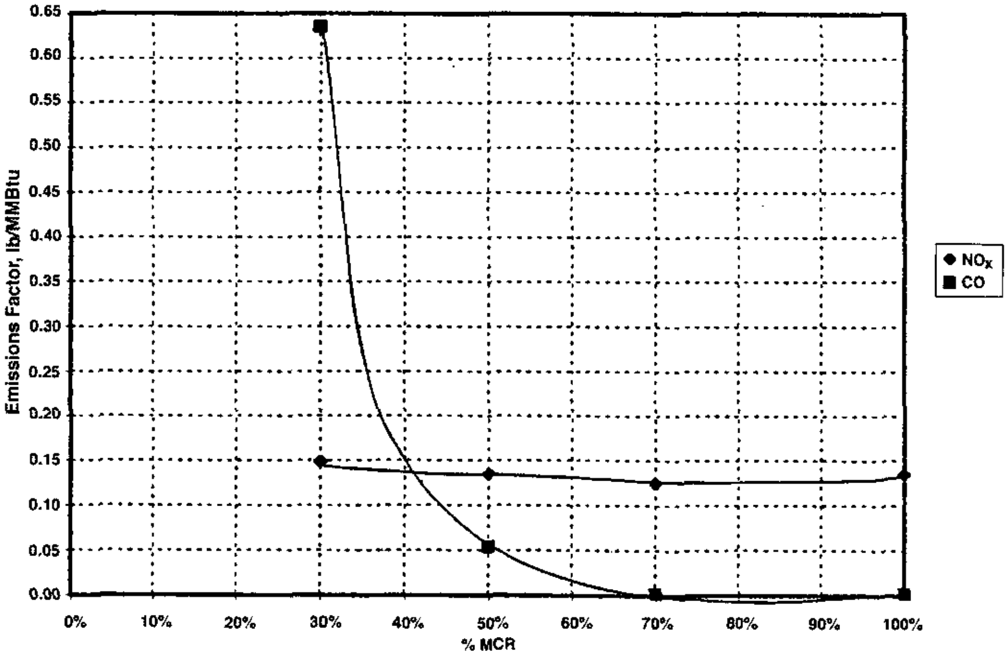


Figure 3-6 NO_x and CO Emissions Factors vs. MCR for a GE Frame 7 Utility Turbine

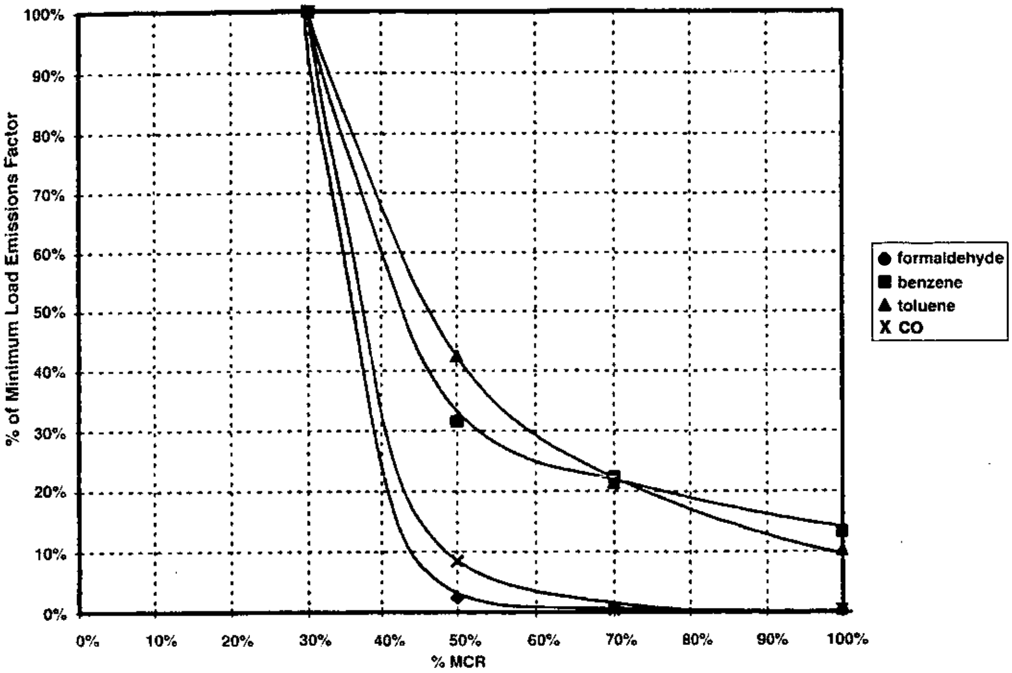


Figure 3-7 VOC and CO Emissions vs. MCR for a GE Frame 7 Utility Turbine

3.4 EMISSIONS FACTORS FOR GAS-FIRED INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

3.4.1 Hydrocarbons and Other Volatile Organic Compounds

Emissions factors for formaldehyde, benzene, methane and total gaseous non-methane organics (TGNMO) are summarized in Table 3-7 for each industrial gas turbine tested. The emissions factors are shown for two load conditions: maximum MCR and minimum MCR. Note that other load conditions were tested on the Solar Mars T14000 SoLoNO$_x$ unit and are presented in Figures 3-8 and 3-9. Key trends are discussed below:

- In almost every case, emissions of all compounds are much greater at minimum load as compared to full load. Formaldehyde showed the largest variations. For example, for the GE LM1500, the formaldehyde emissions factor at full load (4,189 lb/10^{12}Btu) is only 16% of the emissions factor at minimum load (25,450 lb/10^{12}Btu). Similarly, for the Solar Mars T14000 SoLoNO$_x$ turbine, the formaldehyde emissions factor at full load (14.6 lb/10^{12}Btu) is only 7% of the emissions factor at minimum load (20,347 lb/10^{12}Btu). The GE Frame 3 exhibited the smallest change with a full load formaldehyde emissions factor of 260 lb/10^{12}Btu and a minimum load emissions factor of 419 lb/10^{12}Btu.

Table 3-7
HYDROCARBONS AND OTHER VOLATILE ORGANIC COMPOUND EMISSIONS FACTORS FOR A VARIETY OF GAS-FIRED INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

Turbine Type	MCR MWeq	Compound	Units	Maximum Operating Load MCR	Minimum Operating Load MCR(1)
GE Frame 3	7.7	Formaldehyde	lb/10^{12}Btu	260	419
		Benzene	lb/10^{12}Btu	3.4	4.2
		CH_4	lb/MMBtu	ND<0.002	0.012
		TGNMO	lb/MMBtu	0.008	0.011
GE LM1500	10.6	Formaldehyde	lb/10^{12}Btu	4,189	25,450
		Benzene	lb/10^{12}Btu	39	2,359
		CH_4	lb/MMBtu	0.029	2.17
		TGNMO	lb/MMBtu	0.013	0.274
Rolls Royce Avon	10.7	Formaldehyde	lb/10^{12}Btu	5,607	14,997
		Benzene	lb/10^{12}Btu	15.7	53
		CH_4	lb/MMBtu	0.085	0.504
		TGNMO	lb/MMBtu	0.031	0.110
Rolls Royce Spey	12.2	Formaldehyde	lb/10^{12}Btu	18.5	13,227
		Benzene	lb/10^{12}Btu	5.7	63
		CH_4	lb/MMBtu	0.012	0.039
		TGNMO	lb/MMBtu	0.004	0.076
Solar Mars T12000	9.4	Formaldehyde	lb/10^{12}Btu	15.6	9,430
		Benzene	lb/10^{12}Btu	2.0	10.2
		CH_4	lb/MMBtu	ND<0.001	0.207
		TGNMO	lb/MMBtu	0.010	0.043
Solar Mars T14000	10.9	Formaldehyde	lb/10^{12}Btu	2.2	2,485
		Benzene	lb/10^{12}Btu	1.3	2.4
		CH_4	lb/MMBtu	ND<0.001	0.019
		TGNMO	lb/MMBtu	0.006	ND<0.003
Solar Mars T14000 SoLoNO$_x$(2)	10.9	Formaldehyde	lb/10^{12}Btu	14.6	20,347
		Benzene	lb/10^{12}Btu	2.9	67
		CH_4	lb/MMBtu	0.003	2.66
		TGNMO	lb/MMBtu	0.003	0.368

Notes:

(1) For the GE Frame 3, minimum MCR is 50%. For the Solar Mars T14000 SoLoNOx, minimum MCR is 35%. For all other units, minimum MCR is 25%.

(2) This unit was also tested at 50% MCR and 75% MCR. VOC and hydrocarbon results for this unit are plotted in Figures 3-7 and 3-8, respectively.

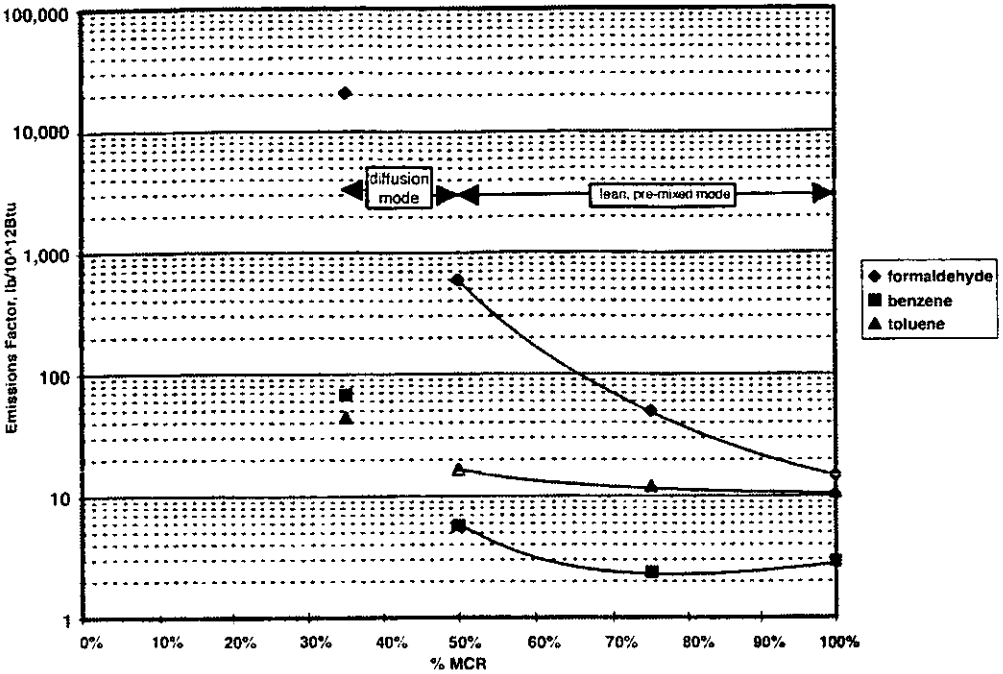


Figure 3-8 VOC Factors/MCR Solar Mars T14000 SoLoNO$_x$ Gas-Fired Industrial Turbine

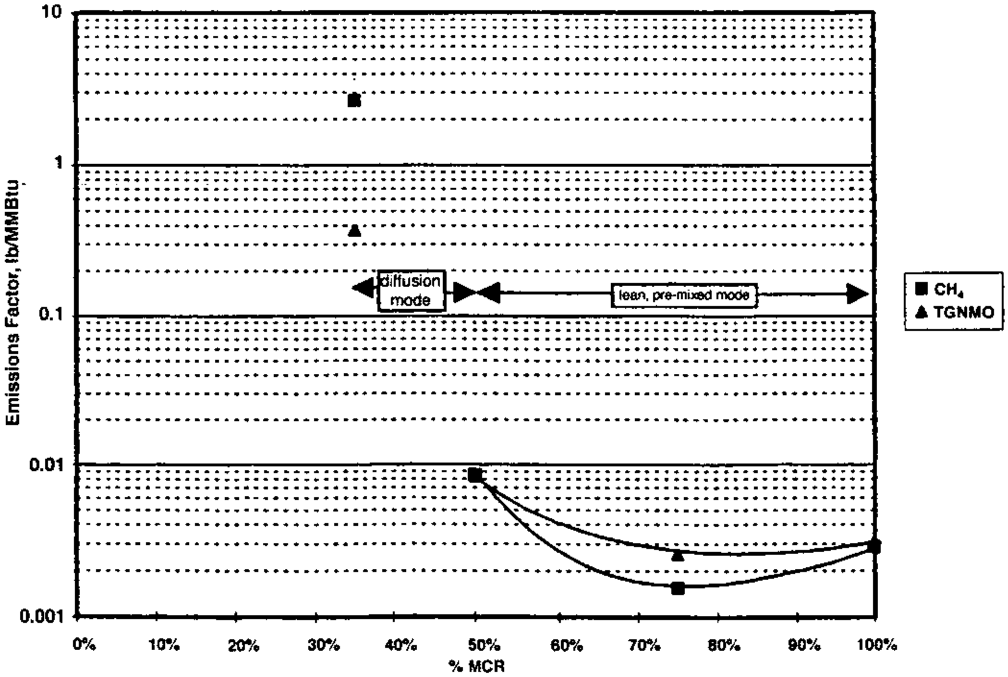


Figure 3-9 Hydrocarbon Factors/MCR Solar Mars T14000 SoLoNO$_x$ Gas-Fired Industrial Turbine

- In all cases, emissions factors for formaldehyde are several orders of magnitude higher than emissions factors for benzene.
- The lean, pre-mixed mode of combustion during operation above 50% MCR on the SoLoNO$_x$ turbine resulted in higher formaldehyde and benzene emissions as compared to the conventional Solar Mars T14000 turbine. A minimum load comparison is provided below:

Compound	Solar Mars T14000	Solar Mars T14000 SoLoNO$_x$	% Increase
Formaldehyde	2.2 lb/10^{12}Btu	14.6 lb/10^{12}Btu	564%
Benzene	1.3 lb/10^{12}Btu	2.9 lb/10^{12}Btu	123%

- Toluene was measured on the SoLoNO$_x$ turbine only. As shown in Figure 3-8, toluene emissions factors during the lean, pre-mixed combustion modes were higher than benzene but lower than formaldehyde. During, diffusion mode combustion, the toluene emissions factor was approximately 20 lb/10^{12}Btu lower than benzene and several orders of magnitude lower than formaldehyde.
- Ambient concentrations of these compounds were measured at the SoLoNO$_x$ turbine site only.

  Formaldehyde. Ambient concentrations of formaldehyde ranged from 0.5 to 1.4 ppb while stack emissions ranged from 5.8 ppb at full load to 5722 ppb at minimum load.

  Benzene. Ambient concentrations of benzene (ppb) were on the same order of magnitude as the stack concentrations measured above 50% MCR. On average, ambient concentrations were only 5% of the stack emissions at minimum load (35% MCR).

  Toluene. Ambient concentrations of toluene varied significantly from 0.26 ppb to 10.7 ppb. Stack concentrations at all loads were also within this range.

  Methane. Ambient concentrations of methane ranged from 1.6 to 1.7 ppm and were higher than the stack concentrations above 50% MCR. At minimum load however, stack concentrations were almost 1000 times the ambient concentrations.

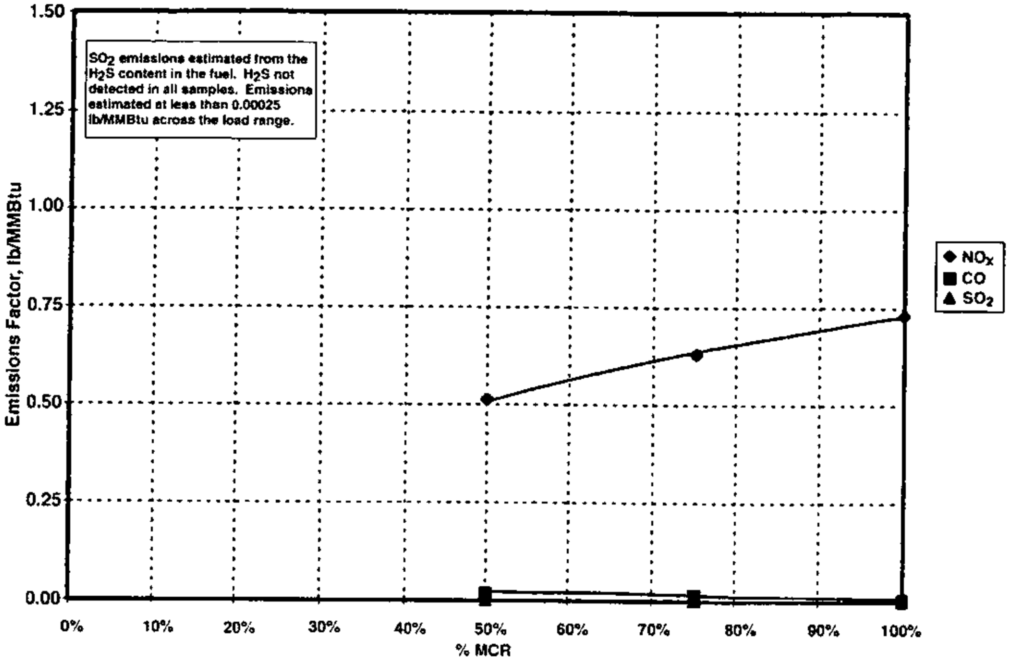
  TGNMO. TGNMO were not detected in most of the ambient samples.

3.4.2 NO_x, N_2O, CO, and SO_2

Emissions factors for NO_x, N_2O (SoLoNO$_x$ turbine only), CO, and SO_2 are presented in Figures 3-10 through 3-16 for each of the turbines. All emissions factors are plotted on a scale of 0 to 1.5 lb/MMBtu to allow direct comparison of units. Note that, for some units, minimum load emissions factors were higher than 1.5 lb/MMBtu. In these cases, the minimum load emissions factors are indicated on the figures. Key trends are discussed below:

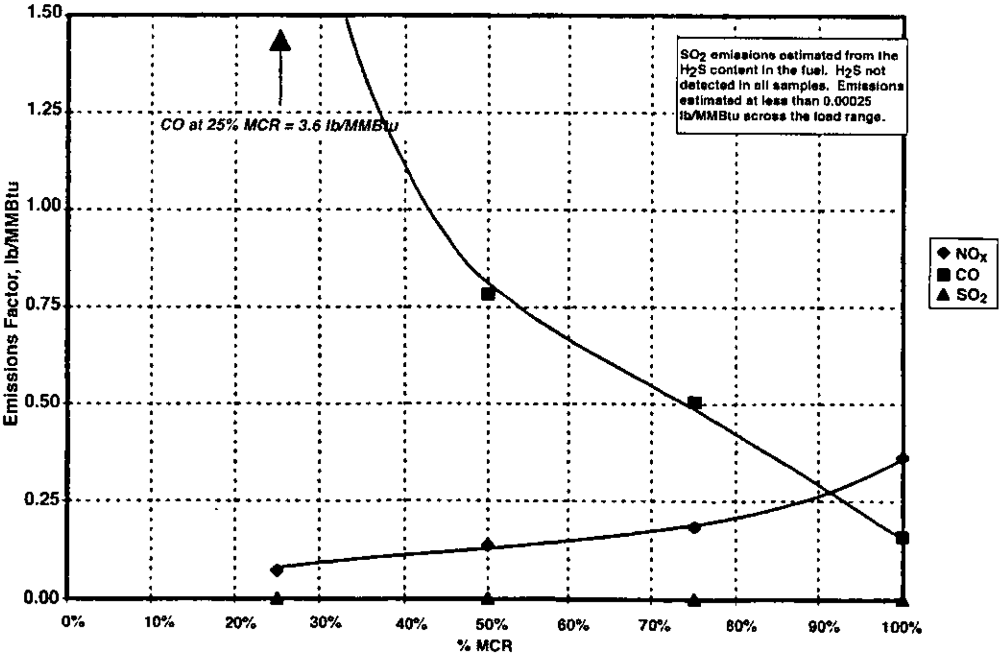
- For all units except the SoLoNO$_x$ turbine, NO_x increases with increasing load. At full load, NO_x ranged from 0.24 to 0.73 lb/MMBtu. At minimum load, NO_x ranged from 0.07 lb/MMBtu to 0.19 lb/MMBtu.
- For all units, CO emissions decreased with increasing load. At full load, CO ranged from 0.004 to 0.410 lb/MMBtu. At minimum load, CO ranged from 0.220 to 4.9 lb/MMBtu. In general, units with higher NO_x emissions (i.e., higher combustion and exhaust temperatures) produced lower CO emissions. Since CO is a product of incomplete or low temperature combustion, factors that reduce CO emissions (e.g, increased fuel air mixing) frequently lead to higher temperatures and thus higher NO_x emissions.
- NO_x emissions factors for the SoLoNO$_x$ turbine do not follow the trend exhibited by the other turbines due to its low NO_x design. The SoLoNO$_x$ dry low-NO_x combustor maintains reduced peak flame temperature through operation of the combustor in a pre-mixed mode (above 50% MCR). On this unit, NO_x emissions were relatively constant across the load range. Typically, NO_x would be much higher at minimum load during conventional combustion; however, the high CO emissions at minimum load indicate that excess air was probably fairly low which helped keep NO_x emissions low.
- N_2O was measured during testing on the Solar Mars T14000 SoLoNO$_x$ combustion turbine only. In the low NO_x mode, N_2O emissions are approximately 0.10 lb/MMBtu lower than the NO_x emissions. In the conventional combustion mode, N_2O emissions are approximately 0.50 lb/MMBtu higher than the NO_x emissions.
- SO_2 emissions factors were estimated from the H_2S content in the fuel. In all cases, H_2S was either not detected or resulted in predicted stack emissions of less than 0.00032 lb/MMBtu.

In general, CO emissions follow the same trends exhibited by formaldehyde, benzene, and toluene. Emissions factors as a percentage of minimum load emissions factors for these pollutants are plotted in Figure 3-17 as a function of MCR. Because of similar trends, CO may be a suitable surrogate for estimating VOC emissions from industrial gas turbines. Furthermore, conditions that reduce CO emissions (e.g., increased fuel/air mixing) generally reduce emissions of VOCs as well.



SO_2 emissions estimated from the H_2S content in the fuel. H_2S not detected in all samples. Emissions estimated at less than 0.00025 lb/MMBtu across the load range.

Figure 3-10 NO_x, CO, SO_2 Factors/MCR GE Frame 3 Gas-Fired Industrial Turbine



CO at 25% MCR = 3.6 lb/MMBtu

SO_2 emissions estimated from the H_2S content in the fuel. H_2S not detected in all samples. Emissions estimated at less than 0.00025 lb/MMBtu across the load range.

