

# NATURAL GAS COFIRING IN A REFUSE DERIVED FUEL INCINERATOR: RESULTS OF A FIELD EVALUATION

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## ABSTRACT

Natural gas was cofired with Refuse Derived Fuel (RDF) in a 15 MWe municipal waste incinerator in Columbus, Ohio. The program goals were to: (1) control CO emissions to less than 150 ppm, (2) achieve smokeless cold start-up of the unit, (3) limit steam flow fluctuations to less than 10% of the average and (4) reduce combustible matter in ash.

Natural gas cofiring was found to have a significant impact on CO emissions. The CO emissions were controlled to less than 50 ppm when cofiring natural gas at 0.47 to 0.63 Nm<sup>3</sup>/s (60,000 to 80,000 SCFH), corresponding to 29.3 to 35.6% of the total heat input. This compares to RDF baseline CO emissions of 530 to 1950 ppm. More moderate natural gas inputs of 0.24 to 0.47 Nm<sup>3</sup>/s (30,000 to 60,000 SCFH) resulted in CO emissions in the 60 to 550 ppm range.

During start-up with gas, the average and maximum stack gas opacities were 8% to 22%, compared to average and maximum opacities of 20% and 61% with coal as the primary start-up fuel. The emitted stack gas was clear during gas start-up and black during coal start-up. Steam load fluctuations were evaluated in terms of the standard deviation (STD) in steam output over the test period. Gas cofiring, under optimum conditions, decreased the steam load STD to 7% from 16% during optimum baseline RDF firing. Baseline steam load STD as high as 25% was mea-

sured, with wider fluctuations occurring during periods of low average steam output. Carbon in ash was low (bottom ash under 1.5%, fly ash under 6%) for both cofiring and baseline operation. A modest reduction in carbon in ash due to natural gas cofiring was observed. The gross boiler efficiency increased by 3% to 5.0% during gas cofiring at a rate of 0.14 to 0.31 Nm<sup>3</sup>/s (18,000 to 40,000 SCFH).

Natural gas cofiring also resulted in a reduction in emissions of SO<sub>2</sub>, CO<sub>2</sub>, hydrocarbons (HC), and polychlorinated dibenzopdioxins and furans (PCDD/PCDF). The reductions in SO<sub>2</sub> and CO<sub>2</sub> emissions are due to differences in fuel composition, natural gas has no sulfur and a lower carbon to hydrogen ratio. Reductions in CO, HC and PCDD/PCDF emissions are due to improved burnout of combustible matter in the furnace.

## INTRODUCTION

Energy and Environmental Research Corporation (EER) conducted a program to evaluate emissions reduction and improved operation of a Municipal Solid Waste (MSW) incinerator through natural gas cofiring. A natural gas cofiring system, designed by EER, was retrofitted to Columbus Solid Waste Reduction Facility (SWRF) Unit 6, located in Columbus, Ohio. This unit is a 15 MWe Refuse Derived Fuel (RDF) combustor. The goals of the program were to evaluate the effectiveness of natural gas

cofiring in reducing emissions of carbon monoxide (CO), controlling steam load variations, reducing opacity during start-up and improving burnout of the fuel combustibles (including hydrocarbons and carbon in ash). The field evaluation was conducted between July 6 and August 5, 1992. The program was sponsored by the Gas Research Institute (GRI), the City of Columbus, the Franklin County Solid Waste Management Authority and the Columbia Gas System Service Corporation.

The program was initiated to evaluate the effectiveness of natural gas cofiring in addressing several problems common to municipal waste incinerators. The primary purpose of the study was to reduce CO emissions. Maximum daily CO emissions often exceeded 1500 ppm at the Columbus SWRF. The second objective was to improve the cold start-up. Unit cold start-up is normally accomplished with coal and auxiliary fuels (e.g., wooden pallets). These fuels produce smokey flue gas until the ESP is preheated and operation is initiated. The third objective was to control steam load variations. These were evaluated by the standard deviation as a percentage of the average steam load. Under baseline operation the average steam load fluctuation was 14 percent and the maximum was 25 percent. These fluctuations are due to variations in RDF composition and feedrate and may interfere with the ability of the plant to generate power at a prescribed rate. Cofiring of natural gas was also expected to enhance fuel burnout.

The specific goals of the field evaluation were to:

- Control CO emissions to less than 150 ppm (at 7% O<sub>2</sub>),
- Achieve smokeless cold start-up of the unit,
- Control steam load fluctuations to less than 10 percent,
- Improve burnout of fuel combustibles, such as hydrocarbons and carbon in ash.

