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DEVELOPMENT AND TESTING OF LOW-BTU FUEL GAS TURBINE COMBUSTORS

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7.2 Development and Testing of Low Btu Fuel Gas Turbine Combustors

CONTRACT INFORMATION

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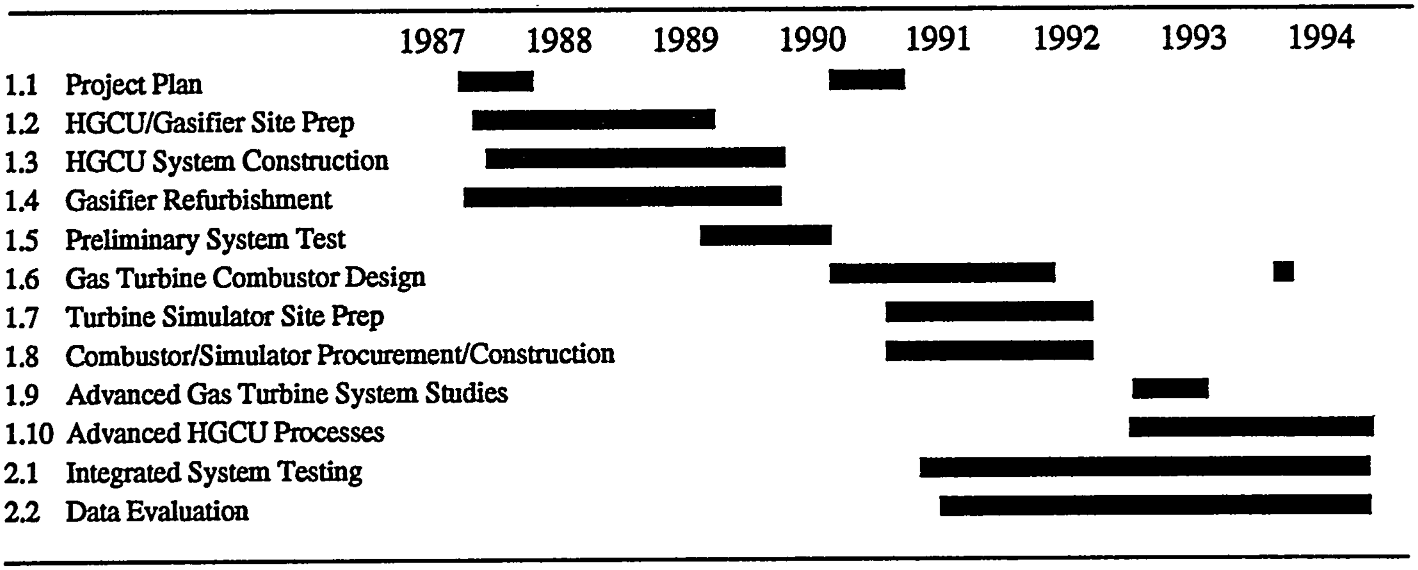
Period of Performance	September 30, 1987 to September 30, 1994

Schedule and Milestones

Program Schedule



OBJECTIVES

The integrated gasification combined cycle (IGCC) concept represents a highly efficient and environmentally compatible advanced coal fueled power generation technology. When IGCC is coupled with high temperature desulfurization, or hot gas cleanup (HGCU), the efficiency and cost advantage of IGCC is further improved with respect to systems based on conventional low temperature gas cleanup.

Commercialization of the IGCC/HGCU concept requires successful development of combustion systems for high temperature low Btu fuel in gas turbines. Toward this goal, a turbine combustion system simulator has been designed, constructed, and fired with high temperature low Btu fuel. Fuel is supplied by a pilot scale fixed bed gasifier and hot gas desulfurization system. The primary objectives of this project are: (1) demonstration of long term operability of the turbine simulator with high temperature low Btu fuel; (2) characterization of particulates and other contaminants in the fuel as well as deposits in the fuel nozzle, combustor, and first stage nozzle; and (3) measurement of NO_x, CO, unburned hydrocarbons, trace element, and particulate emissions.