Figure 3-11 NO_x, CO, and SO_2 Factors/MCR for a GE LM1500 Gas-Fired Industrial Turbine

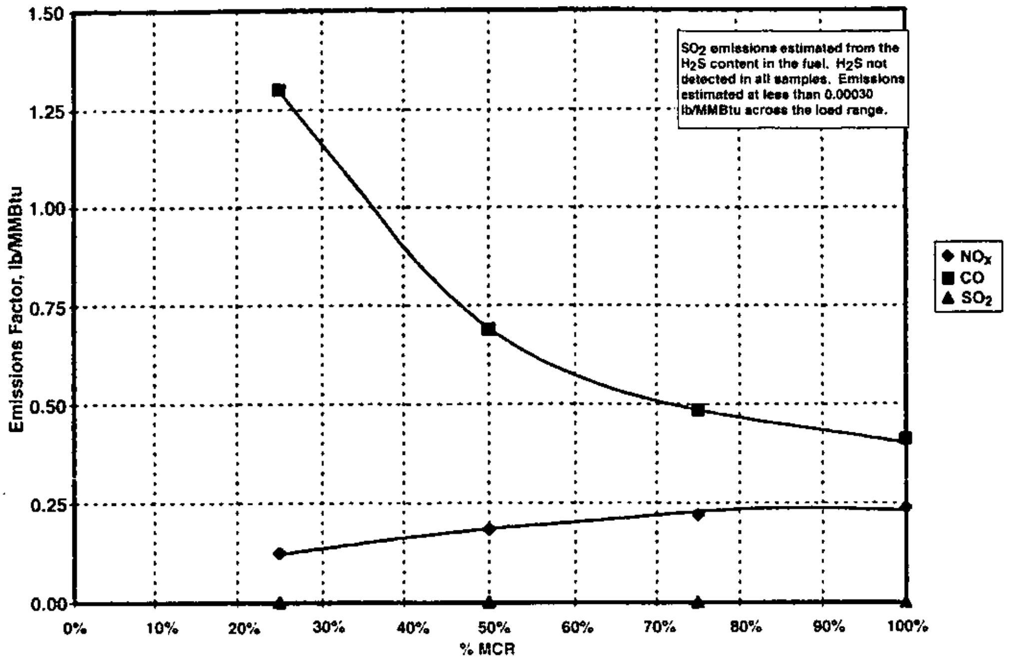


Figure 3-12 NO$_x$, CO, and SO$_2$ Factors/MCR Rolls Royce Avon Gas-Fired Industrial Turbine

SO$_2$ emissions estimated from the H$_2$S content in the fuel. H$_2$S not detected in all samples. Emissions estimated at less than 0.00030 lb/MMBtu across the load range.

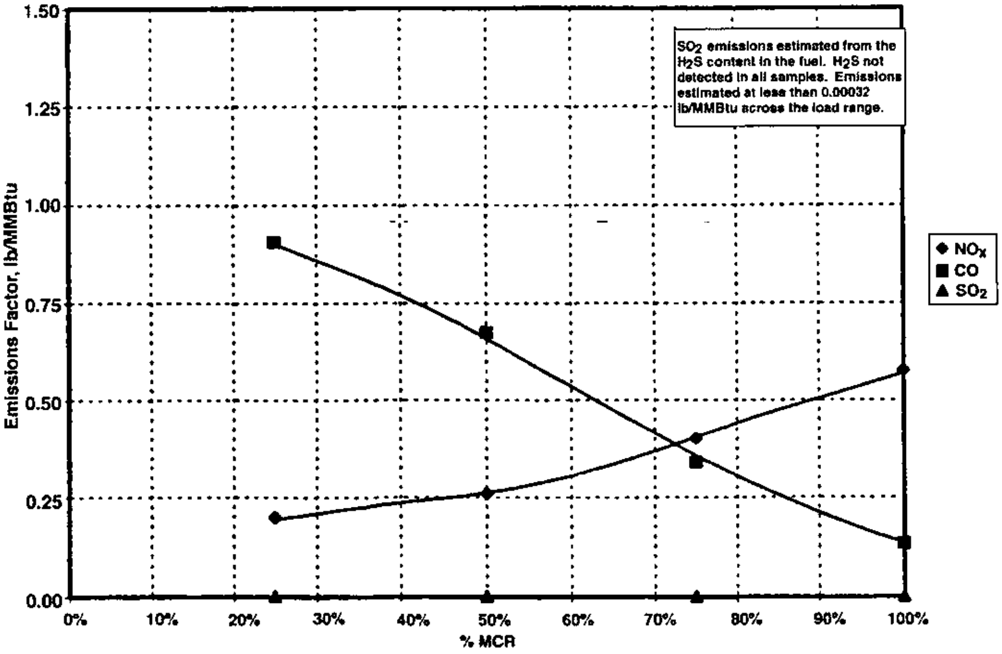
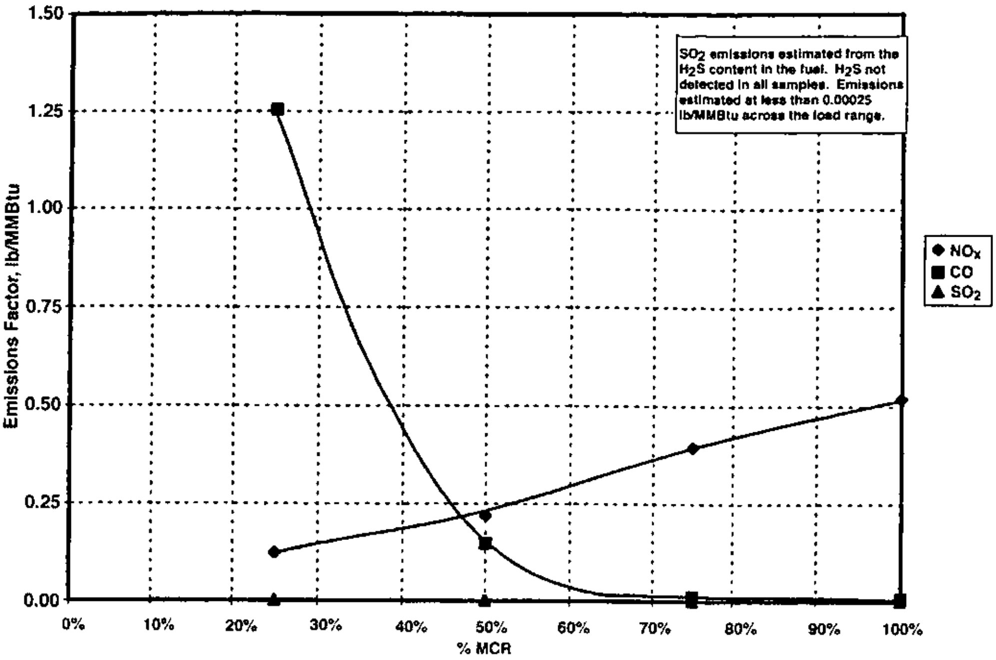


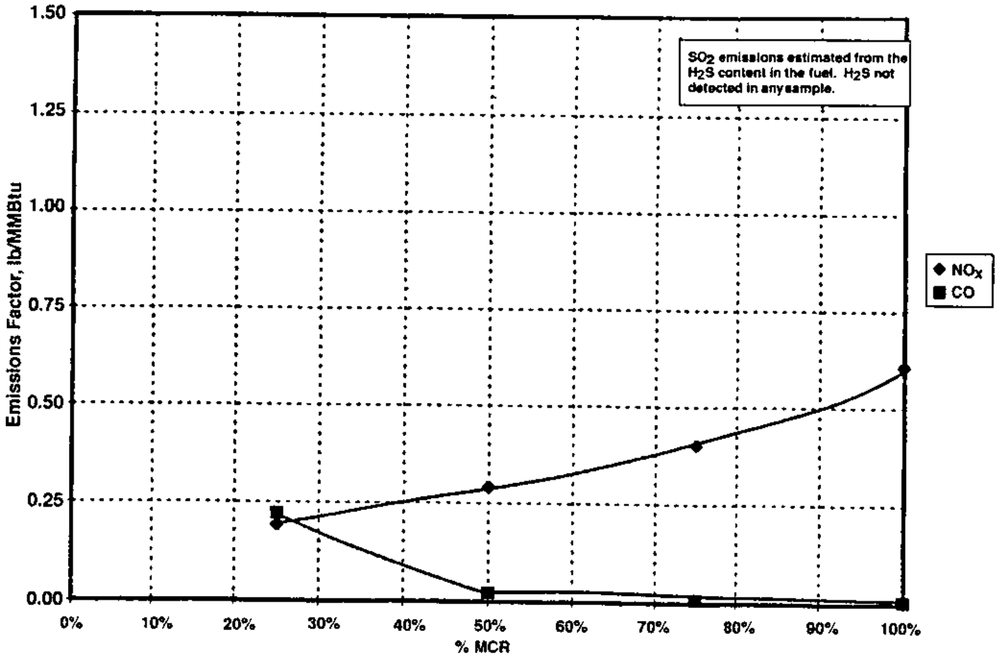
Figure 3-13 NO$_x$, CO, and SO$_2$ Factors/MCR Rolls Royce Spey Gas-Fired Industrial Turbine

SO$_2$ emissions estimated from the H$_2$S content in the fuel. H$_2$S not detected in all samples. Emissions estimated at less than 0.00032 lb/MMBtu across the load range.



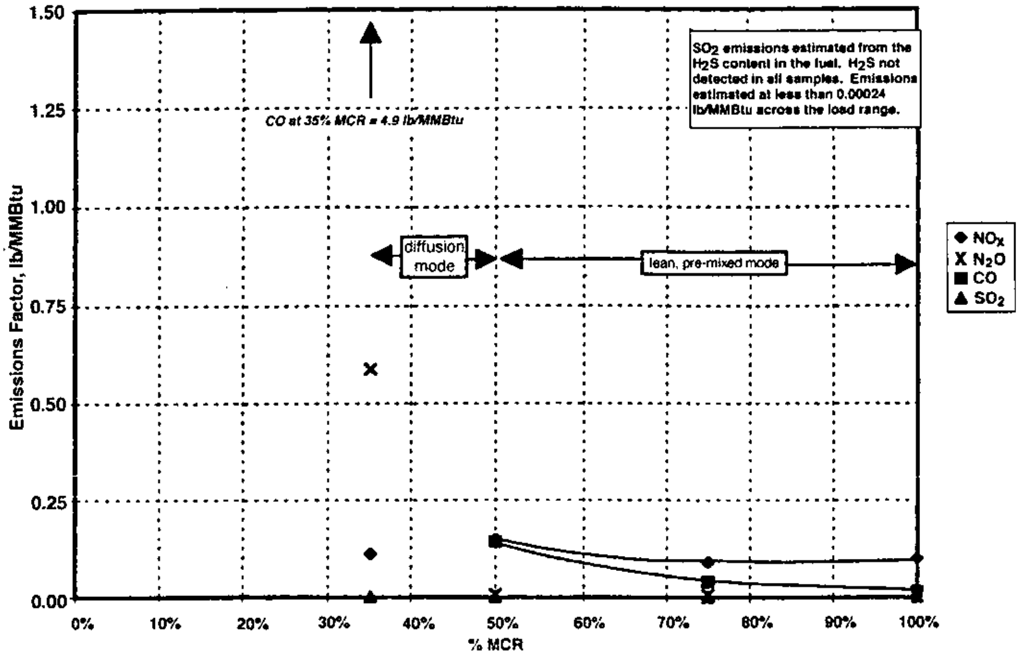
SO_2 emissions estimated from the H_2S content in the fuel. H_2S not detected in all samples. Emissions estimated at less than 0.00025 lb/MMBtu across the load range.

Figure 3-14 NO$_x$, CO, and SO$_2$ Factors/MCR Solar Mars T12000 Gas-Fired Indus. Turbine



SO_2 emissions estimated from the H_2S content in the fuel. H_2S not detected in anysample.

Figure 3-15 NO$_x$, CO, and SO$_2$ Factors/MCR Solar Mars T14000 Gas-Fired Industrial Turbine



SO_2 emissions estimated from the H_2S content in the fuel. H_2S not detected in all samples. Emissions estimated at less than 0.00024 lb/MMBtu across the load range.

Figure 3-16 NO_x, CO, and SO_2 Fac./MCR SolarMars T14000 SoLoNO$_x$ Gas-Fired Indus. Turbine

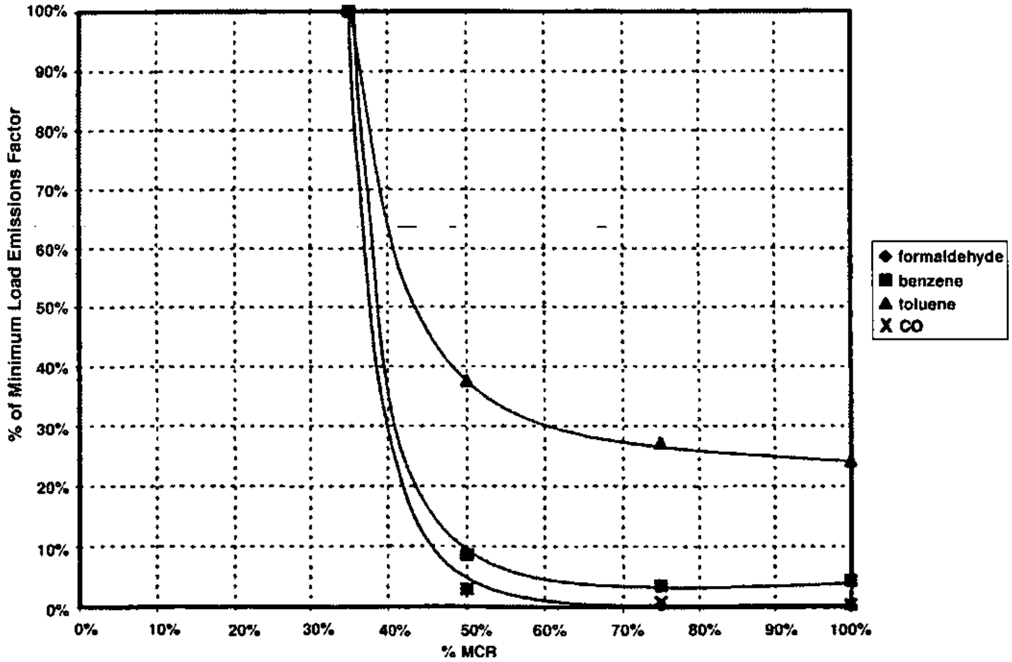


Figure 3-17 VOC, CO/MCR Solar Mars T14000 SoLoNO$_x$ Gas-Fired Industrial Turbine

4

HEALTH RISK ASSESSMENT SUMMARY

This section summarizes two independent studies that assessed the public health risk associated with air toxic emissions from a wide variety of utility sources including, gas-, oil- and coal-fired boilers and gas-fired combustion turbines. Section 4.1 presents the results of health risk assessment studies conducted by EPRI which are based on analysis procedures recommended by the USEPA. Section 4.2 presents the results of a health risk screening study conducted by Carnot in accordance with California Air Pollution Control Officers Association (CAPCOA) risk assessment guidelines. It should be noted that the CAPCOA methodology is much more conservative than the USEPA methodology and was utilized by Carnot in an effort to quickly assess the health impacts of emissions from gas-fired units. Furthermore, the Carnot study included only five sample emissions sources representing each major unit type. In contrast, the study conducted by EPRI included all of the available emissions data available from the PISCES program and used this data to project nationwide emissions for the year 2010. Although the EPRI study is more representative, the results from the CAPCOA-based analysis are presented here for completeness. Note that the two studies do not predict the same substances as the dominant risk contributors because of differences in the risk factors prescribed by the different methods.

<u>Note on the EPRI Study and the CAPCOA Methodology</u>

The results from these two studies, unrelated to each other, cannot be compared to one another. There are several reasons for this:

1. The portion of the EPRI study reproduced here focused on risks due to inhalation alone. The CAPCOA methodology used employs multipathway factors, multipliers applied to calculated inhalation risks to approximate the additional risks due to ingestion and dermal (skin) contact. Thus, the two sets of results are measuring different risks.

2. The EPRI study employs "best technical methods" and "central value estimates" for each step in the risk assessment: source emissions, atmospheric dispersion, human exposure, etc. These values were chosen based on technical assessment of the most characteristic value to use at each step. The CAPCOA method employs "conservative", "high end", or "regulatory default" methods; these methods are purposely selected to overestimate human risk for regulatory protective purposes.

3. Technical evaluation of the CAPCOA SCREEN air model shows that it consistently overestimates ground-level concentrations, and thus inhalation risks, by an order of

magnitude; that is, it overestimates values by factors of about 5 to 50 times the "true" value.

4. These overestimates of inhalation risk are compounded by the CAPCOA calculation of risks due to ingestion and dermal contact. The use of generic "worst-case" multipathway factors, rather than setting- or site-specific factors, has been shown (Levin et al., 1994) to overestimate risk values by 2 to 3 orders of magnitude (factors of 50 to 5,000 times the "best-estimate" value).
5. Finally, a modified CAPCOA approach assumed 6% of total chromium in the most carcinogenic +6 valence state. The EPRI analysis, based on power plant emissions measurements, took 5% of total chromium as the +6 valence. More significantly, however, the cancer potency of the Cr(+6) under the CAPCOA methodology is nearly 12 times as great as that used by EPRI, which reflected US EPA potency values.

Thus, in several ways, the EPRI and the CAPCOA studies begin from different assumptions, use different computational methodologies, and calculate different sets of risks by different routes. The two studies are not comparable to one another. For more information regarding each study, please see the References listed in Appendix A.

4.1 HEALTH RISK ASSESSMENT BASED ON USEPA METHODOLOGY

EPRI sponsored two programs as part of its trace species research efforts. PISCES was an emissions measurement program and CORE (Comprehensive Risk Evaluation) evaluated the emissions in terms of health risk. Two studies were conducted by EPRI as part of the CORE program:

1. Industry-wide evaluation of chronic risk associated with inhalation of substances for two scenarios: the Maximally Exposed Individual (MEI) and the Reasonably Exposed Individual (REI).
2. Analysis of risk associated with multimedia exposure: inhalation, ingestion, dermal uptake. This analysis included four plants only: three coal plants and one oil plant.

A summary of the industry-wide evaluation conducted by EPRI is included below. Details regarding the multimedia exposure analysis can be found in the Reference 10.

4.1.1 Basis for the Industry-Wide Health Risk Assessment

The EPRI health assessment studies were based on emissions of 16 trace substances:

Arsenic
Benzene
Beryllium
Cadmuim
Chlorine
Chromium
Dioxins/Furans
Formaldehyde
Lead
Manganese
Mercury
Nickel
PAHs
Radionuclides
Selenium
Toluene

The risk analysis combined emissions estimates, transport and dispersion modeling results, exposure analyses, and potency information to evaluate carcinogenic and non-carcinogenic health impacts for populations exposed over a 70 year period. Emissions estimates were made for 594 plants in the US including all units with a generation capacity greater than 25 MW. The emissions estimates were based on the data collected during the field measurement programs. These estimates were then projected for the year 2010 assuming that the plants would be equipped with SO_2 and particulate control systems in compliance with the 1990 CAAA. Dispersion modeling was conducted using a 50 km (31 mile) radial grid around each plant. Inhalation exposure was then determined within each grid based on 1990 census data. Both the Maximum Exposed Individual (MEI) and the Reasonably Exposed Individual (REI) were analyzed. Both MEI and REI analyses utilize the individual living in the area of maximum exposure for 70 years. But, the REI analysis considers activity data, breathing rates, and indoor/outdoor concentration ratios and, thus, provides more realistic results. Most of the potency information was drawn from the USEPA's Integrated Risk Information System (IRIS).

4.1.2 Carcinogenic Risk

Figure 4-1 shows the median and range of inhalation carcinogenic risk by plant group for the MEI. As indicated, plants containing gas units only have the lowest median MEI risk at 4×10^{-9}. Furthermore, median risk from gas-fired units is a magnitude lower than risk from other units. Figure 4-2 shows the contributions of individual compounds to MEI inhalation carcinogenic risk for each plant group. Arsenic and chromium are the greatest contributors for coal- or oil-fired units while chromium and formaldehyde are the greatest contributors for gas-fired units.