## HOST SITE DESCRIPTION

The host site for this program is the Columbus Solid Waste Reduction Facility (SWRF), which is located on a 52 acre site in the south side of Columbus, Ohio. This 90 MWe plant has six RDF fired boilers producing superheated steam. Each unit is capable of producing 20.8 kg/sec of steam at a temperature of 371°C and pressure of 4620 to 4960 kPa. The steam is fed to three 30 MWe turbine generators. The primary purpose of the facility is to reduce municipal solid waste. It has the capacity to incinerate RDF at a rate of 2180 tonne per day, but currently burns approximately 1545 tonne daily. The combustion of the RDF reduces the solid mass by approximately 75 percent. The ash is neutralized and disposed of at the Franklin County Sanitary Landfill. The plant began operation in 1983 and was owned by the City of Columbus for ten years. Ownership of the facility was transferred to the

Solid Waste Authority of Central Ohio on April 1, 1993. The plant is now called the Waste to Energy Facility of Central Ohio.

The plant receives municipal waste directly from refuse haulers and shredded refuse from satellite shredding stations. The municipal waste is processed to remove discarded appliances, automobile tires, etc. Steel and other iron containing materials are removed magnetically. The refuse is shredded to a size of 10 to 15 cm, carried by conveyor belts to metering bins and air-blown into the units. The RDF incinerated is classified RDF-2 (in a seven type classification scheme developed by the American Society of Testing Materials (ASTM)) and typically has the following characteristics:

RDF size	95% < 10–11 cm
Density	48–112 kg/m <sup>3</sup>
Moisture	15–25%
Ash	12–20%
RDF yield	70–80% (based on raw MSW)
HHV	10,500–12,800 kJ/kg

Each boiler at the SWRF consists of a Detroit Stoker traveling grate spreader stoker and a Babcock and Wilcox straight-wall refractory-lined water-tube boiler. Combustion air is provided through a single undergrate air plenum and multiple overfire air ports. Figure 1 is a schematic of the boiler. The combustors were designed to cofire RDF and coal in a 80:20 ratio. However due to operational problems, these fuels are not cofired. Typically, five units are on line, firing almost exclusively RDF. Coal is added only during cold start-up of the units and during sudden drop in steam load. Significant improvements in RDF feed and ash handling have been accomplished since the plant began operation (Barr, 1986). To limit upper furnace temperature, each of the units is operated at an average steam load of approximately 15.8 kg/sec. Table 1 lists the boiler design parameters.

Combustion gases flow up the furnace, horizontally through the superheater and boiler banks, then through the economizer, a mechanical dust collector, a hot-side electrostatic precipitator and a regenerative air heater. The flue gases from two adjacent units pass through a common stack.

## COFIRING SYSTEM DESIGN

Columbus SWRF Unit 6 was retrofitted with a natural gas cofiring system designed by EER. Two 11.7 MJ/sec dual air zone register gas burners produced by Coen, were installed on the sidewalls of the unit, approximately 1.5 to 2.4 m above the grate, where wet refuse piles up. They were placed in an offset configuration with the burner on the north side 2.0 m from the back wall, and the burner on the south side 2.0 m from the front wall (total side-

