DOE/NASA/2818-1
NASA CR-167842
SRD-82-023

Evaluation of Catalytic Combustion of Actual Coal-Derived Gas

(NASA-CR-167842) EVALUATION OF CATALYTIC COMBUSTION OF ACTUAL COAL-DERIVED GAS Final Report (General Electric Co.) 54 p N83-13588
HC A04/MF A01 CSCL 21B Unclas
G3/44 02056

John C. Blanton and Roger A. Shisler
General Electric Company

February 1982

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract NAS3-22818

for
U.S. DEPARTMENT OF ENERGY
Fossil Energy
Office of Coal Utilization and Extraction

DOE/NASA/2818-1
NASA CR-167842
SRD-82-023

Evaluation of Catalytic Combustion of Actual Coal-Derived Gas

John C. Blanton and Roger A. Shisler
General Electric Company
Corporate Research and Development
Schenectady, New York 12301

February 1982

Prepared for
National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135
Under Contract NAS3-22818

for
U.S. DEPARTMENT OF ENERGY
Fossil Energy
Office of Coal Utilization and Extraction
Washington, D.C. 20545
Under Interagency Agreement DE-AI01-77ET10350

TABLE OF CONTENTS

Section **Page**

PRECEDING PAGE BLANK NOT FILMED

SUMMARY

The objective of the program described in this report was to explore the combustion characteristics of a NASA-provided Pt-Pd catalytic reactor while burning low-Btu gas produced in a representative coal conversion facility. Of interest were the operating characteristics of the combustor as well as the performance in terms of measured emissions and combustion efficiency. The experiments involved operation of the combustor through a large matrix of test conditions. The parameters controlled during the test were air/fuel inlet temperature and velocity, reactor pressure, and reactor exit temperatures. The data recorded included (in addition to the above parameters) the fuel gas composition, various gas and reactor temperatures, and the exhaust gas composition.

Two reactors were used in the course of the program. The first was used for system checkout and experienced 24 thermal cycles and 19.7 hours of fired operation. The second reactor was used in the parametric testing and experienced 17 thermal cycles and 29 hours of operation.

The ranges of parameter variations in the testing were as follows: 1) inlet temperatures, 500 to 700 K; 2) inlet velocities, 10 to 30 m/s; 3) reactor pressure, 0.5 to 1.5 MPa; 4) exit temperatures, 1300 to 1450 K.

Operating experience with the catalytic combustor was in general quite satisfactory. Ignition and operating stability were not a problem. The major difficulty encountered was that the reactor was relatively intolerant of condensed liquids in the fuel gas.

Combustion efficiencies were quite high (greater than 95 percent) over most of the range of operation, being effected most strongly by inlet gas velocity. Higher efficiencies were obtained at reduced velocity. The magnitude of NO_x emissions was very high over the entire operational range, in some cases exceeding 500 ppmV (wet). This was due to the high concentration of ammonia (NH_3) in the fuel gas, estimated at 3500 ppmV (dry). Ammonia conversion to NO_x was estimated to be approximately 20 to 50 percent, and to increase with increasing inlet temperature.

PRECEDING PAGE BLANK NOT FILMED

1. EXECUTIVE SUMMARY

1.1 INTRODUCTION

The reduced availability and increased cost for high-grade fuels have resulted in a desire to switch power generation capacity to low-grade fuels. This change is being attempted in an environment that stresses increased fuel efficiency and reduced effluent intrusion. Coal and/or coal-derived fuels (CDF) are receiving special attention as the fuels of the future and gas turbine energy conversion systems are being evaluated for this application due to their potential for high efficiency.

If low-grade fuels are to be employed in gas turbines, special care must be given to gaseous emissions. Sulfur compounds in the prime fuel must be removed prior to combustion in order to meet proposed SO_x limits. NO_x limits can, however, be adhered to by removal of nitrogen compounds from the fuel and/or by special design of the combustion system. The use of catalytic material has been proposed as a viable approach for new combustion design to meet NO_x standards.

The coal processing technique which is receiving most favorable commercial attention for the power generation appreciation is coal gasification with gas cleanup prior to combustion in a gas turbine. This fuel plant concept is being proposed for several commercial ventures. Any new combustion concept designed for CDF must be able to utilize the produced fuel from these coal conversion systems in a reliable and efficient manner.