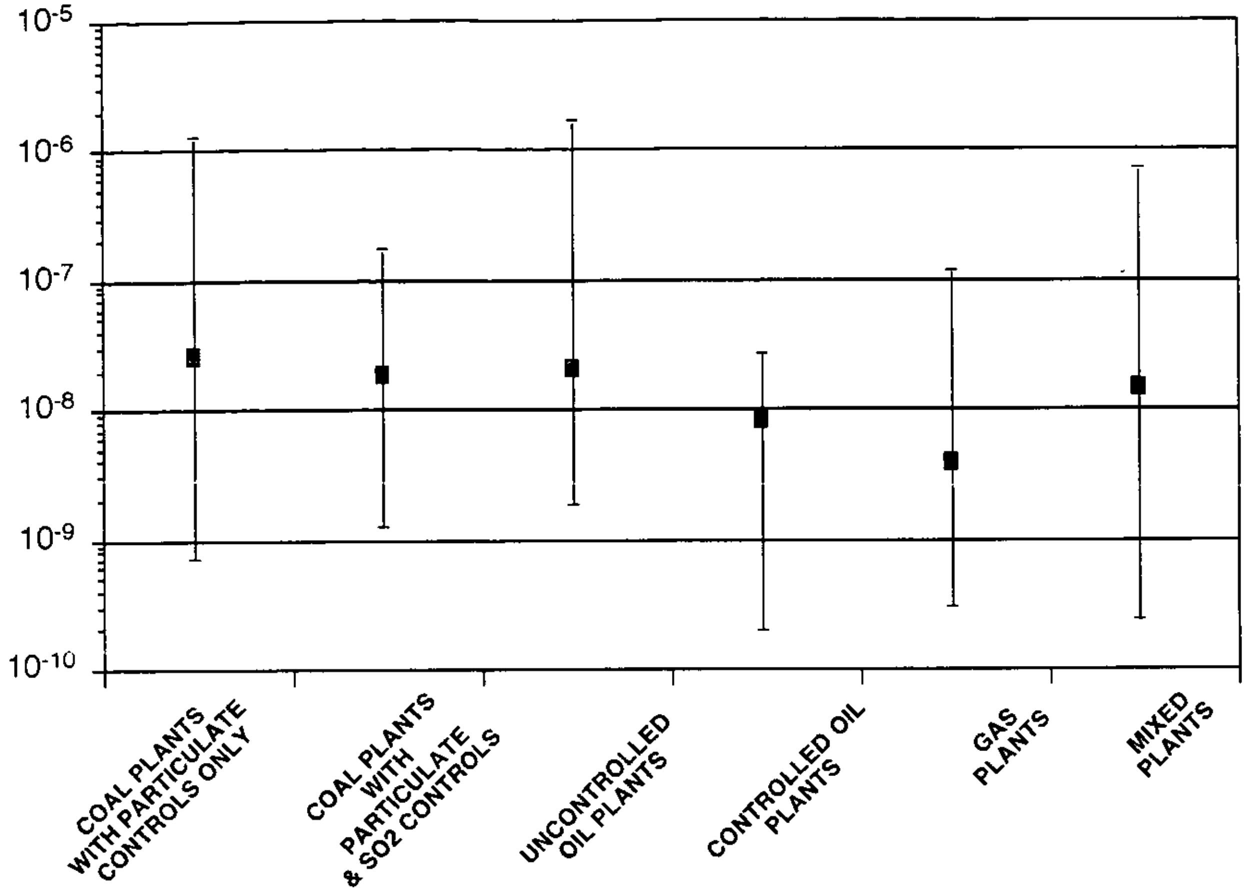
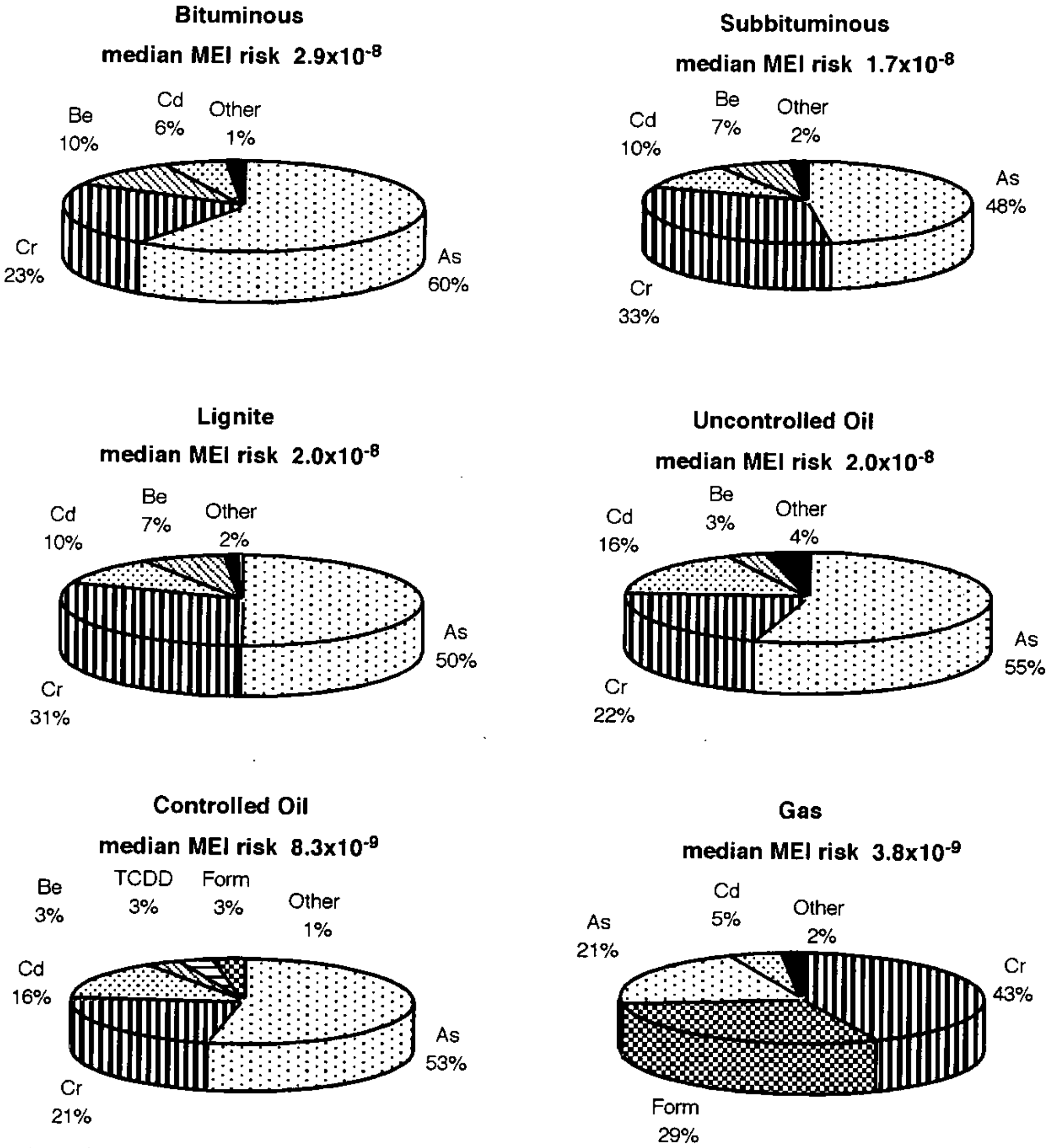


Figure 4-1 MEI Inhalation Carcinogenic Risk, by Plant Group
Reference: EPRI's Utility Trace Substances Synthesis Report, Vol. 1, Figure 7-3

The results of the carcinogenic risk analysis for the REI showed that the REI risks were 2-19% of the corresponding MEI inhalation risks. Furthermore, total annual population carcinogenic risk is less than 0.10 excess cancer occurences due to inhalation exposure. In sum, the cancer risk for all cases analyzed is below levels of concern.

4.1.3 Non-Carcinogenic Risk

The mean and median MEI inhalation hazard indexes (HI) for each plant type are presented in Figure 4-3. As shown, gas plants have the lowest median hazard index at 1.5 x 10^{-3}. Note that the hazard index for all plants is less than 1.0 indicating that inhalation exposure from all plant types is below levels of concern. The contributions of individual substances to the MEI inhalation hazard index for all plant types is shown in Figure 4-4. Total chromium is the greatest contributor for all plant types.



Bituminous

median MEI risk 2.9×10^{-8}

Subbituminous

median MEI risk 1.7×10^{-8}

Lignite

median MEI risk 2.0×10^{-8}

Uncontrolled Oil

median MEI risk 2.0×10^{-8}

Controlled Oil

median MEI risk 8.3×10^{-9}

Gas

median MEI risk 3.8×10^{-9}

* mixed-fuel units and plants are excluded here, since emissions by fuel vary widely from plant to plant

Figure 4-2 Contributions of Individual Substances to MEI Inhalation Carcinogenic Risk, Median Plant by Fuel Type
Reference: EPRI's Utility Trace Substances Synthesis Report, Vol. 1, Figure 7-4

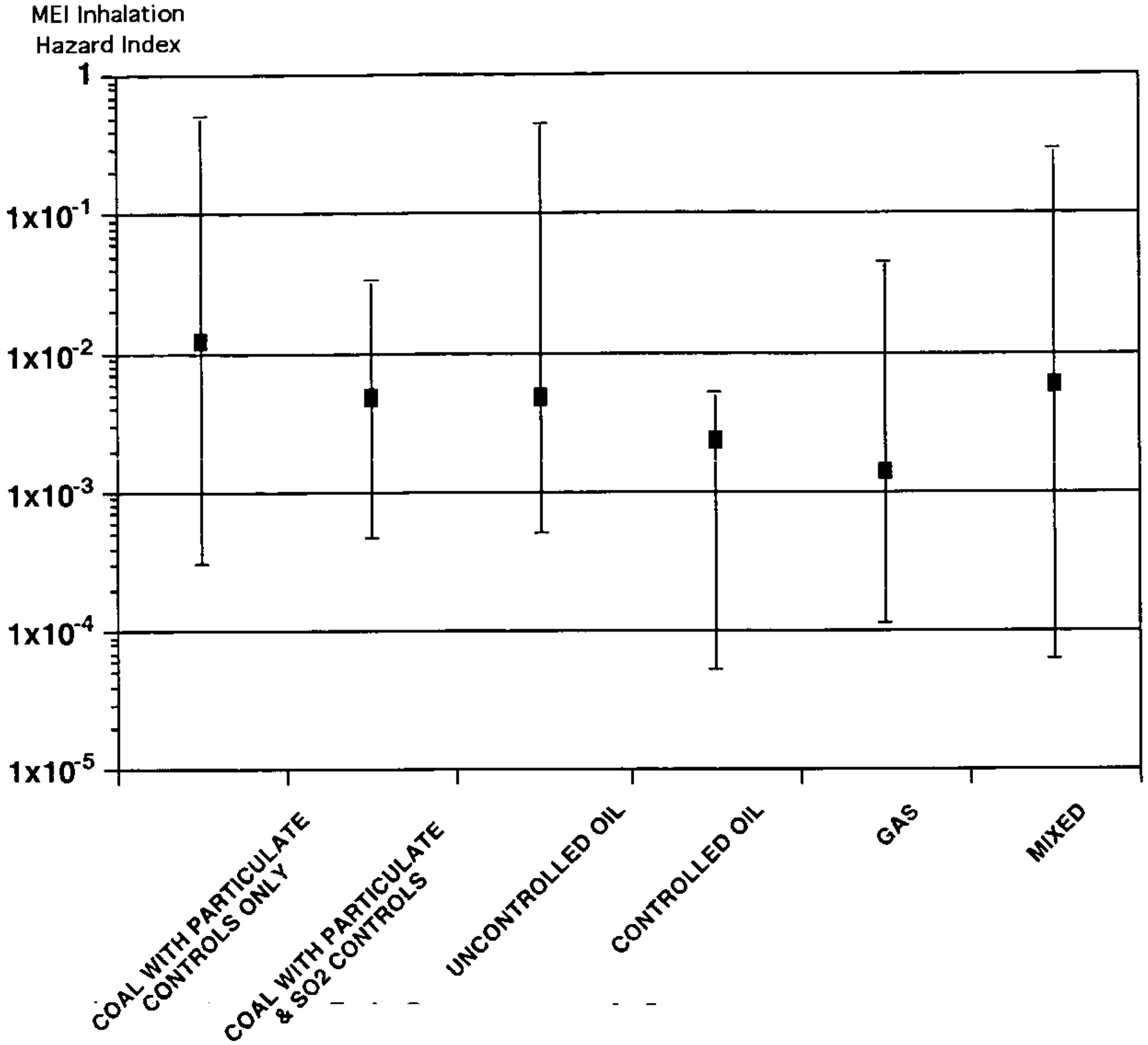


Figure 4-3 MEI Inhalation Hazard Index by Plant Group
Reference: EPRI's Utility Trace Substances Synthesis Report, Vol. 1, Figure 7-7

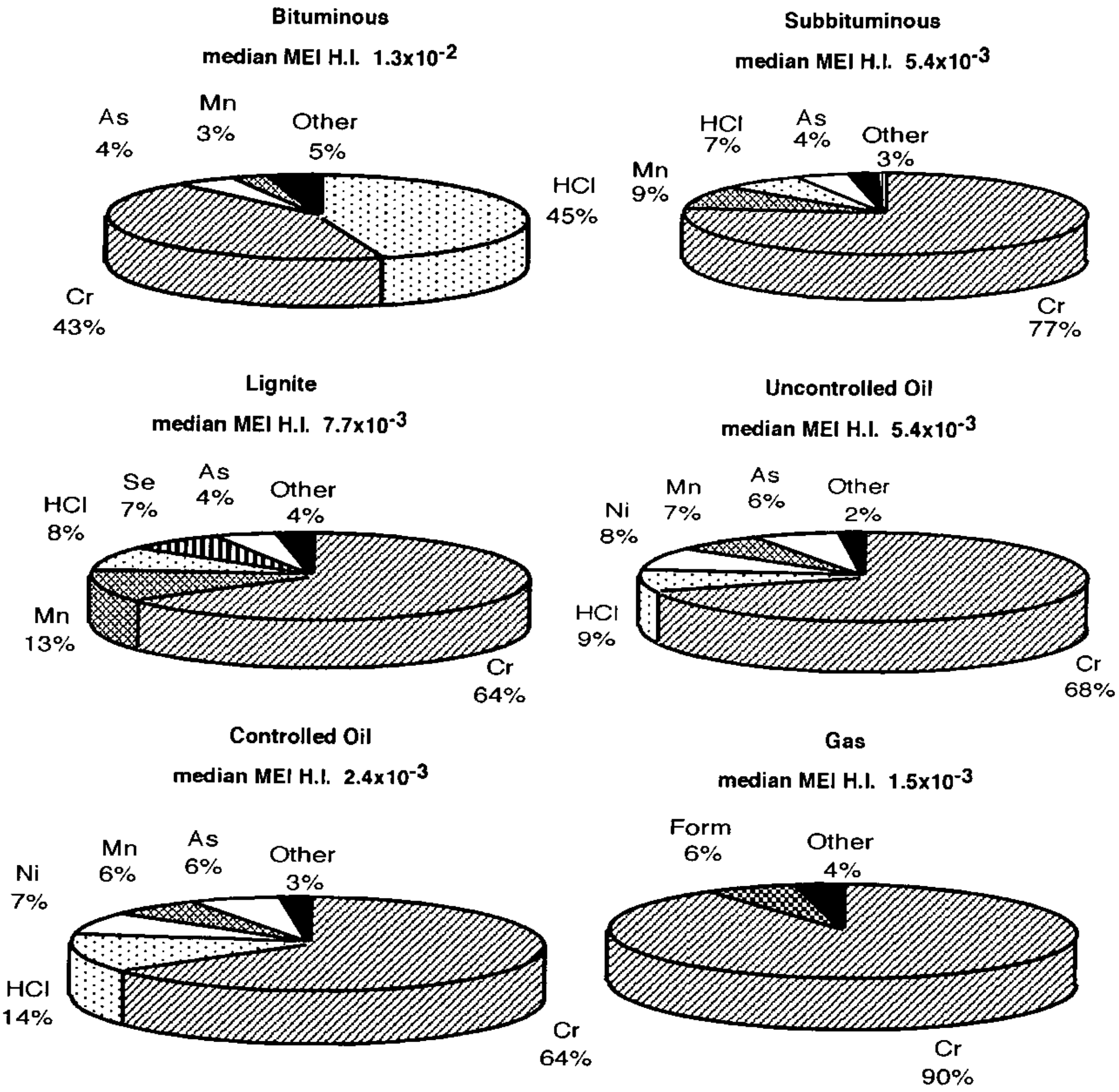


Figure 4-4 Contributions of Individual Substances to MEI Inhalation Hazard Index
Reference: EPRI's Utility Trace Substances Synthesis Report, Vol. 1, Figure 7-8

4.2 SCREENING HEALTH RISK ASSESSMENT BASED ON CAPCOA METHODOLOGY

In 1994, Carnot conducted a screening health risk assessment (HRA) to facilitate interpretation of the Gas PISCES program results. This effort was funded solely by GRI. It was conducted in accordance with California Air Pollution Control Officers Association (CAPCOA) risk assessment guidelines. The CAPCOA methodology is different from the more complex methodology used by EPRI. The CAPCOA methodology uses a very conservative analysis which does not represent the best estimate of the likely degree of exposure, or associated risk. It is intended to be used as a method for demonstrating virtual safety or compliance with regulatory guidelines. The actual levels of human exposure and associated risks should be much less than predicted by the HRA. The purpose of this conservative analysis was to quickly put the results of the emissions measured from the gas-fired units into the context of health risk.

The HRA was based on the SCREEN2 dispersion model and the ACE 2588 risk assessment model. It was conducted for five sample sources:

- Natural Gas-Fired Boiler
- Oil-Fired Boiler
- Coal-Fired Boiler
- Natural Gas-Fired Turbine without NO_x control
- Natural Gas-Fired Turbine with water injection for NO_x control

Emissions from these five sources were evaluated independently based on site-specific full load emissions measurements from the PISCES program. As the toxic emission measurements on the gas-, oil-, and coal-fired boilers were performed on different unit sizes, the mass flow emission rates were scaled to an equivalent 330 MW unit size for comparative purposes. Emissions data for each of the utility boilers were also normalized to a common stack height, exhaust gas temperature, and dry flue gas flow rate to provide a common basis of comparison of fuel effects. The gas turbines were not normalized to a common basis as the two sites both utilized natural gas and the range of operating parameters was more limited. All sources were placed in the same physical environment and meteorological conditions for the HRA.

The HRA was very conservative. It is based on the Maximally Exposed Individual (a hypothetical receptor assumed to reside at the point of maximum ground level impact for 70 years). The potential for human exposure to emissions from these sources was estimated with consideration of three major routes of entry including inhalation, the ingestion of soil and plants, and the uptake of substances through the skin. Health impacts from the following substances were included:

Carcinogenic Risk	Acute Hazard	Chronic Hazard
Arsenic	Copper	Arsenic
Beryllium	Mercury	Beryllium
Cadmium	Nickel	Cadmium
Chromium	Selenium	Chromium
Lead	Formaldehyde	Lead
Nickel		Manganese
Selenium		Mercury
PAH		Nickel
Benzene		Selenium
Formaldehyde		Phosphorus
		Naphthalene
		Benzene
		Toluene
		Formaldehyde

The results of the screening health risk assessment performed by Carnot are presented in Table 4-1. The contribution of each substance to carcinogenic risk is shown in Figure 4-1 for each unit type. Key points are highlighted below.

Table 4-1
SUMMARY OF CONSERVATIVE SCREENING HEALTH RISK ASSESSMENT RESULTS FOR ONE EXAMPLE UTILITY BOILER FOR EACH FUEL TYPE AND TWO EXAMPLE UTILITY GAS TURBINES

	Natural Gas-Fired Boiler	**Oil-Fired Boiler**	**Coal-Fired Boiler**	**Natural Gas-Fired Turbine 1 No NO_x Control**	**Natural Gas-Fired Turbine 2 Water Injection**
Cancer Risk	0.42×10^{-6} (Cr)	14.3×10^{-6} (Cr)	20.4×10^{-6} (Cr)	0.09×10^{-6} (Cr)	0.10×10^{-6} (Cr)
Acute HI*	0.0004 (Ni)	0.0942 (Ni)	0.0323 (Se)	0.0001 (Ni)	0.0001 (Ni)
Chronic HI*	0.0022 (P)	0.0834 (P)	0.0775 (P)	0.0010 (P)	0.0009 (P)

( ) Parenthesis denotes toxic substance which is the primary contributor to risk or Hazard Index (HI). Abbreviations are as follows: Cr = hexavalent chromium, Ni = nickel, P = phosphorus, and Se = selenium.

*Values of less than one (1) are below the significance threshold, and are not considered to represent a risk.

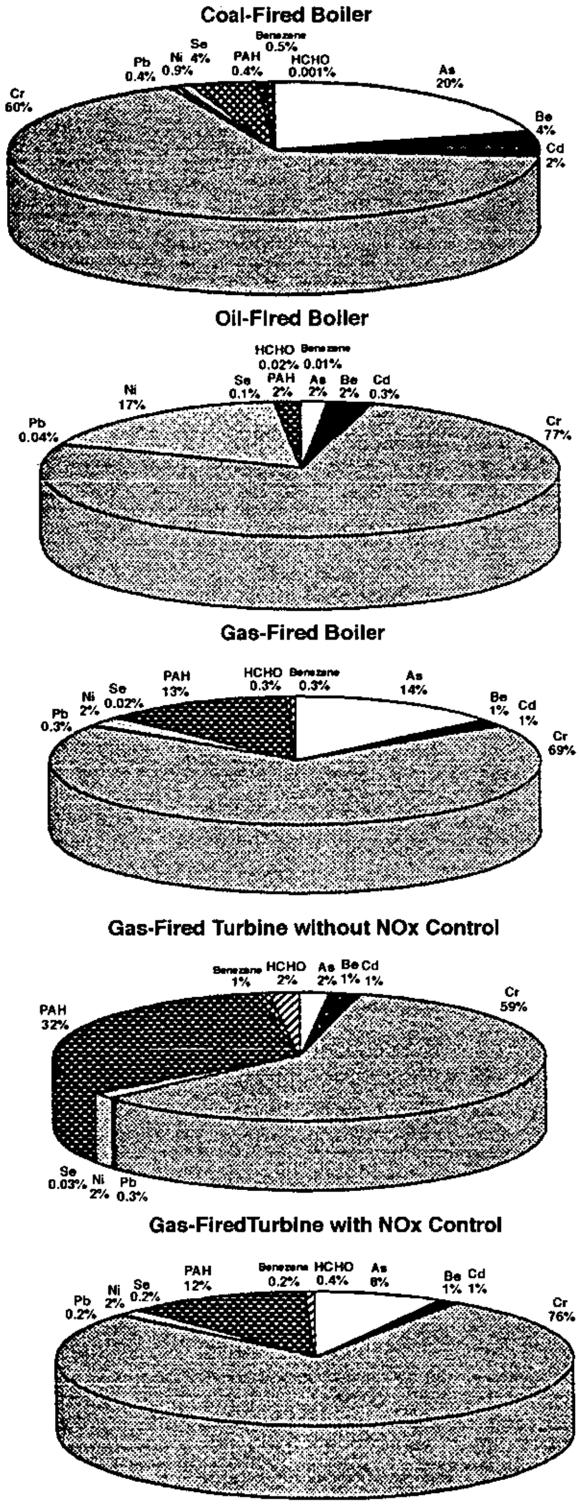


Figure 4-5 Key Contributors to Inhalation Carcinogenic Risk for Each Unit Type Based on Carnot Screening Health Risk Assessment

Cancer Risk

- Hexavalent chromium is the major contributor for all units. The hexavalent chromium values used are assumed to be 6 percent of the total chromium emissions, since only a small fraction of chromium is in hexavalent form and readily converts to trivalent form in the atmosphere. This value is based upon PISCES test data in which the chromium speciation was performed.
- For the gas-fired units, arsenic and PAH are the secondary contributors to carcinogenic risk.
- For the oil-fired unit, nickel is the secondary contributor to risk.
- For the coal-fired unit, arsenic is the secondary contributor to risk.
- The exposure pathway of primary importance is inhalation.
- The incremental risk is highest from coal-fired sources and lowest from gas-fired sources, with gas turbines lower than gas boilers.

Non-Carcinogenic Health Risk

- Both acute and chronic risk is insignificant, regardless of fuel type.
- Nickel is the major contributor to acute risk from gas and oil-fired boilers, and selenium is the major contributor to acute risk from coal-fired boilers.
- Phosphorus is the major contributor to chronic risk from all units. It should be noted that the analytical method could not distinguish between elemental phosphorus and phosphate, a benign oxidized state with no associated health risk. For the purposes of the health risk assessment, the phosphorus emissions for all tests were assumed to be of the elemental form.

In summary, the health risks from the natural gas sources evaluated in this study fall within a level that historically has not been a concern for regulatory agencies. The chronic and acute hazard indices were 3 to 4 orders of magnitude below the significance threshold value of 1.0.