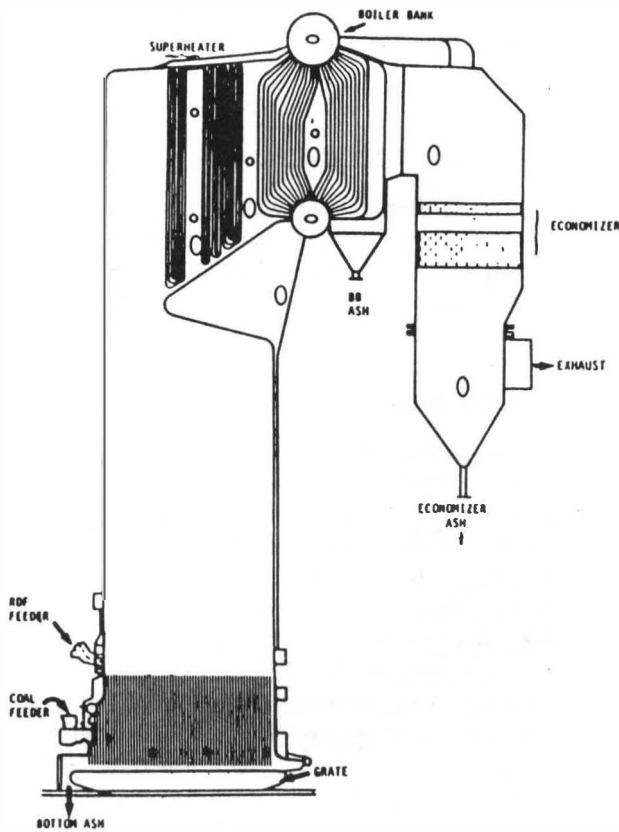


FIG. 1 WASTE TO ENERGY FACILITY OF CENTRAL OHIO UNIT 6

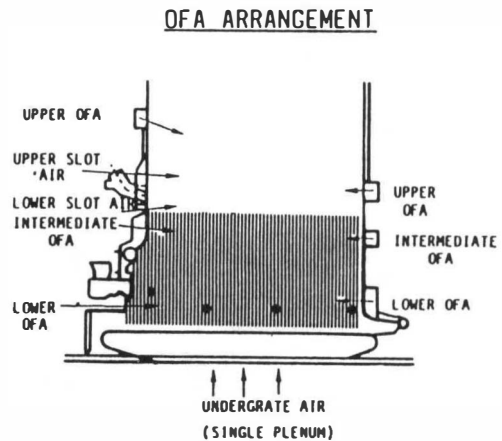


TABLE 1 WASTE TO ENERGY FACILITY OF CENTRAL OHIO UNIT 6 DESIGN DATA

Maximum Capacity	20.8 kg/sec
Design Pressure	5860 kPa
Heating Surface	
Boiler	1,189 m <sup>2</sup>
Furnace	390 m <sup>2</sup>
Maximum Heat Input	69.8 MJ/sec
Firing	Stoker

wall length is 6.4 m). The gas cofiring arrangement on the unit is shown in Figure 2. The cofiring system was designed to input natural gas over a range of 2.34 to 23.4 MJ/sec as required to improve combustion of RDF. Two cofiring modes are possible, the constant natural gas input mode and cascade mode in which natural gas input varies to control steam load at a prescribed level.

The entire cofiring system consists of gas burners, wind-boxes, tube panels to provide burner openings, combustion air ducting, burner air metering and control systems, a natural gas header into the boiler housing and natural gas trains to each burner. The system installed includes a full fuel and air metering system, an analog control system integrated into the existing plant boiler control system (Bailey Net 90) and a safety system designed to trip the burners when an alarm requires shutdown of the cofiring

system. The burners are ignited by two 0.44 MJ/sec natural gas pilots. The system installed also includes four flame scanners to sight each burner and pilot.

The gas is supplied to the burners at a pressure of 172 kPa and is controlled through pressure regulators at the 827 to 1034 kPa Columbia Gas main header. The natural gas header into the plant was sized for a maximum velocity of 30.5 m/sec to limit flow losses. At the entrance of the boiler house there is a manual shutoff valve and drip leg for removal of condensate. This valve may be used to shut off natural gas into the boiler house in the event of an emergency.

Boiler gas trains were designed to carry natural gas from the plant header to each burner. These trains include pressure reducing valves, gas flow metering stations, safety shut-off valves and interlocks in accord with NFPA 85B. Full metering of both air and gas is accomplished with an array of flow orifices.

At the maximum natural gas flow of 0.63 Nm<sup>3</sup>/s, the burner combustion air requirement is 8.07 kg/sec, at 10% excess air. The combustion air is taken from the overfire air duct at a location downstream of the OFA booster fan, at a pressure of 7.5 kPa. The air, at a temperature of 204°C, is carried by 56 cm pipe. Butterfly valves control

which one was most effective in meeting the performance goals established for natural gas cofiring.

## FIELD TEST RESULTS

The cofiring system was evaluated under a test plan prepared by EER, designed to evaluate the unit under a variety of conditions to determine the impacts of many parameters on emissions and unit operation.

### Test Parameters

The parameters studied included the burner heat input, burner control mode, steam load and excess air. Baseline testing, using 100% RDF, was carried out for comparison with gas cofiring results. Cold boiler start up with natural gas was compared to coal start-up. The measurements included flue gas emissions of: O<sub>2</sub>, CO, CO<sub>2</sub>, NO<sub>x</sub>, SO<sub>2</sub>, hydrocarbons (HC), and polychlorinated dibenzo-para-dioxin/furan (PCDD/PCDF), particulate loading, upper furnace temperature, upper furnace CO and O<sub>2</sub> distribution, stack opacity. Ash and fuel samples were also analyzed.

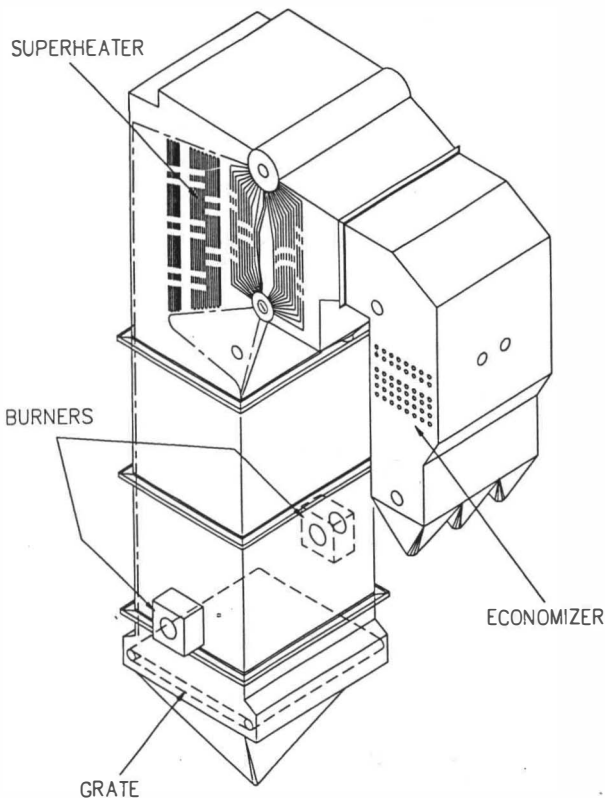
High tube wear rates have been noted in municipal waste incinerators. This is believed to be due to high temperature HCl attack with special concern for the superheater region. The superheater corrosion rates increase at gas temperatures above 871°C, therefore upper furnace temperature measurements with a High Velocity Temperature (HVT) probe were included. These were critical in determining whether natural gas cofiring results in an increase in the upper furnace gas temperature and therefore potentially higher corrosion rates.