In a related project, a reduced scale rich-quench-lean (RQL) gas turbine combustor has been designed, constructed, and fired with simulated low Btu fuel. The overall objective of this work is to develop an RQL combustor with lower conversion of fuel bound nitrogen (FBN) to NO_x than a conventional combustor.

BACKGROUND INFORMATION

Combustion of the high temperature (~1000°F) low Btu fuel produced from an IGCC/HGCU system is significantly different from the combustion of typical gas turbine fuels, such as natural gas and fuel oils. Differences in the air/fuel ratio, fuel composition, and fuel temperature affect many of the combustor operating parameters including the lean blowout limit, flame stability, and emissions. These differences require modification of the fuel nozzle and combustor liner. In addition, gas turbines used in IGCC/HGCU applications will require fuel control valves that are capable of operating with high temperature low Btu fuel. Other concerns include the possibility that particles and vapor phase contaminants in the fuel may form deposits on and/or cause the corrosion of the fuel nozzle, combustor liner, and turbine blades.

PROJECT DESCRIPTION

Turbine Simulator

Figure 1 shows the low Btu gas turbine simulator that has been constructed and integrated with the coal gasification/hot gas cleanup facility at GE Corporate Research and Development in Schenectady NY. The pilot scale gasification/hot gas cleanup system consists of a fixed bed gasifier, a sodium bicarbonate based halogen removal system, a moving bed high temperature desulfurization system, and a polishing cyclone. The turbine simulator is designed to operate at the full capacity of the gasifier, 8000 lb./hr of fuel gas from the gasification of 1800 lb./hr of coal. The low Btu fuel is supplied at a pressure of 20 atm and a nominal temperature of 1000°F. Details of the gasifier and the hot gas cleanup system can be found in Cook *et al.* [1,2].

The turbine simulator includes: a low Btu gas fuel nozzle; a modified GE MS6000 combustor liner; a film cooled, first stage LM6000 nozzle assembly, and an impingement cooled transition piece. A GE MS6000 combustor liner was chosen because its fuel requirements are close to the capacity of the gasifier/HGCU system. The liner was modified to meet the air requirements of low Btu fuel combustion, while the reverse flow sleeve is standard hardware. The fuel nozzle was designed specifically for low Btu gas combustion [3]. A film cooled LM6000 first stage nozzle was chosen to simulate the film cooled nozzles found in advanced gas turbines with high firing temperatures.

Design of the turbine simulator was initiated in April 1991. Fabrication and assembly were completed in August 1992. The current test plan includes seven fired tests with coal gas from the pilot scale gasifier/HGCU system, designated as Runs 3, 3A, 4, 5, 6, 7, and 8. This paper focuses on the results from Runs 5 and 6, which were completed in November 1993 and May 1994, respectively. The results from previous tests have been discussed by Cook *et al.* [4,5].

A recent addition to the turbine simulator is the optional ability to augment the low Btu fuel with natural gas. Because the fuel requirements of the turbine simulator slightly exceed the capacity of the gasifier/HGCU system, the heating value of the low Btu fuel must be enhanced with natural gas to reach sustained combustion exit temperatures in excess of 2100°F. The natural gas is added to the low Btu fuel far upstream of the combustor so that the blended fuel entering the turbine simulator is completely mixed. This capability was first exercised during selected time periods of Run 6. The blended fuel was less than 10% (by volume) added natural gas.

RQL Combustor

A new reduced scale RQL combustor design is nearly complete. Nominal design conditions are 0.75 lbs./sec total flow and combustor exit temperatures up to 2500°F. The RQL combustor has a modular construction, which allows for