4.3 COMPARISON OF EPRI REFINED HRA AND CARNOT SCREENING DATA

Risk estimates generated by the EPRI refined health risk assessment and by the CAPCOA screening health risk assessment used by Carnot utilized fundamentally different assumptions, and consequently yield different estimates of MEI risk and major risk contributors. An understanding of the fundamental differences is critical, since the estimates cannot be directly compared. The screening level health risk assessment set forth an extremely conservative methodology to put on a relative basis, upper bound risk estimates associated with burning different fuels. The screening level assessment methodology employed generic assumptions which tend to generously overpredict risk. On the other hand, the EPRI methodology was carefully structured to provide more realistic maximum risk estimates by considering the individual features of each power station. As such, the EPRI results should be viewed as being more representative estimates of MEI risks associated with individual facilities. The EPRI investigation represents more intense and rigorous examination of individual facility and risk patterns.

A comparison of the key assumptions used in the two assessments is presented in Table 4-2. The table highlights many reasons for screening level MEI risk values which exceed the corresponding EPRI risk values. Several of these key differences are discussed below under the general categories of emission characterization, air dispersion modeling and exposure assessment.

Emission Characterization

Source strength is a key parameter in determining health risk. Emission estimates for the screening level health risk assessment were taken from the stack measurement data sets of five facilities designated as representative of certain fuel and source category combinations. The emission rates represented short term averages (one to three hours) and were not adjusted for expected long term fuel quality characteristics or air pollution control system performance levels. In addition, substances which were not detected were assumed to be present at one-half the detection limit. EPRI's emission calculations were based on a statistical model of individual pollutants, correlating actual measurements with expected variations in fuel quality and control system performance to yield more realistic long term average emission rate estimates. Long term average emission rates are widely recognized as being more appropriate for evaluation of lifetime risk. In addition, carcinogenic PAH's which were not detected at any of the gas-fired sites were assumed to not be present (i.e. zero emissions) in the EPRI model. In the screening level assessment, PAHs were a major contributor to risk when firing on gas, even at ½ the detection limit. These differences could easily be responsible for risk prediction differences of an order of magnitude or more between the two approaches.

Air Dispersion Modeling

Air dispersion modeling in the screening level assessment was based on SCREEN2 computer model simulations which evaluated a worst-case set of assumed atmospheric stability and wind speed combinations, to produce short term exposure concentration estimates. These short term estimates were converted to an annual average using an EPA-accepted conservative multiplier of 0.1. In addition, air dispersion modeling assumed generic stack parameters. EPRI's modeling used the ISCLT computer model, employing one full year of site representative meteorological data (joint frequency distributions of atmospheric stability, wind speed and wind direction) and the actual stack parameters of each individual power station to calculate site specific annual average impacts. These differences could be responsible for exposure concentration predictions which vary by approximately an order of magnitude or more between the two approaches.

Table 4-2
COMPARISON OF EPRI AND CARNOT
HEALTH RISK ASSESSMENT KEY ASSUMPTIONS

Feature	Carnot Screening HRA	EPRI Refined HRA
Emission Characterization		
Emission Rate Basis	Single Site Field Measurements	EPRI Statistical Model
Emission Averaging Time	Short Term	Annual
Treatment of PAH Non-Detects	Emissions Based on ½ of Detection Limit	Zero When All Replicate Measurements Yielded Non-detects
Air Dispersion Modeling		
Computer Model	SCREEN2	ISCLT
Meteorology	Worst-case	Site Specific Data
Stack Parameters	Generic 330 MW Boiler	Site Specific Data
Exposure Assessment		
Risk Assessment Model	ACE2588 (CAPCOA)	CORE
Exposure Pathways	Multimedia Exposure	Inhalation Pathway Only
Pollutant Toxicity	CAPCOA Unit Risk Values	IRIS/EPRI Unit Risk Values
MEI Location	Maximum Ground Level Impact	Maximum Impact in a Populated Area

Exposure Assessment

There are also fundamental differences in the exposure assessment methodologies employed by the screening level and EPRI health risk assessments. The screening level assessment entailed the use of a CAPCOA-approved multimedia exposure model (considering inhalation, dermal exposure and several ingestion pathways), while the EPRI CORE model only considered exposure via the inhalation pathway. In the screening level assessment, the MEI receptor was located at the point of maximum ground level impact, irrespective of whether that location was actually populated. In the EPRI model, the MEI receptor location was consistent with actual populated areas.

Finally, and perhaps most significantly, the pollutant cancer toxicities (or unit risk values) assumed by the two methods were almost always different, with the CAPCOA model consistently using higher cancer potencies. The unit risk values are compared in Table 4-3. A notable example is hexavalent chromium, where the CAPCOA unit risk value is several orders of magnitude greater than the USEPA value. These differences could also easily account for risk overpredictions of an order of magnitude or more when comparing results from the CAPCOA multimedia exposure model to the EPRI model.

Table 4-3
COMPARISON OF SELECTED CANCER TOXICITY (UNIT RISK) VALUES USED BY CAPCOA AND USEPA

	Unit Risk $(\mu g/m^3)^{-1}$	
Component	**CAPCOA**[a]	**USEPA**[b]
Arsenic	3.3×10^{-3}	1.43×10^{-3}
Beryllium	2.4×10^{-3}	2.4×10^{-3}
Cadmium	4.2×10^{-3}	1.8×10^{-3}
Chromium	1.4×10^{-1}	6.0×10^{-4}
Nickel	2.6×10^{-4}	--
Lead	8.0×10^{-5}	--
Selenium	1.4×10^{-4}	--
Benzene	2.9×10^{-5}	8.3×10^{-6}
Formaldehyde	6.0×10^{-6}	1.3×10^{-5}
PAH	1.7×10^{-3}	1.7×10^{-4}

[a] Unit risk values represent California regulatory default values for use in the AB2588 program.

[b] Unit risk values taken from USEPA's IRIS or HEAST data base, except arsenic (which is based on EPRI analysis).

Summary

Differing assumptions regarding emission rates, dispersion modeling, and exposure assessment used by the Carnot and EPRI health risk assessments result in order of magnitude or greater overpredictions of risk by the CAPCOA screening methodology performed by Carnot relative to the EPRI model. The Carnot assessment provides an understanding of the relative risks among differing fuel types using a very conservative methodology which is consistent with the project scope and objectives. Because the EPRI risk assessment utilized a wider range of site-specific factors, its results are more representative of facility-specific MEI risk.

5

CONCLUSIONS

The most important conclusion from the air toxics testing programs conducted on gas units and the subsequent health risk assessment studies performed by Carnot and EPRI is that the emissions of hazardous air pollutants from gas-fired sources will not pose significant carcinogenic or non-carcinogenic public health risk. Conclusions that apply to each of the unit types that were tested follow below.

5.1 UTILITY BOILERS

- Chromium, nickel and vanadium were detected in the flue gas from both utility boilers. In addition, copper was detected in the flue gas from the B&W opposed-fired boiler. Limited analysis of the fuel samples for trace metals revealed that nickel and copper were not detected in the fuel samples for either boiler. However, the fuel analysis detection limits were several orders of magnitude higher than the flue gas analysis detection limits, thus, it cannot be concluded that these metals did not originate in the fuel. Unit surfaces are a possible source of chromium and nickel, since both are present in stainless steel. In addition, vanadium is present in large concentrations in fuel oil which had been fired in both utility boilers in prior years. The boiler surfaces, and/or residual ash from oil firing, may thus be the principal source of metals emissions from these units. Although the chromium emissions can contribute significantly to carcinogenic risk, depending upon the assigned risk value, the mass emission levels were found to be less than 0.05 tons per year.
- PAH emissions from the utility boilers and PCB emissions from the B&W opposed-fired boiler were either not detected or detected at low levels (less than 0.001 tons per year). The results were consistent with PAH emissions from other gas-fired utility boilers.
- Benzene, toluene and formaldehyde emissions from the utility boilers were less than 15 lb/10^{12}Btu and 0.50 tons per year for all tests which is generally considered low from a health risk perspective. In addition, these emissions were not significantly impacted by unit load or excess air level and were lower than emissions from the combustion turbines.
- Total hydrocarbon emissions were less than 0.03 lb/MMBtu from the CE boiler as measured by analysis of bag samples. Emissions did not vary significantly with operating condition. Analysis with a continuous, on-site FID analyzer showed maximum emissions 2 x 10^{-4}lb/MMBtu from the B&W boiler.

- NO_x emissions factors were less than 0.24 lb/MMBtu for all cases. Significant NO_x reductions were achieved with increased flue gas recirculation, minimum excess O_2 levels and alternate burners out of service patterns as compared to as found (or baseline) conditions. On the B&W opposed-fired boilers, a 20% NO_x reduction was achieved at minimum load. On the CE tangentially-fired boiler, 33% NO_x reductions were achieved at both full and minimum loads.
- CO emissions were detected at full load, baseline conditions only and were less than 0.11 lb/MMBtu for both units.

5.2 UTILITY TURBINES

- Barium, chromium, copper, and nickel were detected from the utility turbines. In addition, manganese was detected from the Westinghouse turbine and lead was detected from the GE Frame 7 turbine, although all levels were less than 0.05 tons per year. There are three possible sources of metals emissions: the fuel, the combustion air, and the unit surfaces. For both utility turbine sites, ambient air trace metals analysis results indicated that ambient air is not a significant contributor to metals emissions. Limited analysis of the fuel samples for trace metals revealed that nickel, copper and lead were not detected in the fuel samples for either boiler. However, the fuel analysis detection limits for these metals were several orders of magnitude higher than the flue gas analysis detection limits, thus, it cannot be concluded that these metals did not originate in the fuel. Chromium and nickel are both present in stainless steel, so emissions of these metals may have originated from the turbine surfaces.
- PAH, PCB, and PCDD/PCDF emissions from the utility turbines were either not detected or detected at levels less than 0.001 tons per year.
- The load at which a given gas turbine is operated has a strong effect on the emissions of benzene, toluene, formaldehyde, methane and total non-methane organics (TGNMO). Generally, benzene, toluene, formaldehyde, methane and TGNMO decrease with increasing load. This effect of load is primarily due to the design of a given turbine and its combustion characteristics.
- Benzene, toluene and formaldehyde emissions factors were significantly higher for these units compared to the utility boilers. For both units, formaldehyde emissions increased with decreasing load, although the GE Frame 7 turbine displayed higher formaldehyde emissions as compared to the Westinghouse turbine. The GE Frame 7 formaldehyde emissions factors were as high as 7,500 lb/10^{12}Btu while the Westinghouse formaldehyde emissions factors were only as high as 1,000 lb/10^{12}Btu. Benzene emissions factors were less than 10 lb/10^{12}Btu and toluene emissions factors were less than 120 lb/10^{12}Btu for both units. Based on the Carnot screening health risk assessment, these emission levels contribute less than 3% to the carcinogenic risk associated with these types of units, and the mass emissions for each substance were below the CAAA definition for a major source.

- Maximum emissions factors of methane and TGNMO were on the order of 0.001-0.05 lb/MMBtu for both units.
- NO_x emissions factors for the utility turbine with water injection were less than 0.15 lb/MMBtu while the NO_x emissions factors for the utility turbine without NO_x control were less than 0.45 lb/MMBtu.
- CO emissions were lower for the unit without NO_x control (0.11 lb/MMBtu compared to 0.64 lb/MMBtu). CO emissions provide an indication of combustion conditions for a given turbine and turbine load. CO may be a suitable surrogate for estimating emissions of VOCs from gas turbines since conditions that reduce CO emissions (e.g., increased fuel/air mixing) generally reduce emissions of VOCs as well.
- The emissions measured from the gas turbines are specific to the turbine make and model tested and the operating conditions under which the measurements were taken. These results may not apply to other operating conditions, particularly other ambient temperatures. Other factors which should be taken into consideration when applying these results include atmospheric conditions, turbine elevation and operating loads.

5.3 TURBINES FOR GAS TRANSMISSION

- The load at which a given gas turbine is operated has a strong effect on the emissions of benzene, toluene, formaldehyde, methane and total non-methane organics (TGNMO). Generally, benzene, toluene, formaldehyde, methane and TGNMO decrease with increasing load. This effect of load is primarily due to the design of a given turbine and its combustion characteristics.
- In general, formaldehyde emissions were higher for these units than both the utility boilers and turbines. Maximum formaldehyde emissions ranged from 400 to 25,000 lb/10^{12}Btu with the high emissions factors exhibited by the GE LM1500, the $SoLoNO_x$ and both Rolls Royce units. All of these had maximum emissions factors above 13,000 lb/10^{12}Btu at minimum load. With the exception of the GE LM1500, maximum benzene emissions factors were fairly low ranging from 2.4 to 67 lb/10^{12}Btu. Mass emissions for these substances were below levels specified in the CAAA for defining a major source.
- Based on ambient measurements of benzene, toluene and formaldehyde conducted at the Solar Mars T14000 $SoLoNO_x$ gas turbine site, only formaldehyde emissions from the turbine were significantly greater than ambient concentrations.
- Both methane and TGNMO emissions factors were fairly dependent upon turbine design. The GE LM1500 and $SoLoNO_x$ turbines had the highest emissions factors with methane emissions greater than 2 lb/MMBtu and TGNMO greater than 27 lb/MMBtu. The other units exhibited maximum methane emissions ranging from

0.012 to 0.504 lb/MMBtu and maximum TGNMO ranging from 0.011 to 0.075 lb/MMBtu.

- As with the utility turbines, emissions factors were significantly impacted by low NO_x combustion characteristics. The SoLoNO_x combustion turbine emitted less than 0.15 lb/MMbtu NO_x while maximum emissions from the other units were in the range of 0.24 to 0.73 lb/MMBtu with the GE Frame 3, Solar Mars T14000 (standard combustor), Solar Mars T12000 and the Rolls Royce Spey emitting more than 0.5 lb/MMBtu under highest NO_x conditions.
- CO emissions were highly varied. The GE LM1500 and the SoLoNO_x turbines exhibited the highest CO emissions factors of 3.6 and 4.9 lb/MMBtu, respectively (note that these units also emitted the lowest NO_x emissions). The other units emitted less than 1.5 lb/MMBtu. CO emissions provide an indication of combustion conditions for a given turbine and turbine load. CO may be a suitable surrogate for estimating emissions of HAPs and VOCs from gas turbines since conditions that reduce CO emissions (e.g., increased fuel/air mixing) generally reduce emissions of HAPs and VOCs as well.
- SO_2 emissions levels estimated from the H_2S content in the fuel were either not detected or resulted in predicted stack emissions factors less than 0.00032 lb/MMBtu.
- The emissions measured from the gas turbines are specific to the turbine make and model tested and the operating conditions under which the measurements were taken. These results may not apply to other operating conditions, particularly other ambient temperatures. Other factors which should be taken into consideration when applying these results include atmospheric conditions, turbine elevation and operating loads.

A

REFERENCES

TABLE A-1
REFERENCE DOCUMENTS FOR THE GAS-FIRED UNITS AIR TOXICS SUMMARY REPORT

Ref.	Doc. Type	Title	No.	Conference	Date
1	Technical Paper	A Summary of Air Toxic Emissions from Natural Gas-Fired Combustion Turbines	(included in conference handouts)	AFRC/JFRC Pacific Rim	Oct-94
2	Technical Paper	VOC Emissions from Gas Turbine Compressor Stations	(included in conference handouts)	GRI	Apr-94
3	Technical Paper	Hazardous Air Pollutant Emissions from Natural Gas-Fired Utility Boilers	94-RA130.03	AWMA	Jun-94
4	Technical Paper	PGT's Experience with Low NO_x Combustors on Pipeline Gas Turbines	(included in conference handouts)	PCGA Transmission Conference	Apr-93
5	Carnot Report	Field Chemical Emissions Monitoring Project, Site 121 Emissions Report, Preliminary Draft	EPR1E-12102/R120E916.T	NA	Dec-94
6	Carnot Report	Field Chemical Emissions Monitoring Project, Site 120 Emissions Report, Preliminary Draft	EPR1E-12102/R016F265.T	NA	Feb-95
7	Carnot Report	Gas PISCES Project Screening Health Risk Assessment	GRI1E-12515/R120E972.T	NA	Dec-94
8	Carnot Report	Test Report for the Engineering Testing at [a Gas Transmission Turbine]	GRI1E-12515/R120E973.T	NA	Nov-94
9	Carnot Report	Other reports summarizing gas transmission turbine testing that was not associated with the GRI sponsored program	Client Proprietary	NA	1993/1994
10	EPRI Report	Electric Utility Trace Substances Synthesis Report, Volume I: Synthesis Report*	EPRI TR-104614-VI	NA	Nov-94

*All four volumes of this report can be purchased from EPRI directly at (510) 934-4212.

B

TEST METHODOLOGY

Appendix B.1 Reference Method Parameters for Gas-Fired Units

TABLE B-1
REFERENCE METHOD PARAMETERS FOR UTILITY BOILERS

Parameter	No. of Replicates	Duration of Test (Minutes)	Sample Rate	Reference Method	Measurement Principle	Method Detection Limit	Minimum Sample Volume (dscf)	Comments
NO_x, CO, O_2, CO_2	in conjunction with all tests by EPA Methods 7E, 10 and 3A							
Metals:								
Arsenic	3	360	1 m^3/hr	EPA Draft Method 29	ICP w/hydride generation	0.04 µg/m^3	240	
Barium					ICP	0.08-0.09 µg/m^3		
Beryllium					ICP	0.01 µg/m^3		
Cadmium					ICP	0.04 µg/m^3		
Chromium					ICP	0.08-0.09 µg/m^3		
Cobalt					ICP	0.14 µg/m^3		
Copper					ICP	0.08-0.09 µg/m^3		
Lead					Graphite Furnace AA	0.04-0.28 µg/m^3		Method of standard additions used
Manganese					ICP	0.11 µg/m^3		
Mercury					CVAAS	0.43-0.47 µg/m^3		
Molybdenum					ICP	0.11 µg/m^3		
Nickel					ICP	0.28 µg/m^3		
Phosphorus					ICP	0.85 µg/m^3		
Selenium					ICP w/hydride generation	0.04 µg/m^3		
Vanadium					ICP	0.08-0.09 µg/m^3		
Polycyclic Aromatic Compounds	3	360	1 m^3/hour	CARB 429	HRGC/LRMS-SIM		168-205	Use CARB 429 with isotope dilution where isotopically labeled standards are *available*
2-Methylnaphthalene						0.001-0.01 µg/m^3		
3-Methylcholanthrene						0.004-0.005 µg/m^3		
7,12-Dimethylbenz(a)anthracene						0.011-0.020 µg/m^3		
Acenaphthylene						0.003-0.007 µg/m^3		
Acenaphthene						0.001-0.006 µg/m^3		Use method of internal standardization for 2-Methynaphthalene, 3-Methylcholanthrene and 7,12-Dimethylbenz(a)anthracene
Anthracene						0.003-0.017 µg/m^3		
Benzo(a)*anthracene*						0.002-0.005 µg/m^3		
Benzo(a)pyrene						0.003-0.006 µg/m^3		
Benzo(b)fluoranthene						0.002-0.004 µg/m^3		

TABLE B-1 (continued)
REFERENCE METHOD PARAMETERS FOR UTILITY BOILERS

Parameter	No. of Replicates	Duration of Test (Minutes)	Sample Rate	Reference Method	Measurement Principle	Method Detection Limit	Minimum Sample Volume (dscf)	Comments
Benzo(g,h,i)perylene						0.003-0.004 μg/m^3		
Benzo(k)fluoranthene						0.002-0.006 μg/m^3		
Chrysene						0.003-0.006 μg/m^3		
Dibenzo(a,h)anthracene						0.004 μg/m^3		
Fluoranthene						0.004-0.006 μg/m^3		
Fluorene						0.002-0.015 μg/m^3		
Indeno(1,2,3-cd)pyrene						0.005 μg/m^3		
Naphthalene						0.007-0.26 μg/m^3		
Phenanthrene						0.003-0.14 μg/m^3		
Pyrene						0.004-0.007 μg/m^3		
<u>PCB</u>	3	360	1 m^3/hour	CARB 428	HRGC/LRMS -SIM	0.001-0.03 μg/m^3	205	Analysis from PAH train
PCB isomer groups by level of chlorination Total mono-decachlorobiphenyls								
<u>Volatile Organics</u>	3/2 (1)	30	0.2 ℓ/min.	CARB 410A EPA TO-14			5ℓ	Collect in Tedlar bags.
Benzene					GC/MS	0.2-0.22 ppb		
Toluene					GC/MS	0.2-0.22 ppb		
Methane/TGNMO					FID/TCA	1.0 ppb		
<u>Formaldehyde</u>	3/2 (1)	60	0.07 ft^3/min.	CARB 430	HPLC	3 ppb	3.5-4	Collect in midget impingers.
<u>Velocity, Moisture</u>		in conjunction with all isokinetic tests						

Notes:

(1) Three replicates for full load baseline condition; two replicates for all other conditions.

(2) For bag samples only.