### Temperature Profile

HVT measurements indicate only a minor increase in upper furnace gas temperature due to gas cofiring. The average upper furnace gas temperatures were below 871°C in each case, with peak temperatures approximating 900°C.

### RDF Composition

Proximate and ultimate analyses of twenty-five RDF samples, collected in July and August, 1992, were obtained to determine the composition and variations in composition of RDF. The average composition is shown in Table 2. The composition of individual samples varied significantly. For example, the RDF ash content was in the 10.98% to 24.61% range, the moisture content ranged from 27% to 49%, and the higher heating value was in the 7,900 to 12,300 kJ/kg range. Variations in RDF composi-



**FIG. 2 WASTE TO ENERGY FACILITY OF CENTRAL OHIO UNIT 6 GAS COFIRING ARRANGEMENT**

the air flow in 31 and 56 cm pipes and a low pressure switch is used to indicate inadequate air pressure.

The control system for the cofiring system has two packages, one package for the interlocking/safety system and another package for the analog (modulating) controls. The interlocking/safety system is an independent system that is designed to meet all NFPA 85B guidelines and the requirements of Industrial Risk Insurance (IRI). The system is designed to insure that safe start-up procedures are followed and to trip gas firing in the event a hazardous condition develops, e.g., flame out, fan failure, high furnace pressure etc. Hard wired trip signals are included. An Allen Bradley PLC Model 5 is used for the flame management system.

The analog (modulating) requirements of the system were integrated into the existing Bailey Controls Net 90 System. Two control modes for cofiring natural gas are possible and each was evaluated in the field test. In one mode, the natural gas is input at a constant rate. The other control mode is "cascade" firing, in which the natural gas flow fluctuates to level the steam load at a prescribed target load. When the target steam load is met, the natural gas input is modulated to a set-point gas input. During the field test, both firing modes were evaluated to determine

**TABLE 2 AVERAGE RDF COMPOSITION (AS RECEIVED)**

Proximate Composition		Ultimate Composition		St. Dev.
Moisture	37.79%	Carbon	23.48%	3.40%
Volatile Matter	38.04%	Hydrogen	3.17%	0.56%
Fixed Carbon	7.30%	Nitrogen	0.64%	0.14%
Ash	16.87%	Sulfur	0.21%	0.14%
		Oxygen	17.84%	2.54%
		Chlorine	0.21%	0.05%
		Fluorine	43 ppm (dry)	13 ppm
		Moisture	37.79%	6.32%
		Ash	16.87%	3.88%
		HRV	9340 kJ/kg	1370 kJ/kg

tion and feedrate (due to plugging of feed-chutes) resulted in significant variations in steam output from each unit.

**Cold Boiler Start-up**

Cold start-up with the natural gas burners was carried out successfully. The time required to bring the unit on line with natural gas was approximately the same as that for coal start-up. Start-up was controlled according to the rate of drum pressure increase recommended by the boiler manufacturer. The results are compared in Table 3.

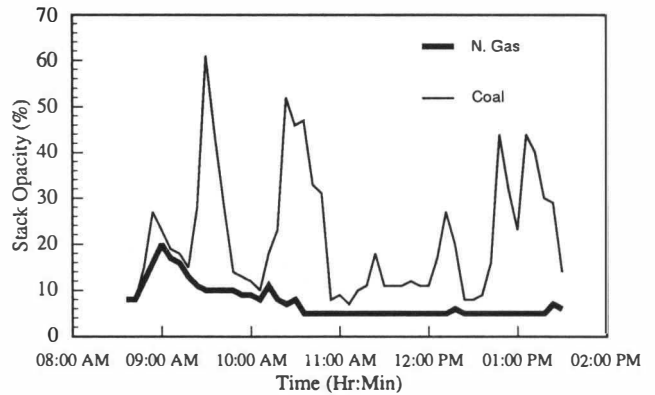
Natural gas start-up resulted in significant reductions in particulate matter emissions over coal start-up as indicated by opacity monitors. During gas start-up the stack opacity averaged 8% with a maximum of 20% at the beginning of the period, due to dust already in the boiler/ESP. Coal start-up resulted in an average stack opacity of 22% and a maximum of 61%. During gas start-up, the stack flue gas was clear, while during coal start-up emissions were laden with particulate matter (black). Figure 3 shows the stack opacity as a function of time, during gas and coal start-up. Natural gas start-up also resulted in significant reductions in emissions of CO, NO<sub>x</sub>, and SO<sub>2</sub> during those periods.