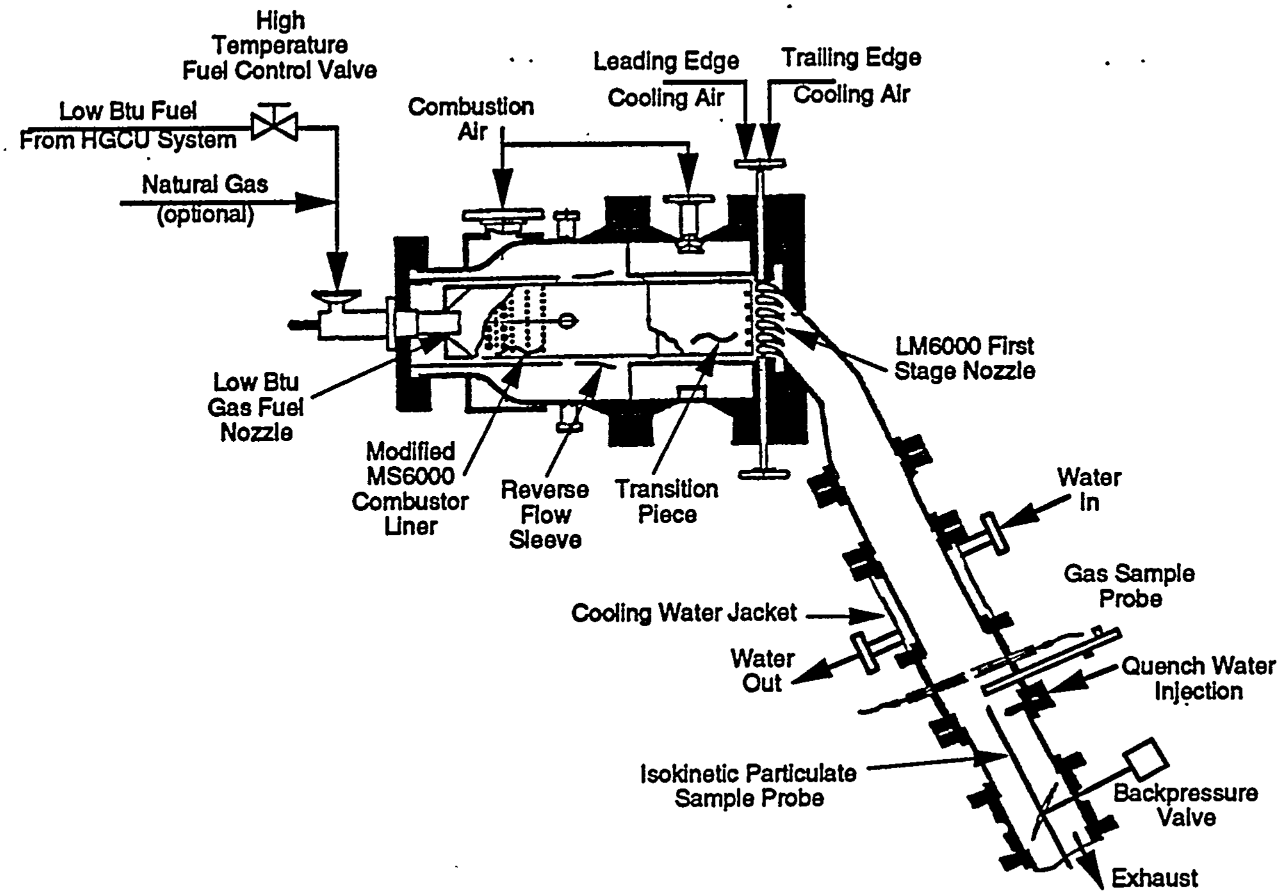


Figure 1. The Turbine Simulator Test Stand

rapid evaluation of different hardware configurations. The rich and lean stages are separate components, and the air flow to each stage can be independently varied.

Insights gathered from previous reduced scale RQL combustion tests [5], cold flow visualization tests, and computational fluid dynamics (CFD) studies have been incorporated into the new design. The new design includes a converging rich stage to separate the fuel rich and fuel lean combustion zones, and a backward facing step at the inlet to the lean stage for flame stabilization. The converging cone has been added to the tail end of the rich stage to close the rich stage recirculation zone. The reduction in diameter also accelerates the flow and helps prevent upstream flow of quench air into the rich stage.