TABLE B-2
REFERENCE METHOD PARAMETERS FOR UTILITY GAS TURBINES

Parameter	No. of Replicates	Duration of Test (Minutes)	Sample Rate	Reference Method	Measurement Principle	Method Detection Limit	Minimum Sample Volume (dscf)	Comments
NO_x, CO, O_2, CO_2	in conjunction with all tests by EPA Methods 7E, 10 and 3A							
Metals								
Arsenic	3	360	1 m^3/hr	EPA Draft Method 29	ICP w/hydride generation	0.04 μg/m^3	245 -275	
Barium					ICP	0.09 μg/m^3		
Beryllium					ICP	0.01 μg/m^3		
Cadmium					ICP	0.04 μg/m^3		
Chromium					ICP	0.09 μg/m^3		
Cobalt					ICP	0.14 μg/m^3		
Copper					ICP	0.09 μg/m^3		
Lead					Graphite Furnace AA	0.04 μg/m^3		Method of standard additions used
Manganese					ICP	0.11 μg/m^3		
Mercury					CVAAS	0.43 μg/m^3		
Molybdenum					ICP	0.11 μg/m^3		
Nickel					ICP	0.28 μg/m^3		
Phosphorus					ICP	0.85 μg/m^3		
Selenium					ICP w/hydride generation	0.04 μg/m^3		
Vanadium					ICP	0.09 μg/m^3		
Polycyclic Aromatic Compounds	3	360	1 m^3/hr	CARB 429	HRGC/LRMS-SIM		120 -200	Use CARB 429 with isotope dilution where isotopically labeled standards are available
2-Methylnaphthalene						0.001 μg/m^3		
3-Methylcholanthrene						0.004 μg/m^3		
7,12-Dimethylbenz(a)anthracene						0.011 μg/m^3		
Acenaphthylene						0.003 μg/m^3		Use method of internal standardization for 2-Methylnaphthalene,
Acenaphthene						0.001 μg/m^3		
Anthracene						0.003 μg/m^3		

TABLE B-2 (continued)
REFERENCE METHOD PARAMETERS FOR UTILITY GAS TURBINES

Parameter	No. of Replicates	Duration of Test (Minutes)	Sample Rate	Reference Method	Measurement Principle	Method Detection Limit	Minimum Sample Volume (dscf)	Comments
Benzo(a)anthracene						0.002 µg/m^3		3-Methylcholanthrene and 7,12-Dimethylbenz(a)anthracene
Benzo(a)pyrene						0.003 µg/m^3		
Benzo(b)fluoranthene						0.002 µg/m^3		
Benzo(g,h,i)perylene						0.003 µg/m^3		
Benzo(k)fluoranthene						0.002 µg/m^3		
Chrysene						0.003 µg/m^3		
Dibenzo(a,h)anthracene						0.004 µg/m^3		
Fluoranthene						0.004 µg/m^3		
Fluorene						0.002 µg/m^3		
Indeno(1,2,3-cd)pyrene						0.005 µg/m^3		
Naphthalene						0.26 µg/m^3		
Phenanthrene						0.003 µg/m^3		
Pyrene						0.004 µg/m^3		
PCB	3	360	1 M^3/HR	CARB 428	HRGC/LRMS-SIM	0.001-0.03 µg/M^3	120-200	Analysis from PAH train
PCB isomer groups by level of chlorination								
Total monodecachlorobiphenyls								
PCDD/PCDF	3	360	1 m^3/hour	CARB 428	HRGC/LRMS-SIM	0.001-0.03 µg/m^3	120-200	Analysis from PAH train
Total tetra- through octa-PCDD and PCDF; all 2,3,7,8-substituted isomers								
Volatile Organics	3/2*	30	0.2 ℓ/min.	CARB 410A EPA TO-14			5ℓ	Collect in Tedlar bags.
Benzene					GC/MS	0.2 ppb		
Toluene					GC/MS	0.2 ppb		
Methane/TGNMO					FID/TCA	1.0 ppb		
Formaldehyde	3/2*	60	0.07 ft^3/min.	CARB 430	HPLC	3 ppb	3.7-4.2	Collect in midget impingers.
Velocity, Moisture	in conjunction with all isokinetic tests							

* Three replicates for full load baseline condition; two replicates for all other conditions.

TABLE B-3
REFERENCE METHOD PARAMETERS FOR GAS TRANSMISSION TURBINES

Parameter	No. of Replicates	Duration of Test (Minutes)	Sample Rate	Reference Method	Measurement Principle	Method Detection Limit	Minimum Sample Volume (dscf)	Comments
NO_x, CO, O_2, CO_2	in conjunction with all tests by EPA Methods 7#, 10 and 3A							
Volatile Organics	3/2*	30	0.2 ℓ/min.	CARB 410A EPA TO-14			5 ℓ	Collect in Tedlar bags.
Benzene					GC/MS	0.2 ppb		
Toluene					GC/MS	0.2 ppb		
Methane/TGNMO					FID/TCA	1.0 ppb		
Formaldehyde	3/2*	60	0.07 ft^3/min.	CARB 430	HPLC	3 ppb	5.0	Collect in midget impingers.
Velocity, Moisture		in conjunction with all isokinetic tests						

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* Three replicates for full load and minimum load for all turbines except Solar Mars SoloNO$_x$. For the SoLoNO$_x$, three replicates at full load and two replicates for lower load conditions.

Appendix B.2 Test Method Procedures

B.1 NO_x, CO, O_2, CO_2

At all but one site, these species were measured using Carnot's CEMS. At the other site, the site provided its own CEMS. However, both CEMS meet EPA and CARB requirement for gaseous species.

Sample location depended on the type of unit being tested.

- For utility boilers, multi-point grids were set up in the air preheater inlets to monitor composite flue gas concentrations. Portable O_2 meters were used with each sample train to provide sample-specific O_2 data. In addition, concentrations of O_2 and CO_2 from the CEMS were used to calculate stack gas molecular weight by correcting APH inlet CO_2 levels to stack O_2 concentrations.
- For the gas turbines, a single probe was used to sample one point in the exhaust gas outlet duct. In addition, ambient air sampling was conducted in the vicinity of the unit combustion air intake location.
- For the compressor station turbines, EPA Methods 1 and 20 criteria were followed since testing on these units involved compliance demonstration. According to Method 20, a preliminary multi-point traverse was conducted to assess stratification. Then, the eight points with the lowest O_2 levels are used for subsequent tests.

In all cases, the sampling system employed a heated line followed by a moisture removal trap to conserve any NO_2 in the exhaust gas.

B.2 N_2O

Testing on the Solar Mars T14000 SoLoNOx gas turbine was the only program that included N_2O measurements (at the request of GRI). These measurements were made with an N_2O analyzer that was integrated into the Carnot CEMS. This analyzer quantified N_2O concentration using nondispersive infrared (NDIR) technology.

B.3 SO_2

At all sites, SO_2 concentration was determined from the sulfur content measured in the natural gas (as H_2S) and the corresponding fuel and exhaust volumetric flow rates as follows:

H_2S (lb/hr) = H_2S (ppm) x 10^{-6} x 34 lb/lbmole H_2S x fuel flow (scfh) x lbmole/385.3 scf

SO_2 (lb/hr) = H_2S (lb/hr) x 64 lb/lbmole SO_2 / 34 lb/lbmole H_2S

SO_2 (ppm) = SO_2 (lb/hr) x 10^6 x 385.3 scf/lbmole x 1/64 lb/lbmole SO_2 x 1/stack flow (scfh)

B.4 METALS

B.4.1 Source Emissions

The multi-metals samples at the stack were collected using EPA draft Method 29. The sample train is of the same configuration as EPA Method 5 train with the following exceptions:

1. The probe and nozzle are glass to eliminate metal contamination of the sample.
2. The filter is ultra-pure fiberglass to minimize interferences.
3. The first two impingers contain 5% nitric acid and 10% hydrogen peroxide to collect any volatile metals which pass through the filter. The third impinger is empty to prevent the permanganate solution in the fourth impinger from contaminating the nitric acid impingers.
4. The fourth impinger contains an acidified potassium permanganate solution to collect any mercury that was not collected in the nitric acid impingers.

Sample train recovery and analysis is summarized in the flow diagram presented in Figure B-1. Sample train components (front-half, back-half, and permanganate) were recovered and digested in separate fractions. Materials collected in the sampling train were digested with acid solutions to solubilize inorganic target species and to remove organic constituents that may create analytical interferences. Acid digestion was performed using conventional Parr Bomb digestion techniques.

Analyses for 15 metals was performed by Curtis and Tompkins of Berkeley, California. The analysis methodology was dependent upon the metal being analyzed as shown below:

Metal	Analysis Methodology
Arsenic	ICP with hydride generation
Barium	ICP
Beryllium	ICP
Cadmium	ICP
Chromium	ICP
Cobalt	ICP
Copper	ICP
Lead	Graphite Furnace Atomic Absorption
Manganese	ICP
Mercury	Cold Vapor Atomic Absorption
Molybdenum	ICP
Nickel	ICP
Phosphorous	ICP
Selenium	ICP with hydride generation
Vanadium	ICP

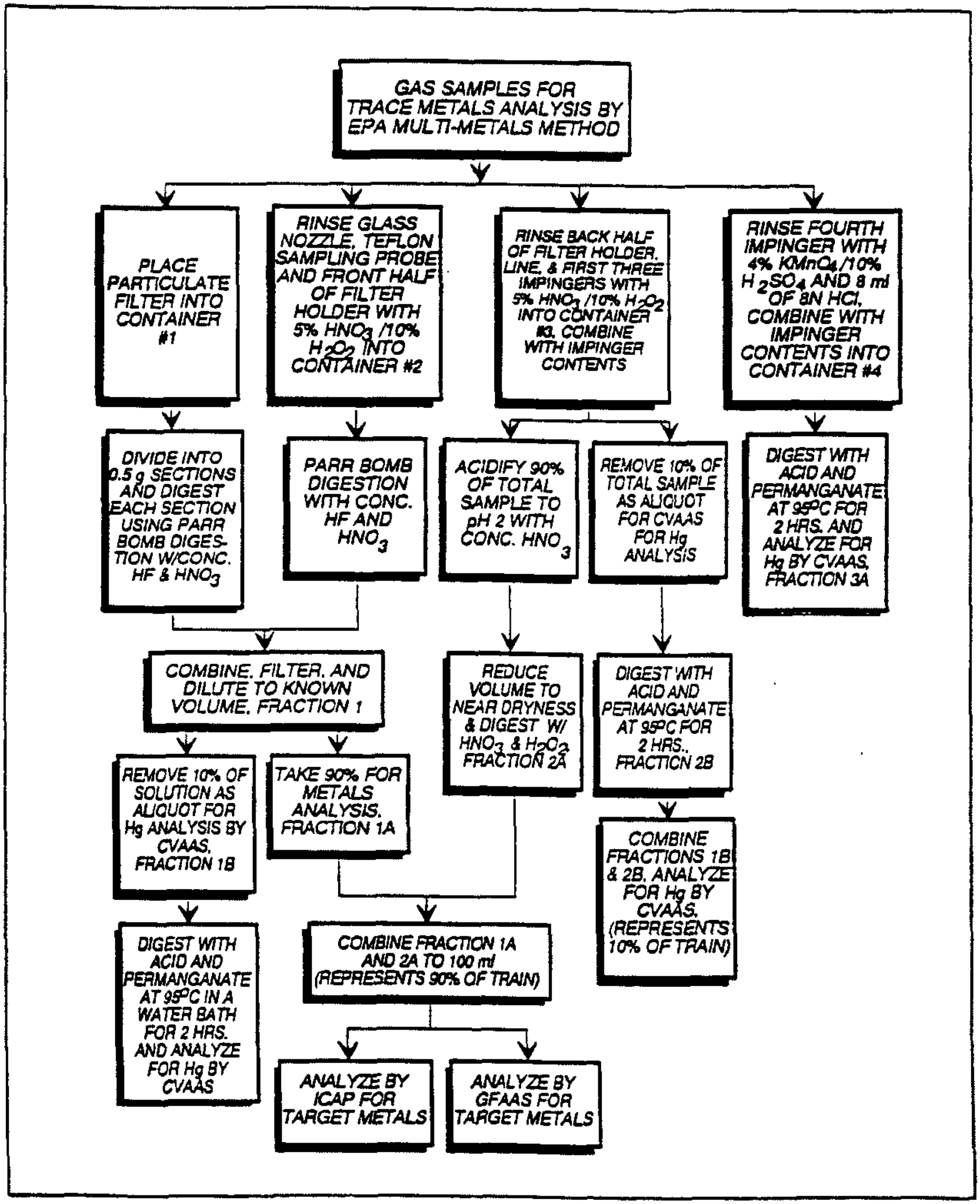

Figure B-1. Multi-Metals Analysis (DSJH-010)

Decomposition of each sample fraction was performed as specified in the EPA multi-metals method. Whenever possible, decomposed sample portions were concentrated and combined to prevent loss of volatile metals so as to achieve the lowest detection limits possible for these samples. The front and back half sample train portions were combined after decomposition to achieve lower detection limits, so no information is available about particulate versus vapor phase metal concentrations.

B.4.2 Ambient Levels

Ambient metals samples were collected on 8" by 10" high volume filters and analyzed for eight metals by Curtis and Tompkins of Berkeley, California. Analysis was by ICP according to the procedures outlined in 40 CFR Part 50, Appendix G.

B.5 SEMI-VOLATILE ORGANIC COMPOUNDS: PAH, PCB, PCDD/PCDF

Samples for the species of interest (PAH, PCB and/or PCDD/PCDF) were collected according to CARB Method 429 using a single sample train. Appropriate surrogate spiking and sample recovery steps were added to ensure that PCB analysis could be conducted by CARB 428 and that PCDD/PCDF analysis could be conducted per EPA 23 where appropriate. Table B-2 summarizes the pertinent information for sample collection. According to the procedure, the sample is collected isokinetically and passed through a heated Method 5 filter followed by an Amberlite XAD-2 resin sorbent module in a water-cooled condenser. The sorbent module is followed by an impinger train to collect moisture and any species that pass through the resin.

Sample analyses were performed by Zenon Environmental Laboratories in Burlington, Ontario, Canada as shown in Figure-B-2. Zenon prepared the resin, loaded the modules, and extracted the modules and other fractions according to appropriate standard procedures. The PAH and PCB analytical methods stated in CARB 429 and CARB 428, respectively, use the addition of isotopically labeled internal standards to all samples to quantitate PAH and PCB species, matrix-specific extraction of the sample with appropriate organic solvents and preliminary fractionation and clean-up of extracts. Appropriate field (surrogate) and pre-extraction (internal) spikes as required by the methods were introduced to the samples. The percent recoveries were reported along with the internal recovery-corrected results. In addition to the sixteen unsubstituted PAH compounds, the samples were also analyzed for three methyl-substituted PAH, however, no recovery corrections were made since deuterated standards for internal spiking are not available. Following extraction, the process extract was split and analyzed for PAH and PCB species using high-resolution capillary column gas chromatograph (HRGC) with low resolution mass spectrometry (LRMS) in selected ion monitoring (SIM) mode.

TABLE B-1
SEMI-VOST TEST INFORMATION

Sampling Methods	CARB 429 - September 12, 1989 CARB 429 - September 12, 1990 revision EPA 23
Analytical Method	HRGC/LRMS with SIM for PAH and PCB HRGC/HRMS for PCDD/PCDF
Analytical Laboratory	Zenon Environmental
Expected Detection Limits	PAH 0.01 - 0.50 $\mu g/m^3$ (per species) PCB 0.025 - 0.25 $\mu g/m^3$ (per cogeners) PCDD/PCDF 0.04 - 0.6 ng/m^3 (per homologue class)
Actual Detection Limits	PAH 0.001-0.04 $\mu g/m^3$ (per species) except naphthalene at 0.26 $\mu g/m^3$ PCB 0.001-0.0031 $\mu g/m^3$ (per cogeners) PCDD/PCDF 0.001-0.02 ng/m^3
Sample Volumes	5 m^3 -6
Surrogate Spiking	Field spikes (surrogates) and recovery spikes (internals) of isotopically labeled PAH , PCB and PCDD/PCDF species were added prior to sampling and prior to extraction, respectively, as per CARB Methods 429, 428 and EPA 23 by Zenon Environmental.
Blank	Full field blank train assembled, recovered and analyzed.
Recovery	Filter stored in Petri dishes lined with hexane-rinsed aluminum foil. XAD-2 column wrapped to protect from light and stored at ≈4°C. Impinger liquid stored in pre-cleaned glass bottles. All glassware rinsed 3 times each with HPLC grade or better methanol, acetone, toluene and methylene chloride. All organic rinses were combined. Organic rinses stored in pre-cleaned glass bottles. All sample fractions stored and shipped cold (≈4°C).
Fractions Analyzed	Probe wash, filter, sorbent module, connecting glassware rinse and first two impingers combined. (All portions combined for final analysis in the laboratory.)
Chain of Custody	Maintained by Carnot and Zenon on all samples.
Glassware Cleaning	Thorough cleaning, followed by DI H_2O, acetone, hexane and methylene chloride rinses, followed by high temperature bake.

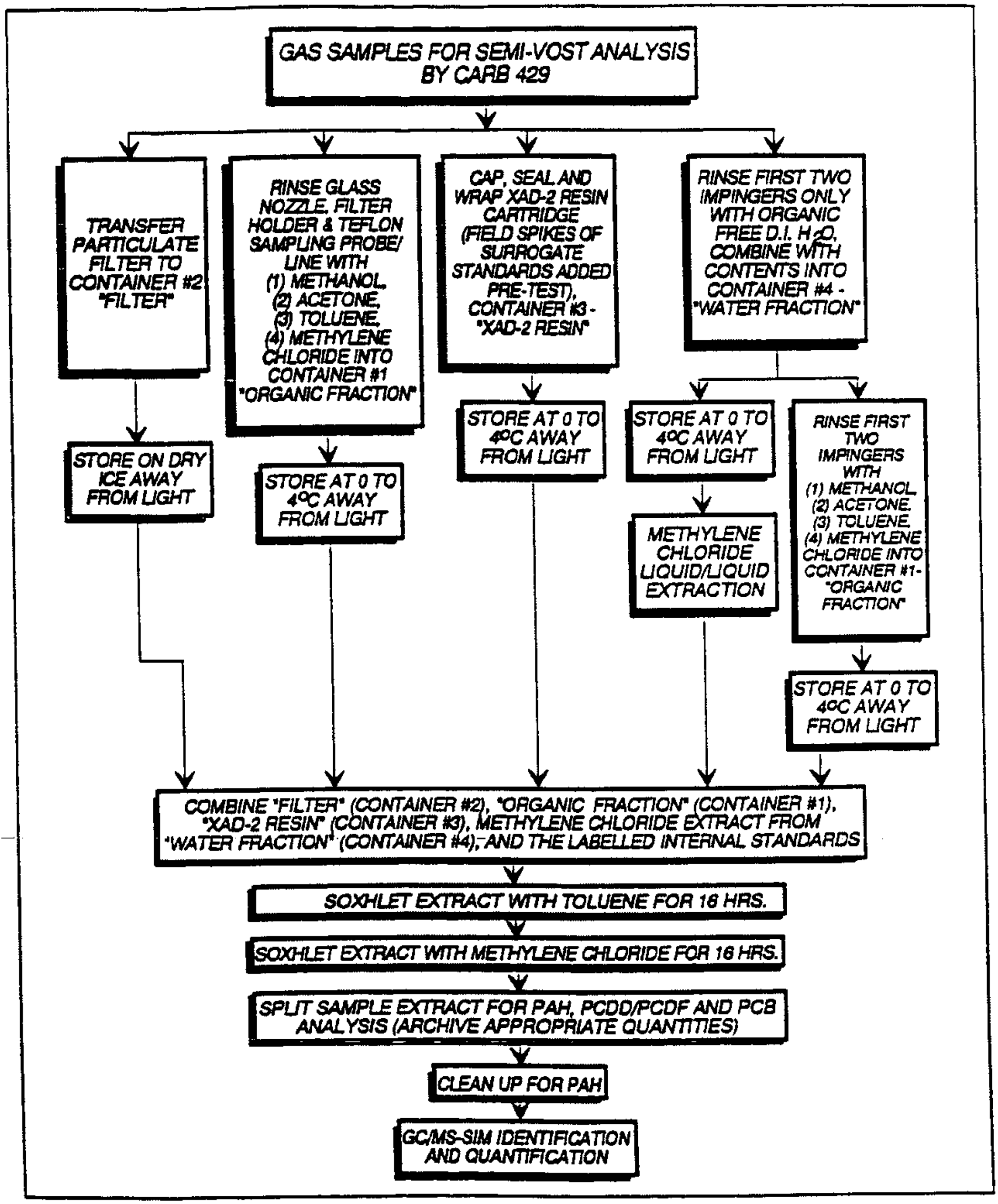

Figure B-2. Semi-VOST Analyses (DSBF-048)

B.6 FORMALDEHYDE

B.6.1 Source Emissions

Samples for formaldehyde analysis were collected non-isokinetically at a single point in acidic 2,4-dinitrophenylhydrazine (DNPH) solution according to CARB 430 using midget impingers. The analysis laboratory, Atmosphere Assessment Associates (AtmAA) located in Chatsworth, California, provided Carnot with DNPH that had been analyzed to verify that there was no significant level of detectable formaldehyde present. The sample train's integrity was verified by checking the train for leaks before and after each test using a low level rotameter.

A field blank was collected for each test by attaching two blank vials of DNPH to the sampling equipment and recovering them in the same way as the sample. Thus, the blank DNPH solution was exposed to the ambient air and the sampling equipment in the same manner as the sample vials. A field spike containing 5.0 ug of formaldehyde was also prepared and exposed to sampling conditions using the same procedures as the field blanks. Trip blanks and trip spikes (neither of which are opened) were also made.

During sample recovery, the teflon sample line between the glass probe and the impingers was rinsed into the first impinger using organic free deionized (DI) water. After collection, all samples were kept cold and sealed.

The analysis for formaldehyde was performed by reverse phase HPLC by Atmosphere Assessment Associates (AtmAA) located in Chatsworth, California as shown in the flow diagram presented in Figure B-3. The collection solution was analyzed before release by AtmAA to verify that there was no significant level of detectable formaldehyde present. All samples were kept cold and sealed during transport.

Formaldehyde reacts with aqueous acidic 2,4-DNPH by nucleophilic addition to the carbonyl, followed by a 1,2-elimination of water to form the 2,4-dinitrophenylhydrazone derivative. Acid is required to promote protonation of the carbonyl because DNPH is a weak nucleophile.

After organic solvent extraction, each formaldehyde-hydrazone derivative is determined using reverse phase HPLC with an ultraviolet (UV) absorption detector. Formaldehyde in the sample is identified and quantitated by comparison of retention times and area counts of standard solutions.

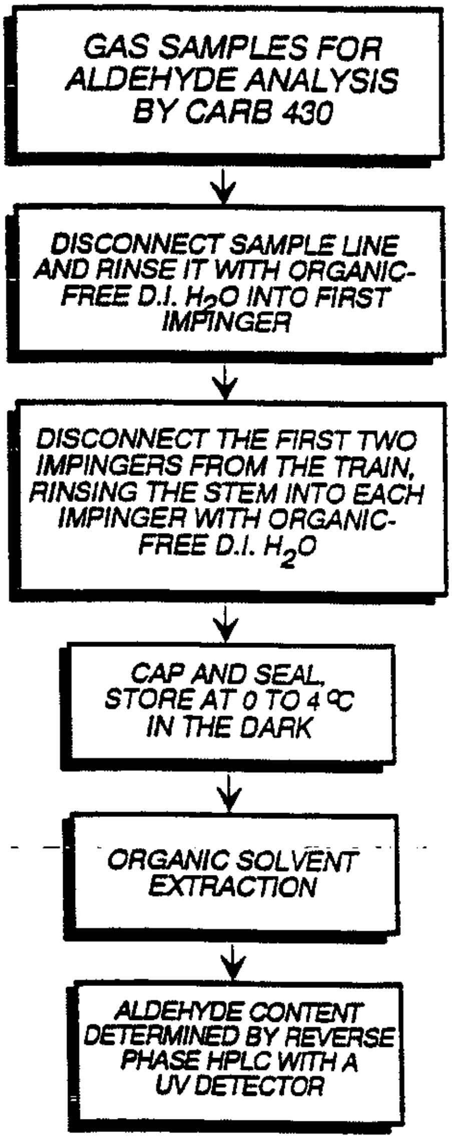

Figure B-3. Formaldehyde Analysis (DSKJ-009)

B.6.2 Ambient Levels

Ambient formaldehyde was measured using EPA Compendium Method TO-11, in which ambient air is drawn through a cartridge containing DNPH-coated resin beads using a pump and meter. The test duration is one hour, and the volume of ambient air sampled is on the order of 2 ft3. The cartridges were prepared by AtmAA and were shipped to the test site in individual plastic vials with an ice pack. The cartridges were kept refrigerated while at the test site and were removed from refrigerated conditions only during the sampling period. Analysis for formaldehyde was conducted using reverse-phase HPLC by AtmAA.

