Summary Report:
Trace Substance Emissions From a
Coal-Fired Gasification Plant

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ABSTRACT

The U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI), and Louisiana Gasification Technology Inc. (LGTI) sponsored field sampling and analyses to characterize emissions of trace substances from LGTI's integrated gasification combined cycle (IGCC) power plant at Plaquemine, Louisiana. The results indicate that emissions from the LGTI facility were quite low, often in the ppb levels, and comparable to a well-controlled pulverized coal-fired power plant.

CONTENTS

LIST OF TABLES
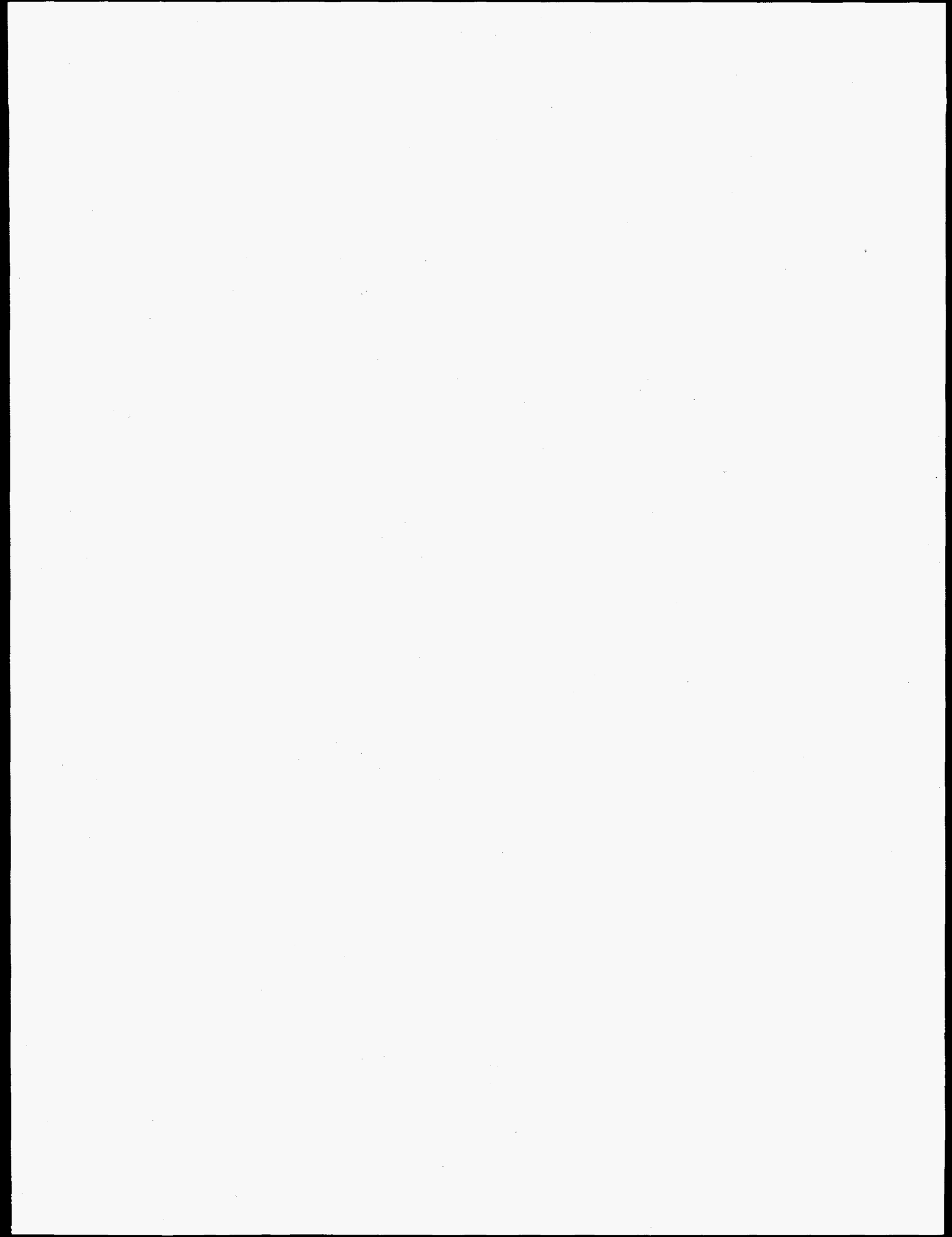
LIST OF FIGURES

1

BACKGROUND AND SUMMARY

This project was a cooperative effort of the U.S. Department of Energy, the Electric Power Research Institute, and the Louisiana Gasification Technology Inc. to characterize the trace substance emissions from an advanced power system. The information gained from this project provides insight into the environmental performance of an integrated gasification combined cycle (IGCC) power plant. This report summarizes the findings originally published in December, 1995, in a comprehensive report prepared by Radian Corporation entitled "A Study of Toxic Emissions From a Coal-Fired Gasification Plant."[1]

Although not widely employed in the utility industry currently, IGCC is an option for future base-load capacity, replacing older conventional pulverized coal–fired boilers as those units are retired. The use of gas turbines to supply peak load demand is now standard practice. The quick startup time of these turbines and their compact, modular size, make them attractive. Unfortunately, they are thermally inefficient, and also fire high–grade fuels (natural gas and light oils). The extraction of useful heat from the gas turbine exhaust by steam generators increases the thermal efficiency of these systems significantly. This is a combined cycle configuration, i.e., the gas turbine generator is driven by expansion of the pressurized combustion gas, while a second generator is powered by steam generated by cooling the exhaust gas. In cogeneration applications, some of the steam also supplies process heating requirements. The heat of vaporization is also recovered (rather than rejected in the condenser), resulting in a very high thermal efficiency. Thermal efficiencies of an IGCC plant can range from 40-45%, compared to 35% for a conventional pulverized coal–fired plant

With the deregulation of natural gas prices several years ago, many natural gas fired combined cycle systems were installed. Some of these systems were designed to also fire synthetic natural gas, which can be produced by coal gasification. Although natural gas prices are currently only at a slight premium relative to other energy sources, prices are expected to gradually rise as supplies dwindle. During times of reduced supply, public policy has traditionally been to divert supplies to residential and commercial users rather than industrial consumers. The demonstration of coal gasification integrated with combined cycle energy production would be an important step toward ensuring reliable power production for the future. Along with the economic assessment of various power technologies, the environmental impacts are of major concern. This report summarizes the environmental issues of a prototype IGCC system.

Background

In 1990 the Electric Power Research Institute (EPRI) implemented the Field Chemical Emissions Monitoring Program (FCEM) as a means of measuring trace substances from a variety of utility combustion boilers. The data generated from this program was provided to the U.S. Environmental Protection Agency (EPA) for their use in addressing Title III of the Clean Air Act Amendments of 1990. In 1993, the Department of Energy (DOE) launched a parallel two-phase program with similar goals and objectives to ensure that the utility industry was well characterized. Phase I of the DOE program was completed in 1994. As a result of the Phase I effort, trace substance emissions data from eight coal-fired stations were provided to EPA. Phase II of the DOE program continued in 1995, expanding the targeted processes to include advanced power systems. This project was conducted as part of DOE's Phase II program, and was co-funded by EPRI, and the host site.

The host site was the Louisiana Gasification Technology Inc. (LGTI) facility located within the Dow Chemical complex in Plaquemine, Louisiana. The LGTI facility was selected by the U.S. Synthetic Fuels Corporation in 1987 to demonstrate the Dow Syngas process. At inception, it was partially funded by a Price Guarantee Commitment between Dow and the Synfuels Corporation. The guarantee has since been assumed by the Office of Synthetic Fuels, U.S. Treasury Department. Dow has formed a subsidiary, Destec Energy, which operates and markets their gasification technology.

Gasification is a partial oxidation process in which a solid, gas, or liquid feed (in this case coal) is reacted with oxygen and steam and converted to a synthesis gas (consisting mainly of hydrogen, carbon monoxide, and carbon dioxide). A high–Btu pipeline grade gas can be produced with additional processing. Coal gasification's major environmental advantages include the ability to reduce sulfur and nitrogen oxide emissions to extremely low levels. In addition, carbon dioxide emissions are lower per MW of power produced because of higher thermal efficiency. IGCC combines the thermal efficiency of a combined cycle combustion turbine (typically 50-60%) with a less expensive fuel source (coal compared to natural gas). Typical pulverized coal unit steam-electrical efficiency is 34-36 percent. The combination of gasification with power production permits energy conversion efficiencies over 40 percent.

An example IGCC process is illustrated schematically in Figure 1-1. A summary of planned and operating IGCC facilities in the U.S. is presented in Table 1-1.[2]
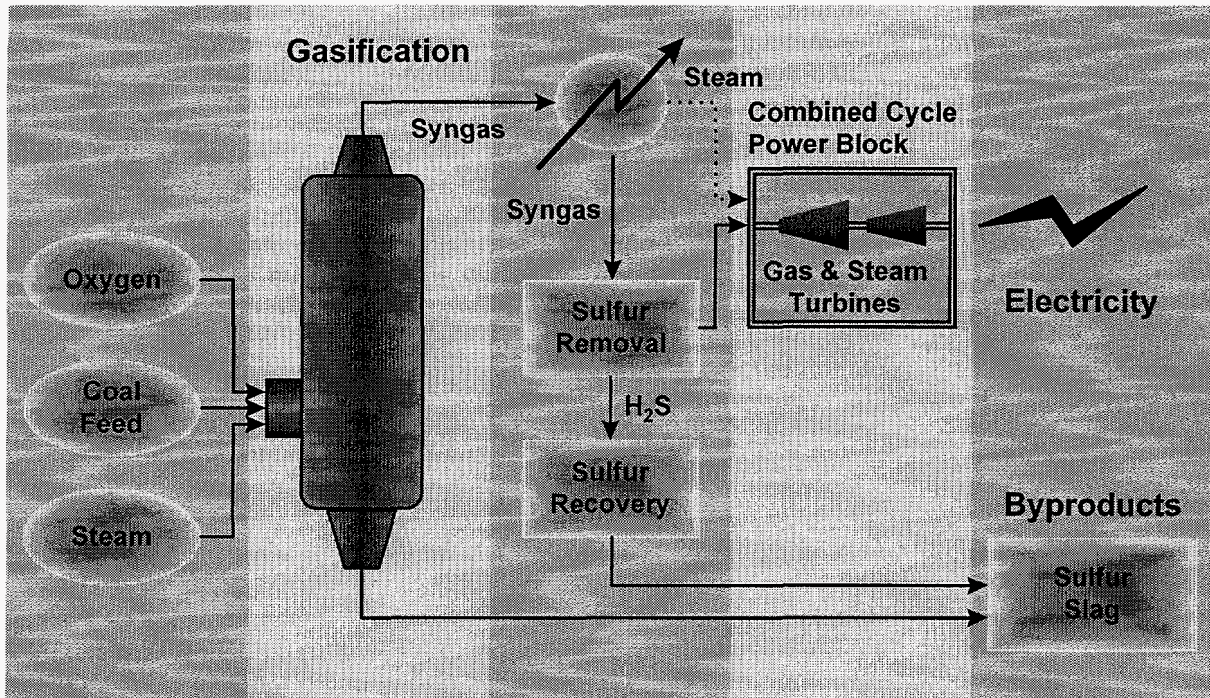
Figure 1-1
Example IGCC Process

Table 1-1
Summary of Recent U.S. Operated IGCC Facilities

	Plaquemine	Wabash River	Pinon Pine	Polk County	
Net Power (MWe)	160	262	100	255	25 (slip-stream)
Coal	Low-Sulfur Subbituminous	High-Sulfur Bituminous	Low-Sulfur Bituminous	High-Sulfur Bituminous	High-Sulfur Bituminous
Gasification Process	Destec two-stage, entrained-bed (slurry fed)	Destec two-stage, entrained-bed (slurry fed)	KRW fluid-bed (dry fed)	Texaco entrained-bed (slurry fed)	Texaco entrained-bed (slurry fed)
Oxidant	Oxygen	Oxygen	Air	Oxygen	Oxygen
Gas Cleanup	Low-temperature	Low-temperature	High-temperature (1,000°F)	Low-temperature	High-temperature (1,000°F)
Particulate Control	Water scrubber	Hot gas barrier filter and water scrubber	Cyclones and hot gas barrier filter	Water scrubber	Cyclone and hot gas barrier filter
Sulfur Control	Selectamine™ scrubber and Selectox™ plant	Selectamine™ scrubber and Claus plant	In-situ absorption (limestone) and external-bed dry adsorption (zinc oxide)	Amine scrubber and H_2SO_4 plant	External moving-bed dry adsorption (zinc titanate) and H_2SO_4 plant
Overall Sulfur Recovery	85% design	99% design	99+% design	98% design	99+% design
NOx Control	Steam dilution	Steam dilution		Nitrogen and steam dilution	
Ammonia Control	Water scrubber	Water scrubber		Water scrubber	
Chloride/Fluoride Control	Water scrubber	Water scrubber		Water scrubber	External fluid-bed dry adsorption ($NaHCO_3$)

Test Objectives

The competitive nature of the power industry will drive the utilization of efficient technology. As one of the few operating plants of this type in the U.S., EPRI and DOE recognized the importance of characterizing the emissions from the LGTI unit. The test objectives for this program fell into four categories:

- Quantitate emissions from the IGCC process;
- Calculate mass balances for selected conserved species;
- Determine control efficiencies for process sub-systems; and
- Design, construct, and demonstrate a retractable sampling system for collecting particulate and gas samples from a high-temperature, high-pressure reduced gas environment.

The test results provide the utility industry with valuable insights into the environmental performance of the IGCC process and provide a basis for a comparison to conventional coal-fired systems.

Data Quality Assessment

The measurement data obtained from this project were subjected to a number of quality control (QC) checks designed to assess the completeness, representativeness, and comparability of the results. The results of these QC checks were evaluated and compared to the data quality objectives (DQOs) established at the onset of this project for precision, accuracy, and representativeness of individual sample measurements. Quality control checks that fail to meet the DQOs do not necessarily render the data unacceptable; however, they may affect the representativeness and comparability of the results reported. The DQOs are not intended for use as acceptance criteria, but rather they are used as empirical estimates of the precision and accuracy expected from existing reference measurement methods considered acceptable for providing meaningful results.

Three major questions were addressed during this assessment: First, was the plant operating in a normal condition? Second, was the sampling of process streams representative, and last, were the analytical results obtained correct? Each of these concerns was addressed in this project.

Process data were collected and analyzed and they indicate the plant operation was very consistent, with major process conditions varying by less than ± 10% during sample collection periods. Samples were collected from the emission streams (gas turbine exhaust, incinerator, slag) with minimal problems and are considered to be representative of normal process operation.

The sampling methods applied to the input and emissions streams produced results that met the data quality objectives and are supported by material balance closures for the overall plant. The sampling methods applied to *internal* process streams are still developmental in nature and have not been validated for reduced gas matrices. Consequently, much of the *internal* data for vapor phase trace metals is considered to be semi-quantitative. In addition, several of the internal sampling points were in less–than–ideal locations for representative sample collection.

Analytical methods were applied to samples collected from both oxidizing (containing excess oxygen) and reducing (containing hydrogen or substoichiometric amounts of oxygen) process streams. Analytical results for those samples collected from the input and emission streams (coal, slag, sweet water, incinerator stack gas, and turbine stack gas) indicate that the analytical data are, with very few exceptions, of good quality and acceptable for use. This statement implies that the bias and precision of the results met the project data quality objectives and that minimal contamination was identified as a result of reagent, sampling, or analytical procedures. The material balances performed around the entire plant also support the reasonableness of the data obtained for the input and output streams of the plant.

Results

- Emissions of hazardous air pollutants from the LGTI facility were quite low. For many substances the combined emission factors (turbine and incinerator stack) were lower than well-controlled pulverized coal steam-electric plants. QA/QC results for the emissions streams show, among other things, that 72% (21 of 29) of the elemental balances met the data quality objectives for material balance closures of 70 - 130 percent.

- Results show that emissions of major elements (Al, Ca, Na, Fe) are controlled to a level of 99.999 percent. Other trace elements that are considered volatile (or semi-volatile) are controlled by 90–99 percent. Only mercury cadmium, and selenium are controlled by less than 90 percent.

- Results from many of the internal process streams show that traditional sampling and analytical methods used in oxidized gas matrices (i.e., flue gas) are not quantitative for reduced gas matrices. Consequently, mass flows for trace elements in internal streams are uncertain.

- A high-pressure, high-temperature sampling system was successfully designed, built, and tested during this project, allowing for representative samples to be collected from the hot (1,000°F) synthesis gas.

- Unique measurements for mercury produced insights into the sampling and analytical methodologies that will be required for future characterization of mercury in reduced gases.

Conclusions

The prototype IGCC system at LGTI emits trace substances at levels equal to or below well-controlled pulverized coal boilers. Conceptually, it is easy to understand how most pollutants of concern are controlled, even though many of the internal measurements are not quantitative.

In the gasifier, large quantities of water are present in a vapor state, due to both the coal–slurry water and the oxidation reaction. The raw gas contains ~30% moisture. As the gas is cooled, this moisture condenses and acts as a very effective agglomeration agent. Since the coal ash is never in a dry environment, the particulate scrubber is very effective at removing particles. As the gas is cooled to about 130°F in the Selectamine™ solution, the moisture level drops to 1% or less. In this solution, the reduced sulfur species are absorbed. It is expected that most organo-metallic species would also be removed to a high degree in the multi-tray absorption tower. After this conditioning, the synthesis gas is combusted in a turbine. Turbine operation requires that the gas be very clean, especially with respect to alkaline elements and particulate matter. The cleanup capabilities of the prototype unit are confirmed by the low emission levels seen from the turbine.

When these results are considered in developing future IGCC units, one must evaluate the type of gas cleanup employed. Newer systems are attempting to employ cleanup methods at high temperatures (~1000°F). Hot gas sulfur removal systems improve the thermal efficiency significantly, but may not be quite as effective at removing vapor phase elements and compounds. These substances would also pass through the turbine as emissions. The developmental work performed during this project to attempt quantifying vapor phase elements in reduced gases identified several analytical problem areas that must be addressed. The hot–gas probe demonstrated that these streams (high temperature and pressure) could be safely sampled.

Report Organization

Section 2 of this report contains a description of the process and describes the test approach that was used. Results are presented in Section 3. Section 4 contains a discussion of special interest topics including mercury and other trace element measurements in reduced gas matrices. A glossary and table for SI conversion units are presented in Sections 5 and 6, and Appendix A contains a comprehensive data summary of all analytical results obtained during the program.

References

[1] *A Study of Toxic Emissions from a Coal-Fired Gasification Plant.* Radian Corporation. Report DE-AC22-93PC93253, U.S. Department of Energy, Pittsburgh Energy Technology Center, Pittsburgh, PA, December 1995.

[2] Mike Epstein, Electric Power Research Institute, July 1996.

2

PROCESS DESCRIPTION

At full capacity, the LGTI Plant produces 30,000 MM Btu of equivalent syngas per day, consuming approximately 2,200 tons per day of western subbituminous coal from the Rochelle mine in the Powder River Basin in Wyoming. This is the equivalent of 160 MW of net power, considering both electricity and process steam production.

The gasification process is radically different from conventional pulverized coal-fired (PC) boilers. The primary distinction is the energy transfer mechanism. In a conventional boiler, the energy released during combustion is transferred directly to water/steam. In the IGCC system, the coal is converted to a gas that is subsequently used to produce power. Major differences are summarized in Table 2-1.

A process flow diagram showing the LGTI process and sample point locations is presented in Figure 2-1. The process is comprised of five main sub-units, each of which is described in the following sections.