RESULTS

The turbine simulator was fired with coal gas for 41 hours during Run 5 and 67 hours during Run 6, for a total of 179 hours of fired operation over 5 tests. The gasifier was fueled with Illinois #6 coal for both Runs 5 and 6. A typical fuel composition (after H_2S removal) is given in Table 1. During Run 5, the turbine simulator was operated at a combustor exit temperature of 2300°F for the first time. In addition, the low Btu fuel and burned gas were sampled for trace elements in both the solid phase and the vapor phase. Radian Corporation assembled and operated the trace element sample trains, and also performed all trace element sample analyses. Deposits were collected from several locations within the turbine simulator at the conclusion of Run 5 and were also analyzed for trace elements.

The turbine simulator reached a combustor exit temperature of 2500°F, representative of GE "F" class gas turbines, for the first time during Run 6. An on-line atomic emission spectrometer, developed at Ames Laboratory, was also used to measure vapor phase alkali species concentrations in the hot low Btu fuel.

Wall Temperatures

Except for the head end of the combustor, metal wall temperatures throughout the turbine simulator (including the transition piece and film-cooled cascade) have been within design specifications for all of the long duration tests. However, metal wall temperatures at the head end of the combustor frequently have exceeded design limits. As a result, sections of the cap/cowl were damaged during three of the first four long duration tests. An improper fuel/air ratio at the head end of the combustor was probably the largest single factor which contributed to the high wall temperatures.

After Run 5, during which the cap/cowl was again damaged by high metal wall temperatures, several modifications were made to the fuel nozzle and combustor liner. First, a small step between the fuel nozzle assembly and the cap/cowl was eliminated by bringing the fuel nozzle forward. Second, the swirl angle on the fuel side of the fuel nozzle was reduced from 40 degrees to 15 degrees. Finally, the first two rows of mixing holes in the combustor liner were

Table 1. Typical Pilot Plant Low Btu Fuel Composition

Species	Mole Percent
CO	8.6
H_2	17.3
CH_4	2.7
N_2	30.1
CO_2	12.6
H_2O	28.0
Ar	0.3
NH_3	0.4
TOTAL	100.0

closed to increase the fuel/air ratio at the head end of the combustor. These changes were designed to reduce recirculation of hot burned gas towards the cap/cowl and to move the combustion zone downstream, away from the cap/cowl.

The effectiveness of these hardware changes was demonstrated during Run 6. Cap/cowl temperatures never exceeded 1000°F, even at combustor exit temperatures as high as 2500°F. The hardware modifications also resulted in significantly lower combustor liner temperatures.

Emissions

The fuel nozzle and combustor liner modifications had little effect on NO_x emissions (see Figure 2). The slightly higher NO_x emissions seen in Run 6 can be attributed to a slightly higher NH_3 content in the fuel. The average NH_3 concentration in the low Btu fuel was 4100 ppmv during Run 5, while the average NH_3 concentration was 4400 ppmv during Run 6. The emissions measurements shown in Figure 2 (and all of the emissions measurements reported in this paper) were taken when the turbine simulator was fueled solely with low Btu gas.

Figure 2 shows NO_x emissions tend to decrease as the combustor exit temperature increases. At 2300°F, NO_x emissions averaged 180 ppmv (on a dry, 15% O_2 basis) during Run 5, representing a conversion of NH_3 to NO_x of about 20%. At a combustor exit temperature of 1600°F, NO_x emissions averaged 300 ppmv (on a dry, 15% O_2 basis) during Run 6, representing a conversion of NH_3 to NO_x of about 30%. The decrease in NO_x as exit temperature increases is primarily due to the increasing equivalence ratio at the head end of the combustor.

The combustor liner and fuel nozzle modifications made to decrease cap/cowl temperatures were expected to cause an increase in CO emissions. Figure 3 shows the increase was relatively small. CO emissions were below the detection limit of about 1 ppmv (on a dry, 15% O_2 basis) at combustor exit temperatures above 2100°F. CO emissions increased as the combustor exit temperature decreased, and CO emissions increased more rapidly with the modified hardware. UHC emissions also increased as the combustor exit temperature decreased (see Figure 4).