B.7 BENZENE AND TOLUENE

B.7.1 Source Emissions

Benzene and toluene were collected in tedlar bags according to CARB 410A. The bags were purged with N_2 and checked for leaks prior to sampling. All exhaust were drawn at a steady sampling rate for 30 minutes at a single sampling location.

The sampling equipment consists of the following components:

- Teflon Sample Probe, 3-4 feet in length
- Teflon Sample Line connecting the probe to the collection bag
- Tedlar Bag enclosed in a rigid vacuum box
- Sample Pump which is used to create a vacuum within the vacuum box and allows the Tedlar Bag to be filled with exhaust gas because of the differential pressure.

This sampling system is designed to allow the sample to come into contact only with tedlar and teflon materials. In addition, the vacuum box is covered to block out any effect the sun could have on the bag's contents. The entire sampling train is leak checked using the sample pump prior to testing.

Integrated bag samples of the flue gas were sent to AtmAA and analyzed by gas chromatography with a mass spectrometer detector (GC/MS) according to EPA TO-14 for benzene and toluene as shown in the flow diagram presented in Figure B-4. Cryogenic pre-concentration of the gas was used to lower detection limits. This method quantitatively measures the gaseous concentrations of various organic compounds. The following QA/QC procedures were followed for VOC sampling:

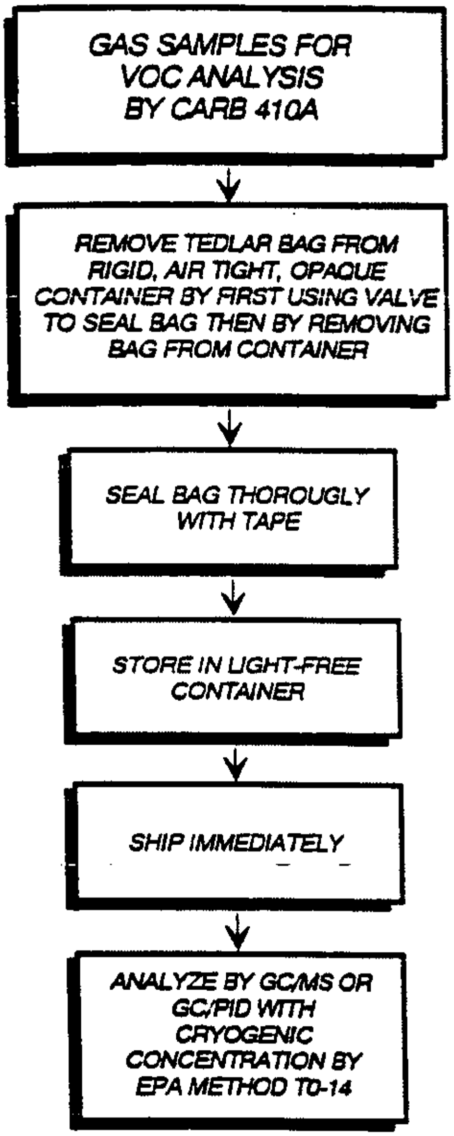

Figure B-4. VOC Analysis (DSMD-049)

- Blank analysis: at each site, one of the tedlar bags that was pre-purges with N2 was sent to AtmAA, filled with their carrier gas, and analyzed for benzene and toluene.

- Duplicate analysis: the analysis for one sample was duplicated and reported by the laboratory.
- Spike analysis: to assess sample degradation: one sample was spiked with benzene and toluene after analysis and re-analyzed after a holding time similar to the original sample.

B.7.2 Ambient Levels

Ambient benzene and toluene were measured using EPA Compendium Method TO-14, in which a sample of ambient air is collected in an evacuated SUMMA passivated stainless steel canister. The sampling rate is controlled through the use of a calibrated orifice which is sized to collect an adequate sample volume for analysis over the 30-minute test duration. The orifice assembly also includes a vacuum gauge to monitor the vacuum in the evacuated canister over the course of the test. Each of the canisters was analyzed for benzene and toluene using GC/MS by AtmAA.

B.8 HYDROCARBONS

B.8.1 Methane/TGNMO

B.8.1.1 Source Emissions

At some sites, methane/TGNMO species were quantified from the exhaust samples collected for benzene and toluene analysis described in Section B.7. As with benzene and toluene, the samples were analyzed by AtmAA by gas chromatography with a mass spectrometer detector (GC/FID-TCA) according to EPA 25.

B.8.1.2 Ambient Levels

Ambient methane/TGNMO were measured using EPA Compendium Method TO-14, in which a sample of ambient air is collected in an evacuated SUMMA passivated stainless steel canister. The sampling rate is controlled through the use of a calibrated orifice which is sized to collect an adequate sample volume for analysis over the 30-minute test duration. The orifice assembly also includes a vacuum gauge to monitor the vacuum in the evacuated canister over the course of the test. Each of the canisters was analyzed for methane/TGNMO using GC/FID-TCA by AtmAA.

B.8.2 Total Hydrocarbons by Continuous Analyzer

Testing at some locations included total hydrocarbon measurements by continuous analyzer instead of or in addition to the bag analysis described above. These measurements were made with an hydrocarbon analyzer that was integrated into the Carnot CEMS. This analyzer quantified hydrocarbon concentration using flame ionization detection. Interference due to moisture content in the exhaust gas was eliminated by using a heated sample line.

B.9 MOISTURE AND VELOCITY

At the sites with utility boilers and gas turbines for electric generation, flue gas velocity and moisture was determined by EPA 2 and 4 in conjunction with every isokinetic test. In addition, at all sites, exhaust gas flow rates were calculated stoichiometrically for each test using the measured natural gas flow rate and exhaust O_2 according to the Method 19 equation:

Stack flow (dscfm) = fuel usage, scfh x HHV, Btu/scf x F factor, dscf/MMBtu at 0% O_2 x MMBtu/10^6 Btu x hr/60 min x (20.9/20.9 - %O_2)

The calculated flow rate is more representative of the actual flow rate because it is not subject to the high bias typically obtained from flow rate measurements made with S-type pitot tubes.

B.10 NATURAL GAS SAMPLING AND ANALYSIS

B.10.1 Utility Boilers and Gas Turbines for Electric Generation

At these units, natural gas sampling and analysis was performed by the Institute of Gas Technology (IGT) located in Chicago, Illinois. Samples were collected using different sampling techniques to preserve and/or pre-concentrate the compounds of interest for later analysis at IGT's Chicago laboratory. Natural gas was extracted from the natural gas pipeline at a rate of 3 ml/min using a sample probe that was placed at the center third of the pipeline to ensure a representative sample. Gas cylinders internally coated with phenolic resin were used to collect gas samples.

For each unit tested, IGT conducted triplicate on-line measurements of natural gas composition (major and minor components) and heating value. Additional samples were collected and analyzed for:

Group	Compounds
Non-hydrocarbons	He, H_2, O_2, CO, CO_2, H_2O, As, Hg
Hydrocarbons	C_1-C_{14} paraffins, C_2-C_3 olefins, BTEX, PAH
Oxygenated Compounds	acetone, methanol, glycols, aldehydes, phenols, cresols
Halocarbons	freons and landfill gas components (C_1-C_3, cyclic aromatic), PCB
Sulfur Compounds	H_2S, SO_2, COS, CS_2, sulfur odorants and derivatives
Metals	volatile compounds of As, Co, Cu, Fe, Ge, Hg, Ni, P, Pb, Sb, Se, Si, Sn
Others	naturally occurring radioactive materials (NORM) including radon

The natural gas analysis methods are summarized in Table B-2.

B.10.2 Compressor Station Turbines

At each unit, a single natural gas sample was collected and analyzed by Zalco Laboratories located in Bakersfield, California. Zalco analyzed the samples for hydrocarbons (CH_4, C_2H_6, C_3H_8, C_4H_{10}, C_6H_{14}) as well as CO, CO_2, O_2, N_2 and total sulfur as H_2S. The samples were also analyzed for higher heating value, density and molecular weight.

TABLE B-2
NATURAL GAS LABORATORY ANALYSIS METHODS

Target Compound	Reference Method	Measurement Principle
Major and minor components	ASTM D-1945, D-1946	GC/FID, GC/TCD
(hydrocarbons, fixed gases)		
C6 plus hydrocarbons	Modified GPA	HRGC/FID
PAH		HPLC
Halocarbons		GC/ELCD
PCB		GC/ECD
Sulfur compounds		GC/FPD, GC/SCD
Nitrogen compounds, oxygenates,		GC/AED
trace elements		
NO		Chemiluminescence
NO_x		IC
Radon		Gamma spectroscopy

Notes:
1. GC = Gas Chromatography
2. FID = Flame Ionization Detection
3. TCD = Thermal Conductivity Detection
4. HRGC = High Resolution Gas Chromatography
5. HPLC = High Performance Liquid Chromatography
6. ELCD = Electroconductivity Detector
7. ECD = Electron Capture Detector
8. FPD = Flame Photometric Detector
9. SCD = Sulfur Chemiluminescence Detector
10. AED = Atomic Emission Detector
11. IC = Ion Chromatography

C

DATA

Appendix C.1: Tabular Data for Curves found in this Report

FORMALDEHYDE EMISSIONS (LB/10^12 BTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	B&W Opposed-Fired Boiler 330 MWe	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq	GE LM1500 Turbine 10.6 MWeq	Rolls Royce Avon Turbine 10.7 MWeq	Rolls Royce Spey Turbine 12.2 MWeq	Solar Mars T12000 Turbine 9.4 MWeq	Solar Mars T14000 Turbine 10.9 MWeq	Solar SoLoNOx Turbine 10.9 MWeq
100%	AF	AF	AF	5.9	11.9	87	15.3	260	4,189	5,607	18.5	15.6	2.2	14.6
100%	Min	High	0		2.7									
100%	Min	Low	0		4.3									
100%	Min	AF	2		4.4									
80%						77								
75%														49
70%							47							
50%						272	175	419						588
37%	AF	AF	AF	5.5										
37%	Min	AF	AF	4.4										
37%	Max	AF	AF	6.3										
35%														20,347
30%						985	7,539							
25%									25,450	14,997	13,227	9,430	2,485	
20%	AF	AF	AF		2.5									
20%	Min	High	AF		2.4									
20%	AF	High	12		2.7									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

BENZENE EMISSIONS (LB/10^12 BTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	B&W Opposed-Fired Boiler 330 MWe	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq	GE LM1500 Turbine 10.6 MWeq	Rolls Royce Avon Turbine 10.7 MWeq	Rolls Royce Spey Turbine 12.2 MWeq	Solar Mars T12000 Turbine 9.4 MWeq	Solar Mars T14000 Turbine 10.9 MWeq	Solar SoLoNOx Turbine 10.9 MWeq
100%	AF	AF	AF	1.4	ND<0.40	6.4	1.3	3.4	39	15.7	5.7	2.0	1.3	2.9
100%	Min	High	0		0.88									
100%	Min	Low	0		0.74									
100%	Min	AF	2		0.53									
80%	AF	AF	AF			7.9								
75%	AF	AF	AF											2.4
70%	AF	AF	AF				2.2							
50%	AF	AF	AF			6.3	3.1	4.2						5.7
37%	AF	AF	AF	1.1										
37%	Min	AF	AF	0.69										
37%	Max	AF	AF	1.3										
35%	AF	AF	AF											67
30%	AF	AF	AF			10.1	9.9							
25%	AF	AF	AF						2,359	53	63	10.2	2.4	
20%	AF	AF	AF		ND<0.70									
20%	Min	High	AF		2.0									
20%	AF	High	12		1.1									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

TOLUENE EMISSIONS (LB/10^12 BTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	B&W Opposed-Fired Boiler 330 MWe	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	Solar SoLoNOx Turbine 10.9 MWeq
100%	AF	AF	AF	13.3	2.2	60	21	10.5
100%	Min	High	0		1.6			
100%	Min	Low	0		1.3			
100%	Min	AF	2		0.80			
80%	AF	AF	AF			109		
75%	AF	AF	AF					11.8
70%	AF	AF	AF				44	
50%	AF	AF	AF			72	87	16.4
37%	AF	AF	AF	2.8				
37%	Min	AF	AF	1.7				
37%	Max	AF	AF	2.5				
35%	AF	AF	AF					44
30%	AF	AF	AF			86	206	
25%	AF	AF	AF					
20%	AF	AF	AF		4.2			
20%	Min	High	AF		1.4			
20%	AF	High	12		1.9			

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8.
For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

TOTAL HYDROCARBON EMISSIONS (LB/MMBTU) VS. MCR (1)

MCR	O2 Level	FGR Level	BOOS (2)	B&W Opposed-Fired Boiler 330 MWe	Westinghouse 501AA Turbine 55/73 MWe (3)	GE Frame 7 Turbine 150 MWe
100%	AF	AF	AF	0.00020	0.009801	0.003386
80%	AF	AF	AF		0.024344	
70%	AF	AF	AF			0.005377
50%	AF	AF	AF		0.003419	0.009580
37%	AF	AF	AF	0.00010		
37%	Min	AF	AF	0.00005		
37%	Max	AF	AF	0.00006		
30%	AF	AF	AF		0.015760	0.051810

Notes:

(1) Based on measurements made with a continuous FID analyzer.

(2) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8.

(3) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

CH4 EMISSIONS (LB/MMBTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq 4B	GE LM1500 Turbine 10.6 MWeq 6B	Rolls Royce Avon Turbine 10.7 MWeq 8C	Rolls Royce Spey Turbine 12.2 MWeq 8D	Solar Mars T12000 Turbine 9.4 MWeq 4C	Solar Mars T14000 Turbine 10.9 MWeq 9A	Solar SoLoNOx Turbine 10.9 MWeq 6A
100%	AF	AF	AF		ND<0.001800	ND<0.001059	ND<0.00230	0.02900	0.08460	0.01180	ND<0.00140	ND<0.00131	0.00286
100%	Min	High	0	ND<0.00041									
100%	Min	Low	0	ND<0.00042									
100%	Min	AF	2	ND<0.00043									
80%	AF	AF	AF		ND<0.002372								
75%	AF	AF	AF										0.00154
70%	AF	AF	AF			0.037389							
50%	AF	AF	AF		ND<0.002576	0.002362	0.01200						0.00857
35%	AF	AF	AF										2.66000
30%	AF	AF	AF		ND<0.010095	0.001304							
25%	AF	AF	AF					2.17000	0.50400	0.03880	0.20700	0.01880	
20%	AF	AF	AF	ND<0.00071									
20%	Min	High	AF	ND<0.00061									
20%	AF	High	12	ND<0.00070									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

TGNMO EMISSIONS (LB/MMBTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq 4B	GE LM1500 Turbine 10.6 MWeq 6B	Rolls Royce Avon Turbine 10.7 MWeq 8C	Rolls Royce Spey Turbine 12.2 MWeq 8D	Solar Mars T12000 Turbine 9.4 MWeq 4C	Solar Mars T14000 Turbine 10.9 MWeq 9A	Solar SoLoNOx Turbine 10.9 MWeq 6A
100%	AF	AF	AF		0.010001	0.007866	0.00764	0.01330	0.03110	0.00381	0.00973	0.00557	0.00310
100%	Min	High	0	0.025									
100%	Min	Low	0	0.011									
100%	Min	AF	2	0.010									
80%	AF	AF	AF		0.012761								
75%	AF	AF	AF										0.00255
70%	AF	AF	AF			0.012763							
50%	AF	AF	AF		0.011182	0.008323	0.01100						0.00825
35%	AF	AF	AF										0.36800
30%	AF	AF	AF		0.016279	0.010765							
25%	AF	AF	AF					0.27400	0.11000	0.07580	0.04280	ND<0.00341	
20%	AF	AF	AF	0.015									
20%	Min	High	AF	0.008									
20%	AF	High	12	0.011									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

NO_x EMISSIONS (LB/MMBTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	B&W Opposed-Fired Boiler 330 MWe	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq	GE LM1500 Turbine 10.6 MWeq	Rolls Royce Avon Turbine 10.7 MWeq	Rolls Royce Spey Turbine 12.2 MWeq	Solar Mars T12000 Turbine 9.4 MWeq	Solar Mars T14000 Turbine 10.9 MWeq	Solar SoLoNOx Turbine 10.9 MWeq
100%	AF	AF	AF	0.119	0.125	0.445	0.134	0.729	0.360	0.237	0.575	0.517	0.606	0.099
100%	Min	High	0		0.083									
100%	Min	Low	0		0.233									
100%	Min	AF	2		0.133									
80%	AF	AF	AF			0.404								
75%	AF	AF	AF					0.629	0.183	0.219	0.400	0.393	0.400	0.088
70%	AF	AF	AF				0.124							
50%	AF	AF	AF			0.315	0.134	0.511	0.134	0.183	0.258	0.218	0.289	0.147
37%	AF	AF	AF	0.069										
37%	Min	AF	AF	0.055										
37%	Max	AF	AF	0.096										
35%	AF	AF	AF											0.110
30%	AF	AF	AF			0.227	0.148							
25%	AF	AF	AF						0.069	0.123	0.198	0.121	0.191	
20%	AF	AF	AF		0.045									
20%	Min	High	AF		0.030									
20%	AF	High	12		0.030									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

CO EMISSIONS (LB/MMBTU) VS. MCR

MCR	O2 Level	FGR Level	BOOS (1)	B&W Opposed-Fired Boiler 330 MWe	CE Tangentially-Fired Boiler 750 MWe	Westinghouse 501AA Turbine 55/73 MWe (2)	GE Frame 7 Turbine 150 MWe	GE Frame 3 Turbine 7.7 MWeq	GE LM1500 Turbine 10.6 MWeq	Rolls Royce Avon Turbine 10.7 MWeq	Rolls Royce Spey Turbine 12.2 MWeq	Solar Mars T12000 Turbine 9.4 MWeq	Solar Mars T14000 Turbine 10.9 MWeq	Solar SoLoNOx Turbine 10.9 MWeq
100%	AF	AF	AF	0.062	0.082	0.005	0.002	0.004	0.158	0.410	0.133	0.006	0.005	0.015
100%	Min	High	0		0.075									
100%	Min	Low	0		0.302									
100%	Min	AF	2		0.111									
80%	AF	AF	AF			*0.012*								
75%	AF	AF	AF					0.015	0.505	0.483	0.339	0.010	0.007	0.038
70%	AF	AF	AF				0.002							
50%	AF	AF	AF			0.055	0.053	0.018	0.782	0.689	0.674	0.146	0.022	0.141
37%	AF	AF	AF	ND<0.0037										
37%	Min	AF	AF	ND<0.0037										
37%	Max	AF	AF	*ND<0.0037*										
35%	AF	AF	AF											4.898
30%	AF	AF	AF			0.111	0.635							
25%	AF	AF	AF						3.569	1.300	0.906	1.253	0.220	
20%	AF	AF	AF		ND<0.00073									
20%	Min	High	AF		ND<0.00073									
20%	AF	High	12		ND<0.00073									

Notes:

(1) For the B&W boiler at 100% MCR, AF (as-found) BOOS = 10 and at 37% MCR, AF BOOS = 8. For the CE boiler at 100% MCR, AF BOOS = 1 and at 20% MCR, AF BOOS = 8. Not applicable to CTs.

(2) During the summer, peak load is 55 MWe, and, during the winter, peak load is 73 MWe. Testing on this unit was conducted during the summer.

SO2 EMISSIONS (LB/MMBTU) VS. MCR

MCR	GE Frame 3 Turbine 7.7 MWeq	GE LM1500 Turbine 10.6 MWeq	Rolls Royce Avon Turbine 10.7 MWeq	Rolls Royce Spey Turbine 12.2 MWeq	Solar Mars T12000 Turbine 9.4 MWeq	Solar Mars T14000 Turbine 10.9 MWeq	Solar SoLoNOx Turbine 10.9 MWeq
100%	0.000184	0.000240	0.000298	0.000278	0.000223	ND<0.000210	0.000213
75%	0.000207	0.000199	0.000237	0.000238	0.000248	ND<0.000238	0.000233
50%	0.000229	0.000216	0.000258	0.000270	0.000237	ND<0.000203	0.000235
35%							0.000228
25%		0.000175	0.000288	0.000313	0.000187	ND<0.000233	

N2O EMISSIONS (LB/MMBTU) VS. MCR

MCR	NOx Solar SoLoNOx Turbine 10.9 MWeq	N2O Solar SoLoNOx Turbine 10.9 MWeq
100%	0.099	0.004
75%	0.088	0.005
50%	0.147	0.006
35%	0.110	0.587

Notes:

(1) SO2 was not detected. Value shown is 1/2 the detection limit.

Appendix C.2: Preliminary FCEM Data for Two Gas-Fired Utility Turbines Site 123 and Site 124

This appendix summarizes preliminary Field Chemical Emissions Monitoring (FCEM) data obtained during sampling programs at two gas-fired turbines—Site 123 and Site 124. Sampling was conducted during June 1993. Site 123 consists of a 53 MW combustion with no controls for NO_x or other emissions. Site 124 consists of a 143 MW combustion turbine with a water injection system to control NO_x.

The primary objective of these sampling programs was to provide information on fuel composition and stack emissions at natural gas-fired combustion turbines at full load. The secondary objectives were to characterize the influence of load on volatile organic compounds (VOC), specifically formaldehyde, benzene, and toluene emissions, to determine emissions of methane and total gaseous non-methane organics (TGNMO) and to obtain ambient air concentrations of trace metals and volatile organic compounds.

The following tests were performed at each site:

Full Load

- Exhaust gas emissions: trace metals, polycyclic aromatic hydrocarbons, polychlorinated biphenyls, polychlorinated dibenzo-p-dioxins, polychlorinated dibenzofurans, volatile organic compounds, and methane/total gaseous non-methane organics.
- Fuel analysis for: major/minor components, C6 + hydrocarbons, non-hydrocarbons, sulfur compounds, halocarbons, nitrogen compounds, and oxygenates.
- Ambient air sampling for: trace metals, VOC

Reduced Load (3 conditions)

- Exhaust gas emissions: VOC, methane/TGNMO
- Ambient air sampling for: trace metals, VOC

The attached tables present the results of each sampling run and the average of each set of replicates. Table 1 presents the results of Site 123 testing at a nominal full load of 56 MW. Table 2 presents the results of Site 124 testing at a nominal full load of 149 MW. Table 3 presents the results obtained at Site 123 for ambient air, methane/TGNMO exhaust gas emissions and for VOC exhaust gas emissions at reduced load conditions (80%, 50% and 30% of full load). Table 4 presents the results obtained at Site 124 for ambient air, methane/TGNMO exhaust gas emissions and VOC exhaust gas emissions at reduced load conditions (70%, 50% and 30% of full load). The tables also contain detailed summaries of the measurement techniques.