Gasification

The gasifier is a high-temperature, oxygen blown, two-stage, entrained-flow, slagging design. Coal slurry is pumped into the reactor and mixed with steam and oxygen in the burner nozzles. Oxygen is controlled to maintain the reactor temperature within a narrow range. Sulfur in the coal is converted almost totally to H_2S with small amounts of COS, while nitrogen is converted to ammonia, nitrogen and trace amounts of cyanide and thiocyanate. Coal ash fuses into molten slag that is drained from the reactor through a let–down system. The large majority of all trace and major elements are captured in the slag.

Gas Cooling and Particulate Removal

The hot raw syngas produced in the gasifier passes through several cooling and cleaning systems. The gas is first cooled in a convective fire-tube heat exchanger producing steam. Next, entrained particulate matter (char) is removed from the gas by a wet venturi scrubber system. The char is returned to the gasifier for complete combustion. The gas is cooled further to near ambient temperature prior to the Selectamine ™ sulfur removal process. The condensate resulting from this gas cooling step contains substantial amounts of soluble sulfide, ammonia, and carbon dioxide. At

this point, the gas contains very little particulate matter. It has an appreciable amount of H_2S and some organo-metallic compounds may be present at low levels.

Table 2-1
Comparison of Typical PC Boiler and IGCC Systems

Element	Typical PC Boiler	Typical IGCC System
Operating Principle	Fuel is combusted, heat is transferred to produce high-pressure steam that drives a turbine.	Fuel is partially combusted which results in gasification of remaining fuel. The high-pressure synthesis gas is expanded and combusted in a gas turbine to produce power. Heat recovery systems raise steam for additional power production.
Oxidant	Air	Air or oxygen in the gasifier. Air in the combustion turbine.
System pressure	1 atmosphere	25-40 atmospheres
Coal Sulfur	Converted to SO_2 in the combustion process and generally removed via a flue gas desulfurization process such as a limestone scrubber.	Converted primarily to H_2S and some COS. H_2S and COS are removed from the synthesis gas prior to combustion and recovered as elemental sulfur or sulfuric acid.
Coal nitrogen	Converted to NO_x	Converted to ammonia and nitrogen.
Process Solids	Typically 80% of the ash produced from the combustion process is collected in a downstream control device (such as an ESP). 20% of the coal ash is recovered as bottom ash.	Virtually all of the coal ash is recovered as an inert slag from the gasifier.
Thermal Efficiency	34-36%	>40% (typical full–scale commercial system

Denotes Sampling Location Number
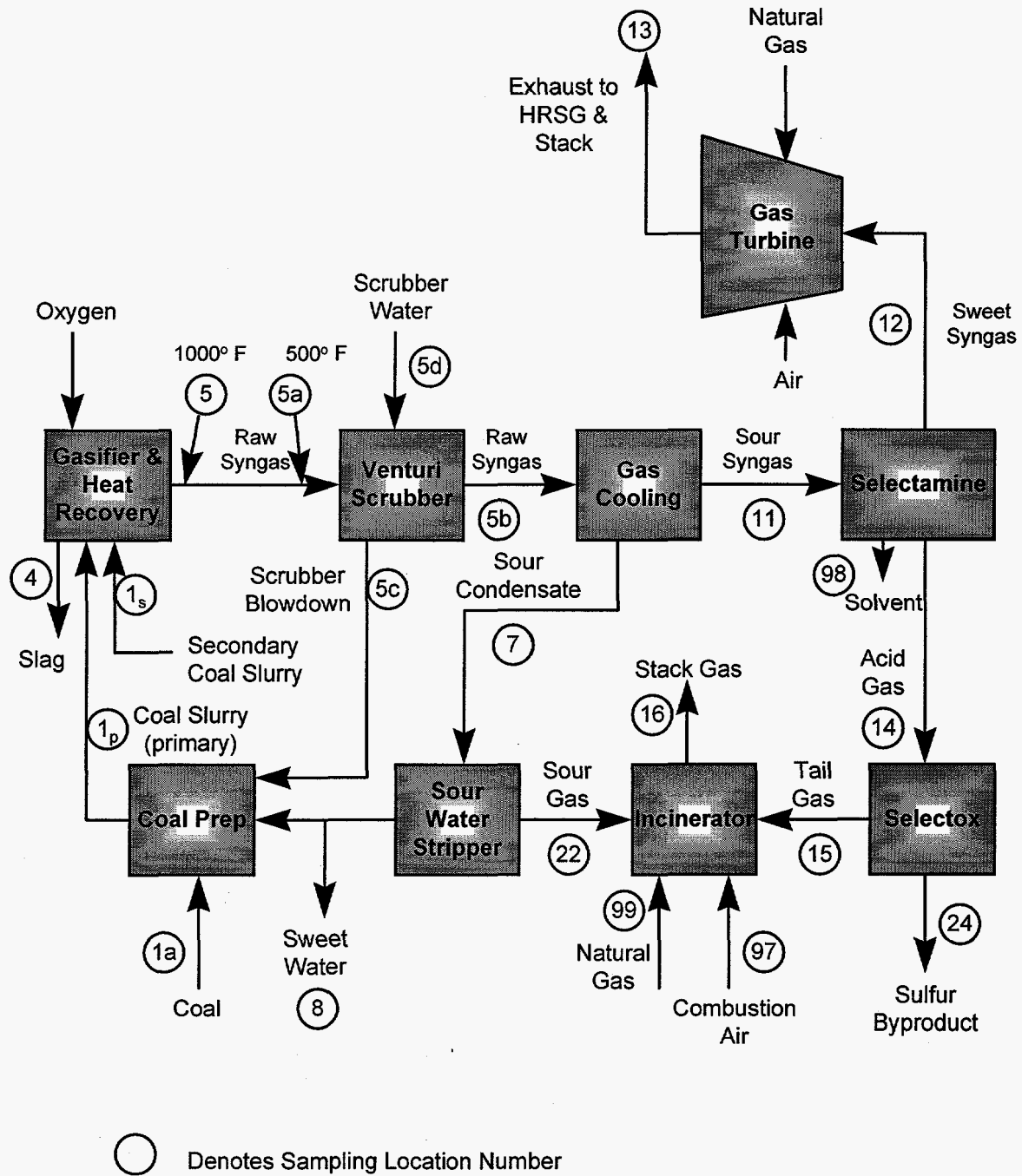
Figure 2-1
LGTI Process Flow Diagram

Acid Gas Removal

Dow's Selectamine™ acid gas removal process removes over 97% of the sulfur from the sour syngas. The principal ingredient in the Selectamine™ solvent is methyl diethanolamine (MDEA). The acid gases are absorbed in the MDEA solution and the sweetened product gas is sent by pipeline to the power plant for use as gas turbine fuel. The concentrated acid gas, composed primarily of H_2S, CO_2, and water, is recovered by stripping the rich MDEA solvent. The concentrated acid gas stream is sent to the sulfur recovery unit. Periodically, the MDEA solution is regenerated to remove heat–stable salts that are formed. In addition, sludge in the storage tank is periodically removed and discarded.

Sulfur Recovery and Incineration

The Selectox™ process is used to recover the sulfur from the acid gas produced in the Selectamine™ unit. This process uses a fixed bed of catalyst to oxidize a portion of the H_2S to SO_2 prior to the sulfur production. Claus reactors then catalyze an oxidization-reduction (redox) reaction between the H_2S and SO_2 to produce elemental sulfur. Because low-sulfur coal is used as the feedstock, the design removal efficiency was only 85 percent. The tail gas from the Selectox™ unit is fed to an incinerator to oxidize the remaining H_2S to SO_2. The incinerator stack gas is exhausted to the atmosphere.

Power Production

Clean syngas from the acid gas removal unit is co-fired with natural gas in two gas turbines at Dow's Power II facility. The two Westinghouse WD501-D5 gas turbines burn either natural gas or a blend of syngas and natural gas and they can produce up to 105-MW of electrical power each. In addition, a waste heat boiler recovers much of the energy in the turbine exhaust and produces steam for the Dow Chemical facility. During the testing, approximately 63% of the Btu content of the fuel to the turbines was from syngas and 37% was from natural gas. Emission factors were determined on a total energy basis (coal and natural gas).

Test Approach

Due to the number and type of sampling locations as well as the groups of analytes measured, it was necessary to employ a phased approach during the test program. The majority of the plant was characterized during three consecutive test periods in November 1994. In a fourth test period, conducted in May 1995, a hot-gas probe was used to gather high-temperature/pressure samples from the raw syngas. Table 2-2 lists the sampling locations (the number refers to the location on Figure 2-1), the test period, and the types of analytes measured. Testing was coordinated so that inlet and outlet

process streams of the various sub-units were characterized simultaneously. Samples were collected in triplicate (at a minimum) to provide an acceptable level of statistical significance.

Table 2-2
Sampling Locations and Analytes

Location	Stream	Test Period	Analytes
1a	Coal pile	1, 2, 3	Metals, ultimate, proximate, anions
		3	Radionuclides
1p, 1s	Coal slurry	1, 2, 3	Metals, ultimate, proximate, anions
4	Slag	1, 2, 3	Metals, ultimate, proximate, anions
		3	Radionuclides
5	Raw gas, 1,000°F	4	Vapor: metals, Cl, F, NH_3, HCN Particulate: metals
5a	Raw gas, 500°F	3	Metals, C_1-C_{10}, Cl, F, NH_3, HCN
5a	Raw gas, 500°F	probe shakedown test	Particulate: metals
5b	Raw gas, scrubbed	3	Metals, C_1-C_{10}, Cl, F, NH_3, HCN
5c	Scrubber blowdown (char)	3	Metals, ultimate, proximate, anions
	(filtrate)	3	Metals, ultimate, proximate, anions, ammonia, cyanide, suspended solids
5d	Scrubber water	3	Metals, ultimate, proximate, anions, ammonia, cyanide
7	Sour condensate	2	Metals, cyanide, volatile/semivolatile organics, aldehydes, anions, ammonia, phenol, sulfide, water quality
8	Sweet water	2	Metals, cyanide, volatile/semivolatile organics, aldehydes, anions, ammonia, phenol, sulfide, water quality
11	Sour syngas	1	Particulates, metals, C_1-C_{10}, volatile organics, major gases, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN

Table 2-2
Sampling Locations and Analytes

Location	Stream	Test Period	Analytes
12	Sweet syngas	1	Particulates, metals, C_1-C_{10}, volatile organics, major gases, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN
13	Turbine Exhaust	1	Particulates, PM-10, metals, VOST, semivolatile organics, aldehydes, Cl, F, NH_3, HCN, H_2SO_4, CEM gases
14	Acid gas	1	Metals, C_1–C_{10}, major gases, sulfur species, semivolatile organics, Cl, F, NH_3, HCN
15	Tail gas	1	Metals, C_1–C_{10}, major gases, sulfur species, semivolatile organics, NH_3, HCN
		2	C_1–C_{10}, sulfur species, semivolatile organics, NH_3, HCN CEM gases
16	Incinerator stack	2	Particulates, PM-10, metals, VOST, sulfur species, semivolatile organics, aldehydes, Cl, F, NH_3, HCN, H_2SO_4, CEM gases
22	Sour gas	2	C_1–C_{10}, major gases, NH_3, HCN
24	Sulfur	1	Metals, ultimate, proximate
97	Combustion air	2	C_1–C_{10}, major gases, sulfur species, NH_3, HCN
98	Selectamine ™ solvent	1	Ash, volatile organics, heat stable salts
		3	Ash, heat stable salts
99	Natural gas	2	Metals, C_1–C_{10}, sulfur species

3

RESULTS

Highlights of the comprehensive test results are presented in this section. Specifically, the feed coal and the four emission streams are discussed. The reader is referred to the comprehensive report[1] for a complete discussion of all results. Analytical result summaries of all the data obtained during the comprehensive test are contained in Appendix A of this document.

Process operation trend plots are presented to illustrate the stability of plant operations during the testing. The process was very stable during all test periods and can be considered representative of normal operations. The values in Figure 3-1 show the percent coal feed slurry solids, the gasifier temperature, and the sweet syngas flow rates plotted as the percent of the average value. The relative deviation during the period is also shown. The composition and concentration of trace contaminants can be affected by gasifier temperature, so a consistent temperature in the gasifier is an important indicator of stable process operation. The feed slurry rate has not been plotted, but remained constant throughout the testing, ranging between 412 and 420 gpm. The percent solids in the coal feed slurry is plotted in Figure 3-1 and again indicates the process stability during the test program. Finally, the sweet syngas flow rate is plotted to illustrate the consistency of the syngas production rate.

Figure 3-2 shows plots for four parameters associated with the gas turbine. Unit load, stack temperature, percent syngas in the turbine fuel, and percent oxygen have been plotted to illustrate the stability during the test periods. These turbine parameters were generally within ± 10% of their mean value, with the exception of a spike on November 11. The cause for this spike is unknown, but is most likely due to an instrumental anomaly. Oxygen was the most variable of these parameters, but this variability appears to have had little effect on the combustion performance, as evidenced by the stable stack temperatures throughout the test periods.

Analytical Results by Major Stream

Data for the feed coal, the emission streams, and combustion byproducts are presented in the following sections. All results are shown as averages along with the 95% confidence interval (CI). The confidence interval represents the range around the average where the true mean lies with a probability of 95 percent. For example, from Table 3-1, there is a 95% probability that the true raw coal arsenic concentration was between 0.91 and 1.05 $\mu g/g$.
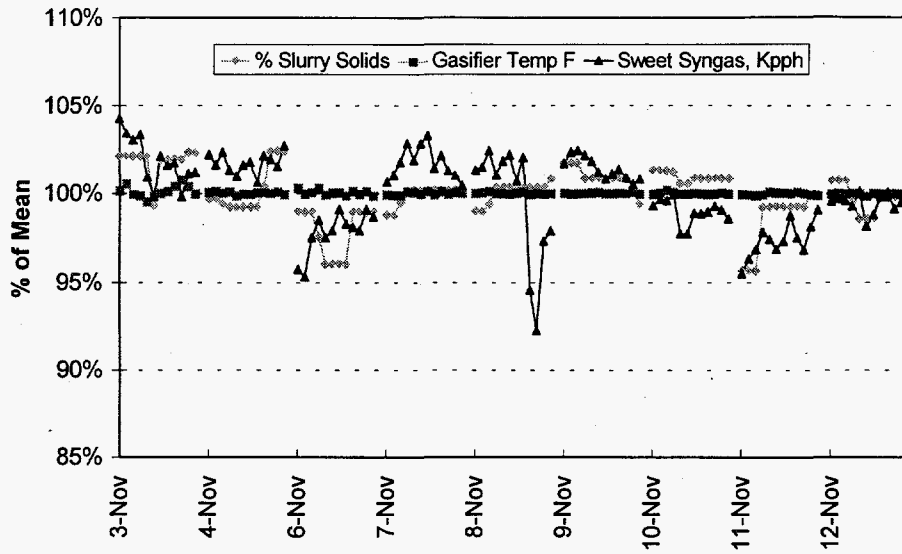
Figure 3-1
Process Parameters for the Gasification System
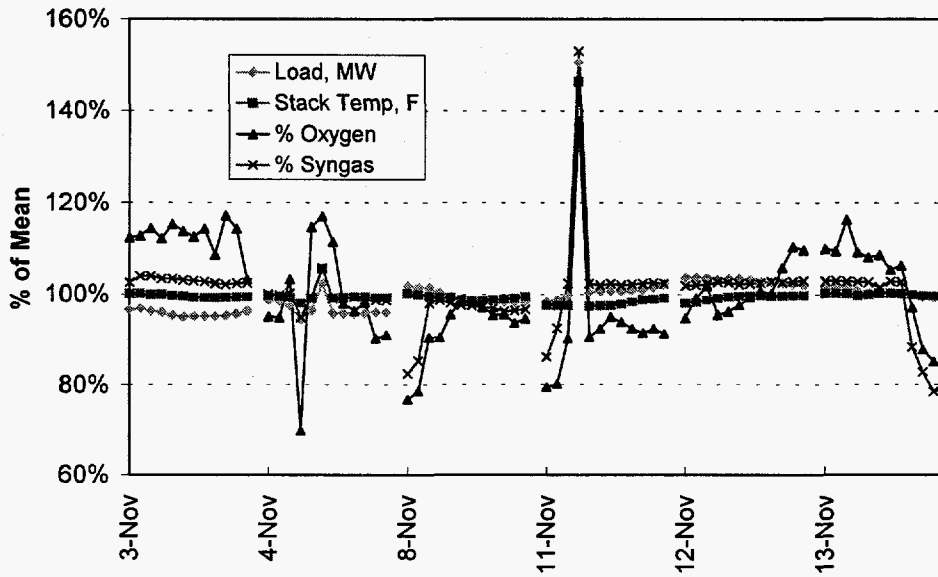
Figure 3-2
Process Parameters for the Gas Turbine

Coal

Coal analyses are shown in Table 3-1 for the raw coal as well as the primary and secondary slurry feed streams. All of the results are on a dry–coal basis. The raw coal is slurried with water to form the primary and secondary feed streams. Char, recycled from the venturi scrubber, is also added to the secondary slurry feed stream. The raw coal and the primary slurry feed analyses are very similar. Since the secondary slurry feed stream contains recycled char from the venturi scrubber, the analytical results for this stream may vary considerably from the raw coal and primary slurry feed stream. This is especially the case for certain volatile elements (antimony, arsenic, cadmium, fluorine, and lead) that are enriched in the recycled char and are clearly evident in the secondary slurry feed analysis. The overall quality of the coal data is considered good and permits a good estimate for the mass balance input stream.

Emitted Gas Streams

The two gaseous emission sources from the LGTI process are the turbine and incinerator stacks. The analytical results for these streams are presented in Table 3-2. The data are presented as mean total values for the elements of interest (i.e., both vapor and solid phases) along with the 95% confidence interval. Several compounds are present at higher concentrations in the incinerator stack gases. However, the gas flow and hence mass emissions are higher from the turbine. This is illustrated in Figure 3-3 and Figure 3-4. Figure 3-3 shows a comparison of the substance concentrations in the turbine and incinerator stacks. This same information is shown in Figure 3-4 on a mass flow basis, which indicates the relative partitioning of these elements within the process. These two figures provide indirect insight into the performance of the Selectamine™ and Selectox™ units with respect to trace elements. Note that the concentration of most substances are comparable in both gas streams, and are very low (1-2 µg/Nm³). Also, the air intake to the gas turbine (another possible source of trace elements) was not tested during this program.

Manganese and mercury are present at significantly higher levels in the incinerator stack. The manganese concentration is believed to be erroneous because one of the three test runs had a high impinger concentration of manganese relative to the other two runs. The potassium permanganate solution used to capture mercury in the Method 29 sampling train could have contaminated the nitric acid impinger used for the manganese measurement. On the other hand, the high mercury level in the incinerator stack is believed to be accurate, and may be explained by the formation of mercuric sulfide, which would be removed by the methyl diethanol amine (MDEA) in the Selectamine™ unit. During the MDEA regeneration, the mercury would be desorbed into the acid gas stream going to the Selectox™ unit. The volatile mercury would pass through the Selectox™ system, exit in the tail gas, and be emitted in the incinerator stack gas.