**CO Emissions**

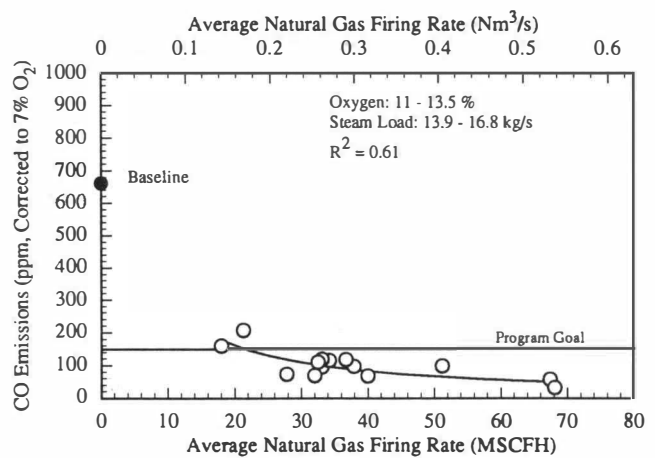
During normal baseline operation, CO emissions above 1500 ppm are recorded daily, with measured baseline CO emissions in the 530 to 1,950 ppm range. Natural gas cofiring reduced CO emissions below 50 ppm (at 7% O<sub>2</sub>) at gas firing rates of 0.47 to 0.63 Nm<sup>3</sup>/s. The goal of the program was to reduce CO emissions to 150 ppm. As shown in Figure 4, there is a dramatic reduction in CO emissions with the natural gas firing rate. Cofiring natural gas at more moderate rates of 0.31 to 0.47 Nm<sup>3</sup>/s resulted in CO emissions of less than 150 ppm, over a steam load range of 14.2 to 16.8 kg/sec. The CO emissions also showed a minor dependence on average steam load during baseline operation and while cofiring gas at lower rates of 0.14 to 0.31 Nm<sup>3</sup>/s. Operation at natural gas input above 0.31 Nm<sup>3</sup>/s indicated no dependence of CO emissions on steam load. No clear dependence on excess O<sub>2</sub> was observed for baseline and cofiring operations, indicating that elevated CO emissions are not due to insufficient oxygen in the furnace, but probably due to the gas

**TABLE 3 COLD BOILER START-UP WITH NATURAL GAS AND COAL**

Period	Total Fuel Used	Opacity, %		Stack Gas Clear	ppm (at 7% O <sub>2</sub> )		
		Avg.	Max.		CO	NO <sub>x</sub>	SO <sub>2</sub>
Gas 4.75 hr	5900 Nm <sup>3</sup>	8	20		220	72	0
Coal 4.83 hr	8.2 Tonne	22	61		1,110	329	625



**FIG. 3 STACK OPACITY DURING COAL AND GAS START-UP**

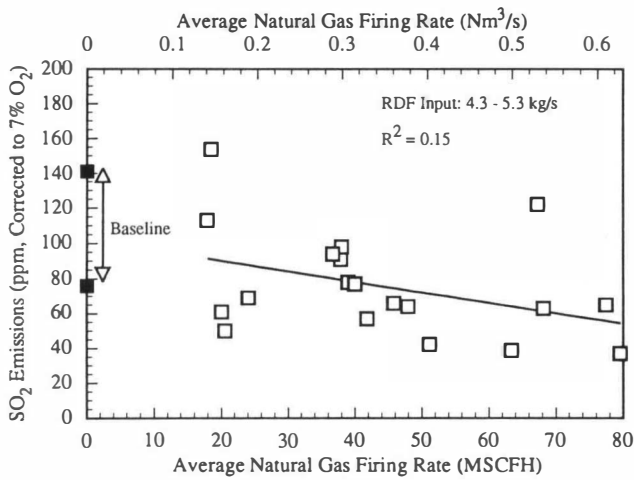


**FIG. 4. CO EMISSIONS AS A FUNCTION OF GAS INPUT**

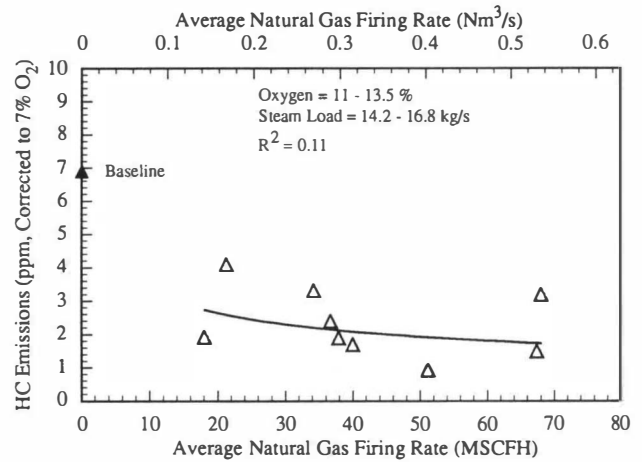
temperature in the lower furnace below the level required for CO burnout.