The following data flags are used in these tables:

- ND< Not detected at less than the reporting limit

- NA Not analyzed
- @ Concentration is less than five times the reporting limit
- B Blank correction exceeded 50% of the uncorrected result
- F Field blank levels exceeded 50% of the uncorrected result

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 6	Run 7	Average Used
Stack Gas, Metals	Arsenic	GFAAS	ug/Nm^3	ND< 0.04	ND< 0.04	ND< 0.04	ND< 0.04
Stack Gas, Metals	Barium	ICP-AES	ug/Nm^3	1.72	2.89	3.52	2.71
Stack Gas, Metals	Beryllium	ICP-AES	ug/Nm^3	0.01 @	ND< 0.01	ND< 0.01	ND< 0.01
Stack Gas, Metals	Cadmium	ICP-AES	ug/Nm^3	0.05 @F	ND< 0.04	ND< 0.04	ND< 0.04
Stack Gas, Metals	Chromium	ICP-AES	ug/Nm^3	0.58 F	1.11	0.59 F	0.76
Stack Gas, Metals	Cobalt	ICP-AES	ug/Nm^3	ND< 0.13	0.27 @	0.27 @	0.20
Stack Gas, Metals	Copper	ICP-AES	ug/Nm^3	0.62	2.04	1.20	1.29
Stack Gas, Metals	Lead	GFAAS	ug/Nm^3	0.45 @F	0.47 @F	0.32 @F	0.41 @F
Stack Gas, Metals	Manganese	ICP-AES	ug/Nm^3	0.5 @F	0.6	3.1	1.4
Stack Gas, Metals	Mercury	CVAAS	ug/Nm^3	0.53	0.23 @	ND< 0.22	0.29
Stack Gas, Metals	Molybdenum	ICP-AES	ug/Nm^3	2.40 F	2.23 F	2.20 F	2.28 F
Stack Gas, Metals	Nickel	ICP-AES	ug/Nm^3	0.7 @	0.7 @	0.7 @	0.7 @
Stack Gas, Metals	Selenium	ICP-Hydride	ug/Nm^3	ND< 0.04	ND< 0.04	ND< 0.03	ND< 0.04
Stack Gas, Metals	Phosphorus	ICP-AES	ug/Nm^3	7.5 F	6.7 F	7.8 F	7.3 F
Stack Gas, Metals	Vanadium	ICP-AES	ug/Nm^3	0.08 @F	0.1 @F	ND< 0.08	0.08 @F
				Run 1A	Run 1B	Run 6C	
Stack Gas, Aldehyde	Formaldehyde, Full Load	HPLC	ug/Nm^3	37.5	41.2	26.6	35.1
				Run 1A	Run 1B	Run 6C	
Stack Gas, VOC	Benzene, Full Load	GC/MS	ug/Nm^3	2.62	3.59	1.47 @	2.56
Stack Gas, VOC	Toluene, Full Load	GC/MS	ug/Nm^3	21.4	41.0	9.46	24.0

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 6	Run 7	Average Used
Stack Gas, PAH	Naphthalene	HRGC/LRMS-SIM	ug/Nm^3	0.45 F	0.24 F	0.17 F	0.29 F
Stack Gas, PAH	Acenaphthylene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.006	ND< 0.007	ND< 0.018	ND< 0.018
Stack Gas, PAH	Acenaphthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.020	ND< 0.017	ND< 0.018	ND< 0.020
Stack Gas, PAH	Fluorene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.043	ND< 0.044	ND< 0.035	ND< 0.044
Stack Gas, PAH	Phenanthrene	HRGC/LRMS-SIM	ug/Nm^3	0.045	0.053	0.037	0.045
Stack Gas, PAH	Anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.014	0.004	ND< 0.014
Stack Gas, PAH	Fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.005	ND< 0.002	ND< 0.005
Stack Gas, PAH	Pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.011	ND< 0.008	ND< 0.005	ND< 0.011
Stack Gas, PAH	Benz(a)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.010	ND< 0.003	ND< 0.006	ND< 0.010
Stack Gas, PAH	Chrysene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.010	ND< 0.003	ND< 0.006	ND< 0.010
Stack Gas, PAH	Benzo(b)fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.010	ND< 0.003	ND< 0.011	ND< 0.011
Stack Gas, PAH	Benzo(k)fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.011	ND< 0.024	ND< 0.012	ND< 0.024
Stack Gas, PAH	Benzo(a)pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.012	ND< 0.009	ND< 0.010	ND< 0.012
Stack Gas, PAH	Indeno(1,2,3-cd)pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.007	ND< 0.006	ND< 0.013	ND< 0.013
Stack Gas, PAH	Dibenzo(a,h)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.011	ND< 0.012	ND< 0.004	ND< 0.012
Stack Gas, PAH	Benzo(g,h,i)perylene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.006	ND< 0.008	ND< 0.008	ND< 0.008
Stack Gas, PAH	2-Methylnaphthalene	HRGC/LRMS-SIM	ug/Nm^3	0.052	0.077	0.068	0.066
Stack Gas, PAH	7,12-Dimethylbenz(a)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.004	ND< 0.004
Stack Gas, PAH	3-Methylcholanthrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.015	ND< 0.014	ND< 0.016	ND< 0.016
Stack Gas, PCB	total Chlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.005	ND< 0.004	ND< 0.005
Stack Gas, PCB	total Dichlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.002	ND< 0.002	ND< 0.003	ND< 0.003
Stack Gas, PCB	total Trichlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.002	ND< 0.003	ND< 0.004
Stack Gas, PCB	total Tetrachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.002	ND< 0.002	ND< 0.002	ND< 0.002
Stack Gas, PCB	total Pentachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.003	ND< 0.003	ND< 0.004
Stack Gas, PCB	total Hexachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.002	ND< 0.002	ND< 0.003	ND< 0.003
Stack Gas, PCB	total Heptachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.003	ND< 0.003
Stack Gas, PCB	total Octachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.003	ND< 0.003
Stack Gas, PCB	total Nonachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.002	ND< 0.003
Stack Gas, PCB	Decachlorobiphenyl	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.003	ND< 0.003

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 6	Run 7	Average Used
Stack Gas, PCDD/DF	2378-TCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0030	ND< 0.0044	ND< 0.0035	ND< 0.0044
Stack Gas, PCDD/DF	12378 PeCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0065	ND< 0.0018	ND< 0.0022	ND< 0.0065
Stack Gas, PCDD/DF	123478 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0124	0.0048 F	0.0053 F	0.0075 F
Stack Gas, PCDD/DF	123678 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0119	0.0022 F	ND< 0.0022	0.0051 F
Stack Gas, PCDD/DF	123789 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0204	ND< 0.0022	ND< 0.0031	0.0077
Stack Gas, PCDD/DF	1234678 HpCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0427	ND< 0.0046	0.0033 F	0.0161 F
Stack Gas, PCDD/DF	OCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0427	0.0070 F	0.0059 F	0.0185 F
Stack Gas, PCDD/DF	2378 TCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0390	0.0035 F	0.0029 F	0.0151
Stack Gas, PCDD/DF	12378 PeCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0152	0.0018	ND< 0.0017	0.0152
Stack Gas, PCDD/DF	23478 PeCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0334	0.0022	ND< 0.0012	0.0121
Stack Gas, PCDD/DF	123478 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0502	0.0026 F	ND< 0.0017	0.0179
Stack Gas, PCDD/DF	123678 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0156	ND< 0.0015	ND< 0.0012	0.0056
Stack Gas, PCDD/DF	234678 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0204	ND< 0.0024	ND< 0.0018	0.0075
Stack Gas, PCDD/DF	123789 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0072	ND< 0.0026	ND< 0.0020	ND< 0.0072
Stack Gas, PCDD/DF	1234678 HpCDF	HRGC/HRMS-SIM	ng/Nm^3	0.054	ND< 0.0181	ND< 0.0040	0.0216
Stack Gas, PCDD/DF	1234789 HpCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0045	ND< 0.0037	ND< 0.0059	ND< 0.0059
Stack Gas, PCDD/DF	OCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0128 F	ND< 0.0038	ND< 0.0051	0.0058 F
Stack Gas, PCDD/DF	Total TCDD	HRGC/HRMS-SIM	ng/Nm^3	0.1709	ND< 0.0044	ND< 0.0035	0.0583
Stack Gas, PCDD/DF	Total PeCDD	HRGC/HRMS-SIM	ng/Nm^3	0.1244	ND< 0.0018	ND< 0.0022	0.0421
Stack Gas, PCDD/DF	Total HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.1560	0.0064 F	0.0042 F	0.0555
Stack Gas, PCDD/DF	Total HpCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0854	ND< 0.0040	0.0033 F	0.0303
Stack Gas, PCDD/DF	Total TCDF	HRGC/HRMS-SIM	ng/Nm^3	0.1597	0.0081 F	0.0049 F	0.0576
Stack Gas, PCDD/DF	Total PeCDF	HRGC/HRMS-SIM	ng/Nm^3	0.2229	0.0073 F	0.0042 F	0.0781
Stack Gas, PCDD/DF	Total HxCDF	HRGC/HRMS-SIM	ng/Nm^3	0.1579	0.0026 F	ND< 0.0016	0.0538
Stack Gas, PCDD/DF	Total HpCDF	HRGC/HRMS-SIM	ng/Nm^3	0.080	ND< 0.0031	ND< 0.0048	0.0279

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Average Used
N.G. Fuel, Major Comp.	Moisture	Hygrometer	ppmv	80
N.G. Fuel, Major Comp.	Oxygen	GC/TCD	ppmv	8.3
N.G. Fuel, Major Comp.	Helium	GC/TCD	mole %	0.006
N.G. Fuel, Major Comp.	Hydrogen	GC/TCD	mole %	0.006
N.G. Fuel, Major Comp.	Nitrogen	GC/TCD	mole %	0.42
N.G. Fuel, Major Comp.	Carbon Dioxide	GC/TCD	mole %	0.87
N.G. Fuel, Major HC	Methane	GC/FID	mole %	96
N.G. Fuel, Major HC	Ethane	GC/FID	mole %	2
N.G. Fuel, Major HC	Propane	GC/FID	mole %	0.413
N.G. Fuel, Major HC	Isobutane	GC/FID	mole %	0.087
N.G. Fuel, Major HC	n-Butane	GC/FID	mole %	0.094
N.G. Fuel, Major HC	Neopentane	GC/FID	mole %	0.0015 @
N.G. Fuel, Major HC	Isopentane	GC/FID	mole %	0.039
N.G. Fuel, Major HC	n-Pentane	GC/FID	mole %	0.027
N.G. Fuel, Major HC	C6 & Heavier	HRGC/FID	mole %	0.073
N.G. Fuel, Aliphatics	Cyclopentane	HRGC/FID	ppmv	12
N.G. Fuel, Aliphatics	Hexanes	HRGC/FID	ppmv	290
N.G. Fuel, Aliphatics	Methyl cyclopentane	HRGC/FID	ppmv	37
N.G. Fuel, Aliphatics	Cyclohexane	HRGC/FID	ppmv	36
N.G. Fuel, Aliphatics	Heptanes	HRGC/FID	ppmv	147
N.G. Fuel, Aliphatics	Methyl cyclohexane	HRGC/FID	ppmv	42
N.G. Fuel, Aliphatics	Octanes	HRGC/FID	ppmv	59
N.G. Fuel, Aliphatics	Nonanes	HRGC/FID	ppmv	22
N.G. Fuel, Aliphatics	Decanes	HRGC/FID	ppmv	11
N.G. Fuel, Aliphatics	Undecanes	HRGC/FID	ppmv	4.1
N.G. Fuel, Aliphatics	Dodecanes	HRGC/FID	ppmv	1.8
N.G. Fuel, Aliphatics	Tridecanes	HRGC/FID	ppmv	0.5
N.G. Fuel, Aliphatics	Tetradecanes	HRGC/FID	ppmv	ND< 0.1

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Average Used
N.G. Fuel, Aromatics	Benzene	HRGC/FID	ppmv	59
N.G. Fuel, Aromatics	Toluene	HRGC/FID	ppmv	23
N.G. Fuel, Aromatics	Ethylbenzene	HRGC/FID	ppmv	1.8
N.G. Fuel, Aromatics	Xylenes	HRGC/FID	ppmv	7
N.G. Fuel, Aromatics	C3-benzenes	HRGC/FID	ppmv	ND< 0.1
N.G. Fuel, Aromatics	Naphthalenes	HRGC/FID	ppmv	ND< 0.1
N.G. Fuel, Aromatics	PAHs	HPLC	ppmv	ND< 0.02
N.G. Fuel, S-Components	Hydrogen sulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Carbonyl sulfide	GC/FPD/SCD	ppmv	0.03 @
N.G. Fuel, S-Components	Carbon disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl mercaptan	GC/FPD/SCD	ppmv	0.02 @
N.G. Fuel, S-Components	Ethyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl mercaptan	GC/FPD/SCD	ppmv	0.86
N.G. Fuel, S-Components	n-Propyl mercaptan	GC/FPD/SCD	ppmv	0.05 @
N.G. Fuel, S-Components	t-Butyl mercaptan	GC/FPD/SCD	ppmv	0.14
N.G. Fuel, S-Components	Dimethyl sulfide	GC/FPD/SCD	ppmv	0.03 @
N.G. Fuel, S-Components	Methyl ethyl sulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Diethyl sulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl ethyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Diethyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl n-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl n-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Di-i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Di-t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Thiophane	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Other target compounds	GC/FPD/SCD	ppmv	ND< 0.02

TABLE 1
SITE 123 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Average Used
N.G. Fuel, Halocarbons	35 target compounds	GC/ELCD	ppmv	ND< 0.1
N.G. Fuel, Halocarbons	PCBs	GC/ECD	ppmv	ND< 0.01
N.G. Fuel, N-Compounds	Ammonia	GC/AED	ppmv	ND< 4
N.G. Fuel, N-Compounds	17 target compounds	GC/AED	ppmv	ND< 0.5
N.G. Fuel, Oxygenates	Methanol	GC/AED	ppmv	13
N.G. Fuel, Oxygenates	Acetaldehyde	GC/AED	ppmv	ND< 1
N.G. Fuel, Oxygenates	Acetone	GC/AED	ppmv	ND< 1
N.G. Fuel, Oxygenates	Other 14 target compounds	GC/AED	ppmv	ND< 1
N.G. Fuel, Elmts/Compds	Total Arsenic	GC/AED	ug/m^3	ND< 2
N.G. Fuel, Elmts/Compds	Total Mercury	GC/AED	ug/m^3	ND< 0.01
N.G. Fuel, Elmts/Compds	NO	Chemiluminescense	ppmv	0.1 @
N.G. Fuel, Elmts/Compds	NOx	IC	ppmv	ND< 0.3
N.G. Fuel, Elmts/Compds	Radon	Gamma-Spectroscopy	pCi/L	ND< 0.1
N.G. Gas, Speciation	Cobalt	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Copper	GC-AED	ppmv	ND< 0.05
N.G. Gas, Speciation	Lead	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Nickel	GC-AED	ppmv	ND<0.05
N.G. Gas, Speciation	Selenium	GC-AED	ppmv	ND< 0.002
N.G. Gas, Speciation	Phosphorus	GC-AED	ppmv	ND< 0.01
N.G. Gas, Speciation	Chlorine	GC-AED	ppmv	ND< 0.2
N.G. Gas, Speciation	Fluorine	GC-AED	ppmv	ND< 1
N.G. Gas, Speciation	Bromine	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Other metals	GC-AED	ppmv	ND

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 5	Run 7	Average Used
Stack Gas, Metals	Arsenic	GFAAS	ug/Nm^3		0.12@	0.12@	0.12@
Stack Gas, Metals	Barium	ICP-AES	ug/Nm^3	2.1F	2.7	2.9	2.6
Stack Gas, Metals	Beryllium	ICP-AES	ug/Nm^3	ND< 0.01	ND< 0.01	ND< 0.02	ND< 0.02
Stack Gas, Metals	Cadmium	ICP-AES	ug/Nm^3	ND< 0.04	ND< 0.04	ND< 0.05	ND< 0.05
Stack Gas, Metals	Chromium	ICP-AES	ug/Nm^3	1.0	1.6	1.2	1.3
Stack Gas, Metals	Cobalt	ICP-AES	ug/Nm^3	ND< 0.14	ND< 0.15	ND< 0.15	ND< 0.15
Stack Gas, Metals	Copper	ICP-AES	ug/Nm^3	1.1	5.7	5.8	4.2
Stack Gas, Metals	Lead	GFAAS	ug/Nm^3	0.34@	0.35@	0.37@	0.35@
Stack Gas, Metals	Manganese	ICP-AES	ug/Nm^3		5.7	0.39F@	3.0
Stack Gas, Metals	Mercury	CVAAS	ug/Nm^3	0.34@	ND< 0.36	ND< 0.39	ND< 0.39
Stack Gas, Metals	Molybdenum	ICP-AES	ug/Nm^3	2.4F	2.5F	2.5F	2.5F
Stack Gas, Metals	Nickel	ICP-AES	ug/Nm^3	0.7@	0.9@	0.9@	0.8@
Stack Gas, Metals	Selenium	ICP-Hydride	ug/Nm^3	ND< 0.04	ND< 0.04	ND< 0.04	ND< 0.04
Stack Gas, Metals	Phosphorus	ICP-AES	ug/Nm^3		6.7F	9.6F	8.1F
Stack Gas, Metals	Vanadium	ICP-AES	ug/Nm^3	ND< 0.09	0.09@	0.09@	ND< 0.09
				Run 5A	**Run 5B**	**Run 5C**	
Stack Gas, Aldehyde	Formaldehyde, Full Load	HPLC	ug/Nm^3	17.0	8.76	10.1	12.0
Stack Gas, VOC	Benzene, Full Load	GC/MS	ug/Nm^3	0.91	0.80	0.94	0.87
Stack Gas, VOC	Toluene, Full Load	GC/MS	ug/Nm^3	13.9	14.2	14.3	14.1

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 5	Run 6	Average Used
Stack Gas, PAH	Naphthalene	HRGC/LRMS-SIM	ug/Nm^3	0.31F	0.15F	0.11F	0.19F
Stack Gas, PAH	Acenaphthylene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.009	ND< 0.014	ND< 0.014	ND< 0.014
Stack Gas, PAH	Acenaphthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.015	ND< 0.013	ND< 0.010	ND< 0.015
Stack Gas, PAH	Fluorene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.036	ND< 0.030	ND< 0.040	ND< 0.040
Stack Gas, PAH	Phenanthrene	HRGC/LRMS-SIM	ug/Nm^3	0.010@	ND< 0.007	0.006@	0.007@
Stack Gas, PAH	Anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.006	ND< 0.008	ND< 0.009	ND< 0.009
Stack Gas, PAH	Fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.013	ND< 0.009	ND< 0.009	ND< 0.013
Stack Gas, PAH	Pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.012	ND< 0.009	ND< 0.010	ND< 0.012
Stack Gas, PAH	Benz(a)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.006	ND< 0.007	ND< 0.009	ND< 0.009
Stack Gas, PAH	Chrysene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.007	ND< 0.009	ND< 0.009
Stack Gas, PAH	Benzo(b)fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.018	ND< 0.014	ND< 0.010	ND< 0.018
Stack Gas, PAH	Benzo(k)fluoranthene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.016	ND< 0.016	ND< 0.011	ND< 0.016
Stack Gas, PAH	Benzo(a)pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.014	ND< 0.012	ND< 0.014
Stack Gas, PAH	Indeno(1,2,3-cd)pyrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.006	ND< 0.008	ND< 0.006	ND< 0.008
Stack Gas, PAH	Dibenzo(a,h)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.007	ND< 0.010	ND< 0.006	ND< 0.010
Stack Gas, PAH	Benzo(g,h,i)perylene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.007	ND< 0.005	ND< 0.007
Stack Gas, PAH	2-Methylnaphthalene	HRGC/LRMS-SIM	ug/Nm^3	0.007@	0.007F@	0.006F@	0.007F@
Stack Gas, PAH	7,12-Dimethylbenz(a)anthracene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.020	ND< 0.023	ND< 0.027	ND< 0.027
Stack Gas, PAH	3-Methylcholanthrene	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.006	ND< 0.004	ND< 0.006
Stack Gas, PCB	total Chlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.002	ND< 0.001	ND< 0.002	ND< 0.002
Stack Gas, PCB	total Dichlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.003	ND< 0.003
Stack Gas, PCB	total Trichlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.004	ND< 0.006	ND< 0.006
Stack Gas, PCB	total Tetrachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.004	ND< 0.004
Stack Gas, PCB	total Pentachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.007	ND< 0.006	ND< 0.007
Stack Gas, PCB	total Hexachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.003	ND< 0.003	ND< 0.004	ND< 0.004
Stack Gas, PCB	total Heptachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.005	ND< 0.006	ND< 0.006
Stack Gas, PCB	total Octachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.004	ND< 0.005	ND< 0.006	ND< 0.006
Stack Gas, PCB	total Nonachlorobiphenyls	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.004	ND< 0.004	ND< 0.005
Stack Gas, PCB	Decachlorobiphenyl	HRGC/LRMS-SIM	ug/Nm^3	ND< 0.005	ND< 0.005	ND< 0.006	ND< 0.006