Table 3-1
Solid Feed Stream Characteristics

Analyte	Raw Coal (1a)		Primary Slurry Feed (1_p)		Secondary Slurry Feed (1_s)	
	Average	95% CI	Average	95% CI	Average	95% CI
Ultimate/Proximate Parameters						
Moisture (Wt. %)	29	0.24	45	0.30	48	0.44
% Solids (Wt. %)	–	–	55	0.30	52	0.44
Ash (Wt. %)	6.7	0.30	6.4	0.08	7.7	0.15
Carbon (Wt. %)	70	0.37	69	0.43	69	0.31
Hydrogen (Wt. %)	4.6	0.08	4.8	0.09	4.7	0.07
Nitrogen (Wt. %)	0.99	0.02	1	0.02	1.1	0.06
Sulfur (Wt. %)	0.28	0.01	0.28	0.01	0.28	0.01
Oxygen (by difference) (Wt. %)	17	0.39	19	0.34	17	0.31
Volatile Matter (Wt. %)	46	0.34	46	0.29	45	0.48
Fixed Carbon (Wt. %)	47	0.43	48	0.32	47	0.52
Higher Heating Value (Btu/lb)	12,000	68	12,000	39	12,000	46
Elemental Composition, µg/g						
Antimony	0.12	0.023	0.10	0.031	0.43	0.047
Arsenic	0.98	0.066	0.74	0.13	2.2	0.32
Beryllium	0.27	0.029	0.21	0.04	0.31	0.039
Cadmium	0.1	0.035	0.074	0.016	1.8	0.87
Chloride	39	5.7	43	7.0	56	9.2
Chromium	4.7	2.1	3.3	1.4	5.2	1.9
Cobalt	1.9	0.11	1.5	0.27	2.2	0.15
Fluoride	76	27	45	5.0	260	45
Lead	1.3	0.20	0.85	0.16	8.3	2.2
Manganese	9.9	0.62	8	1.3	11.0	0.80
Mercury	0.11	0.013	0.11	0.028	0.087	0.0086
Nickel	1.6	0.56	1.8	0.51	1.1	0.37
Selenium	3.4	2.6	1.4	0.54	5	1.3

Table 3-2
Emission Stream Characteristics

Analyte Levels (μg/Nm³, unless specified)	Turbine Stack (13)		Incinerator (16)	
	Average	95% CI	Average	95% CI
Flow, Nm³/hr	2,180,000	–	19,400	–
Particulate Loading mg/Nm³	3.9	3.5	141	26
Ammonia as N	190	250	750	1,400
Antimony	<2.2	NC	<2.1	NC
Arsenic	1.2	1.1	0.69	0.90
Beryllium	<0.012	NC	<0.012	NC
Cadmium	1.6	2.2	2.0	2.9
Chloride	420	110	<2,100	NC
Chromium	1.5	0.38	3.6	0.75
Cobalt	0.32	0.34	0.38	0.22
Cyanide	<3.2	NC	5.0	7.9
Fluoride	22	13	26	22
Lead	1.6	0.90	2.2	2.1
Manganese	1.7	3.8	9.6	22
Mercury	0.71	0.26	28	3.3
Nickel	2.2	2.1	5.2	1.8
Selenium	1.7	0.76	<0.21	NC
Sulfur dioxide	13,000	6,700	7,400,000	1,600,000
Volatile Organic Compound Levels				
Benzene	2.5	1.0	2.5	3.0
Toluene	<0.57	NC	0.91	1.0
Formaldehyde	9.4	4.4	0.78	0.29
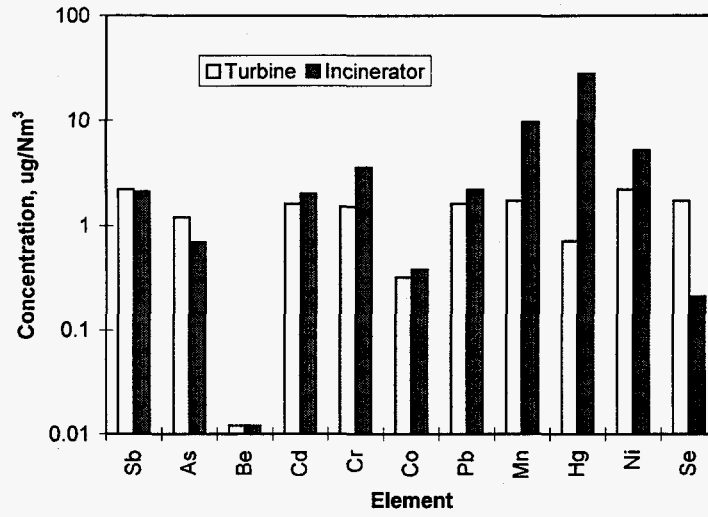
Figure 3-3
Comparison of Emission Stream Elemental Concentrations
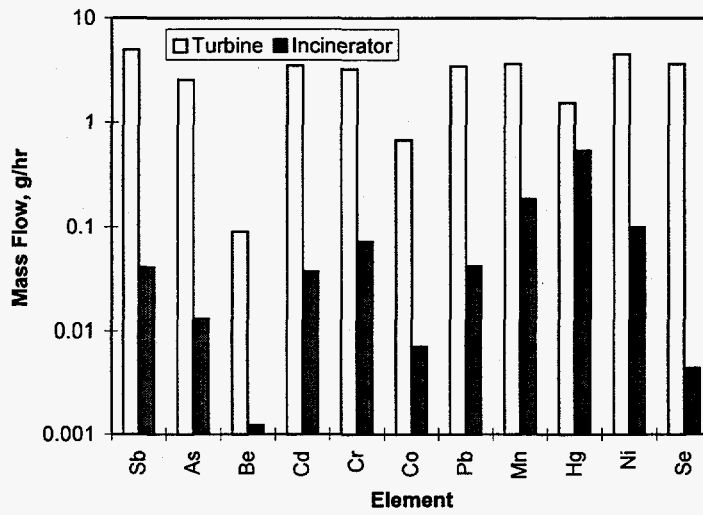
Figure 3-4
Comparison of Emission Streams Elemental Mass Flow

Most of the trace elements present in the coal are removed in the LGTI process. Figure 3-5 shows the removals of several trace elements across the LGTI system. These data are presented in terms of total air emissions (on a lb/10^{12} Btu of coal basis) as a function of the amounts present in the coal. The major elements, typically associated with the particulate material, are reduced by more than 99.99 percent. Other elements that could be classified as volatile (or semi-volatile) such as arsenic, lead, and selenium are removed by 90-99% in the process. Only mercury cadmium and antimony were controlled by less than 90 percent. These removals are comparable to those of conventional coal-fired boilers.

Combustion Byproducts

There are two byproducts from the LGTI process, slag and elemental sulfur. The results of the analyses of these two solid streams is presented in Table 3-3. The slag consists of about 90% ash and 10% carbon with minor amounts of the other elements of concern. Most of the trace elements present in the coal leave the process in the slag. The exception are certain "volatile" elements (such as mercury) that migrate downstream in the process.

The recovered sulfur is approximately 99% pure with only very small trace element amounts. Chromium and selenium were measured above the analytical detection limits, but the multiple test results exhibited high variability.
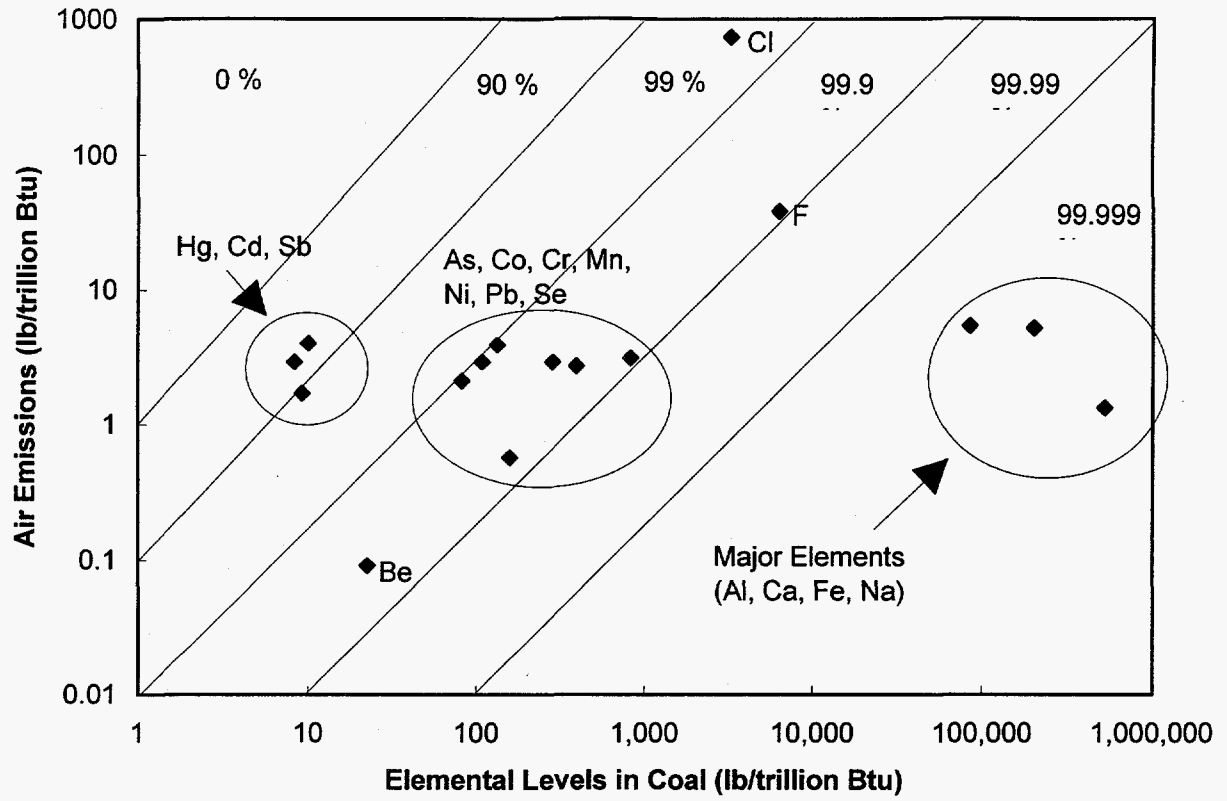
Figure 3-5
Removal of Selected Trace Elements Across the LGTI System

Table 3-3
Combustion Byproduct Characteristics

Analyte	Slag (4)		Sulfur (24)	
	Average	95% CI	Average	95% CI
Ultimate/Proximate Parameters				
Ash (Wt. %)	89.8	5.1	NA	
Carbon (Wt. %)	9.5	5.2	NA	
Hydrogen (Wt. %)	0.15	0.07	NA	
Nitrogen (Wt. %)	0.04	0.05	NA	
Sulfur (Wt. %)	0.03	0.02	98.7	7.0
Oxygen (by difference) (Wt. %)	0.27	0.19	NA	
Elemental Composition, µg/g				
Antimony	1.07	0.25	<3	
Arsenic	6	0.96	<3	
Beryllium	3.4	0.37	<2	
Cadmium	0.20	0.11	<2	
Chloride	84	56	NA	
Chromium	76	8.3	4	38
Cobalt	26	2.8	<4	
Fluoride	200	50	NA	
Lead	3	1.1	<3	
Manganese	130	12	<2	
Mercury	0.020	0.006	0.095	0.19
Nickel	38	4.1	<4	
Selenium	14	5.7	24	180

NA = Not analyzed.

Aqueous Discharge

Table 3-4 shows the results for the sweet water discharge from the process. Total suspended solids, chemical oxygen demand (COD), ammonia, formate, and cyanide are the only species that are present at levels greater than 1 mg/L. Of the organic compounds that were detected, most were present in the low μg/L range. Phenol was the exception at 400 μg/L.

Table 3-4
Aqueous Discharge Characteristics

	Sweet Water (8)	
Analyte	**Average**	**95% CI**
Water Quality Parameters (mg/L)		
pH	8.75	0.22
Specific conductance (μmhos)	71.8	18
Total Suspended Solids	1.9	3.4
Chemical Oxygen Demand	53	3.9
Elemental Composition (mg/L)		
Ammonia as N	7.3	3.6
Antimony	< 0.076	NC
Arsenic	0.0038	0.0024
Barium	0.53	0.07
Beryllium	0.0006	0.0013
Boron	0.039	0.051
Cadmium	0.005	0.0024
Chloride	0.88	0.15
Chromium	0.0087	0.003
Cobalt	< 0 .004	NC
Copper	0.015	0.0044
Cyanide, amenable	0.035	0.1
Cyanide, total	1.5	1.2
Fluoride	1.8	0.7
Formate	3.2	0.41

Table 3-4
Aqueous Discharge Characteristics

Analyte	Sweet Water (8)	
	Average	**95% CI**
Lead	0.33	0.25
Manganese	0.0024	0.0034
Mercury	< 0.00003	NC
Molybdenum	0.011	0.0051
Nickel	0.022	0.042
Phosphate, total (as P)	0.26	0.1
Selenium	0.032	0.02
Sulfate	< 0.047	NC
Thiocyanate	0.82	0.72
Volatile Organic Compound Levels, µg/L		
1,4-Bromofluorobenzene	46	1.2
Acetone	5.2	3.2
Benzene	< 0.46	NC
Methylene chloride	< 3	NC
Semivolatile Organic Compound Levels, µg/L		
2,4,6-Tribromophenol	160	32
2-Fluorobiphenyl	61	15
2-Fluorophenol	160	33
4-Methylphenol/3-Methylphenol	0.49	1.1
Benzoic acid	9.2	26
Fluoranthene	2.6	1.1
Phenol	400	84
Pyrene	11	5.6

Emission Estimates

Emission factors, expressed as pounds emitted per 10^{12} Btu of heat input to the entire plant (coal and natural gas), were calculated for the combined incinerator and turbine exhaust streams. Emission factors provide a common basis for a comparison of emissions from different processes. However, since an IGCC process can be as much as 15% more thermally efficient, the emissions, if expressed as lb/MW, would be 15% less for an IGCC system as compared to a conventional coal-fired boiler.

The emission rates and emission factors for LGTI are presented in Table 3-5. In Figure 3-6, these emission factors are compared to those from Plant Yates (a DOE Phase I pulverized-coal site with an ESP and FGD system). This graph shows that in general, the emissions from the LGTI facility are comparable to a well controlled pulverized coal-fired process. [*Note, this graph is presented to provide an overall comparison of the order of magnitude of emissions from the two processes. These two units were not burning the same coal, so a direct comparison is not possible. In addition, natural gas was co-fired with the syngas in the LGTI turbines.*]

Mass Balances

Mass balances were calculated for the major process subsystems, as well as around the entire IGCC process as a QA check on the reasonableness of the data. Material balances for some of the internal subsystems support the concern for a lack of proven sampling techniques for reduced gas matrices since many of the elemental balances did not meet the closure objectives of 70-130 percent. Material balances calculated around the entire plant were much better, with 72% of the measured elements meeting the material balance closure objectives. For the overall plant balances compositional data from reduced gas matrices were not required.

From a QA perspective, the fact that the material balance closure data quality objectives were met by a majority of the elemental measurements around the entire plant increases the confidence in the data. Table 3-6 presents data for the major elemental flows around the LGTI unit. Elements in the table that did not meet the minimum closure objectives include, chloride, fluoride, lead, arsenic, mercury, and selenium. These elements are volatile and typically do not concentrate in the slag. These elements could be accumulating in the Selectamine ™ solvent, but no trace element analysis was done on this stream due to the regeneration of the solvent being performed during the middle of the testing. Nickel has a high closure, but the refractory in the gasifier contains nickel, so a higher mass flow in the slag is not unexpected. The good closure for the major elements indicates the stream flow rates are correct and that analytical sample preparation methods completely dissolved the sample solids.

Table 3-5
Emission Factors for Selected Substances

| | Combined Incinerator and Turbine Stack Emissions | | |
| | Emission Rate | Emission Factor | |
	lb/hr	lb/10^{12} Btu	95% CI
Criteria Pollutants,			
Particulate Loading	25	0.0091 lb/10^6 Btu	0.006 lb/10^6 Btu
Sulfur Dioxide	330	0.12 lb/10^6 Btu	0.02 lb/10^6 Btu
Nitrogen Oxides	700	0.26 lb/10^6 Btu	0.037 lb/10^6 Btu
Ionic Species			
Chloride	1.7	740	180
Fluoride	0.090	38	22
Ammonia as N	1.2	440	430
Metals			
Antimony	0.011	4	4.7
Arsenic	0.0056	2.1	1.9
Beryllium	0.00025	0.09	0.03
Cadmium	0.0078	2.9	3.8
Chromium	0.0073	2.7	0.63
Cobalt	0.0015	0.57	0.58
Lead	0.0077	2.9	1.5
Manganese	0.0083	3.1	6.5
Mercury	0.0046	1.7	0.43
Nickel	0.011	3.9	3.6
Selenium	0.008	2.9	1.3
Aldehydes			
Acetaldehyde	0.0048	1.8	1.5
Benzaldehyde	0.0079	2.9	2.6
Formaldehyde	0.045	17	7.5
Volatile Organic Compounds			
Benzene	0.012	4.4	1.7
Carbon Disulfide	0.12	46	14
Toluene	0.000053	0.033	0.02
PAHs/SVOCs			
2-Methylnaphthalene	0.001	0.36	0.55
Acenaphthylene	0.00007	0.026	0.0075
Benzo(a)anthracene	0.000006	0.0023	0.0002
Benzo(e)pyrene	0.000015	0.0056	0.0007
Benzo(g,h,i)perylene	0.000026	0.0096	0.0005
Naphthalene	0.0011	0.4	0.12
Benzoic acid	0.39	140	65
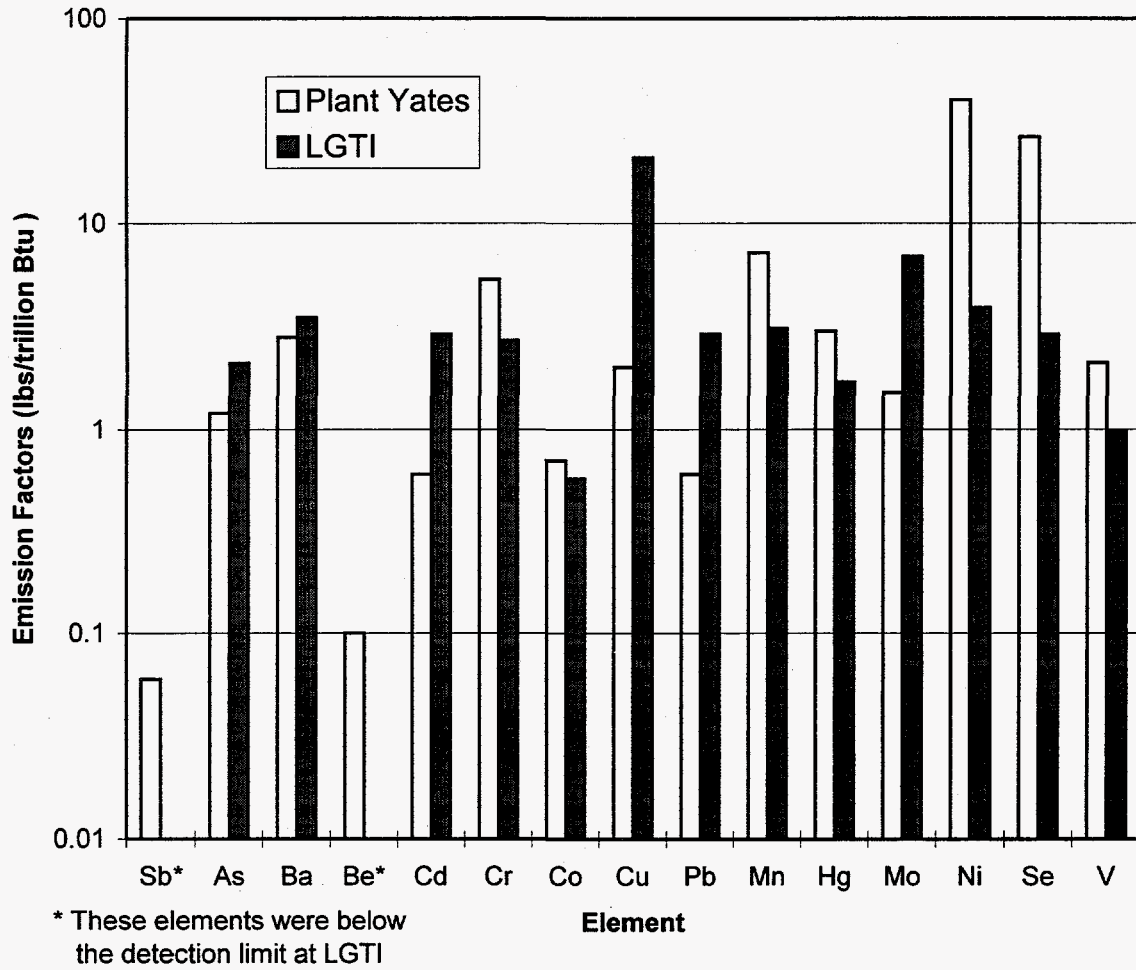
Figure 3-6
Elemental Emission Factor Comparison of LGTI to Conventional Boiler
with ESP and FGD Systems (Plant Yates)

Table 3-6
Selected Elemental Flows Around the LGTI Process

Analyte	Input [a]	Output [a]			% Closure
	Coal Feed	Slag	Incinerator	Gas Turbine	
Antimony	0.016	0.011	0.00009	<0.011	69-138
Chloride	5.3	0.83	0.09	2.0	57
Fluoride	10	2.0	0.0012	0.1	22
Arsenic	0.13	0.059	0.000029	0.0056	50
Beryllium	0.037	0.034	0.0000027	<0.00025	95
Cadmium	0.014	0.0020	0.000083	0.0077	78
Chromium	0.64	0.76	0.00016	0.0071	120
Cobalt	0.26	0.26	0.000016	0.0015	101
Copper	1.6	1.5	0.00011	0.040	100
Lead	0.18	0.030	0.000093	0.0076	37
Manganese	1.3	1.3	0.00041	0.0080	99
Mercury	0.015	0.00020	0.0012	0.0034	33
Molybdenum	0.074	0.075	0.00022	0.018	134
Nickel	0.21	0.38	0.00022	0.010	187
Selenium	0.45	.013	0.0000098	0.0080	33
Major Elements					
Aluminum	850	900	<0.003	0.2	107
Calcium	1,400	1,600	<0.004	0.6	111
Iron	330	370	0.009	0.4	113
Magnesium	300	330	<0.001	0.08	109
Potassium	28	27	<0.01	0.9	98
Sulfur [b]	380	3.0	170	38	119

[a] All values in lb/hr.