**SO<sub>2</sub> Emissions**

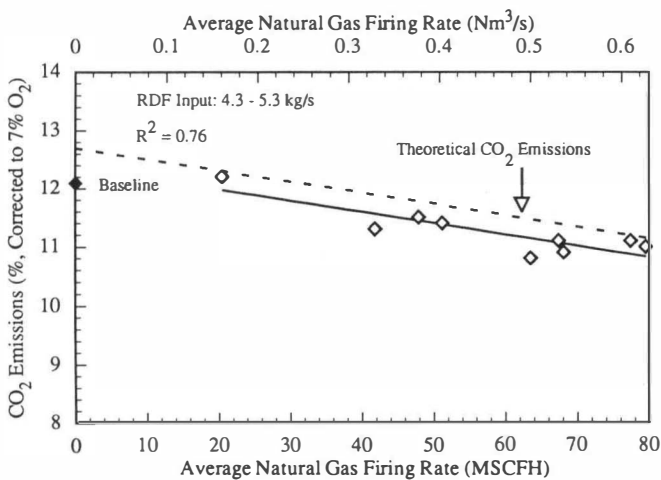
Since RDF has a low sulfur content (an average of 0.21% for RDF samples analyzed for this field test), the SO<sub>2</sub> emissions during baseline operation were relatively low. The baseline SO<sub>2</sub> emissions range from 76 to 143 ppm (at 7% O<sub>2</sub>). Natural gas cofiring resulted in some reduction in SO<sub>2</sub> emissions, to a minimum of 37 ppm at the maximum gas input of 0.625 Nm<sup>3</sup>/s. The SO<sub>2</sub> emissions



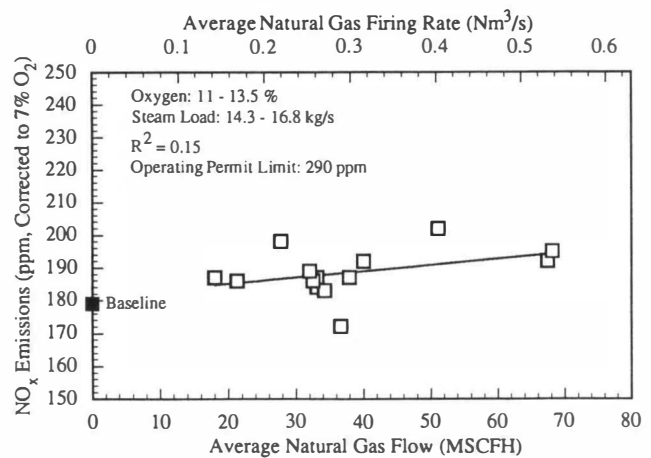
**FIG. 5. SO<sub>2</sub> EMISSIONS AS A FUNCTION OF GAS INPUT**



**FIG. 7. HYDROCARBON EMISSIONS AS A FUNCTION OF GAS INPUT**



**FIG. 6. CO<sub>2</sub> EMISSIONS AS A FUNCTION OF GAS INPUT**



**FIG. 8. NO<sub>x</sub> EMISSIONS AS A FUNCTION OF GAS INPUT**

are presented as a function of gas input is shown in Figure 5. The large variation in SO<sub>2</sub> emissions from test to test is due to variations in the RDF composition. The RDF sulfur content ranged from 0.09 to 0.83 percent with an average of 0.21 percent.

### CO<sub>2</sub> Emissions

Emissions of CO<sub>2</sub> were also reduced with natural gas cofiring. CO<sub>2</sub> emission is a function of the fuel carbon/hydrogen ratio. Based on the average RDF composition, the baseline CO<sub>2</sub> emissions rate is 92.1 g CO<sub>2</sub>/MJ, which may be compared to 49.5 g CO<sub>2</sub>/MJ from natural gas firing. Therefore, cofiring of these fuels, results in CO<sub>2</sub> emissions commensurate with percent of heat input from each fuel. Emissions of CO<sub>2</sub> as a function of natural gas flow are shown in Figure 6.

### Hydrocarbon (HC) Emissions

Natural gas cofiring also resulted in reductions in hydrocarbons (HC), as shown in Figure 7. Baseline HC emissions ranged from 4.3 to 24 ppm, while HC emissions for tests carried out with natural gas cofiring ranged from 0 to 7.8 ppm for gas input in the range of 0.16 to 0.31 Nm<sup>3</sup>/s. The tests conducted while cofiring 0.47 to 0.63 Nm<sup>3</sup>/s natural gas resulted in emissions in the 0.7 to 3.2 ppm range.