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4	Run 5	Run 6	Average Used
Stack Gas, PCDD/DF	2378-TCDD	HRGC/LRMS-SIM	ng/Nm^3	ND< 0.0065	ND< 0.0061	ND< 0.0053	ND< 0.0065
Stack Gas, PCDD/DF	12378 PeCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0062	ND< 0.0064	ND< 0.0068	ND< 0.0068
Stack Gas, PCDD/DF	123478 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0125@F	ND< 0.0168	0.0102@F	ND< 0.0168
Stack Gas, PCDD/DF	123678 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0055@	ND< 0.0076	ND< 0.0062	ND< 0.0076
Stack Gas, PCDD/DF	123789 HxCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0075	ND< 0.0107	ND< 0.0087	ND< 0.0107
Stack Gas, PCDD/DF	1234678 HpCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0101	0.0107@F	ND< 0.0108	ND< 0.0108
Stack Gas, PCDD/DF	OCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0125@F	0.0165@F	0.0077@F	0.0122@F
Stack Gas, PCDD/DF	2378 TCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0055F	ND< 0.0061	ND< 0.0043	ND< 0.0061
Stack Gas, PCDD/DF	12378 PeCDF	HRGC/HRMS-SIM	ng/Nm^3	0.006@	ND< 0.0049	ND< 0.0050	ND< 0.0050
Stack Gas, PCDD/DF	23478 PeCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0042@	ND< 0.0049	ND< 0.0050	ND< 0.0050
Stack Gas, PCDD/DF	123478 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0039	ND< 0.0052	ND< 0.0046	ND< 0.0052
Stack Gas, PCDD/DF	123678 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0026	ND< 0.0037	ND< 0.0034	ND< 0.0037
Stack Gas, PCDD/DF	234678 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0044	ND< 0.0055	ND< 0.0053	ND< 0.0055
Stack Gas, PCDD/DF	123789 HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0044	ND< 0.0058	ND< 0.0056	ND< 0.0058
Stack Gas, PCDD/DF	1234678 HpCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.026	ND< 0.0055	ND< 0.0056	ND< 0.0260
Stack Gas, PCDD/DF	1234789 HpCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0047	ND< 0.0079	ND< 0.0077	ND< 0.0079
Stack Gas, PCDD/DF	OCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0101@F	0.0122@F	0.0062@F	0.0095@F
Stack Gas, PCDD/DF	Total TCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0065	ND< 0.0061	ND< 0.0053	ND< 0.0065
Stack Gas, PCDD/DF	Total PeCDD	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0159	ND< 0.0168	ND< 0.0068	ND< 0.0168
Stack Gas, PCDD/DF	Total HxCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0156@	ND< 0.0131	0.008@F	ND< 0.0131
Stack Gas, PCDD/DF	Total HpCDD	HRGC/HRMS-SIM	ng/Nm^3	0.0099@	0.0107@	ND< 0.0108	ND< 0.0108
Stack Gas, PCDD/DF	Total TCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0055@	ND< 0.0061	ND< 0.0043	ND< 0.0061
Stack Gas, PCDD/DF	Total PeCDF	HRGC/HRMS-SIM	ng/Nm^3	0.0101@	ND< 0.0070	ND< 0.0050	ND< 0.0070
Stack Gas, PCDD/DF	Total HxCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.0036	ND< 0.0034	ND< 0.0043	ND< 0.0043
Stack Gas, PCDD/DF	Total HpCDF	HRGC/HRMS-SIM	ng/Nm^3	ND< 0.031	ND< 0.0640	ND< 0.0065	ND< 0.0310

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 1	Run 2	Run 3	Average Used
N.G. Fuel, Major Comp.	Moisture	Hygrometer	ppmv				650
N.G. Fuel, Major Comp.	Oxygen	GC/TCD	ppmv				5.3
N.G. Fuel, Major Comp.	Helium	GC/TCD	mole %				0.008@
N.G. Fuel, Major Comp.	Hydrogen	GC/TCD	mole %				0.017
N.G. Fuel, Major Comp.	Nitrogen	GC/TCD	mole %				0.54
N.G. Fuel, Major Comp.	Carbon Dioxide	GC/TCD	mole %				0.92
N.G. Fuel, Major HC	Methane	GC/FID	mole %				95.7
N.G. Fuel, Major HC	Ethane	GC/FID	mole %				2.12
N.G. Fuel, Major HC	Propane	GC/FID	mole %				0.414
N.G. Fuel, Major HC	Isobutane	GC/FID	mole %				0.082
N.G. Fuel, Major HC	n-Butane	GC/FID	mole %				0.093
N.G. Fuel, Major HC	Neopentane	GC/FID	mole %				0.0015@
N.G. Fuel, Major HC	Isopentane	GC/FID	mole %				0.038
N.G. Fuel, Major HC	n-Pentane	GC/FID	mole %				0.027
N.G. Fuel, Major HC	C6 & Heavier	HRGC/FID	mole %				0.069
N.G. Fuel, Aliphatics	Cyclopentane	HRGC/FID	ppmv				12
N.G. Fuel, Aliphatics	Hexanes	HRGC/FID	ppmv				280
N.G. Fuel, Aliphatics	Methyl cyclopentane	HRGC/FID	ppmv				33
N.G. Fuel, Aliphatics	Cyclohexane	HRGC/FID	ppmv				33
N.G. Fuel, Aliphatics	Heptanes	HRGC/FID	ppmv				135
N.G. Fuel, Aliphatics	Methyl cyclohexane	HRGC/FID	ppmv				42
N.G. Fuel, Aliphatics	Octanes	HRGC/FID	ppmv				71
N.G. Fuel, Aliphatics	Nonanes	HRGC/FID	ppmv				29
N.G. Fuel, Aliphatics	Decanes	HRGC/FID	ppmv				15
N.G. Fuel, Aliphatics	Undecanes	HRGC/FID	ppmv				5.5
N.G. Fuel, Aliphatics	Dodecanes	HRGC/FID	ppmv				2.6
N.G. Fuel, Aliphatics	Tridecanes	HRGC/FID	ppmv				0.7
N.G. Fuel, Aliphatics	Tetradecanes	HRGC/FID	ppmv				0.1@

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Average Used
N.G. Fuel, Aromatics	Benzene	HRGC/FID	ppmv	58
N.G. Fuel, Aromatics	Toluene	HRGC/FID	ppmv	26
N.G. Fuel, Aromatics	Ethylbenzene	HRGC/FID	ppmv	2
N.G. Fuel, Aromatics	Xylenes	HRGC/FID	ppmv	10
N.G. Fuel, Aromatics	C3-benzenes	HRGC/FID	ppmv	ND< 0.1
N.G. Fuel, Aromatics	Naphthalenes	HRGC/FID	ppmv	ND< 0.1
N.G. Fuel, Aromatics	PAHs	HPLC	ppmv	ND< 0.02
N.G. Fuel, S-Components	Hydrogen sulfide	GC/FPD/SCD	ppmv	0.07@
N.G. Fuel, S-Components	Carbonyl sulfide	GC/FPD/SCD	ppmv	0.02@
N.G. Fuel, S-Components	Carbon disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	n-Propyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	t-Butyl mercaptan	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Dimethyl sulfide	GC/FPD/SCD	ppmv	0.03@
N.G. Fuel, S-Components	Methyl ethyl sulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Diethyl sulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl ethyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Diethyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Methyl i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl n-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl n-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Di-i-propyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	i-Propyl t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Ethyl t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Di-t-butyl disulfide	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Thiophane	GC/FPD/SCD	ppmv	ND< 0.02
N.G. Fuel, S-Components	Other target compounds	GC/FPD/SCD	ppmv	ND< 0.02

TABLE 2
SITE 124 DATA USED IN CALCULATIONS

Stream	Substance	Method	UOM	Average Used
N.G. Fuel, Halocarbons	35 target compounds	GC/ELCD	ppmv	ND< 0.1
N.G. Fuel, Halocarbons	PCBs	GC/ECD	ppmv	ND< 0.01
N.G. Fuel, N-Compounds	Ammonia	GC/AED	ppmv	ND< 4
N.G. Fuel, N-Compounds	17 target compounds	GC/AED	ppmv	ND< 0.5
N.G. Fuel, Oxygenates	Methanol	GC/AED	ppmv	23
N.G. Fuel, Oxygenates	Acetaldehyde	GC/AED	ppmv	ND< 1
N.G. Fuel, Oxygenates	Acetone	GC/AED	ppmv	ND< 1
N.G. Fuel, Oxygenates	Other 14 target compounds	GC/AED	ppmv	ND< 1
N.G. Fuel, Elmts/Compds	Total Arsenic	GC/AED	ug/m^3	ND< 2
N.G. Fuel, Elmts/Compds	Total Mercury	GC/AED	ug/m^3	ND< 0.01
N.G. Fuel, Elmts/Compds	NO	Chemiluminescense	ppmv	ND< 0.1
N.G. Fuel, Elmts/Compds	NOx	IC	ppmv	ND< 0.3
N.G. Fuel, Elmts/Compds	Radon	Gamma-Spectroscopy	pCi/L	ND< 1
N.G. Gas, Speciation	Cobalt	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Copper	GC-AED	ppmv	ND< 0.05
N.G. Gas, Speciation	Lead	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Nickel	GC-AED	ppmv	ND< 0.05
N.G. Gas, Speciation	Selenium	GC-AED	ppmv	ND< 0.002
N.G. Gas, Speciation	Phosphorus	GC-AED	ppmv	ND< 0.01
N.G. Gas, Speciation	Chlorine	GC-AED	ppmv	ND< 0.2
N.G. Gas, Speciation	Fluorine	GC-AED	ppmv	ND< 1
N.G. Gas, Speciation	Bromine	GC-AED	ppmv	ND< 0.1
N.G. Gas, Speciation	Other metals	GC-AED	ppmv	ND< 0.3

TABLE 3
SITE 123 DATA NOT USED IN CALCULATIONS

Stream	Substance	Method	UOM				Average Used
				Run 2A	Run 2B		
Stack Gas, Aldehyde	Formaldehyde, 80% Load	HPLC	ug/Nm^3	16.40 BF	29.8		23.1
				Run 3A	Run 3B		
Stack Gas, Aldehyde	Formaldehyde, 50% Load	HPLC	ug/Nm^3	57.1	94.0		75.5
				Run 5A	Run 5B		
Stack Gas, Aldehyde	Formaldehyde, 30% Load	HPLC	ug/Nm^3	226.0	216.9		221.4
				Run 1A	Run 1B	Run 4	
Stack Gas, VOC	Total Hydrocarbons (as CH4), Full Load	FID	ug/Nm^3	6159	6875	1361	
				Run 7			
Stack Gas, VOC	Total Hydrocarbons (as CH4) Full Load	FID	ug/Nm^3	6159			4100
				Run 2A			
Stack Gas, VOC	Total Hydrocarbons (as CH4) 80% Load	FID	ug/Nm^3	8379			8379
				Run 3B			
Stack Gas, VOC	Total Hydrocarbons (as CH4) 50% Load	FID	ug/Nm^3	1003 @			1003 @
				Run 5A			
Stack Gas, VOC	Total Hydrocarbons (as CH4) 30% Load	FID	ug/Nm^3	3724			3724
				Run 1A	Run 1B	Run 6C	
Stack Gas, VOC	Methane, Full Load	GC/FID	ug/Nm^3	ND< 716	ND< 716	ND< 716	ND< 716
Stack Gas, VOC	TGNMO, Full Load	GC/FID	ug/Nm^3	3294 @	4591	4254	4046
				Run 2A	Run 2B		
Stack Gas, VOC	Methane, 80% Load	GC/FID	ug/Nm^3	ND< 716	ND< 716		ND< 716
Stack Gas, VOC	TGNMO, 80% Load	GC/FID	ug/Nm^3	4125	3581		3853
				Run 3A	Run 3B		
Stack Gas, VOC	Methane, 50% Load	GC/FID	ug/Nm^3	ND< 716	ND< 716		ND< 716
Stack Gas, VOC	TGNMO, 50% Load	GC/FID	ug/Nm^3	2564 @	3653		3108
				Run 5A	Run 5B		
Stack Gas, VOC	Methane, 30% Load	GC/FID	ug/Nm^3	2428 @	2120 @		2277 @
Stack Gas, VOC	TGNMO, 30% Load	GC/FID	ug/Nm^3	3839	3495 @		3667
				Run 2A	Run 2B		
Stack Gas, VOC	Benzene, 80% Load	GC/MS	ug/Nm^3	2.72	2.02		2.11
Stack Gas, VOC	Toluene, 80% Load	GC/MS	ug/Nm^3	40.8	25.1		32.9
				Run 3A	Run 3B		
Stack Gas, VOC	Benzene, 50% Load	GC/MS	ug/Nm^3	1.78	1.71 @		1.74
Stack Gas, VOC	Toluene, 50% Load	GC/MS	ug/Nm^3	16.6	23.2		19.9
				Run 5A	Run 5B		
Stack Gas, VOC	Benzene, 30% Load	GC/MS	ug/Nm^3	2.3	2.3		2.3
Stack Gas, VOC	Toluene, 30% Load	GC/MS	ug/Nm^3	26.5	12.2		19.4

TABLE 3
SITE 123 DATA NOT USED IN CALCULATIONS

Stream	Substance	Method	UOM				Average Used
				Run 1A	Run 1B	Run 6C	
Ambient Air, VOC	Benzene, Full Load	GC/MS	ug/Nm^3	0.84	1.3	0.56	0.88
Ambient Air, VOC	Toluene, Full Load	GC/MS	ug/Nm^3	4.6	2.7	1.9	3.1
				Run 2A	Run 2B		
Ambient Air, VOC	Benzene, 80% Load	GC/MS	ug/Nm^3	0.77	0.77		0.77
Ambient Air, VOC	Toluene, 80% Load	GC/MS	ug/Nm^3	3.7	2.4		3.1
				Run 3A	Run 3B		
Ambient Air, VOC	Benzene, 50% Load	GC/MS	ug/Nm^3	0.42	1.0		0.73
Ambient Air, VOC	Toluene, 50% Load	GC/MS	ug/Nm^3	1.3	2.2		1.7
				Run 5A	Run 5B		
Ambient Air, VOC	Benzene, 30% Load	GC/MS	ug/Nm^3	0.66	0.52		0.59
Ambient Air, VOC	Toluene, 30% Load	GC/MS	ug/Nm^3	2.1	1.9		2.0
				Run 1A	Run 1B	Run 6C	
Ambient Air, VOC	Formaldehyde, Full Load	HPLC	ug/Nm^3	4.6 @F	4.6 @F	1.6 @F	3.6 @F
				Run 2A	Run 2B		
Ambient Air, VOC	Formaldehyde, 80% Load	HPLC	ug/Nm^3	4.0 @F	3.7 @F		3.9 @F
				Run 3A	Run 3B		
Ambient Air, VOC	Formaldehyde, 50% Load	HPLC	ug/Nm^3	3.8 @F	3.2 @F		3.5 @F
				Run 5A	Run 5B		
Ambient Air, VOC	Formaldehyde, 30% Load	HPLC	ug/Nm^3	3.1 @F	3.1 @F		3.1 @F
				Run 4	Run 6	Run 7	
Ambient Air, Metals	Arsenic	GFAAS	ug/Nm^3	ND< 0.007	ND< 0.008	ND< 0.008	ND< 0.008
Ambient Air, Metals	Barium	ICP-AES	ug/Nm^3	ND< 0.014	ND< 0.016	ND< 0.016	ND< 0.015
Ambient Air, Metals	Chromium	ICP-AES	ug/Nm^3	ND< 0.014	ND< 0.016	ND< 0.016	ND< 0.015
Ambient Air, Metals	Cobalt	ICP-AES	ug/Nm^3	ND< 0.023	ND< 0.026	ND< 0.027	ND< 0.026
Ambient Air, Metals	Copper	ICP-AES	µg/Nm^3	0.220	0.200	0.062 @	0.161
Ambient Air, Metals	Nickel	ICP-AES	µg/Nm^3	ND< 0.046	ND< 0.053	ND< 0.054	ND< 0.051
Ambient Air, Metals	Phosphorus	ICP-AES	ug/Nm^3	ND< 0.139	ND< 0.158	ND< 0.163	ND< 0.153
Ambient Air, Metals	Vanadium	ICP-AES	ug/Nm^3	ND< 0.014	ND< 0.016	ND< 0.016	ND< 0.015

TABLE 4
SITE 124 DATA NOT USED IN CALCULATIONS

Stream	Substance	Method	UOM	Run 4			
Stack Gas, Metals	Arsenic	GFAAS	ug/Nm^3	ND< 0.43			
Stack Gas, Metals	Manganese	ICP-AES	ug/Nm^3	300F			
Stack Gas, Metals	Phosphorus	ICP-AES	ug/Nm^3	ND< 8.6			
				Run 3A	Run 3B		Average
Stack Gas, Aldehyde	Formaldehyde, 70% Load	HPLC	ug/Nm^3	18.8	32.8		25.8
				Run 2A	Run 2B		
Stack Gas, Aldehyde	Formaldehyde, 50% Load	HPLC	ug/Nm^3	81.4	61.2		71.3
				Run 1A	Run 1B		
Stack Gas, Aldehyde	Formaldehyde, 30% Load	HPLC	ug/Nm^3	2,496	2,347		2,421
				Run 5A	Run 5B	Run 5C	
Stack Gas, VOC	Total Hydrocarbons (as CH4), Full Load	FID	ug/Nm^3	3072	1643		2358
Stack Gas, VOC	Methane, Full Load	FID/TCA	ug/Nm^3	ND< 714	ND< 714	ND< 714	ND< 714
Stack Gas, VOC	TGNMO (as CH4), Full Load	FID/TCA	ug/Nm^3	5322	5037		5180
				Run 3A	Run 3B		
Stack Gas, VOC	Benzene, 70% Load	GC/MS	ug/Nm^3	1.08@	1.32@		1.20@
Stack Gas, VOC	Toluene, 70% Load	GC/MS	ug/Nm^3	22.3	25.9		24.1
Stack Gas, VOC	Total Hydrocarbons (as CH4), 70% Load	FID	ug/Nm^3	2715	3215		2965
Stack Gas, VOC	Methane, 70% Load	FID/TCA	ug/Nm^3	ND< 714	ND< 714		ND< 714
Stack Gas, VOC	TGNMO (as CH4), 70% Load	FID/TCA	ug/Nm^3	6880	4915		5897
				Run 2A	Run 2B		
Stack Gas, VOC	Benzene, 50% Load	GC/MS	ug/Nm^3	1.36@	1.18@		1.27@
Stack Gas, VOC	Toluene, 50% Load	GC/MS	ug/Nm^3	35.1	36.3		35.7
Stack Gas, VOC	Total Hydrocarbons (as CH4), 50% Load	FID	ug/Nm^3	3501	4358		3929
Stack Gas, VOC	Methane, 50% Load	FID/TCA	ug/Nm^3	986@	943		964
Stack Gas, VOC	TGNMO (as CH4), 50% Load	FID/TCA	ug/Nm^3	3136	3665		3400
				Run 1A	Run 1B		
Stack Gas, VOC	Benzene, 30% Load	GC/MS	ug/Nm^3	3.45	2.89		3.17
Stack Gas, VOC	Toluene, 30% Load	GC/MS	ug/Nm^3	53.8	78.5		66.6
Stack Gas, VOC	Total Hydrocarbons (as CH4), 30% Load	FID	ug/Nm^3	15360	17860		16610
Stack Gas, VOC	Methane, 30% Load	FID/TCA	ug/Nm^3	13431	10573		12002
Stack Gas, VOC	TGNMO (as CH4), 30% Load	FID/TCA	ug/Nm^3	3536	4658		4097

TABLE 4
SITE 124 DATA NOT USED IN CALCULATIONS

Stream	Substance	Method	UOM				Average Used
				Run 5A	Run 5B	Run 5C	
Ambient Air, VOC	Benzene, Full Load	GC/MS	ug/Nm^3	1.46@	0.49@	1.36@	1.10@
Ambient Air, VOC	Toluene, Full Load	GC/MS	ug/Nm^3	3.00	2.10	3.21	2.8
				Run 3A	Run 3B		
Ambient Air, VOC	Benzene, 70% Load	GC/MS	ug/Nm^3	1.11@	0.87@		0.99@
Ambient Air, VOC	Toluene, 70% Load	GC/MS	ug/Nm^3	3.94	2.26		3.10
				Run 2A	Run 2B		
Ambient Air, VOC	Benzene, 50% Load	GC/MS	ug/Nm^3	0.84@	0.94@		0.89@
Ambient Air, VOC	Toluene, 50% Load	GC/MS	ug/Nm^3	3.41	3.37		3.4
				Run 1A	Run 1B		
Ambient Air, VOC	Benzene, 30% Load	GC/MS	ug/Nm^3	1.6@	0.84@		1.22@
Ambient Air, VOC	Toluene, 30% Load	GC/MS	ug/Nm^3	6.78	5.59		6.18
				Run 5A	Run 5B	Run 5C	
Ambient Air, VOC	Formaldehyde, Full Load	HPLC	ug/Nm^3	5.88F	5.27F	4.72F@	5.3 @F
				Run 3A	Run 3B		
Ambient Air, VOC	Formaldehyde, 70% Load	HPLC	ug/Nm^3	5.45F	4.86F		5.2 @F
				Run 2A	Run 2B		
Ambient Air, VOC	Formaldehyde, 50% Load	HPLC	ug/Nm^3	4.56F@	4.64F		4.6 @F
				Run 1A	Run 1B		
Ambient Air, VOC	Formaldehyde, 30% Load	HPLC	ug/Nm^3	4.89F@	5.68F@		5.3 @F
				Run 4	Run 5	Run 7	
Ambient Air, Metals	Arsenic	GFAAS	ug/Nm^3	ND< 0.005	ND< 0.006	ND< 0.005	ND< 0.006
Ambient Air, Metals	Barium	ICP-AES	ug/Nm^3	0.011	0.014	0.011	0.012
Ambient Air, Metals	Chromium	ICP-AES	ug/Nm^3	ND< 0.011	ND< 0.012	ND< 0.011	ND< 0.012
Ambient Air, Metals	Cobalt	ICP-AES	ug/Nm^3	ND< 0.018	ND< 0.020	ND< 0.018	ND< 0.020
Ambient Air, Metals	Copper	ICP-AES	ug/Nm^3	0.074	0.175	0.109	0.120
Ambient Air, Metals	Nickel	ICP-AES	ug/Nm^3	ND< 0.036	ND< 0.039	ND< 0.036	ND< 0.039
Ambient Air, Metals	Phosphorus	ICP-AES	ug/Nm^3	ND< 0.108	ND< 0.118	ND< 0.036	ND< 0.118
Ambient Air, Metals	Vanadium	ICP-AES	ug/Nm^3	ND< 0.011	ND< 0.012	ND< 0.011	ND< 0.012

D

STANDARD INTERNATIONAL UNITS

BRITISH UNITS TO SI UNITS CONVERSION TABLE

BRITISH UNIT (B)	**Metric Equivalent (M)**
BRITISH THERMAL UNIT, Btu	= 1,055 J
CUBIC FOOT, ft^3	= 0.2832 m^3
ft^3/min	= 471.9 cm^3/s = 0.0004719 m^3/s
scfm (60F, 1 atm)	= 0.4474 liter/s = 0.0004474 m^3/s (0C,
FOOT, ft	= 0.3048 m
kWh	= 3.6 E6 J = 3.6 MJ
POUND, lb (mass)	= 0.4536 kg/m^3
lb/10^{12}Btu	= 0.43 μg/MJ
TON, ton (short)	= 907.2 kg