[b] Elemental sulfur flow = 240 lb/hr. All other elemental flows were insignificant in the sulfur.

Trace Substance Partitioning

The trace substances addressed in this program can be separated into three categories. One category is those substances that are volatile, such as mercury, chloride, and fluoride. These substances are nearly completely vaporized during gasification and carried downstream in the process. Only small portions, if any, are retained in the slag. These substances are transported in the gas stream and may be removed during cooling or scrubbing of the gas. However, they may also remain in the gas phase and ultimately be found in the turbine exhaust. The partitioning of these volatile elements in the LGTI process is shown in Figure 3-7.

A second category includes those trace substances that are considered "semivolatile" such as arsenic, cadmium, lead, and selenium. These elements partition partially into the slag, but are also present in the vapor phase throughout the process. As can be seen from Figure 3-7, some of these elements (cadmium and lead) may partition slightly in the water system, while others remain in the gas steam.

It is not unusual to see material balance closures of less than 100% for these volatile and semi-volatile trace substances. Many are present in extremely low levels in the coal and there is evidence to suggest that some may accumulate in the Selectamine™ sulfur removal system. The Selectamine™ solvent is periodically regenerated to prevent the excessive buildup of heat stable salts. These salts, primarily carboxylic acids, can keep metallic elements in solution by chelation. Additionally, the solvent storage tank is not agitated and a sludge layer accumulates in the bottom. Unfortunately, no samples were taken during the test period that could confirm that the sulfur removal system is also an accumulation point for other trace substances.

A final category contains those trace substances that are non-volatile, including beryllium, chromium, cobalt, manganese, and nickel. Most of these substances partition into the slag and are often not detected in the gas stream or in other parts of the process. The partitioning of these substances at LGTI is shown in Figure 3-8. The higher concentration of both chromium and nickel found in the slag is most likely due to both these materials being present in the refractory material used in the gasifier. A small fraction of these two elements was also measured in the turbine exhaust. Normally one would not consider chromium and nickel as volatile; however, in a reduced gas environment, there is a potential for forming volatile carbonyl compounds of these elements. Turbine blade erosion is also a potential (though very minor) source of emissions.

Figure 3-9 and Figure 3-10 illustrate the partitioning of volatile and non-volatile substances across the IGCC system. Mercury, shown in Figure 3-9, is largely unaccounted for, while nickel, for reasons previously discussed, is enriched in the slag stream.

Distribution of Volatile and Semivolatile Trace Elements in LGTI Discharge Streams
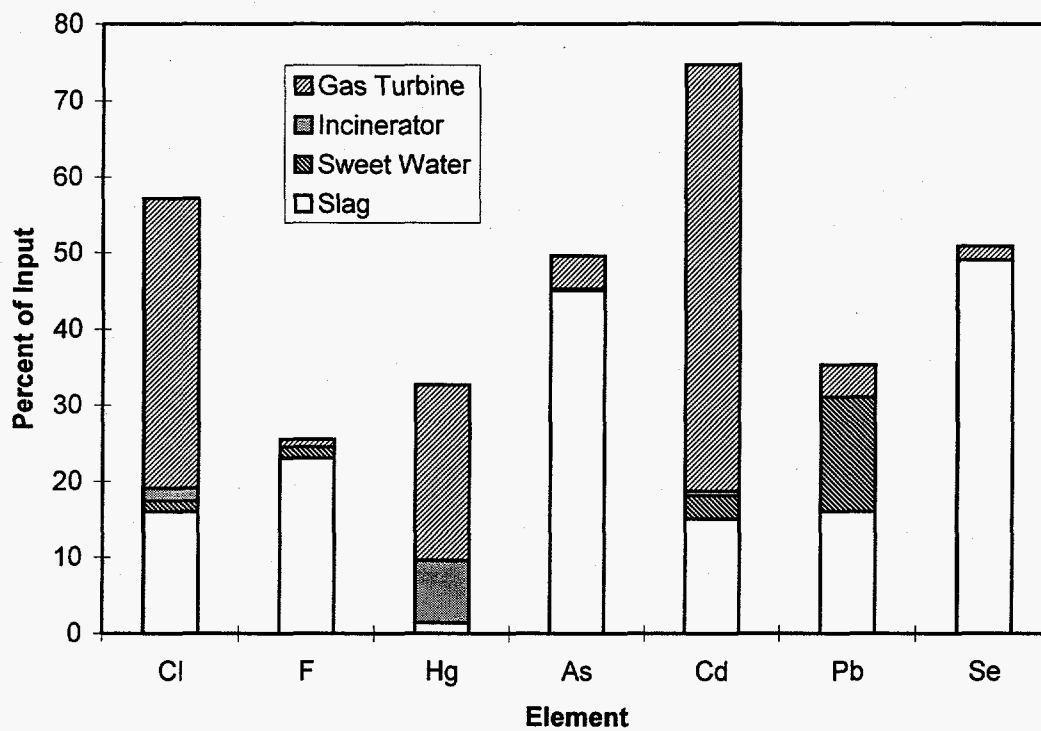
Figure 3-7
Volatile and Semivolatile Trace Substance Distribution

Distribution of Non-volatile Trace Elements in LGTI Discharge Streams
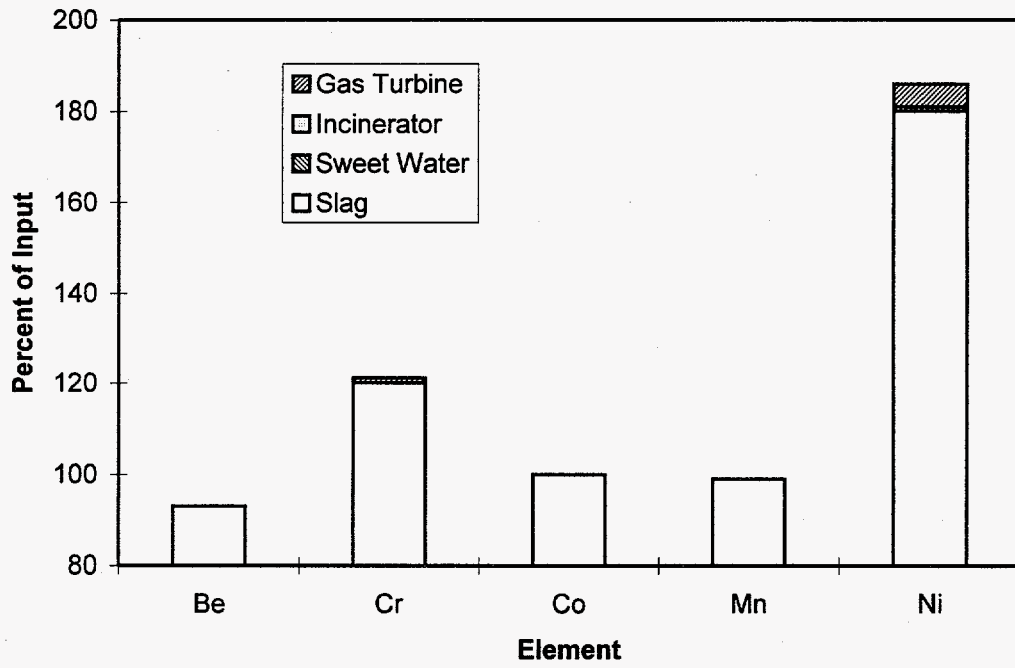
Figure 3-8
Non-Volatile Trace Substance Distribution at LGTI
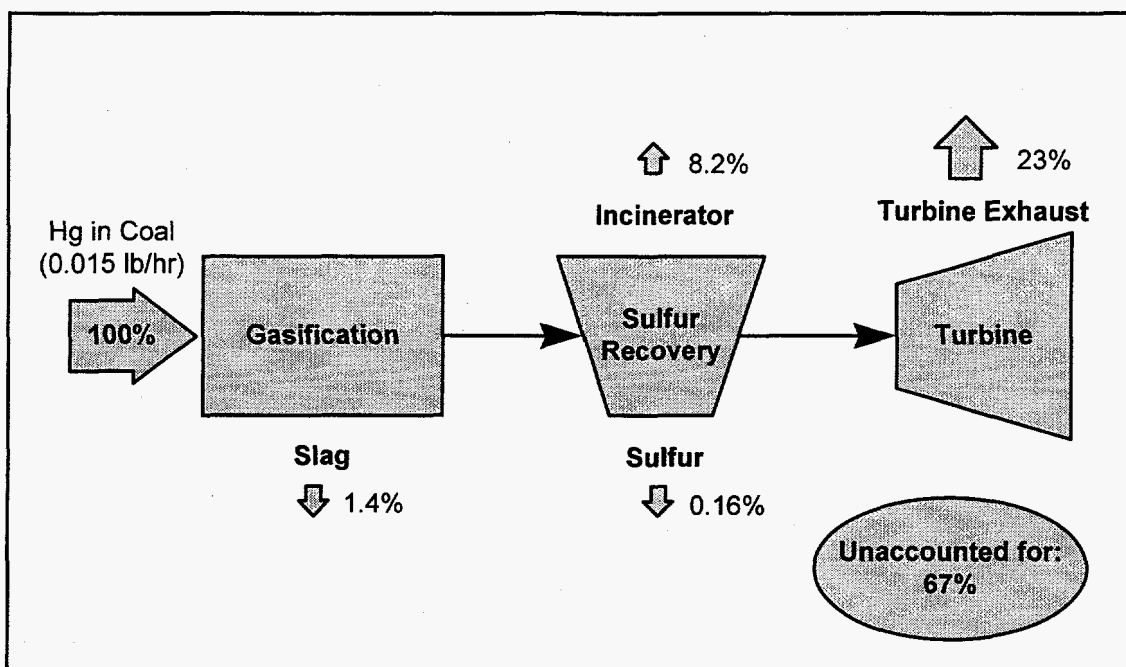
Figure 3-9
Typical Partitioning of a Volatile Substance (Mercury)
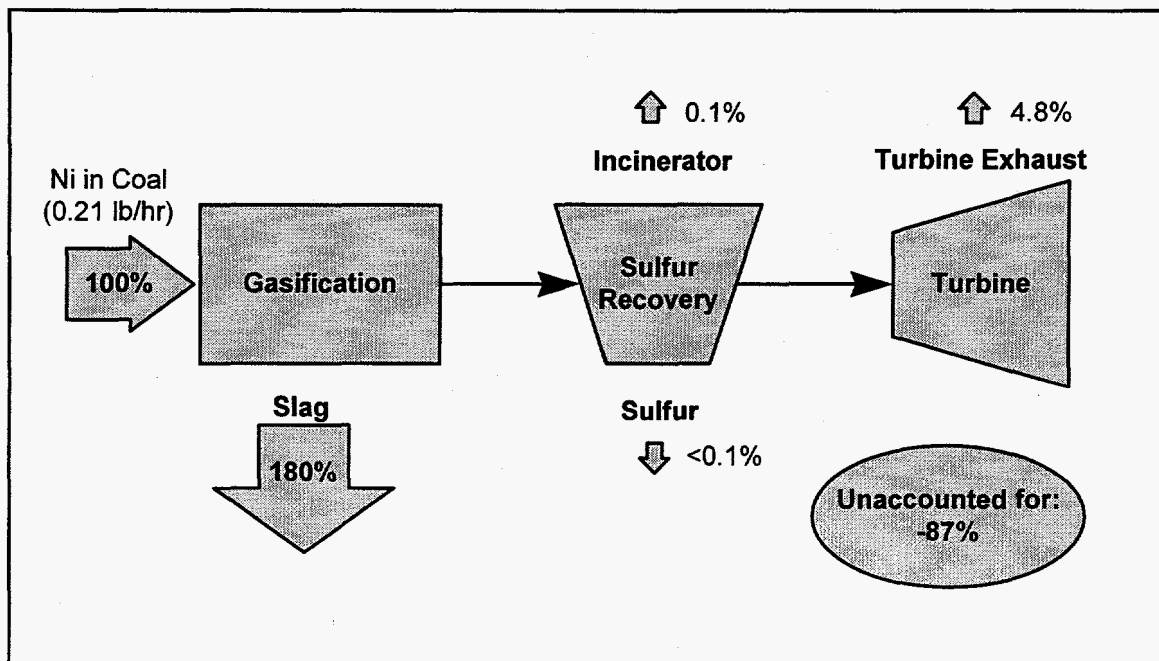
Figure 3-10
Typical Partitioning of a Non-Volatile Substance (Nickel)

References

[1] *A Study of Toxic Emissions from a Coal-Fired Gasification Plant.* Radian Corporation. Report DE-AC22-93PC93253, U.S. Department of Energy, Pittsburgh Energy Technology Center, Pittsburgh, PA, December 1995.

4

SPECIAL INTEREST TOPICS

Because very few gasification systems are in operation, there have been limited opportunities to sample and analyze their internal process streams. Upon combustion, the emission streams can be accurately quantified using the validated sampling methods available for conventional fossil fuel fired power plants. The reducing nature of the internal process streams of an IGCC process requires modifications for some of the sampling methods to obtain valid results.

The special topics covered in this section apply to the sampling and analysis of trace metals in reduced gas environments. The reason for the focus on trace metals is that standard EPA test methods for volatile organics, semivolatile organics, ammonia, cyanide etc. seem to work fine in a reducing environment. This is not the case with vapor phase trace metal test methods. Trace elements emissions in general and mercury emissions in specific tend to be the key air toxic issues for the utility industry.[1]

The validated method for the collection of trace metals is EPA Method 29, which consists of sampling the gas isokinetically through a heated probe, collecting particulate matter on a filter, and then bubbling the gas through a series of five impingers. The first two impingers contain a mixture of nitric acid and hydrogen peroxide. These impingers are followed by a knockout impinger (to prevent carryover) and two impingers containing a solution of potassium permanganate specifically for the collection of elemental mercury.

For the sampling of only vapor phase metals in the internal process streams, Method 29 was modified by increasing the nitric acid and hydrogen peroxide concentrations. The gas was still filtered, but the filter only served to prevent potential contamination of the impinger solutions due to trace amounts of particulate. In addition, the potassium permanganate impingers were not used, as their oxidizing capacity for mercury collection is rapidly depleted by the hydrogen sulfide that is present in the syngas. Other trace metal sampling techniques involving solid sorbent adsorption and an instrumental technique using a specially modified gas chromatograph were also applied. Even so, some questionable trace metals results were obtained for many of the internal streams. Nevertheless, discovering which method did *not* work and which procedures showed promise has provided valuable information to DOE and EPRI for future work in this area.

In this section three special topics are discussed that involve the collection of samples in reduced gas matrices. The first is the measurement of mercury in a reduced gas

atmosphere. Next, the issue of sampling and analyzing for trace elements in a reduced gas matrix will be discussed, followed by a description of a "hot gas" sampling probe that was designed, built and used during this test program.

Mercury Measurements

Extensive research is currently being done to develop sampling and analytical protocols for the speciation of mercury in flue gas (oxidized gas matrix). Many of the mercury tests that were conducted during this project were done on internal process streams (in a reduced gas matrix), where interferents such as H_2S (which are not found in flue gas) were encountered. Reduced species such as H_2S complicate the task of acquiring representative mercury samples, as they react with the oxidants in the Method 29 sampling train impingers, degrading the oxidizing/collection efficiency of the sampling method. In an attempt to determine alternative approaches to the collection of mercury, Radian implemented parallel tests during the field program to evaluate the absorbing capacity of several solutions for the collection of mercury. An atomic absorption spectrophotometer (AAS), designed such that the synthesis gas can pass directly through a cold vapor cell allowing for the direct measurement of mercury, was used to monitor the efficiency of these absorbing solutions. A schematic of this system is shown in Figure 4-1. Testing was conducted on both the sweet and sour syngas. In general, sample gas was passed through the impinger train where either:

- All forms of mercury were reduced to the elemental state; or

- Ionic and elemental forms of mercury were selectively retained in the impinger train; or

- Ionic forms were retained while elemental mercury was passed on to the gold amalgamation unit.

Depending upon the configuration, mercury was either allowed to concentrate on the gold trap during sample collection, or it was later purged with argon from the collecting impinger solutions after the introduction of a reducing agent (sodium borohydride). The sample gas was vented through additional scrubbing solutions before being metered with a dry gas meter. After the desired sample volume was delivered, enough argon was passed through the impingers to purge any remaining mercury through the system. A total of nine different combinations of impingers were used and are described in Table 4-1.