### NO<sub>x</sub> Emissions

Emissions of NO<sub>x</sub> were not significantly affected by gas cofiring. NO<sub>x</sub> emissions generally vary with oxygen level and unit load (due to higher gas temperatures). Small increases with oxygen and gas input were determined, but the emissions rate is still well within operating permit compliance limit. The NO<sub>x</sub> emissions are shown as a function of gas input in Figure 8.

## Polychlorinated dibenzo-p-dioxin and furan (PCDD/PCDF) Emissions

Formation of PCDD/PCDF is considered to take place primarily in the Electrostatic Precipitator (ESP) and is believed to be enhanced by low temperature combustion resulting in the flow of partially uncombusted particulate matter through the upper furnace to the ESP (Barton, 1989). Volatilized fuel PCDD/PCDF also contribute to total PCDD/PCDF emissions. Initially, one of the goals of the program was to control PCDD/PCDF emissions by burnout of volatilized PCDD/PCDF (and precursors to downstream formation) by installation of four 2.9 MJ/sec gas burners in the upper furnace. These burners were, however, not installed because of funding constraints. The cofiring system without these burners was not expected to significantly impact PCDD/PCDF emissions.

Emissions of PCDD/PCDF were measured at the stack during cofiring tests designed to comply with the requirements of the Permit to Install granted by the Ohio Environmental Protection Agency (EPA). Emissions of PCDD/PCDF were also measured during normal baseline (RDF) operation for comparison with cofiring results. These tests, carried out according to EPA Method 23, were taken at the stack while Unit 5 was not in operation, since flue gases from both Units 5 and 6 flow to the same stack. The conditions evaluated are shown in Table 4.

The measured PCDD/PCDF emissions, expressed in micrograms/MJ, and expressed as a percent of the highest measurement are:

Test ID	PCDD/PCDF	% of max
Cofiring 1	4.7	64
Cofiring 2	5.3	73
Cofiring 3	4.5	62
Baseline 1	7.4	100

Natural gas cofiring at Columbus Unit 6 has a modest impact on PCDD/PCDF emissions. Cofiring natural gas consisting of 14.6 to 18.7 percent of the heat input resulted in PCDD/PCDF reductions of 27 to 38 percent of the baseline emissions. The gas burner placement (just above the travelling grate) is too low to fully burn out volatilized PCDD/PCDF and precursors to PCDD/PCDF formation in the upper furnace or ESP. The burner placement was chosen based on steam load control and startup capability. While the fuel PCDD/PCDF content was not determined, the reductions are believed to be due more to burnout of precursors to PCDD/PCDF formation in the upper furnace, convective passes, or ESP than to dilution due to fuel switching.

PCDD/PCDF emissions from municipal waste incinerators have been correlated with CO emissions (U.S. EPA report by Midwest Research Institute, 1987). Relatively low PCDD/PCDF emissions have been measured from

**TABLE 4 TEST CONDITIONS FOR PCDD/PCDF MEASUREMENTS**

Run #	Steam Load (kg/s)	Gas Flow (Nm <sup>3</sup> /s)	Gas Heat (%)
Cofiring 1	16.5	0.26	18.7
Cofiring 2	16.6	0.26	18.7
Cofiring 3	16.8	0.22	14.6
Baseline 1	13.9	0	0

incinerators emitting low CO. A clear relationship between these species was not observed from the limited PCDD/PCDF emissions data obtained at the Columbus SWRF.

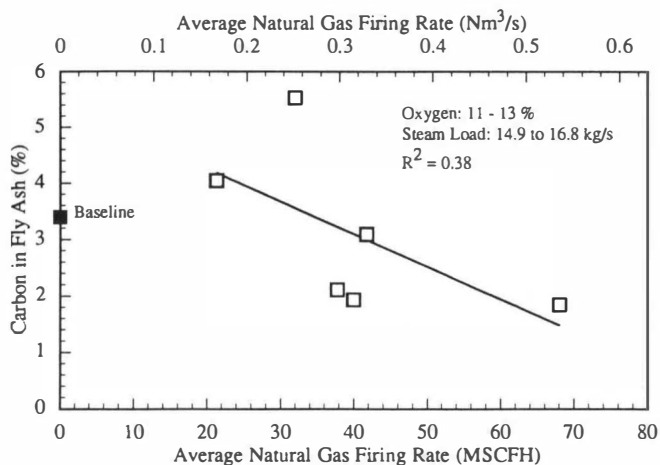
### Boiler Steam Load Fluctuations

The cofiring system was designed to cofire natural gas to reduce fluctuations in steam load. As required, the natural gas input fluctuated from a total of 2.35 to 23.5 MJ/sec. Steam load fluctuations are due to variations in RDF composition and feedrate. RDF feed blockages occur frequently. Steam load fluctuations were evaluated throughout the test period. During baseline testing with both dry and wet RDF, the standard deviation in steam load varied from 0.91 to 2.90 kg/sec corresponding to 6.0 to 24.7 percent of the average steam load. Reduced fluctuations were noted during baseline operation when the RDF input was relatively dry. Natural gas cofiring reduced fluctuations in steam load, with higher average levels of gas input resulting in the most steady steam generation. The steam load standard deviation during gas cofiring at rates above 0.31 Nm<sup>3</sup>/s ranged from 0.54 to 1.75 kg/sec, corresponding to 4.2 to 11.4 percent of the average. Gas firing effectively levels heat input during RDF feed interruptions improving the uniformity of steam/power generation.