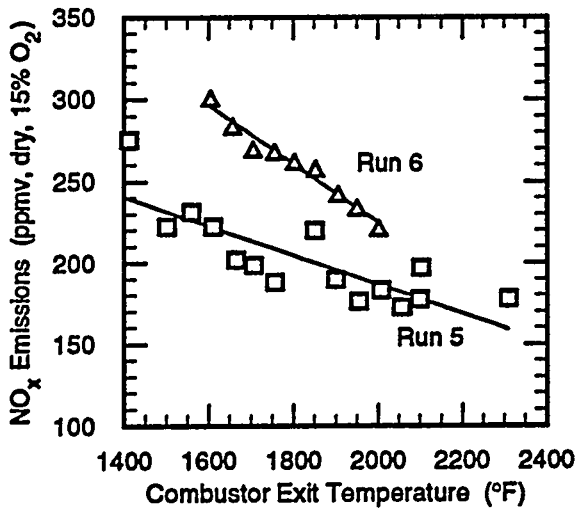


Figure 2. Turbine Simulator NO_x Emissions

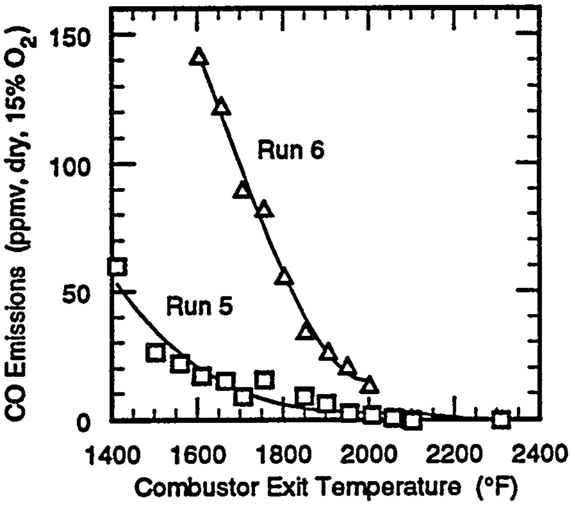


Figure 3. Turbine Simulator CO Emissions

Fuel Alkali Levels

During Run 6, vapor phase alkali concentrations were measured with the Ames Alkali Monitor, an on-line atomic emission spectrometer developed by Ames Laboratory [6]. Low Btu fuel was sampled isokinetically just upstream of the turbine simulator and then filtered before being sent to the alkali monitor. Although the low Btu fuel exited the HGCU system at about 1000°F, the fuel cooled to about 860°F at the alkali sample location. The sample line and filter were maintained at a temperature of about 950°F.

The results of the vapor-phase alkali measurements are shown in Table 2. The alkali monitor was unable to observe any vapor phase potassium above the detection limit of about 1 ppb by weight as K. Vapor phase sodium concentrations averaged about 3 ppb, with a maximum of approximately 5 ppb by weight as Na.

Also shown in Table 2 are chemical equilibrium calculations of expected vapor-phase alkali species concentrations at two coal gas temperatures. The calculations were performed with a modified version of CET89, the NASA chemical equilibrium code [7]. The coal gas composition listed in Table 1 was used for the calculations, with the addition of 200 ppmv HCl, 2500 ppmv H_2S, and sufficient amounts of sodium and potassium to insure the existence of condensed sodium and potassium species in the equilibrium mix.

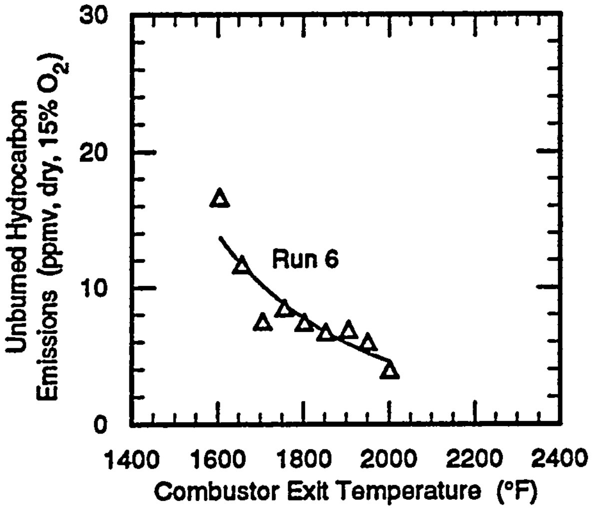


Figure 4. Turbine Simulator UHC Emissions

The two principal sources of thermodynamic data were the JANAF tables [8] and the extensive compilation of Barin [9]. Approximately 60 solid, liquid, and vapor sodium and potassium species were considered. Only the most abundant alkali species are listed in Table 2; all other alkali species were present in the vapor phase at concentrations below 0.01 ppb by weight as Na or K. Solid carbon (coke) was deliberately excluded from the equilibrium composition, based on kinetic constraints. Sodium and potassium silicates and aluminates were also excluded for similar reasons.