Mercury was also sampled by collection / adsorption onto charcoal. The specially-cleaned coconut-based charcoal was placed into pre-cleaned quartz tubes. Samples of the sweet and sour syngas were passed through the tubes. The charcoal tubes were returned to the laboratory and analyzed by digesting the charcoal with nitric acid and then determining mercury by CVAAS (SW7470).[2]

The results from these tests were variable and in many cases indicate that both H_2S and water can have a significant effect on the sample collection efficiency. In the sour syngas, charcoal appeared to collect mercury more efficiently than the impinger techniques that were tried, and in the sweet syngas, just the opposite was true. Moisture and H_2S content are the primary differences in these two gaseous streams.
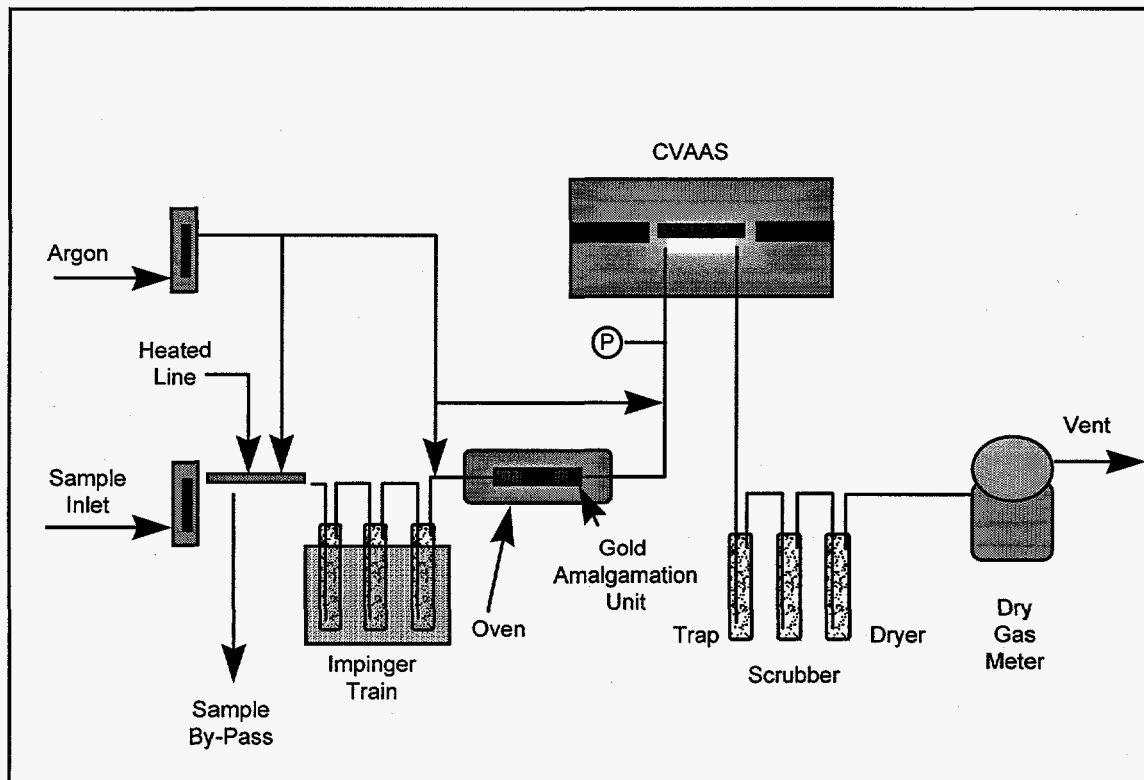
Figure 4-1
Schematic of CVAAS System

Table 4-1
Gold Amalgamation-CVAAS Impinger Train Configurations

Configuration No.	Impinger Solutions				Function
	Impinger 1	Impinger 2	Impinger 3	Impinger 4	
1	50 mM $NaBH_4$	NA	NA	NA	Total Hg reduction to Hg^0
2	0.1 N NaOH	50 mM $NaBH_4$	NA	NA	Remove H_2S prior to total Hg reduction to Hg^0
2a	2M NaOH	50 mM $NaBH_4$	NA	NA	Remove H_2S prior to total Hg reduction to Hg^0
3	4% H_2O_2/ 5% HNO_3	0.1N NaOH	cold knockout	4% $KMnO_4$/10% H_2SO_4	Collect ionic and elemental Hg separately with H_2S removal
4	80% IPA / 0.1M DEDTC [a]	0.1N NaOH	cold knockout	4% $KMnO_4$/10% H_2SO_4	Collect ionic and elemental Hg separately with H_2S removal
5	80% IPA / 0.1M DEDTC	0.1N NaOH	4% $KMnO_4$/10% H_2SO_4	NA	Collect ionic and elemental Hg separately with H_2S removal
6	4% H_2O_2/5% HNO_3	cold knockout	4% $KMnO_4$/10% H_2SO_4	NA	Collect ionic and elemental Hg separately without H_2S removal
7	4% H_2O_2/5% HNO_3	50 mM $NaBH_4$	NA	NA	Collect ionic Hg and reduce penetrated Hg
8	80% IPA / 0.1M DEDTC	50 mM $NaBH_4$	NA	NA	Collect ionic Hg and reduce penetrated Hg
9	Sat'd $SnCl_2$ / 0.5N H_2SO_4	NA	NA	NA	Total Hg reduction to Hg^0

[a] Diethyldithiocarbamic acid

Based upon the initial results, additional changes were made to EPA Method 29 (see discussion page 4-1) by inserting an impinger containing sodium hydroxide following the nitric acid impingers, then adding the potassium permanganate impingers as per the original method. This configuration was tested in the last test period (Test Period 4) that focused strictly on a hot syngas location upstream of the carbon scrubber. This modification appeared to greatly help in the collection of mercury. Although it was evident that H_2S still penetrated the potassium permanganate, mercury collection in the potassium permanganate impingers was greatly enhanced over the early test periods.

The procedures implemented during Test Period 4 did not yield a definitive test method for mercury (nor was the approach designed to do so). However, using a caustic impinger to reduce or eliminate the H_2S prior to the potassium permanganate impinger appears to be a promising approach, at least for total mercury measurements. Complete details of the methodologies and results that were obtained under the various test conditions can be found in the comprehensive report.[3]

Trace Elements in Reduced Gas Streams

To date, all gasification processes have used sulfur removal systems that require the sour gas to be cooled to near ambient temperatures. Following sulfur removal, the sweet fuel gas is then preheated prior to being fired in a gas turbine. The ability to remove H_2S from syngas without cooling allows for a substantial increase in overall process efficiency. Since some trace elements are volatile (especially in a reduced gas matrix), it is likely that measurable amounts of these trace elements (relative to the coal concentration) will be present in the hot syngas. Syngas associated with a hot gas cleanup system will not go through a "cold" acid gas absorption process (where there is evidence to suggest that some removal occurs), and, therefore, emissions could be different from those currently attributed to gasification processes. From this perspective, it is important to know:

- If the sample collection technique that is used accounts for all species of the particular element;
- How to accurately sample and analyze for trace elements in reduced gases;
- Whether a hot gas cleanup system affects speciation; and
- If volatile trace elements are removed in a hot gas cleanup system.

As with mercury, it was strongly suspected that Method 29 (modified or not) *was not* a good method for the collection of other vapor phase trace elements in a reduced gas matrix. During this test effort, additional trace element collection / analytical techniques were tried to provide as much insight as possible as to what may or may not be acceptable approaches for characterizing trace elements in a reduced gas matrix. Three collection / analytical methods were tried on the sweet and sour syngas. First, the

nitric acid/hydrogen peroxide concentrations of Radian's modified EPA Method 29 were increased to 10 and 30%, respectively, in an effort to increase the oxidizing capacity of the solution. Second, gas samples were collected / adsorbed onto specially cleaned charcoal, as described in the previous section for mercury. Third, the sweet and sour syngas streams were analyzed by a vapor phase atomic absorption spectrophotometer (VPAAS). The AAS was modified to accept syngas for a portion of the fuel gas going to the nebulizer mixing chamber and flame. In the flame, vapor-phase compounds are atomized and absorb light energy from an element-specific light source just like aqueous samples in conventional AAS. Seven elements, (arsenic, cadmium, nickel, chromium, lead, selenium, and zinc) were analyzed using this technique. A schematic of the VPAAS system is shown in Figure 4-2.
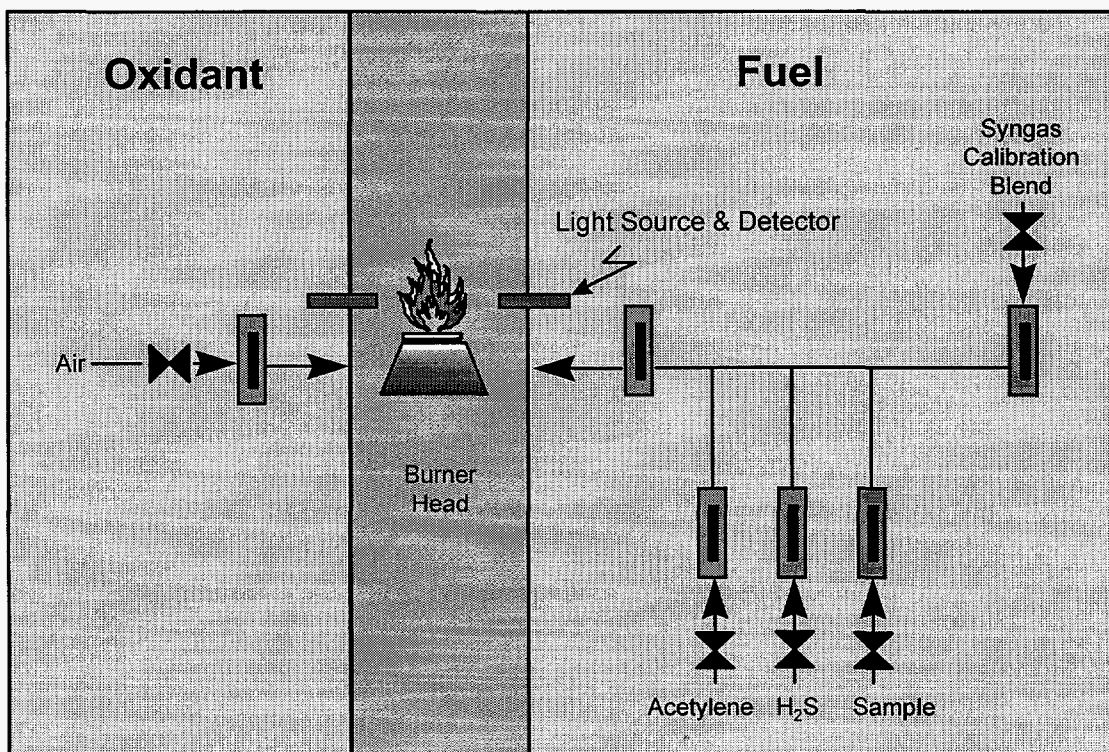
Figure 4-2
Schematic of On-line AAS

The results from these three methods varied considerably for most of the metals that were measured. The results using the modification to EPA Method 29 were consistently low or not detected As discussed earlier, the presence of H_2S and the moisture content of the gas stream seemed to have an effect on the collection of trace elements using charcoal. The results obtained using the VPAAS system generally represented the highest concentrations obtained by any of the methods. This is illustrated in Figure 4-3

where the average concentrations of four metals determined by the three different techniques are compared. Intuitively, one might expect the VPAAS system to yield the highest results as this method is not compound specific, and should produce a total elemental concentration. This is the case for the four elements shown in Figure 4-3. Until further study can be done with the charcoal collection technique, it is not known if, for a given element, all forms of the element are collected with this method. As can be seen from the graph, EPA Method 29 (modified) produced the lowest results of any of the collection techniques.

Sour Syngas
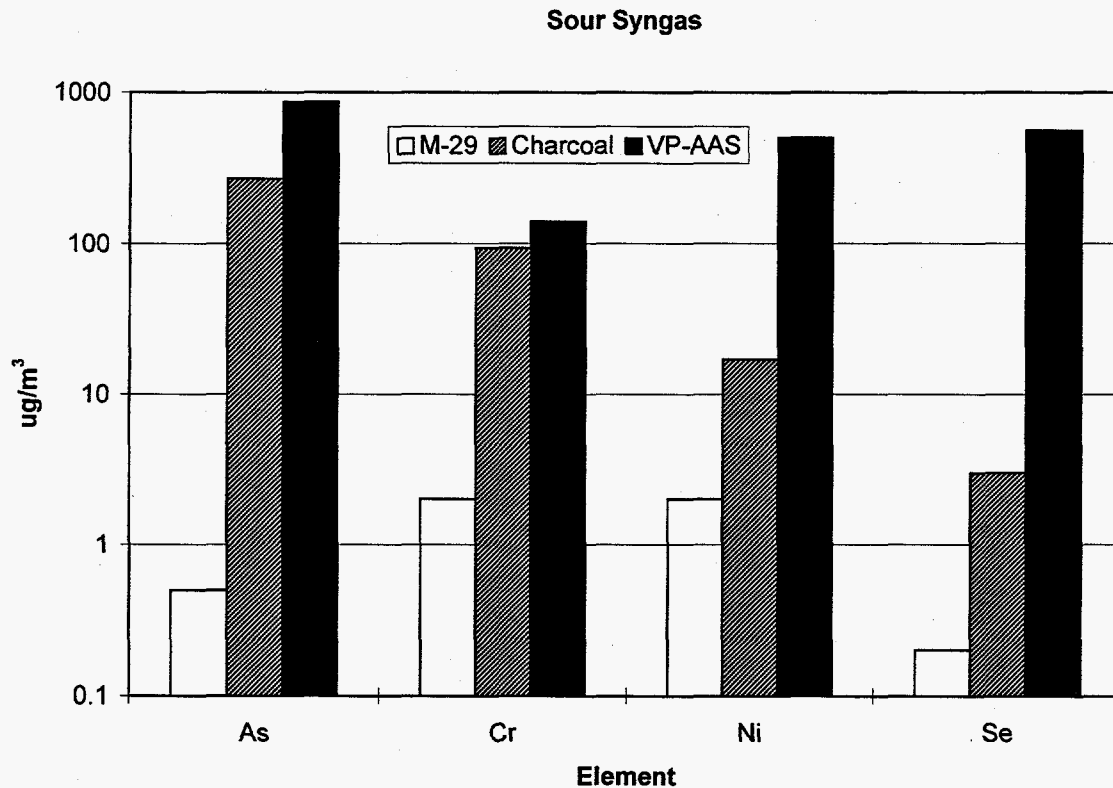
Figure 4-3
Trace Element Methods Comparison

Hot Gas Testing

Radian designed and fabricated a sampling system specifically for the characterization of the hot synthesis gas upstream of the venturi scrubber. The temperature and pressure at this location were approximately 900°F and 350 psig respectively. The sampling system was designed to obtain a representative sample of the hot gas and particulate. This required that the particulate and vapor phases be separated at process conditions in order to avoid any changes that may occur to either phase as a result of cooling or pressure reduction. This was accomplished by filtering the gas "in-stack." The probe

was retractable, in order to retrieve the collected particulate material. The sample was cooled and recovered in a non-reactive nitrogen atmosphere. The probe was inserted and retrieved via a trolley and winch system. The packing gland was designed such that only nitrogen would leak through seals and not flammable, toxic syngas. The sampling system was designed for a syngas temperature of 1,200°F, and provisions were made for lowering the gas dew point by dilution with nitrogen. The sampling system worked well, and the only problem encountered was that the syngas temperature was lower than anticipated. Consequently, the gas temperature fell below the dew point before dilution nitrogen could be injected into the gas steam and some condensation occurred within the probe during the testing.

With the exception of the condensation that occurred during sample collection, the collected samples were judged to be representative of the process. The major problems encountered had to do with the sample collection techniques that were used. For lack of alternative methods, EPA Method 29 (modified) and charcoal tubes were used for sample collection. (The VPAAS was not used during this test period.) Although results were again very scattered, arsenic, mercury and selenium were all detected using the charcoal tube collection technique. (Chromium and nickel were also detected, but since they are each potential contamination products from the sampling system materials of construction, their presence and measured concentrations are questionable.)

References

[1] L. Levin, et al. "Electric Utility Trace Substances Synthesis Report", Volumes 1-4, Electric Power Research Institute, Palo Alto CA, TR-104614, November 1994.

[2] U.S. Environmental Protection Agency, Office of Solid Waste. "Method 7470: Mercury in Liquid Waste (Manual Cold–Vapor Technique)," *Test Methods for Evaluating Solid Waste*. SW-846, 3rd ed. Washington, DC (November 1986)

[3] *A Study of Toxic Emissions from a Coal-Fired Gasification Plant*. Radian Corporation. Report DE-AC22-93PC93253, U.S. Department of Energy, Pittsburgh Energy Technology Center, Pittsburgh, PA, December 1995.

5

GLOSSARY

AAS	Atomic absorption spectrophotometry
Btu	British thermal unit
CI	Confidence interval
COD	Chemical oxygen demand
CVAAS	Cold vapor atomic absorption spectrophotometry
CVAFS	Cold vapor atomic fluorescence spectrophotometry
DL	Detection limit
dscfm	Dry standard cubic feet per minute (1 atm., 60°F)
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
FCEM	Field Chemical Emissions Monitoring
FGD	Flue gas desulfurization
GC/MS	Gas chromatography/mass spectroscopy
GFAAS	Graphite furnace atomic absorption spectrophotometry
HGAAS	Hydride generation atomic absorption spectrophotometry
HHV	Higher heating value
IC	Ion chromatography
ICP-AES	Inductively coupled plasma argon emissions spectrometry
IS	Invalid sample
LGTI	Louisiana Gasification Technology Inc.
MS/MSD	Matrix spike/matrix spike duplicate

NA	Not analyzed
NC	Not calculated
ND	Not detected
NIST	National Institute of Standards and Technology (formerly NBS)
Nm^3	Normal cubic meter (1 atm, 0°C)
NO_x	Nitrogen oxides
NS	Not able to obtain a sample
PAH	Polynuclear aromatic hydrocarbons
POM	Polycyclic organic matter
QA/QC	Quality assurance/quality control
RPD	Relative percent difference
VOC	Volatile organic compound
VOST	Volatile organic sampling train
XAD	Trade name for a resin used in gaseous sample collection

6

CONVERSION FACTORS

Table 6-1
Conversion Factors for SI Units

To Convert From	To SI Unit	Multiply by
°F	degrees Celsius (°C)	°C=(°F-32)/1.8
ton, short (2,000 lb)	kilogram(kg)	907.1
atm	kilopascal (kPa)	101.325
gpm	liter per second (L/s)	6.309 E-02
Btu	joule (J)	1,054
Btu/lb	joule per kilogram (J/kg)	2,324
lb	kilogram (kg)	0.4535
lb/hr	kilogram per second (kg/s)	1.259 E-04
psig	kilopascal (kPa)	6.894

A

ANALYTICAL RESULTS

Table A-1
CEM Data Summary

	Oxygen, %	Carbon Dioxide, %	Carbon Monoxide, ppmv	Sulfur Dioxide, ppmv	Nitrogen Oxides, ppmv
Turbine Stack (13)–Reporting Periods 11/3, 11/4, 11/7					
Average	15.2	5.9	<1	3.1	70.5
Maximum	16.3	6.1	NC	6.2	80.6
Minimum	14.5	4.8	NC	<1	54.6
Standard Deviation	0.07	0.08	NC	1.9	4.9
Incinerator Stack (16)–Reporting Period 11/9					
Average	3.5	38.5	0.9	2,340	28
Maximum	4.3	40.2	2.9	2,480	33.4
Minimum	3.1	34.1	0	2,240	20.1
Standard Deviation	0.3	0.9	0.7	50	1.8

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Particulate Loading, mg/Nm^3	3.86	3.5	NS			
Ionic Species, µg/Nm3						
Chloride	68	200	350	270	420	110
Fluoride	2.4	3.7	19	18	22	13
Sulfate	1,100	680	23,000	7,500	24,000	7,500
Ammonia as N	NA		190	250	NC	NC
Cyanide	NA		<3.2	NC	NC	NC
Metals, µg/Nm^3						
Aluminum	34	18	<15	NC	34	18
Antimony	<2.2	NC	<0.022	NC	<2.2	NC
Arsenic	1.1	1.6	0.084	0.089	1.2	1.1
Barium	1.6	1.3	0.36	0.62	2	0.75
Beryllium	<0.012	NC	<0.04	NC	<0.012	NC
Boron	NA		<4.9	NC	NC	NC
Cadmium	0.62	0.035	0.99	3.1	1.6	2.2
Calcium	82	200	34	27	120	150
Chromium	1	0.61	0.47	0.57	1.5	0.38
Cobalt	0.29	0.48	0.028	0.026	0.32	0.34
Copper	7.5	15	0.77	3.2	8.3	11
Iron	74	230	8	5.6	82	160