The objective of the present investigation was to explore the combustion characteristics of a NASA-provided catalytic reactor while burning low-Btu gas produced in a representative coal conversion facility. Of interest were the operating characteristics of the combustor as well as the performance in terms of measured emissions and combustion efficiency.

1.2 FACILITIES

A coal gasification/gas cleanup/power generation facility has been constructed and is operational at the General Electric Corporate Research and Development site. This fuel plant can handle 24 tons per day of coal and convert it to a producer gas for gas turbine hot gas parts evaluation tests. This Process Evaluation Facility (PEF)-sized fuel plant simulates all the critical operations of a full-scale Integrated Gasification Gas Turbine Combined Cycle (IGCC) System. The coal gas supplied to the gas turbine simulators from this fuel plant is representative of the actual gas from a full-scale IGCC system.

In the present program, low-Btu gas from the PEF facility was utilized in a 12 cm diameter by 15 cm long catalytic reactor, supplied to General Electric by the NASA-Lewis Research Center. This reactor was constructed of cordierite monolithic elements with platinum and paladium as the catalyst.

The various support systems at the GE site used in the program included two 800 hp air compressors, an indirect gas-fired air preheater, and a computer-based data acquisition and test control system.

1.3 LOW-BTU GAS TESTS

Two sets of test groups were planned in the present program. The first set was to be a checkout test of the combined facilities, and was to involve the use of a relatively dry (~9% water) fuel gas. The second test was to include a large matrix of test points, with parametric variations in reactor inlet temperature and pressure, reference velocity, and reactor exit temperature. The second matrix was to be performed using gas of ordinary (~21%) water content.

Two catalytic reactors were used in the program. The first was used for checkout testing and was subsequently destroyed during the initial stages of the second test. A second reactor was installed and used for all of the parametric testing. This reactor was also destroyed at the end of the testing program.

Data from the checkout testing was limited to 2 test points, each at a somewhat different condition than desired. Full gas analysis and emissions data were obtained. The first reactor experienced 24 thermal cycles and 19.7 hours of operation prior to its destruction.

In the second set of testing, 8 test groups were explored, and 26 test point variations were analyzed. The principal factors limiting the reactor operation were unstable behavior at low inlet velocities and high reactor bed temperatures. The second reactor was operated for 29 hours and experienced 17 thermal cycles.

1.4 PERFORMANCE RESULTS

The measured and calculated data from the low-Btu test matrix are summarized in Table 1. The four parametric variables defining the test matrix are listed first, followed by the various data acquired for that test point. The exhaust emissions shown have been corrected to a wet basis, using an exhaust water content determined from an oxygen balance of the overall reaction. The emissions indices also rely on the overall oxygen balance for determining the fuel/air ratio for the calculation. The combustion efficiency is determined assuming that a value of unity would be obtained for no measured combustibles in the exhaust products.

The trends observed in carbon monoxide (CO) and unburned hydrocarbon (UHC) emissions were as expected, i.e., decreasing with increased reaction temperatures. The oxides of nitrogen emissions appeared to track the fuel/air ratio (constant emission index), thus indicating a dependence principally on fuel-bound nitrogen. The NO_x yield fractions (from NH_3 in the fuel) were estimated to be approximately 0.2-0.5, with the lower values occurring at the higher reactor pressures. The yield appeared to increase with increasing reactor inlet temperature, but there was no dramatic effect of fuel/air ratio changes.

The absolute magnitude of the CO and UHC emissions were higher than anticipated by EPA standards, but are, by definition, acceptable since no EPA requirements exist. When expressed in terms of the emissions indices, the CO and UHC levels are relatively low owing to the high fuel/air ratios.

The combustion efficiencies were quite high, reaching in excess of 95 percent in all but one test group. Most of the groups had points with greater than 98 percent efficiency. One possible reason for the lower efficiencies in the one group is the high throughflow velocity (V_{ref} = 30 m/s).

There appeared to be little or no effect on combustor emissions due to reactor pressure variation.

The effect of reactor inlet temperature was primarily on the NO_x emission levels and yields, which increased with increasing temperature.

The NO_x emission levels were in general higher than those allowed by EPA standards. In this application compliance may be obtained only by at least partial removal of ammonia from the fuel.

Increases in reference velocity were seen to strongly increase the unreacted combustibles (CO, UHC) in the exhaust products, and hence reduce the combustion efficiency.