Table 2 shows the measured total vapor phase sodium concentration is within the range of the equilibrium calculations, assuming a coal gas temperature of between 850°F and 1000°F. Alkali species concentrations were calculated at two temperatures because of the uncertainty in the fuel temperature. As the low Btu gas in the main fuel line cooled from 1000°F to 860°F, some of the vapor phase alkali may have condensed on the surface of entrained particles. This condensed material may have been partially (or fully) volatilized when the sample gas was heated in the sample line and/or when the particles came to rest on the heated particulate filter.

At these temperatures, both the measured and calculated vapor phase alkali levels are well within gas turbine limits (20 ppb by weight total alkali in the products of combustion). The bulk of the sodium is expected to exist in the solid phase as sodium carbonate (Na_2CO_3) and sodium chloride (NaCl), and the bulk of the potassium is predicted to exist in the solid phase as potassium chloride (KCl). The predicted vapor phase potassium concentrations shown in Table 2 are slightly higher than previously reported [5] because of refinements to the thermodynamic database and computational procedures.

The chemical equilibrium calculations were performed assuming a large excess of solid sodium and potassium compounds in the equilibrium mix. This is a good assumption for sodium, because sodium bicarbonate is injected into the low Btu fuel upstream of the HGCU system. However, this is a very conservative assumption for potassium. For this reason, the calculated equilibrium vapor phase concentration of sodium is in better agreement with the measurements than the calculated equilibrium vapor phase concentration of potassium.

Trace Elements

The turbine simulator burned gas was sampled isokinetically for vapor phase trace elements during Run 5. The burned gas was diluted 1:1 with nitrogen and then cooled to approximately 250°F before being filtered according to EPA Method 5. A portion of the sample gas was then passed through the impinger train specified in EPA Method 29. Three vapor phase trace element samples were collected using this technique. Two blank samples, collected during a period when low Btu fuel was not available, were obtained by establishing normal air flows through the simulator and sampling according to the above procedure.

Table 3 shows the average concentration of each element detected in the vapor phase burned gas samples. Element concentrations were determined by GFAAS (Graphite Furnace Atomic Absorption Spectrophotometry), ICPES (Inductively Coupled Plasma Emission Spectroscopy), or CVAAS (Cold Vapor Atomic Absorption Spectrophotometry). Ten other elements (aluminum, antimony, beryllium, cobalt, copper, magnesium, molybdenum, phosphorus, potas-

Table 2. Comparison of Measured and Equilibrium-Modeled Vapor Phase Alkali Concentrations in Low Btu Fuel

	Gas Phase Concentration (ppb by weight as Na or K)		
	Equilibrium Model Calculations		Measurements
Gas Phase Species	*T* = 850°F	*T* = 1000°F	*T* = 860°F
Na	<0.01	<0.01	
NaCl	0.1	4.3	
NaOH	<0.01	<0.01	
$(NaCl)_2$	0.03	1.9	
Total Na	0.13	6.2	3
K	<0.01	<0.01	
KCl	0.5	19.6	
KOH	<0.01	0.01	
$(KCl)_2$	0.1	7.6	
Total K	0.6	27.2	<1

sium, and vanadium) were below the detection limit in all the burned gas samples.

The presence of relatively volatile elements (such as arsenic, mercury, and selenium) in the vapor phase samples is not surprising. Even at an exhaust gas temperature as low as 250°F, these elements might be expected to remain in the vapor phase. The detection of relatively non-volatile elements (such as iron and and manganese) suggests the vapor phase samples were contaminated with a small amount of particulate matter. In particular, the concentration of sodium in the vapor phase samples is greater than expected, based on the measured amount of condensed-phase and vapor-phase sodium in the fuel. The relatively large amount of sodium in the blank samples indicates the blank samples were also contaminated with some sodium containing condensed matter.