### Boiler Gross Efficiency

Cofiring natural gas resulted in an increase in the boiler gross efficiency. The baseline RDF efficiency, calculated by the heat loss method averaged 63.1 percent. The relatively low efficiency is due to the high flue gas excess air levels (flue gas oxygen: 12–15%) and the high fuel moisture content (38% average). Cofiring natural gas resulted in an average efficiency of 68.1 percent. The largest change in efficiency was due to heat loss due to fuel moisture. The large moisture content in RDF resulted in an average moisture heat loss of 10.3 percent. This was reduced to an average of 7.4 percent while cofiring natural gas. The heat loss due to dry gas also decreased, from an RDF baseline of 15.1 percent to a natural gas cofiring level of 12.8 percent. Gas cofiring allowed operation at lower excess air levels, resulting in the reduction in dry gas heat loss. These efficiency improvements were accomplished from cofiring natural gas in the 0.14 to 0.31 Nm<sup>3</sup>/s range.





**FIG. 9. ASH COMBUSTIBLE MATTER AS A FUNCTION OF GAS INPUT**

### Combustibles in Refuse (Carbon in Ash)

Generally, carbon in ash was low for both cofiring and baseline operation. Ash samples were collected from three locations: the boiler bottom, boiler hopper, and the ESP. The combustible carbon content of samples obtained during baseline and gas cofiring, as measured by ASTM Method D3174, were comparable and relatively low. The boiler bottom samples generally had a carbon content less than 1.5%, while boiler hopper samples were generally less than 3% carbon, and ESP ash samples had less than 6% carbon. Figure 9 shows the results at the excess O<sub>2</sub> range of 11 to 13%, and steam loads of 14.9 to 16.8 kg/sec.

### ECONOMIC ASSESSMENT

An assessment of capital and operating costs indicates that the annual cost of the system, including the capital charge and operating costs, is \$240,000. The cofiring system may be installed for roughly \$1,000,000. Table 5 compares costs for normal baseline operation and gas cofiring, with the same input of RDF and a constant natural gas input of 0.14 Nm<sup>3</sup>/s, at the Columbus unit for 10 months/yr. This analysis uses a capital charge of 13 percent per year (which is based on an annual interest rate of 8% and a system life of 20 years), a natural gas cost of \$96 per 1000 m<sup>3</sup>, an electricity revenue of \$24/MW-hr and an RDF tipping fee of \$34.52/tonne (80% RDF yield from waste received). The baseline case considers an RDF input 4.34 kg/s resulting in a steam output of 12.4 kg/s, while the gas cofiring case considers an RDF input of 4.34 kg/s, a natural gas input of 0.14 Nm<sup>3</sup>/s, resulting in a steam load of 14.4 kg/s.

**TABLE 5 GAS COFIRING ANNUAL COST AT THE COLUMBUS PLANT**

	RDF Baseline	Gas Cofiring (10% Gas Heat)	Incremental Cost
Capital Charge	----	\$130,000	\$130,000
Natural Gas Cost	----	\$360,000	\$360,000
Electric Power	(\$1,550,000)	(\$1,800,000)	(\$250,000)
RDF Tipping Fee	(\$4,930,000)	(\$4,930,000)	----
total (\$/yr)	(\$6,480,000)	(\$6,240,000)	\$240,000

The unit generally operates under 75% of its capacity, therefore the natural gas may be input over the same RDF input level, resulting in collection of the same tipping fees.

### CONCLUSIONS

Natural gas cofiring with RDF results in significant improvements in emissions and boiler operation. CO emissions were reduced from the baseline case of 530 to 1950 ppm to less than 50 ppm, at gas inputs above 0.47 Nm<sup>3</sup>/s. Emissions of CO<sub>2</sub>, SO<sub>2</sub>, hydrocarbons, and PCDD/PCDF were also reduced. Start-up of the unit with gas showed vast improvement over coal startup. Gas start-up was steady with significant reductions in stack opacity and emissions of CO, NO<sub>x</sub>, and SO<sub>2</sub>. A reduction in fluctuations in steam load due to gas cofiring was evident. Refuse combustible matter was relatively low for both baseline and natural gas cofiring. Some reduction in the carbon content of ash due to gas cofiring was measured. These were accomplished with only a minor increase in upper furnace gas temperature.

### ACKNOWLEDGEMENTS

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