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Lead	0.99	1.5	0.6	0.92	1.6	0.90
Magnesium	10	12	<13	NC	10	12
Manganese	0.45	1.3	1.2	5.2	1.7	3.8
Mercury	0.01	0.01	0.7	0.19	0.71	0.26
Molybdenum	3.8	3.3	<0.037	NC	3.8	3.3
Nickel	0.98	0.53	1.2	2.9	2.2	2.1
Phosphorus	130	5.2	<31	NC	130	5.2
Potassium	81	250	<230	NC	81	250
Selenium	0.44	1.2	1.2	1.1	1.7	0.76
Silicon	NA		40	20	NC	NC
Sodium	140	82	64	64	210	48
Titanium	2.9	6.3	0.48	0.73	3.3	4.5
Vanadium	0.37	0.19	0.1	0.21	0.47	0.13
Zinc	13	13	14	26	28	15
Aldehydes, μg/Nm^3						
Acetaldehyde	NA		0.99	0.86	NC	NC
Benzaldehyde	NA		1.7	1.5	NC	NC
Formaldehyde	NA		9.4	4.4	NC	NC
Volatile Organic Compounds, μg/Nm^3						
1,1,1-Trichloroethane	NS		<0.57	NC	NC	NC
1,1,2,2-Tetrachloroethane	NS		<0.57	NC	NC	NC

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
1,1,2-Trichloroethane	NS		<0.57	NC	NC	NC
1,1-Dichloroethane	NS		<0.57	NC	NC	NC
1,1-Dichloroethene	NS		<0.57	NC	NC	NC
1,2-Dichlorobenzene	NS		<0.57	NC	NC	NC
1,2-Dichloroethane	NS		<0.57	NC	NC	NC
1,2-Dichloropropane	NS		<0.57	NC	NC	NC
1,3-Dichlorobenzene	NS		<0.57	NC	NC	NC
1,4-Dichlorobenzene	NS		<0.57	NC	NC	NC
2-Butanone	NS		<2.8	NC	NC	NC
2-Hexanone	NS		<2.8	NC	NC	NC
4-Methyl-2-Pentanone	NS		<2.8	NC	NC	NC
Acetone	NS		<2.8	NC	NC	NC
Benzene	NS		2.5	1.0	NC	NC
Bromodichloromethane	NS		<0.57	NC	NC	NC
Bromoform	NS		<0.57	NC	NC	NC
Bromomethane	NS		<0.57	NC	NC	NC
Carbon Disulfide	NS		2.8	8.4	NC	NC
Carbon Tetrachloride	NS		<0.57	NC	NC	NC
Chlorobenzene	NS		<0.57	NC	NC	NC
Chloroethane	NS		<0.57	NC	NC	NC
Chloroform	NS		<0.57	NC	NC	NC

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Chloromethane	NS		<0.57	NC	NC	NC
cis-1,3-Dichloropropene	NS		<0.57	NC	NC	NC
Dibromochloromethane	NS		<0.57	NC	NC	NC
Ethyl Benzene	NS		<0.57	NC	NC	NC
m,p-Xylene	NS		<0.57	NC	NC	NC
Methylene Chloride	NS		55	81	NC	NC
o-Xylene	NS		<0.57	NC	NC	NC
Styrene	NS		<0.57	NC	NC	NC
Tetrachloroethene	NS		<0.57	NC	NC	NC
Toluene	NS		<0.57	NC	NC	NC
trans-1,2-Dichloroethene	NS		<0.57	NC	NC	NC
trans-1,3-Dichloropropene	NS		<0.57	NC	NC	NC
Trichloroethene	NS		<0.57	NC	NC	NC
Trichlorofluoromethane	NS		26	45	NC	NC
Vinyl Acetate	NS		<2.8	NC	NC	NC
Vinyl Chloride	NS		<0.57	NC	NC	NC
PAHs/SVOC Compounds, µg/Nm3						
1,2,4-Trichlorobenzene	<0.55	NC	<0.92	NC	NC	NC
1,2-Dichlorobenzene	<0.54	NC	<0.96	NC	NC	NC
1,3-Dichlorobenzene	<0.54	NC	<0.92	NC	NC	NC
1,4-Dichlorobenzene	<0.10	NC	<0.90	NC	NC	NC

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
2,2'-oxybis(1-Chloropropane)	<0.76	NC	<1.3	NC	NC	NC
2,4,5-Trichlorophenol	<1.1	NC	<1.2	NC	NC	NC
2,4,6-Trichlorophenol	<1.1	NC	<1.2	NC	NC	NC
2,4-Dichlorophenol	<1.1	NC	<1.1	NC	NC	NC
2,4-Dimethylphenol	<1.1	NC	<1.10	NC	NC	NC
2,4-Dinitrophenol	<3.3	NC	<3.2	NC	NC	NC
2,4-Dinitrotoluene	<1.1	NC	<1.3	NC	NC	NC
2,6-Dinitrotoluene	<1.6	NC	<1.8	NC	NC	NC
2-Chloronaphthalene	0.00006	0.00007	0.00011	0.00007	0.00017	0.00007
2-Chlorophenol	<1.1	NC	<1.10	NC	NC	NC
2-Methylnaphthalene	0.13	0.32	0.072	0.024	0.20	0.32
2-Methylphenol	<1.3	NC	<1.3	NC	NC	NC
2-Nitroaniline	<1.5	NC	<1.6	NC	NC	NC
2-Nitrophenol	<1.7	NC	<1.7	NC	NC	NC
3,3'-Dichlorobenzidine	<1.1	NC	<1.40	NC	NC	NC
3-Nitroaniline	<1.7	NC	<1.8	NC	NC	NC
3/4-Methylphenol	<1.2	NC	<1.2	NC	NC	NC
4,6-Dinitro-2-methylphenol	<2.2	NC	<2.1	NC	NC	NC
4-Aminobiphenyl	<0.48	NC	<0.51	NC	NC	NC
4-Bromophenyl-phenylether	<1.4	NC	<1.5	NC	NC	NC
4-Chloro-3-methylphenol	<1.2	NC	<1.1	NC	NC	NC

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
4-Chloroaniline	<0.89	NC	<0.88	NC	NC	NC
4-Chlorophenyl-phenylether	<0.80	NC	<0.90	NC	NC	NC
4-Nitroaniline	<1.6	NC	<1.9	NC	NC	NC
4-Nitrophenol	<1.9	NC	<2.2	NC	NC	NC
Acenaphthene	0.0057	0.0078	0.0089	0.0016	0.015	0.008
Acenaphthylene	0.0028	0.0044	0.006	0.0029	0.0088	0.0044
Acetophenone	<0.88	NC	<2.0	NC	NC	NC
Aniline	<0.74	NC	<0.76	NC	NC	NC
Anthracene	0.0016	0.0021	0.0023	0.0012	0.0028	0.0021
Benzidine	<0.64	NC	<0.82	NC	NC	NC
Benzo(a)anthracene	0.0003	0.00009	0.001	0.00067	0.0013	0.0007
Benzo(a)pyrene	0.0004	0.00003	0.0006	0.0004	0.001	0.0004
Benzo(b)fluoranthene	0.0007	0.0001	0.0018	0.0006	0.0025	0.0006
Benzo(e)pyrene	0.0013	0.0004	0.0018	0.0007	0.0031	0.0007
Benzo(g,h,i)perylene	0.003	0.0004	0.0024	0.0016	0.0054	0.0016
Benzo(k)fluoranthene	0.0002	0.0001	0.0004	0.0003	0.0006	0.0003
Benzoic acid [b]	<2.3	NC	80	38	NC	NC
Benzyl alcohol	<1.7	NC	<1.5	NC	NC	NC
Butylbenzylphthalate	<0.67	NC	<0.80	NC	NC	NC
Chrysene	0.0006	0.0002	0.0019	0.0003	0.0025	0.0003
Di-n-butylphthalate [c]	<0.33	NC	100	350	NC	NC

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Di-n-octylphthalate	<0.25	NC	<0.41	NC	NC	NC
Dibenz(a,h)anthracene	<0.0001	NC	<0.0002	NC	NC	NC
Dibenzofuran	<0.31	NC	<0.34	NC	NC	NC
Diethylphthalate	<0.87	NC	<1.4	NC	NC	NC
Dimethylaminoazobenzene	<0.85	NC	<1.6	NC	NC	NC
Dimethylphthalate	<0.41	NC	<0.45	NC	NC	NC
Fluoranthene	0.0053	0.0035	0.015	0.0047	0.020	0.005
Fluorene	0.021	0.04	0.015	0.0036	0.036	0.04
Hexachlorobenzene	<1.1	NC	<1.1	NC	NC	NC
Hexachlorobutadiene	<1.3	NC	<1.4	NC	NC	NC
Hexachlorocyclopentadiene	<1.3	NC	<1.8	NC	NC	NC
Hexachloroethane	<1.6	NC	<1.6	NC	NC	NC
Indeno(1,2,3-cd)pyrene	0.0006	0.00004	0.001	0.0003	0.0016	0.0003
Isophorone	<0.59	NC	<0.63	NC	NC	NC
N-Nitroso-di-n-propylamine	<1.7	NC	<2.0	NC	NC	NC
Naphthalene	0.048	0.069	0.18	0.36	NC	NC
Nitrobenzene	<1.0	NC	<1.0	NC	NC	NC
Pentachloronitrobenzene	<2.8	NC	<3.0	NC	NC	NC
Pentachlorophenol	<2.2	NC	<1.8	NC	NC	NC
Perylene	0.0001	0.0001	0.0003	0.0004	0.0004	0.0004
Phenanthrene	0.033	0.033	0.045	0.018	0.078	0.033

Table A-2
Turbine Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Phenol	<1.7	NC	<0.74	NC	NC	NC
Pyrene	0.0054	0.0027	0.014	0.009	NC	NC
bis(2-Chloroethoxy)methane	<1.1	NC	<1.1	NC	NC	NC
bis(2-Chloroethyl)ether	<1.5	NC	<1.5	NC	NC	NC
bis(2-Ethylhexyl)phthalate [c]	4.2	18	<0.65	NC	NC	NC
n-Nitrosodimethylamine	<3.0	NC	<3.3	NC	NC	NC

[a] Total concentration calculated only when results for both particulate and vapor phases were analyzed.
[b] Probable artifact of XAD resin.
[c] Most likely sample contamination.

NA = Not analyzed.
NC = Not calculated.
NS = Not sampled.

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase Average	Particulate Phase 95% CI	Vapor Phase Average	Vapor Phase 95% CI	Total[a] Average	Total[a] 95% CI
Particulate Loading, mg/Nm^3	141	26	NA		NC	NC
Ionic Species, µg/Nm^3						
Chloride	<150	NC	<2,100	NC	<2,100	NC
Fluoride	<1.7	NC	26	22	26	22
Sulfate (g/Nm^3)	0.14	0.019	11	1.7	12	1.7
Ammonia as N	NA		750	1,400	NC	NC
Cyanide	NA		5	7.9	NC	NC
Metals, µg/Nm^3						
Aluminum	52	0.9	<18	NC	52	0.9
Antimony	<2.1	NC	<0.028	NC	<2.1	NC
Arsenic	0.18	0.41	0.51	1.2	0.69	0.90
Barium	1.7	0.98	0.11	0.21	1.8	0.71
Beryllium	<0.012	NC	<0.051	NC	<0.012	NC
Boron	NA		14	17	NC	NC
Cadmium	0.44	0.18	1.5	4.1	2	2.9
Calcium	42	4.1	42	48	85	34
Chromium	2.8	1.2	0.84	1.1	3.6	0.75
Cobalt	0.33	0.31	0.048	0.08	0.38	0.22
Copper	1.9	1	0.65	2.6	2.6	1.5
Iron	190	130	16	9.8	200	89

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Lead	0.27	0.47	1.9	2.9	2.2	2.1
Magnesium	7.3	1.1	<17	NC	7.3	1.1
Manganese	1.4	0.65	8.2	30	9.6	22
Mercury, total	0.015	0.018	28	2.4	28	3.7
Molybdenum	5.1	0.5	0.048	0.064	5.2	0.36
Nickel	3.1	3.1	2.1	1.4	5.2	1.8
Phosphorus	180	12	<760	NC	180	12
Potassium	<16	NC	<290	NC	<16	NC
Selenium	<0.029	NC	<0.21	NC	<0.21	NC
Silicon	NA	NC	57	17	NC	NC
Sodium	130	150	86	120	210	87
Titanium	0.9	0.46	<0.55	NC	0.9	0.46
Vanadium	0.55	0.12	0.74	1.9	1.3	1.3
Zinc	9.5	7.4	16	28	26	20
Aldehydes, μg/Nm^3						
Acetaldehyde	NA		0.65	0.95	NC	NC
Acrolein	NA		<0.59	NC	NC	NC
Benzaldehyde	NA		<0.59	NC	NC	NC
Formaldehyde	NA		0.78	0.29	NC	NC
Volatile Organic Compounds, μg/Nm^3						
1,1,1-Trichloroethane	NA		<0.55	NC	NC	NC

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
1,1,2,2-Tetrachloroethane	NA		<0.55	NC	NC	NC
1,1,2-Trichloroethane	NA		<0.55	NC	NC	NC
v1,1-Dichloroethane	NA		<0.55	NC	NC	NC
1,1-Dichloroethene	NA		<0.55	NC	NC	NC
1,2-Dichlorobenzene	NA		<0.55	NC	NC	NC
1,2-Dichloroethane	NA		<0.55	NC	NC	NC
1,2-Dichloropropane	NA		<0.55	NC	NC	NC
1,3-Dichlorobenzene	NA		<0.55	NC	NC	NC
1,4-Dichlorobenzene	NA		<0.55	NC	NC	NC
2-Butanone	NA		<3	NC	NC	NC
2-Hexanone	NA		<3	NC	NC	NC
4-Methyl-2-Pentanone	NA		<3	NC	NC	NC
Acetone	NA		<3	NC	NC	NC
Benzene	NA		2.5	3	NC	NC
Bromodichloromethane	NA		<0.55	NC	NC	NC
Bromoform	NA		<0.55	NC	NC	NC
Bromomethane	NA		3.8	2.3	NC	NC
Carbon Disulfide	NA		5.2	1.6	NC	NC
Carbon Tetrachloride	NA		<0.55	NC	NC	NC
Chlorobenzene	NA		<0.55	NC	NC	NC
Chloroethane	NA		<0.55	NC	NC	NC

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Chloroform	NA		<0.55	NC	NC	NC
Chloromethane	NA		<0.55	NC	NC	NC
cis-1,3-Dichloropropene	NA		<0.55	NC	NC	NC
Dibromochloromethane	NA		<0.55	NC	NC	NC
Ethyl Benzene	NA		<0.55	NC	NC	NC
m,p-Xylene	NA		<0.55	NC	NC	NC
Methylene Chloride	NA		<0.55	NC	NC	NC
o-Xylene	NA		<0.55	NC	NC	NC
Styrene	NA		<0.55	NC	NC	NC
Tetrachloroethene	NA		<0.55	NC	NC	NC
Toluene	NA		0.91	1	NC	NC
trans-1,2-Dichloroethene	NA		<0.55	NC	NC	NC
trans-1,3-Dichloropropene	NA		<0.55	NC	NC	NC
Trichloroethene	NA		<0.55	NC	NC	NC
Trichlorofluoromethane	NA		0.5	0.45	NC	NC
Vinyl Acetate	NA		<3	NC	NC	NC
Vinyl Chloride	NA		<0.55	NC	NC	NC
PAHs/SVOCs, Compounds μg/Nm^3						
1,2,4-Trichlorobenzene	<0.76	NC	<0.87	NC	NC	NC
1,2-Dichlorobenzene	<0.73	NC	<0.88	NC	NC	NC
1,3-Dichlorobenzene	<0.75	NC	<0.90	NC	NC	NC

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
1,4-Dichlorobenzene	ND	NC	<0.82	NC	NC	NC
2,2'-oxybis(1-Chloropropane)	<0.98	NC	<1.2	NC	NC	NC
2,4,5-Trichlorophenol	<0.93	NC	<1.1	NC	NC	NC
2,4,6-Trichlorophenol	<0.98	NC	<1.2	NC	NC	NC
2,4-Dichlorophenol	<0.93	NC	<1.1	NC	NC	NC
2,4-Dimethylphenol	<0.96	NC	<1.1	NC	NC	NC
2,4-Dinitrophenol	<2.9	NC	<3.4	NC	NC	NC
2,4-Dinitrotoluene	<0.99	NC	<1.2	NC	NC	NC
2,6-Dinitrotoluene	<1.4	NC	<1.7	NC	NC	NC
2-Chloronaphthalene	<0.0001	NC	0.0001	0.0001	0.0001	0.0001
2-Chlorophenol	<0.89	NC	<1.1	NC	NC	NC
2-Methylnaphthalene	0.065	0.016	0.066	0.012	0.13	0.016
2-Methylphenol	<1.1	NC	<1.3	NC	NC	NC
2-Nitroaniline	<1.3	NC	<1.5	NC	NC	NC
2-Nitrophenol	<1.4	NC	<1.7	NC	NC	NC
3,3'-Dichlorobenzidine	<0.95	NC	<1.2	NC	NC	NC
3-Nitroaniline	<1.5	NC	<1.7	NC	NC	NC
3,4-Methylphenol	<0.97	NC	<1.2	NC	NC	NC
4,6-Dinitro-2-methylphenol	<1.9	NC	<2.1	NC	NC	NC
4-Aminobiphenyl	<0.41	NC	<0.47	NC	NC	NC
4-Bromophenyl-phenylether	<1.2	NC	<1.4	NC	NC	NC

**Table A-3
Incinerator Stack Emissions**

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
4-Chloro-3-methylphenol	<0.99	NC	<1.1	NC	NC	NC
4-Chloroaniline	<0.77	NC	<0.89	NC	NC	NC
4-Chlorophenyl-phenylether	<0.71	NC	<0.84	NC	NC	NC
4-Nitroaniline	<1.4	NC	<1.7	NC	NC	NC
4-Nitrophenol	<1.7	NC	<2.0	NC	NC	NC
Acenaphthene	0.0097	0.0071	0.011	0.0048	0.021	0.0071
Acenaphthylene	0.0032	0.002	0.012	0.0027	0.015	0.0027
Acetophenone	<0.74	NC	<2.0	NC	NC	NC
Aniline	<0.62	NC	<0.74	NC	NC	NC
Anthracene	0.0017	0.0014	0.0014	0.0008	0.0031	0.0014
Benzidine	<0.56	NC	<0.69	NC	NC	NC
Benzo(a)anthracene	0.0004	0.0001	0.0009	0.0003	0.0012	0.0003
Benzo(a)pyrene	0.0003	0.0002	0.0006	0.0002	0.0009	0.0002
Benzo(b)fluoranthene	0.0008	0.0002	0.0019	0.0006	0.0027	0.0006
Benzo(e)pyrene	0.0015	0.0008	0.0020	0.0006	0.0035	0.0008
Benzo(g,h,i)perylene	0.0025	0.0007	0.0023	0.0012	0.0048	0.0012
Benzo(k)fluoranthene	0.0008	0.0026	0.0005	0.0001	0.0013	0.0026
Benzoic acid [b]	<2.0	NC	81	20	81	20
Benzyl alcohol	<1.3	NC	<1.5	NC	NC	NC
Butylbenzylphthalate	<0.60	NC	<0.72	NC	NC	NC
Chrysene	0.001	0.0007	0.001	0.003	0.002	0.002

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Di-n-butylphthalate [c]	4.1	18	31	29	35	18
Di-n-octylphthalate	<0.35	NC	<0.40	NC	NC	NC
Dibenz(a,h)anthracene	<0.0001	NC	<0.0002	NC	NC	NC
Dibenzofuran	<0.27	NC	<0.32	NC	NC	NC
Diethylphthalate	<0.32	NC	<1.4	NC	NC	NC
Dimethylaminoazobenzene	<1.1	NC	<1.5	NC	NC	NC
Dimethylphthalate	<0.36	NC	<0.42	NC	NC	NC
Fluoranthene	0.0061	0.0026	0.014	0.0038	0.020	0.0038
Fluorene	0.018	0.0085	0.013	0.0021	0.031	0.0085
Hexachlorobenzene	<0.90	NC	<1.0	NC	NC	NC
Hexachlorobutadiene	<1.1	NC	<1.3	NC	NC	NC
Hexachlorocyclopentadiene	<1.2	NC	<1.4	NC	NC	NC
Hexachloroethane	<1.3	NC	<1.6	NC	NC	NC
Indeno(1,2,3-cd)pyrene	0.0006	0.0003	0.0008	0.0003	0.001	0.0003
Isophorone	<0.51	NC	<0.60	NC	NC	NC
N-Nitroso-di-n-propylamine	<1.4	NC	<1.7	NC	NC	NC
Naphthalene	0.088	0.016	0.094	0.36	0.18	0.36
Nitrobenzene	<0.90	NC	<1.0	NC	NC	NC
Pentachloronitrobenzene	<2.4	NC	<2.8	NC	NC	NC
Pentachlorophenol	<1.9	NC	<2.1	NC	NC	NC
Perylene	0.0001	0.00006	0.0003	0.0002	0.0004	0.0002

Table A-3
Incinerator Stack Emissions

Analyte	Particulate Phase		Vapor Phase		Total[a]	
	Average	95% CI	Average	95% CI	Average	95% CI
Phenanthrene	0.033	0.009	0.041	0.0048	NC	NC
Phenol	<0.85	NC	<0.74	NC	NC	NC
Pyrene	0.0059	0.0009	0.022	0.029	0.022	0.029
bis(2-Chloroethoxy)methane	<0.93	NC	<1.1	NC	NC	NC
bis(2-Chloroethyl)ether	<1.2	NC	<1.5	NC	NC	NC
bis(2-Ethylhexyl)phthalate [c]	<0.06	NC	5.3	23	5.3	23
n-Nitrosodimethylamine	<2.5	NC	<3.0	NC	NC	NC

[a] Total concentration calculated only when results for both particulate and vapor phases were analyzed.
[b] Probable artifact of XAD resin.
[c] Likely due to sample contamination.