RQL Combustor

Figure 5 shows the velocity vectors calculated by a two-dimensional CFD analysis of the new RQL combustor rich stage. The strong swirl generated by the fuel nozzle creates a central recirculation zone and a corner recirculation zone at the head end of the rich stage. There is also another weak recirculation zone, near the wall of the converging section, which extends most of the length of the rich stage. Without a converging section the rich stage recirculation zone would extend to the point of quench air injection, and quench air would be drawn into the rich stage.

Table 3. Vapor Phase Emissions of Trace Elements

	Concentration in Turbine Simulator Exhaust (μg/Nm^3)	
Element	Burned Gas	Blank Sample
Arsenic	16	BDL
Barium	6.0	1.4
Cadmium	0.4	BDL
Calcium	70	44
Chromium	40	2.0
Iron	1440	13
Lead	3.2	1.1
Manganese	280	24
Mercury	4.0	0.6
Nickel	52	7.9
Selenium	1.2	0.8
Sodium	120	61
Titanium	2.0	BDL
Zinc	32	6.6

BDL = below detection limit

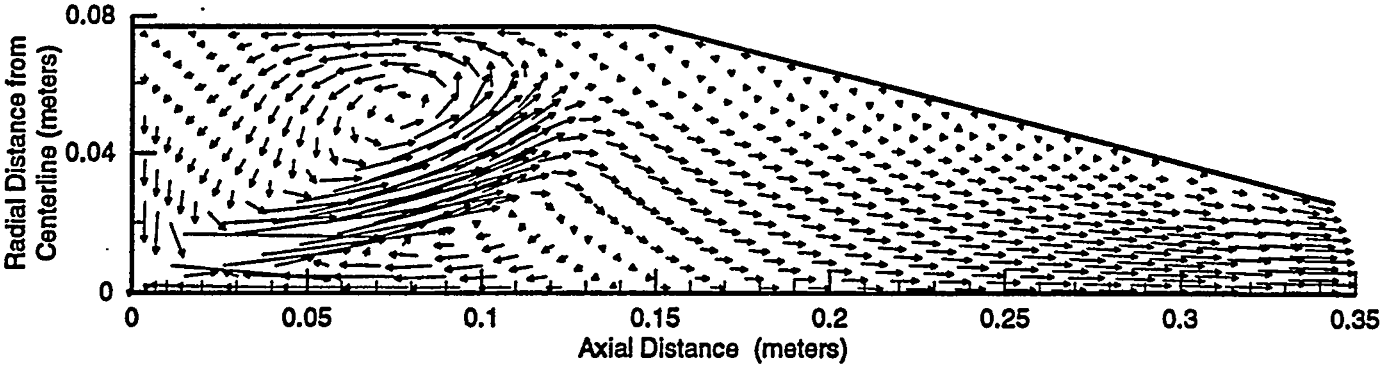


Figure 5. Computed Velocity Vectors in Rich Stage of RQL Combustor

FUTURE WORK

One additional long duration test of the turbine simulator is scheduled for 1994. A new low Btu fuel nozzle design, incorporating a radial air swirler, will be used in this test. The cap/cowl will have to be modified to accept the new fuel nozzle, since the new nozzle has a significantly smaller overall diameter than the current nozzle. Fuel nozzle performance will be evaluated by measuring NO_x, CO, and UHC emissions, as well as combustor liner and cap/cowl temperatures. After the test, the nozzle will be examined for deposits and signs of erosion.

Design of the new reduced scale RQL combustor is nearly complete. Initial tests will be conducted using natural gas/nitrogen/ammonia blends for fuel. A reduced scale RQL combustion test with a slip stream of low Btu fuel from the pilot plant gasifier/HGCU system is also scheduled for 1994. The information gathered from these tests will be used to design a larger scale (turbine simulator scale) RQL combustor.

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