1.5 CONCLUSIONS AND RECOMMENDATIONS

The emissions of carbon monoxide (CO) and unburned hydrocarbons (UHC) were reasonable relative to the amount of fuel used. The normal trends of decreasing emissions with higher fuel/air ratios (and hence higher adiabatic reaction temperatures) were noted. This was consistent with the combustion efficiency trends, which revealed peak values in excess of 99 percent.

The nitrous oxide (NO_x) emission levels were somewhat higher than the maximum projected for power generation system emissions, and were due principally to the fuel-bound nitrogen (NH_3). In commercial fuel plant designs, ammonia reduction would be required to obtain compliance with projected emission specifications.

In addition to the data obtained and discussed above, significant operating experience was gained in the course of the program. Extensive and sophisticated computer software was generated, and a sensible test performance methodology developed.

ORIGINAL PAGE IS
OF POOR QUALITY

Table 1
TEST RESULTS

Group	I				II				IV			V			VII			VIII		X				XII		
Point Number	1	2	3	4	6	7	8	9	16	17	18	21	22	23	31	32	33	36	37	46	47	48	49	56	57	58
Mixed Inlet Temp K	502	501	498	496	506	504	504	502	593	587	582	594	592	592	613	589	606	591	588	606	602	598	596	687	685	682
Reactor Pres MPa	1.01	1.04	1.04	1.08	0.95	0.98	0.99	1.03	0.48	0.48	0.48	0.53	0.55	0.54	1.01	0.99	0.98	0.99	1.01	1.47	1.49	1.51	1.53	0.97	0.97	0.97
Ref Velocity m/s	10.6	10.4	10.4	9.99	19.3	19.2	19.1	18.8	20.3	19.9	19.6	31.6	31.2	21.1	20.4	21.0	21.6	30.4	30.1	20.2	19.9	19.7	19.5	21.4	21.2	21.2
Exit Temp K	1300	1341	1401	1458	1299	1344	1398	1450	1289	1334	1394	1300	1337	1392	1307	1348	1400	1325	1330	1293	1352	1393	1432	1293	1357	1405
Air Flow, kg/s	650	648	618	618	1.075	1.079	1.074	1.068	522	511	497	849	845	832	1.038	1.070	1.046	1.556	1.516	1.504	1.492	1.483	1.478	955	933	924
Air Temp K	531	531	533	531	539	540	540	540	644	642	640	659	661	661	671	645	671	645	646	661	658	657	656	756	761	763
Fuel Flow kg/s	141	145	174	176	263	286	297	334	093	100	103	202	217	216	209	235	241	332	360	316	329	356	367	169	181	193
Fuel Temp K	409	411	411	412	409	410	413	417	388	387	387	401	403	406	409	410	410	416	416	424	425	426	426	405	406	407
Reactor ΔP kPa	9.4	10.2	13.8	16.3	27.4	31.1	32.4	37.7	14.4	15.9	18.2	37.6	39.7	40.9	22.7	24.0	25.8	59.2	60.6	32.8	35.6	38.6	40.5	27.2	31.2	32.0
Fuel Inj ΔP kPa	24.9	25.0	27.2	28.3	50.6	53.5	57.5	62.4	35.6	35.5	36.1	79.9	79.8	77.4	41.9	42.1	44.2	82.9	86.9	69.0	68.3	68.2	70.5	63.2	63.4	63.3
Cat Temp #1, K	1470	1413	–	1435	–	–	–	–	1443	1484	1529	1516	1541	1571	1276	1311	1378	–	–	1407	1447	1477	1503	1247	1288	1367
Cat Temp #2, K	1283	1251	1422	1370	1346	1341	1382	1424	1307	1350	1383	1448	1472	1497	1195	1223	1292	1219	1214	1389	1432	1468	1495	1213	1257	1328
Cat Temp #3, K	1166	1132	1290	1313	1207	1216	1267	1308	1185	1215	1267	1286	1293	1321	1168	1228	1276	1197	1207	1235	1278	1313	1334	1136	1183	1242
Cat Temp #4, K	1112	1080	1234	1345	1131	1154	1211	1266	1147	1175	1248	1203	1206	1232	1116	1174	1223	1175	1186	1129	1176	1228	1257	1117	1162	1199
Cat Temp #5, K	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1168	1226	1265
Cat Temp #6, K	1211	1206	1391	1465	1207	1226	1286	1378	1182	1227	1327	1215	1230	1280	1245	1292	1376	1273	1288	1199	1269	1321	1365	1198	1283	1330
Fuel H_2 Fraction	1435	1471	1392	1382	1463	1399	1392	1395	1459	1465	1489	1359	1433	1439	1475	1450	1504	1466	1455	1464	1437	1416	1424	1468	1496	1429
Fuel CO Fraction	1395	1278	1268	1149	1438	1338	1356	1218	1304	1279	1369	1250	1173	1213	1312	1304	1346	1422	1248	1269	1323	1353	1331	1303	1383	1258
Fuel CH_4 Fraction	0272	0339	0246	0422	0281	0313	0238	0336	0350	0325	0324	0324	0274	0318	0286	0296	0302	0300	0318	0323	0314	0313	0324	0284	0266	0370
Fuel CO_2 Fraction	0514	0518	0552	0558	0466	0504	0508	0530	0546	0555	0536	0550	0535	0568	0556	0563	0548	0528	0557	0582	0580	0581	0594	0562	0540	0582
Fuel N_2 Fraction	3073	3042	3240	3186	3094	3175	3198	3225	3197	3222	3180	3179	3193	3171	3154	3159	3092	3070	3199	3089	3073	3086	3089	3217	3108	3170
Fuel H_2O Fraction	3310	3352	3303	3303	3259	1270	3307	3296	3145	3153	3102	3339	3392	3290	3216	3229	3206	3214	3222	3273	3273	3251	3239	3166	3206	3190
Fuel Mole Wt	21.5	21.3	21.8	21.6	21.4	21.5	21.7	21.6	21.6	21.6	21.6	21.7	21.5	21.6	21.6	21.6	21.5	21.5	21.6	21.5	21.6	21.6	21.6	21.6	21.5	21.7
Fuel LHV kJ/kg	3840	3950	3555	3975	4104	3800	3642	3800	3992	3894	4021	3753	3740	3941	3841	3834	3958	4008	3848	4044	4050	4062	4080	3793	3860	3973
Measured $(F/A)_1$	217	224	281	285	245	265	276	313	178	196	208	238	257	259	201	220	231	213	233	210	221	240	249	177	194	209
Adiab Temp $(T_F)_1$	1165	1201	1233	1321	1246	1268	1245	1340	1179	1203	1245	1273	1281	1320	1227	1243	1306	1259	1273	1252	1271	1309	1327	1234	1285	1329
O_2 Balance $(F/A)_2$	358	379	461	438	347	382	425	456	231	261	290	253	294	299	223	228	278	239	260	232	259	285	293	145	166	186
Adiab Temp $(T_F)_2$	1412	1472	1479	1555	1425	1457	1461	1542	1288	1325	1400	1296	1337	1382	1267	1256	1391	1306	1320	1292	1340	1386	1403	1162	1223	1281
C Balance $(F/A)_3$	266	284	363	367	256	288	325	375	211	237	264	226	255	268	226	–	283	230	267	197	226	257	268	130	164	185
Adiab Temp $(T_F)_3$	1245	1306	1355	1455	1236	1287	1309	1433	1210	1256	1345	1201	1233	1300	1251	–	1399	1275	1315	1188	1258	1323	1346	1106	1209	1278