NA = Not analyzed.
NC = Not calculated.
NS = Not sampled.

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Particulate Loading, mg/Nm^3	NS		0.0038	0.0098
Ionic Species, μg/Nm^3				
Ammonia as N	3,400	2,700	310	270
Chloride	<2,100	NC	<2,400	NC
Cyanide	5,600	12,000	110	130
Fluoride	15	6.5	21	3.6
Metals, Vapor Phase (Direct AAS)				
Arsenic	870	NC	<220	NC
Cadmium	<2.2	NC	9.5	NC
Chromium	140	NC	<39	NC
Lead	<85	NC	<85	NC
Mercury	6.1	2.1	3.8	3.6
Nickel	500	NC	19	NC
Selenium	560	NC	200	NC
Zinc	<2.2	NC	<2.2	NC
Metals-Vapor Phase (Charcoal), μg/Nm^3				
Antimony	<1.1	NC	<0.039	NC
Arsenic	270	270	6	2.1
Barium	6.3	2.3	0.23	0.14
Beryllium	<0.36	NC	<0.013	NC

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Boron	100	15	3.2	0.23
Cadmium	<0.85	NC	<0.031	NC
Chromium	93	14	3.6	1.7
Cobalt	<5.9	NC	<0.22	NC
Copper	46	10	1.8	0.18
Iron	2,300	190	85	12
Lead	<0.85	NC	<0.031	NC
Manganese	10	4.2	0.4	0.57
Mercury	11	13	0.099	0.024
Molybdenum	45	20	1.6	0.74
Nickel	17	24	0.94	1.5
Selenium	2.8	5.9	0.18	0.15
Vanadium	8.3	2.8	0.28	0.31
Zinc	<3.8	NC	0.37	0.32
Metals, Vapor Phase (M-29) $\mu g/Nm^3$				
Aluminum	<12	NC	<12	NC
Antimony	<0.018	NC	<0.017	NC
Arsenic	0.50	0.32	0.42	0.097
Barium	0.064	0.041	0.17	0.3
Beryllium	<0.033	NC	<0.031	NC
Boron	<4.1	NC	7.1	23

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Cadmium	0.27	0.17	0.44	0.14
Calcium	49	26	40	47
Chromium	1.6	0.38	1.4	0.052
Cobalt	0.021	0.02	0.038	0.043
Copper	<0.046	NC	3.68	16
Iron	6.7	4.8	7.8	4.9
Lead	0.75	2.1	0.33	0.48
Magnesium	<11	NC	<10	NC
Manganese	0.018	0.04	<0.018	NC
Mercury	0.81	0.93	0.23	0.22
Molybdenum	0.16	0.032	0.13	0.046
Nickel	2.3	3.7	1.2	0.3
Phosphorus	<25	NC	<24	NC
Potassium	<190	NC	<180	NC
Selenium	0.18	0.5	0.26	0.84
Silicon	26	18	33	17
Sodium	27	9.6	40	60
Titanium	<0.37	NC	<0.330	NC
Vanadium	0.060	0.011	0.050	0.017
Zinc	8.7	2.7	5.3	2.1

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Aldehydes, μg/Nm^3				
Acetaldehyde	9.2	0.99	140	41
Acrolein	<0.6	NC	<1.3	NC
Benzaldehyde	0.72	1.1	<1.3	NC
Formaldehyde	1.6	1.6	2.3	2.3
PAHs/SVOCs-Vapor Phase, μg/Nm^3				
1,2,4-Trichlorobenzene	<1.8	NC	<1.5	NC
1,2-Dichlorobenzene	<2.4	NC	<2.1	NC
1,3-Dichlorobenzene	<2.2	NC	<2.0	NC
1,4-Dichlorobenzene	<3.8	NC	<3.4	NC
2,4,5-Trichlorophenol	<3.2	NC	<2.8	NC
2,4,6-Trichlorophenol	<3.0	NC	<2.6	NC
2,4-Dimethylphenol	<2.6	NC	<8.7	NC
2,4-Dinitrophenol	<10	NC	<18	NC
2,4-Dinitrotoluene	<21	NC	<3.2	NC
2,6-Dinitrotoluene	<3.6	NC	<2.7	NC
2-Chloronaphthalene	<3.0	NC	<4.3	NC
2-Chlorophenol	<4.9	NC	<3.1	NC
2-Fluorophenol	<3.5	NC	49	9.4
2-Methylnaphthalene	60	21	8.9	3
2-Methylphenol	<9.0	NC	<7.9	NC

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
2-Nitroaniline	<3.3	NC	<2.9	NC
2-Nitrophenol	<4.1	NC	<3.5	NC
3,3'-Dichlorobenzidine	<8.2	NC	<7.3	NC
3-Nitroaniline	<4.0	NC	<3.5	NC
4,6-Dinitro-2-methylphenol	<5.9	NC	<5.3	NC
4-Aminobiphenyl	<14	NC	<13	NC
4-Bromophenylphenyl ether	<4.3	NC	<3.8	NC
4-Chloro-3-methylphenol	<2.8	NC	<2.3	NC
4-Chlorophenylphenyl ether	<6.3	NC	<5.2	NC
4-Methylphenol/3-Methylphenol	<8.2	NC	<7.2	NC
4-Nitroaniline	<4.0	NC	<3.5	NC
4-Nitrophenol	<3.6	NC	<3.1	NC
Acenaphthene	114	19	<2.8	NC
Acenaphthylene	260	19	8.4	2.6
Acetophenone	<2.7	NC	<2.3	NC
Aniline	<6.3	NC	<5.6	NC
Anthracene	8.5	0.06	<3.5	NC
Benz(a)anthracene	<3.1	NC	<2.8	NC
Benz(a)pyrene	<4.9	NC	<4.3	NC
Benzidine	<160	NC	<140	NC
Benzo(b)fluoranthene	<7.7	NC	<6.8	NC

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Benzo(g,h,i)perylene	<3.4	NC	<3.0	NC
Benzo(k)fluoranthene	<5.2	NC	<4.6	NC
Benzoic acid	<50	NC	<42	NC
Benzyl alcohol	<3.6	NC	<3.2	NC
Butylbenzylphthalate	<4.1	NC	<3.7	NC
Chrysene	<2.1	NC	<1.9	NC
Di-n-butylphthalate	<3.4	NC	<3.0	NC
Di-n-octylphthalate	<3.5	NC	<3.1	NC
Dibenz(a,h)anthracene	<3.8	NC	<3.4	NC
Dibenzofuran	22	7	<2.5	NC
Diethylphthalate	<26	NC	<2.2	NC
Dimethylphthalate	<27	NC	<2.2	NC
Diphenylamine/N-NitrosoDPA	<61	NC	<5.1	NC
Fluoranthene	8	NC	<1.2	NC
Fluorene	28	97	<2.0	NC
Hexachlorobenzene	<3.7	NC	<3.3	NC
Hexachlorobutadiene	<2	NC	<1.7	NC
Hexachlorocyclopentadiene	<13	NC	<11	NC
Hexachloroethane	<1.9	NC	<1.7	NC
Indeno(1,2,3-cd)pyrene	<4.1	NC	<3.6	NC
Isophorone	<3.1	NC	<2.6	NC

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
N-Nitroso-di-n-propylamine	<4.5	NC	<3.9	NC
N-Nitrosodimethylamine	<3.3	NC	<2.9	NC
Naphthalene	6,900	1,300	960	88
Nitrobenzene	<2.7	NC	<2.2	NC
Pentachloronitrobenzene	<8.7	NC	<7.7	NC
Pentachlorophenol	17	58	<1.3	NC
Phenanthrene	55	87	<2.5	NC
Phenol	7.6	35	<3.7	NC
Pyrene	10	9.6	<1.7	NC
bis(2-Chloroethoxy)methane	<2.3	NC	<1.9	NC
bis(2-Chloroethyl)ether	<3.1	NC	<2.7	NC
bis(2-Chloroisopropyl)ether	<3.4	NC	<3.0	NC
bis(2-Ethylhexyl)phthalate	<14	NC	<12	NC
p-Chloroaniline	<4.9	NC	<4.1	NC
p-Dimethylaminoazobenzene	<18	NC	<16	NC
Gas Composition				
Hydrogen (mol %)	32	4	32	8
Nitrogen (mol %)	2	2	2	0.5
Oxygen/Argon (mol %)	<1	NC	<1	NC
Carbon Dioxide (mol %)	31	2	30	5
Carbon Monoxide (mol %)	33	2	33	3

Table A-4
Synthesis Gas Streams

Analyte	Sour Syngas (11)		Sweet Syngas (12)	
	Average	95% CI	Average	95% CI
Methane (mol %)	2	0.1	2	0.1
C2 (ppmv)	7.8	0.1	9.2	1.2
C3 (ppmv)	0.2	0.3	0.2	0.2
C4 (ppmv)	<0.1	NC	<0.1	NC
C5 (ppmv)	0.1	0.1	0.1	0.1
C6 (ppmv)	250	16	240	23
C7 (ppmv)	1	0.5	2.9	3.1
C8 (ppmv)	<0.1	NC	<0.1	NC
H_2S (ppmv)	920	70	27	10
COS (ppmv)	29	4	26	2
CS_2 (ppmv)	<1	NC	<1	NC

NC = Not calculated.

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
Ionic Species, mg/Nm³						
Ammonia as N	34%	11%	19	12	100	130
Chloride	NS		<5.6	NC	NC	NC
Cyanide	190	110	1.4	0.15	89	22
Fluoride	NS		0.042	0.018	NC	NC
Metals-Vapor Phase (Charcoal), µg/Nm³						
Antimony	NS		<2.1	NC	NS	
Arsenic	NS		4.9	7.3	NS	
Barium	NS		12	5.4	NS	
Beryllium	NS		<0.69	NC	NS	
Boron	NS		180	56	NS	
Cadmium	NS		<1.6	NC	NS	
Chromium	NS		210	78	NS	
Cobalt	NS		<11	NC	NS	
Copper	NS		58	20	NS	
Iron	NS		4,000	1,600	NS	
Lead	NS		9.6	30	NS	
Manganese	NS		11	27	NS	
Mercury	NS		4	1.1	NS	
Molybdenum	NS		72	13	NS	

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
Nickel	NS		25	29	NS	
Selenium	NS		<1.7	NC	NS	
Vanadium	NS		9.9	8.2	NS	
Zinc	NS		<7.3	NC	NS	
Metals-Vapor Phase (M-29), μg/Nm^3						
Aluminum	NS		<13	NC	<120	NC
Antimony	NS		0.062	0.043	<0.18	NC
Arsenic	NS		2.7	4.9	0.4	1.2
Barium	NS		0.47	0.5	0.69	1.9
Beryllium	NS		<0.034	NC	<0.32	NC
Boron	NS		5.8	9	<40	NC
Cadmium	NS		0.41	0.26	1.7	5.6
Calcium	NS		95	110	220	580
Chromium	NS		65	110	27	110
Cobalt	NS		1.2	1.8	6.5	25
Copper	NS		15	21	3.8	9
Iron	NS		140	190	34	91
Lead	NS		0.66	0.71	7.8	25
Magnesium	NS		21	30	<110	NC
Manganese	NS		19	45	0.76	1.9
Mercury	NS		0.99	1.2	11	31

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
Molybdenum	NS		4.6	7.2	0.61	1.7
Nickel	NS		230	340	33	60
Phosphorus	NS		88	120	<5,000	NC
Potassium	NS		<200	NC	<1,900	NC
Selenium	NS		3.7	9.7	<1.3	NC
Silicon	NS		74	36	170	480
Sodium	NS		78	110	270	740
Titanium	NS		0.82	0.91	<3.6	NC
Vanadium	NS		0.94	2.5	0.42	1.2
Zinc	NS		14	34	50	120
PAHs/SVOCs-Vapor Phase, $\mu g/Nm^3$						
1,2,4-Trichlorobenzene	NS		NA	NC	<60	NC
1,2-Dichlorobenzene	NS		<4.5	NC	<11	NC
1,3-Dichlorobenzene	NS		<4.2	NC	<10	NC
1,4-Dichlorobenzene	NS		<7.2	NC	<17	NC
2,4,5-Trichlorophenol	NS		<6.0	NC	<15	NC
2,4,6-Tribromophenol	NS		23	6.2	NA	
2,4,6-Trichlorophenol	NS		<5.6	NC	<13	NC
2,4-Dichlorophenol	NS		NA	NC	<180	NC
2,4-Dimethylphenol	NS		NA	NC	<400	NC
2,4-Dinitrophenol	NS		<39	NC	<95	NC

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
2,4-Dinitrotoluene	NS		<6.7	NC	<16	NC
2,6-Dinitrotoluene	NS		<5.7	NC	<14	NC
2-Chloronaphthalene	NS		<9.2	NC	<22	NC
2-Chlorophenol	NS		<6.7	NC	<16	NC
2-Fluorobiphenyl	NS		17	2.3	NA	
2-Fluorophenol	NS		25.7	4.4	NA	
2-Methylnaphthalene	NS		<640	NC	<520	NC
2-Methylphenol	NS		<17	NC	<41	NC
2-Nitroaniline	NS		<6.2	NC	<15	NC
2-Nitrophenol	NS		NA	NC	<130	NC
3,3'-Dichlorobenzidine	NS		<15	NC	<37	NC
3-Nitroaniline	NS		<7.5	NC	<18	NC
4,6-Dinitro-2-methylphenol	NS		<11	NC	<27	NC
4-Aminobiphenyl	NS		<27	NC	<64	NC
4-Bromophenylphenyl ether	NS		<8.0	NC	<19	NC
4-Chloro-3-methylphenol	NS		NA	NC	<140	NC
4-Chlorophenylphenyl ether	NS		<11	NC	<27	NC
4-Methylphenol/3-Methylphenol	NS		<15	NC	<37	NC
4-Nitroaniline	NS		<7.5	NC	<18	NC
4-Nitrophenol	NS		<6.7	NC	<16	NC
Acenaphthene	NS		1,700	440	44	140

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
Acenaphthylene	NS		3,100	800	<27	NC
Acetophenone	NS		<5.0	NC	<12	NC
Aniline	NS		<12	NC	<29	NC
Anthracene	NS		31	18	<18	NC
Benz(a)anthracene	NS		<5.9	NC	<14	NC
Benz(a)pyrene	NS		<9.2	NC	<22	NC
Benzidine	NS		<290	NC	<710	NC
Benzo(b)fluoranthene	NS		<14	NC	<35	NC
Benzo(g,h,I)perylene	NS		<6.4	NC	<15	NC
Benzo(k)fluoranthene	NS		<9.7	NC	<23	NC
Benzoic acid	NS		NA		<940	NC
Benzyl alcohol	NS		<6.8	NC	<16	NC
Butylbenzylphthalate	NS		<7.8	NC	<19	NC
Chrysene	NS		<4.1	NC	<9.7	NC
Di-n-butylphthalate	NS		<6.5	NC	<16	NC
Di-n-octylphthalate	NS		<6.5	NC	<16	NC
Dibenz(a,h)anthracene	NS		<7.2	NC	<17	NC
Dibenzofuran	NS		270	82	160	440
Diethylphthalate	NS		<4.6	NC	<11	NC
Dimethylphthalate	NS		<4.8	NC	<11	NC
Diphenylamine/N-NitrosoDPA	NS		<11	NC	<26	NC

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
Fluoranthene	NS		<2.5	NC	<6.0	NC
Fluorene	NS		660	12	11	81
Hexachlorobenzene	NS		<7.0	NC	<17	NC
Hexachlorobutadiene	NS		NA		<210	NC
Hexachlorocyclopentadiene	NS		<24	NC	<58	NC
Hexachloroethane	NS		<3.6	NC	<8.7	NC
Indeno(1,2,3-cd)pyrene	NS		<7.7	NC	<18	NC
Isophorone	NS		NA		<95	NC
N-Nitroso-di-n-propylamine	NS		<8.4	NC	<20	NC
N-Nitrosodimethylamine	NS		<6.2	NC	<15	NC
Naphthalene	NS		110,000	28,000	89,000	38,000
Nitrobenzene	NS		NA		<120	NC
Pentachloronitrobenzene	NS		<16	NC	<39	NC
Pentachlorophenol	NS		<2.7	NC	<6.4	NC
Phenanthrene	NS		240	290	<150	NC
Phenol	NS		<7.9	NC	<19	NC
Pyrene	NS		<3.6	NC	<8.6	NC
bis(2-Chloroethoxy)methane	NS		NA		<110	NC
bis(2-Chloroethyl)ether	NS		<5.9	NC	<14	NC
bis(2-Chloroisopropyl)ether	NS		<6.4	NC	<15	NC
bis(2-Ethylhexyl)phthalate	NS		<26	NC	<63	NC