ORIGINAL PAGE IS
OF POOR QUALITY

Table 1 (Cont'd)

TEST RESULTS

Group	I				II				IV			V		
Point Number	1	2	3	4	6	7	8	9	16	17	18	21	22	23
CO Emissions, ppmv	1973	1621	238	26	2726	2524	2128	476	2744	2504	1086	3016	2887	2722
UHC Emissions, ppmv	88	39	14	12	1258	407	24	7	2033	918	79	3177	2802	1619
NO_x Emissions, ppmv	385	376	534	497	394	394	405	485	331	390	389	386	390	406
O_2 Emissions, %V	5.55	5.77	6.74	7.09	5.26	5.75	6.19	7.01	4.55	5.03	5.88	4.48	4.[illegible]6	5.31
CO_2 Emissions, %V	8.22	7.27	6.41	5.67	8.29	7.52	7.08	5.81	.1.53	10.74	9.70	11.20	[illegible].21	9.78
EI_{CO} gm/kgfuel	7.48	6.04	.78	.09	10.59	9.17	7.14	1.53	14.58	12.07	4.94	15.02	12.81	11.89
EI_{UHC} gm/kgfuel	15	.08	02	.02	2.80	.85	05	.01	6.18	2.54	2.06	9.07	7.12	4.05
EI_{NO_x} gm/kgfuel	2.37	2.24	2.78	2.67	2.51	2.38	2.25	2.56	2.86	3.04	2.76	3.13	2.8[illegible]	2.89
Comb Efficiency	975	981	.997	.9996	946	.963	.976	.995	.904	941	.984	.870	.895	.929
NO_x Yield	0.30	0.32	0.46	0.43	0.29	0.29	0.32	0.41	0.33	0.36	0.37	0.35	0.43	0.37
No. Data Points	17	17	24	11	21	16	13	17	12	13	14	14	8	10
No Pts. with NO_x Data	6	10	18	7	10	6	8	9	7	6	6	8	7	5