Table A-5
Internal Process Streams

Analyte	Sour Gas (22)		Acid Gas (14)		Tail Gas (15)	
	Average	95% CI	Average	95% CI	Average	95% CI
p-Chloroaniline	NS		NA		<310	NC
p-Dimethylaminoazobenzene	NS		<33	NC	<80	NC
Gas Composition						
Hydrogen (mol %)	NA		<1	NC	NA	
Nitrogen (mol %)	NA		<1	NC	3	0.3
Oxygen/Argon (mol %)	NA		<1	NC	<1	NC
Carbon Dioxide (mol %)	NA		98	NC	97	0.3
Carbon Monoxide (mol %)	NA		<1	NC	<0.1	NC
Methane (ppmv)	700	50	420	44	390	40
C2 (ppmv)	5.4	0.5	2.3	0.6	1.3	0.5
C3 (ppmv)	170	40	8.8	2.4	6.5	4.7
C4 (ppmv)	7	4	<0.1	NC	<0.1	NC
C5 (ppmv)	<0.1	NC	<0.1	NC	<0.1	NC
C6 (ppmv)	440	20	350	24	330	30
C7 (ppmv)	2	3	2.1	1.5	2.7	2
C8 (ppmv)	6	7	<0.1	NC	2	4
H_2S (ppmv)	1.3%	NC	1.5%	0.2	3,000	300
COS (ppmv)	<1	NC	170	NC	85	55
CS_2 (ppmv)	<1	NC	<1	NC	42	28

Table A-6
Incinerator Fuel Gases

Analyte	Natural Gas (99)		Combustion Air (97)	
	Average	95% CI	Average	95% CI
Ionic Species, mg/Nm³				
Ammonia as N	NA		460	55
Cyanide	NA		10	2.4
Metals-Vapor Phase (M-29), µg/Nm³				
Aluminum	<12	NC	NA	
Antimony	<0.018	NC	NA	
Arsenic	0.068	0.031	NA	
Barium	0.04	0.043	NA	
Beryllium	<0.033	NC	NA	
Boron	<4.1	NC	NA	
Cadmium	0.37	0.26	NA	
Calcium	43	19	NA	
Chromium	1.5	0.22	NA	
Cobalt	0.54	2.2	NA	
Copper	<0.047	NC	NA	
Iron	6	3.4	NA	
Lead	3.6	12	NA	
Magnesium	<11	NC	NA	
Manganese	0.049	0.17	NA	
Mercury	0.35	0.16	NA	

Table A-6
Incinerator Fuel Gases

Analyte	Natural Gas (99)		Combustion Air (97)	
	Average	95% CI	Average	95% CI
Molybdenum	0.14	0.055	NA	
Nickel	0.74	1.6	NA	
Phosphorus	<26	NC	NA	
Potassium	<190	NC	NA	
Selenium	<0.14	NC	NA	
Silicon	24	10	NA	
Sodium	28	12	NA	
Titanium	<0.37	NC	NA	
Vanadium	0.032	0.037	NA	
Zinc	8.3	2.3	NA	
Gas Composition				
Hydrogen (mol %)	<1	NC	NA	
Nitrogen (mol %)	<1	NC	NA	
Oxygen/Argon (mol %)	<1	NC	NA	
Carbon Dioxide (mol %)	<1	NC	NA	
Carbon Monoxide (mol %)	<1	NC	NA	
Methane (ppmv)	99%	NC	650	120
C2 (ppmv)	4,500	90	5	3
C3 (ppmv)	1,400	140	0.9	0.3
C4 (ppmv)	390	50	0.2	0.2
C5 (ppmv)	140	20	<0.1	NC

Table A-6
Incinerator Fuel Gases

Analyte	Natural Gas (99)		Combustion Air (97)	
	Average	95% CI	Average	95% CI
C6 (ppmv)	53	12	7.2	0.3
C7 (ppmv)	110	20	1	1
C8 (ppmv)	10	1	0.6	0.05
H_2S (ppmv)	<1	NC	<1	NC
COS (ppmv)	<1	NC	<1	NC
CS_2 (ppmv)	<1	NC	<1	NC

Table A-7
Solid Feed Streams

Analyte	Raw Coal (1a)		Primary Slurry Feed (32)		Secondary Slurry Feed (33)	
	Average	95% CI	Average	95% CI	Average	95% CI
Ultimate/Proximate Parameters						
Moisture, total (Wt. %)	29	0.24	45	0.30	48	0.44
% Solids in Slurry (Wt. %)	NA		55	0.30	52	0.44
Ash (Wt. %)	6.7	0.30	6.4	0.08	7.7	0.15
Carbon (Wt. %)	70	0.37	69	0.43	69	0.31
Hydrogen (Wt. %)	4.6	0.08	4.8	0.09	4.7	0.07
Nitrogen (Wt. %)	0.99	0.02	1	0.02	1.1	0.06
Sulfur (Wt. %)	0.28	0.01	0.28	0.01	0.28	0.01
Oxygen (by difference) (Wt. %)	17	0.39	19	0.34	17	0.31
Volatile Matter (Wt. %)	46	0.34	46	0.29	45	0.48
Fixed Carbon (Wt. %)	47	0.43	48	0.32	47	0.52
Higher Heating Value (Btu/lb)	12,000	68	12,000	39	12,000	46
Chloride (μg/g)	39	5.7	43	7.0	56	9.2
Fluoride (μg/g)	76	27	45	5.0	260	45
Metals, μg/g						
Aluminum	6,300	400	5,800	140	7,200	220
Antimony	0.12	0.023	0.01	0.031	0.43	0.047
Arsenic	0.98	0.066	0.74	0.13	2.2	0.32
Barium	370	97	390	8.6	500	27

Table A-7
Solid Feed Streams

Analyte	Raw Coal (1a)		Primary Slurry Feed (32)		Secondary Slurry Feed (33)	
	Average	95% CI	Average	95% CI	Average	95% CI
Beryllium	0.27	0.029	0.21	0.04	0.31	0.039
Boron	32	0.95	26	2.4	35	0.77
Cadmium	0.1	0.035	0.074	0.016	1.8	0.87
Calcium	11,000	440	10,000	170	13,000	280
Chromium	4.7	2.1	3.3	1.4	5.2	1.9
Cobalt	1.9	0.11	1.5	0.27	2.2	0.15
Copper	11	0.79	9.6	1.5	15	1.6
Iron	2,400	98	2,300	77	2,900	84
Lead	1.3	0.20	0.85	0.16	8.3	2.2
Magnesium	2,200	93	2,100	41	2,700	78
Manganese	9.9	0.62	8	1.3	11.0	0.80
Mercury	0.11	0.013	0.11	0.028	0.087	0.0086
Molybdenum	0.55	0.054	0.49	0.091	0.73	0.073
Nickel	1.6	0.56	1.8	0.51	1.1	0.37
Phosphorus	300	50	290	26	310	26
Potassium	210	26	200	50	210	26
Selenium	3.4	2.6	1.4	0.54	5	1.3
Silicon	11,000	790	9,900	230	12,000	340
Sodium	1,000	34	1,000	500	1,300	50
Strontium	200	50	200	50	200	50

Table A-7
Solid Feed Streams

Analyte	Raw Coal (1a)		Primary Slurry Feed (32)		Secondary Slurry Feed (33)	
	Average	95% CI	Average	95% CI	Average	95% CI
Titanium	580	75	540	56	690	26
Vanadium	13	0.87	10	1.4	14	0.91
Zinc	7.9	0.81	8.6	2.5	57	25
Radionuclides, pCi/g						
Actinium-228 @ 338 KeV	0.047	0.29	NA		NA	
Actinium-228 @ 911 KeV	0.12	0.45	NA		NA	
Actinium-228 @ 968 KeV	0.14	0.85	NA		NA	
Bismuth-212 @ 727 KeV	-0.27	1.5	NA		NA	
Bismuth-214 @ 1120 KeV	0.31	0.11	NA		NA	
Bismuth-214 @ 1764 KeV	0.32	0.61	NA		NA	
Bismuth-214 @ 609 KeV	0.16	0.19	NA		NA	
Lead-210 @ 46 KeV	0.4	1.7	NA		NA	
Lead-212 @ 238 KeV	0.13	0.029	NA		NA	
Lead-214 @ 295 KeV	0.21	0.11	NA		NA	
Lead-214 @ 351 KeV	0.15	0.066	NA		NA	
Potassium-40 @ 1460 KeV	-0.038	0.12	NA		NA	
Radium-226 @ 226 KeV	0.057	0.038	NA		NA	
Thallium-208 @ 583 KeV	0.037	0.076	NA		NA	
Thallium-208 @ 860 KeV	-0.23	0.95	NA		NA	
Thorium-234 @ 63 KeV	0.13	0.29	NA		NA	

Table A-7
Solid Feed Streams

Analyte	Raw Coal (1a)		Primary Slurry Feed (32)		Secondary Slurry Feed (33)	
	Average	95% CI	Average	95% CI	Average	95% CI
Thorium-234 @ 92 KeV	0.047	0.38	NA		NA	
Uranium-235 @ 143 KeV	-0.023	0.17	NA		NA	

NA = Not analyzed.
NC = Not calculated.
NS = Not sampled.

Table A-8
Solid Effluent Streams

Analyte	Slag (4)		Sulfur (24)	
	Average	95% CI	Average	95% CI
Ultimate/Proximate Parameters				
Ash (Wt. %)	89.8	5.1	NA	
Carbon (Wt. %)	9.5	5.2	NA	
Hydrogen (Wt. %)	0.15	0.07	NA	
Nitrogen (Wt. %)	0.04	0.05	NA	
Sulfur (Wt. %)	0.03	0.02	98.7	7.0
Oxygen (by difference) (Wt. %)	0.27	0.19	NA	
Volatile Matter (Wt. %)	NA		NA	
Fixed Carbon (Wt. %)	NA		NA	
Higher Heating Value (Btu/lb)	NA		NA	
Chloride (µg/g)	84	56	NA	
Fluoride (µg/g)	200	50	NA	
Metals, µg/g				
Aluminum	91,000	5,300	16	150
Antimony	1.1	0.25	<3	NC
Arsenic	6	0.96	<3	NC
Barium	5,900	390	<2	NC
Beryllium	3.4	0.37	<2	NC
Boron	350	30	<10	NC
Cadmium	0.20	0.11	<2	NC

Table A-8
Solid Effluent Streams

Analyte	Slag (4)		Sulfur (24)	
	Average	95% CI	Average	95% CI
Calcium	160,000	9,800	20	95
Chromium	76	8.3	4	38
Cobalt	26	2.8	<4	NC
Copper	150	11	<2	NC
Iron	37,000	2,200	9	38
Lead	3	1.1	<3	NC
Magnesium	33,000	2,200	4	25
Manganese	130	12	<2	NC
Mercury	0.020	0.006	0.095	0.19
Molybdenum	7.6	0.52	<20	NC
Nickel	38	4.1	<4	NC
Phosphorus	4,100	210	NA	
Potassium	2,700	250	<20	NC
Selenium	14	5.7	24	180
Silicon	160,000	9,500	<20	NC
Sodium	16,000	1,100	<20	NC
Strontium	2,300	910	NA	NC
Titanium	8,100	500	2	13
Vanadium	170	13	<2	NC
Zinc	47	5.6	15	170

Table A-8
Solid Effluent Streams

Analyte	Slag (4)		Sulfur (24)	
	Average	95% CI	Average	95% CI
Radionuclides, pCi/g				
Actinium-228 @ 338 KeV	2.3	0.9	NA	
Actinium-228 @ 911 KeV	2.5	1.1	NA	
Actinium-228 @ 968 KeV	2.5	1.1	NA	
Bismuth-212 @ 727 KeV	2.8	1.1	NA	
Bismuth-214 @ 1120 KeV	2.7	0.9	NA	
Bismuth-214 @ 1764 KeV	2.6	1.4	NA	
Bismuth-214 @ 609 KeV	2.7	1.2	NA	
Lead-210 @ 46 KeV	0.33	1.4	NA	
Lead-212 @ 238 KeV	2.3	0.87	NA	
Lead-214 @ 295 KeV	2.8	1.2	NA	
Lead-214 @ 351 KeV	2.8	1.2	NA	
Potassium-40 @ 1460 KeV	2	1.8	NA	
Radium-226 @ 226 KeV	3.5	1.3	NA	
Thallium-208 @ 583 KeV	0.82	0.34	NA	
Thallium-208 @ 860 KeV	1.1	0.52	NA	
Thorium-234 @ 63 KeV	1.9	2.3	NA	
Thorium-234 @ 92 KeV	1.4	0.76	NA	
Uranium-235 @ 143 KeV	0	0.56	NA	

NA = Not analyzed.
NC = Not calculated.
NS = Not sampled.

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	**95% CI**
Water Quality Parameters		
pH	8.75	0.22
Specific conductance (μmhos)	71.8	18
Total Suspended Solids (mg/L)	1.9	3.4
Chemical Oxygen Demand (mg/L)	53	3.9
Total phenolics (mg/L)	0.55	0.1
Ionic Species, mg/L		
Ammonia as N	7.3	3.6
Chloride	0.88	0.15
Cyanide, amenable	0.035	0.1
Cyanide, total	1.5	1.2
Fluoride	1.8	0.7
Formate	3.2	0.41
Phosphate, total (as P)	0.26	0.1
Sulfate	<0.047	NC
Thiocyanate	0.82	0.72
Metals, mg/L		
Aluminum	0.5	0.14
Antimony	<0.076	NC
Arsenic	0.0038	0.0024

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
Barium	0.53	0.07
Beryllium	0.0006	0.0013
Boron	0.039	0.051
Cadmium	0.005	0.0024
Calcium	2.6	0.11
Chromium	0.0087	0.003
Cobalt	<0.004	NC
Copper	0.015	0.0044
Iron	1.2	0.14
Lead	0.33	0.25
Magnesium	1	0.058
Manganese	0.0024	0.0034
Mercury	<0.00003	NC
Molybdenum	0.011	0.0051
Nickel	0.022	0.042
Phosphorus	0.24	0.07
Potassium	0.9	1.1
Selenium	0.032	0.02
Silicon	7.23	0.35
Sodium	3.79	0.038
Titanium	0.02	0.011

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
Vanadium	<0.0045	NC
Zinc	0.25	0.13
Aldehydes, mg/L		
Acetaldehyde	<0.01	NC
Acrolein	<0.01	NC
Benzaldehyde	<0.01	NC
Formaldehyde	<0.01	NC
Volatile Organic Compounds, μg/L		
1,1,1-Trichloroethane	<0.87	NC
1,1,2,2-Tetrachloroethane	<0.63	NC
1,1,2-Trichloroethane	<0.27	NC
1,1-Dichloroethane	<0.59	NC
1,1-Dichloroethene	<0.34	NC
1,2-Dichloroethane	<0.82	NC
1,2-Dichloropropane	<0.16	NC
1,4-Bromofluorobenzene	46	1.2
1,4-Dichlorobenzene	<0.56	NC
2-Hexanone	<0.71	NC
4-Methyl-2-pentanone(MIBK)	<0.49	NC
Acetone	5.2	3.2
Benzene	<0.46	NC

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
Bromodichloromethane	<0.37	NC
Bromomethane	<0.54	NC
Carbon disulfide	<0.49	NC
Carbon tetrachloride	<0.80	NC
Chlorobenzene	<0.32	NC
Chloroethane	<0.77	NC
Chloroform	<0.53	NC
Chloromethane	<0.52	NC
Dibromochloromethane	<0.25	NC
Ethyl benzene	<0.59	NC
Methyl ethyl ketone	<1.6	NC
Methylene chloride	<3.0	NC
Styrene	<0.43	NC
Tetrachloroethene	<0.54	NC
Toluene	<0.41	NC
Tribromomethane (Bromoform)	<0.56	NC
Trichloroethene	<0.46	NC
Vinyl acetate	<0.64	NC
Vinyl chloride	<0.69	NC
cis-1,3-Dichloropropene	<0.41	NC
m&p-Xylene	<0.51	NC

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
o-Xylene	<0.40	NC
trans-1,2-Dichloroethene	<0.54	NC
trans-1,3-Dichloropropene	<0.42	NC
Semivolatile Organic Compounds, μg/L		
1,2,4-Trichlorobenzene	<0.53	NC
1,2-Dichlorobenzene	<0.64	NC
1,3-Dichlorobenzene	<0.43	NC
1,4-Dichlorobenzene	<1.7	NC
2,4,5-Trichlorophenol	<0.34	NC
2,4,6-Tribromophenol	160	32
2,4,6-Trichlorophenol	<0.41	NC
2,4-Dichlorophenol	<0.43	NC
2,4-Dimethylphenol	<0.70	NC
2,4-Dinitrophenol	<1.3	NC
2,4-Dinitrotoluene	<0.34	NC
2,6-Dinitrotoluene	<0.65	NC
2-Chloronaphthalene	<0.84	NC
2-Chlorophenol	<0.57	NC
2-Fluorobiphenyl	61.2	15
2-Fluorophenol	160	33
2-Methylnaphthalene	<0.86	NC

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
2-Methylphenol	<0.51	NC
2-Nitroaniline	<0.55	NC
2-Nitrophenol	<0.82	NC
3,3'-Dichlorobenzidine	<3.9	NC
3-Nitroaniline	<0.54	NC
4,6-Dinitro-2-methylphenol	<3.1	NC
4-Aminobiphenyl	<4.3	NC
4-Bromophenylphenyl ether	<0.31	NC
4-Chloro-3-methylphenol	<0.40	NC
4-Chlorophenylphenyl ether	<0.48	NC
4-Methylphenol/3-Methylphenol	0.49	1.1
4-Nitroaniline	<0.66	NC
4-Nitrophenol	<0.81	NC
Acenaphthene	<0.64	NC
Acenaphthylene	<0.65	NC
Acetophenone	<0.57	NC
Aniline	<1.1	NC
Anthracene	<0.70	NC
Benz(a)anthracene	<0.77	NC
Benz(a)pyrene	<0.70	NC
Benzidine	<21	NC

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
Benzo(b)fluoranthene	<0.69	NC
Benzo(g,h,i)perylene	<0.74	NC
Benzo(k)fluoranthene	<1.0	NC
Benzoic acid	9.2	26
Benzyl alcohol	<0.45	NC
Butylbenzylphthalate	<0.50	NC
Chrysene	<0.78	NC
Di-n-butylphthalate	<0.50	NC
Di-n-octylphthalate	<0.68	NC
Dibenz(a,h)anthracene	<0.86	NC
Dibenzofuran	<0.64	NC
Diethylphthalate	<0.69	NC
Dimethylphthalate	<0.43	NC
Diphenylamine/N-NitrosoDPA	<0.69	NC
Fluoranthene	2.6	1.1
Fluorene	<0.75	NC
Hexachlorobenzene	<0.57	NC
Hexachlorobutadiene	<0.76	NC
Hexachlorocyclopentadiene	<2.1	NC
Hexachloroethane	<1.9	NC
Indeno(1,2,3-cd)pyrene	<0.81	NC

Table A-9
Aqueous Streams

Analyte	Sweet Water (8)	
	Average	95% CI
Isophorone	<0.36	NC
N-Nitroso-di-n-propylamine	<0.60	NC
N-Nitrosodimethylamine	<0.54	NC
Naphthalene	<0.76	NC
Nitrobenzene	<0.58	NC
Pentachloronitrobenzene	<1.9	NC
Pentachlorophenol	<0.51	NC
Phenanthrene	<1.9	NC
Phenol	400	84
Pyrene	11	5.6
bis(2-Chloroethoxy)methane	<0.58	NC
bis(2-Chloroethyl)ether	<0.63	NC
bis(2-Chloroisopropyl)ether	<0.59	NC
bis(2-Ethylhexyl)phthalate	<1.0	NC
p-Chloroaniline	<0.95	NC
p-Dimethylaminoazobenzene	<0.51	NC