Group	VII			VIII			X			XII		
Point Number	31	32	33	36	37	46	47	48	49	56	57	58
CO Emissions, ppmv	2655	2751	188	2127	2529	2779	2685	2182	1889	2567	1181	192
UHC Emissions, ppmv	272	14	2	112	282	1350	298	77	48	198	49	36
NO_x Emissions, ppmv	379	527	524	—	—	236	273	282	241	274	334	385
O_2 Emissions, %V	4.94	—	6.31	5.28	5.60	4.27	5.02	5.72	5.94	2.99	3.96	4.49
CO_2 Emissions, %V	12.04	11.90	10.13	11.35	10.85	11.61	10.82	1C.05	9.76	14.77	13.93	13.88
EI_{CO} gm/kgfuel	14.56	14.82	.87	11.00	12.30	14.79	13.01	9.90	8.39	20.16	8.22	1.22
EI_{UHC} gm/kgfuel	.87	.04	.005	.33	.56	4.12	.84	.20	.12	.90	.28	.14
EI_{NO_x} gm/kgfuel	3.52	4.69	3.90	—	—	2.05	2.13	2.10	1.88	3.57	3.68	4.04
Comb Efficiency	.947	.953	997	.964	.957	.922	955	.969	.974	929	.973	.986
NO_x Yield	0.34	—	0.47	0.19	0.23	0.20	0.20	0.20	0.18	0.43	0.45	0.51
No. Data Points	18	20	16	1	8	12	21	.18	8	17	18	19
No Pts. with NO_x Data	9	13	9	0	0	5	8	5	1	9	9	9

2. TASK DESCRIPTION

2.1 OBJECTIVE

The objective of this program was to explore the combustion characteristics of a NASA-provided catalytic reactor while burning low-Btu gas produced in an existing coal gasification/gas cleanup facility. Data was to be gathered over a matrix of system conditions to determine the range of acceptable operation for this combustion system. Specific information was to have been obtained to indicate combustor operating efficiency and exhaust product compositions; the temperatures and pressures of the combustion system were to be recorded as well as pressure drops across the fuel injector and catalyst bed.

2.2 TECHNICAL APPROACH

One of the advantages of catalytically supported combustion is the demonstrated ability to achieve very good combustion efficiency and thus low exhaust carbon monoxide (CO) and unburned hydrocarbon (UHC) concentrations. Due to premixed and uniform operating conditions, catalytic combustion also produces extremely low levels of thermal NO_x. These characteristics have been observed for operation on premixed liquid and laboratory mixtures of gaseous fuels.

The current interest in utilizing available coal resources as replacement for premium fuels has placed the emphasis on programs to study viable coal conversion and cleaning processes. In order to establish catalytic combustion as an appropriate combustion technique for these synthetic fuel products, experiments must be performed by using the actual fuels at conditions representative of those found in the end-use equipment.

The components of the experimental coal conversion Process Evaluation Facility (PEF) simulate the major subsystems of a full-scale fuel plant and power generation subsystem. Coal gasification is accomplished in a 24 tons per day, air-blown, advanced fixed bed gasifier with a design operating pressure of 22 atmospheres. A full flow, low-temperature, cleanup train removes uncracked hydrocarbons, particulates, and sulfur compounds from the product gas. Equipment is available to reheat and resaturate the cleaned gas by reinjecting the liquids that condense as the gas is cooled at the inlet of the cleanup system.

The cleaned gas is then directed to the combustion turbine simulation facilities. The turbine simulator component is designed to duplicate the pressure, temperature, and flow parameters found in current industrial gas turbine combustors. These simulators are routinely used to evaluate the deposition and corrosion characteristics of heavy and residual fuel oils for proposed commercial applications and have been employed previously for the investigation of low-Btu coal gas utilization.

The necessary modifications were made to the inlet and exhaust piping in one of the combustion test cells to accommodate the NASA-supplied catalytic combustion rig. A series of experiments were performed in which the catalytic combustor was supplied with actual low-Btu gas from the PEF fuel plant. The fuel plant operation would simulate the characteristics of an Integrated Gasification and Combined Cycle (IGCC) system operating in a utility application.

The data gathered would serve to characterize (1) the operating parameters of the combustor, (2) the inlet fuel gas composition, and (3) the combustor exhaust products.

3. FACILITY DESCRIPTION

3.1 PROCESS EVALUATION FACILITY

A coal gasification/gas cleanup/power generation simulation facility has been constructed and is operational at the General Electric Corporate Research and Development site. This fuel plant can handle 24 tons per day of coal and convert it to a producer gas for gas turbine hot gas parts evaluation tests. This Process Evaluation Facility (PEF)-sized fuel plant simulates all the critical operations of a full-scale Integrated Gasification Gas Turbine Combined Cycle (IGCC) System. The coal gas supplied to the gas turbine simulators from this fuel plant is representative of the actual gas from a full-scale IGCC system.

The various support systems at the GE site used in the program included two 800-hp air compressors, an indirect gas-fired air preheater, and a computer-based data acquisition and test control system.

A detailed description of the PEF and associated sampling and support systems may be found in Appendix A.

3.2 CATALYTIC COMBUSTOR FACILITY

The catalytic reactor used in the test program was supplied by the NASA-Lewis Research Center, and was similar to reactors used in previous investigations (1,2). Figure 1 shows a cross-section through the test section. It is constructed from a 15.2 cm (6 in.) inside diameter stainless steel pipe lined on the inside with Carborundum T30R Fiberfrax tube insulation and an inner Hastelloy-X sheet liner to give a test section diameter of 12 cm. The gaseous fuel was injected into the inlet airstream through a multiple conical tube fuel injector. Figure 2 shows the fuel inlet tube arrangement and the mixing/diffuser section is shown in Figure 3. This fuel injector was located approximately 2 section diameters upstream from the catalyst bed.

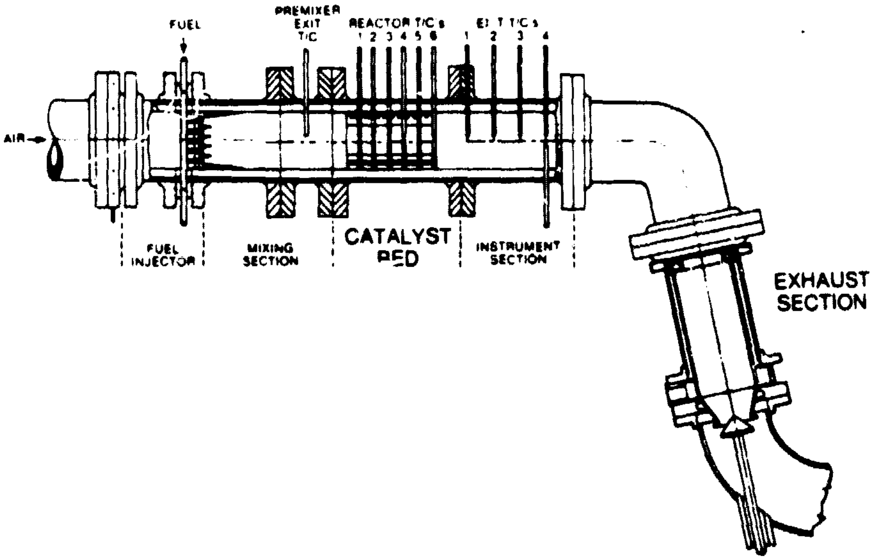


Figure 1. NASA Catalytic Reactor Cross Section

---

1 Anderson, D.N., "Effect of Inlet Temperature on the Performance of a Catalytic Reactor," NASA TM-78977, 1978.

2 T'ien, J.S. and Anderson, D.N., "Gas Phase Oxidation Downstream of a Catalytic Combustor," NASA TM-81551, 1979.

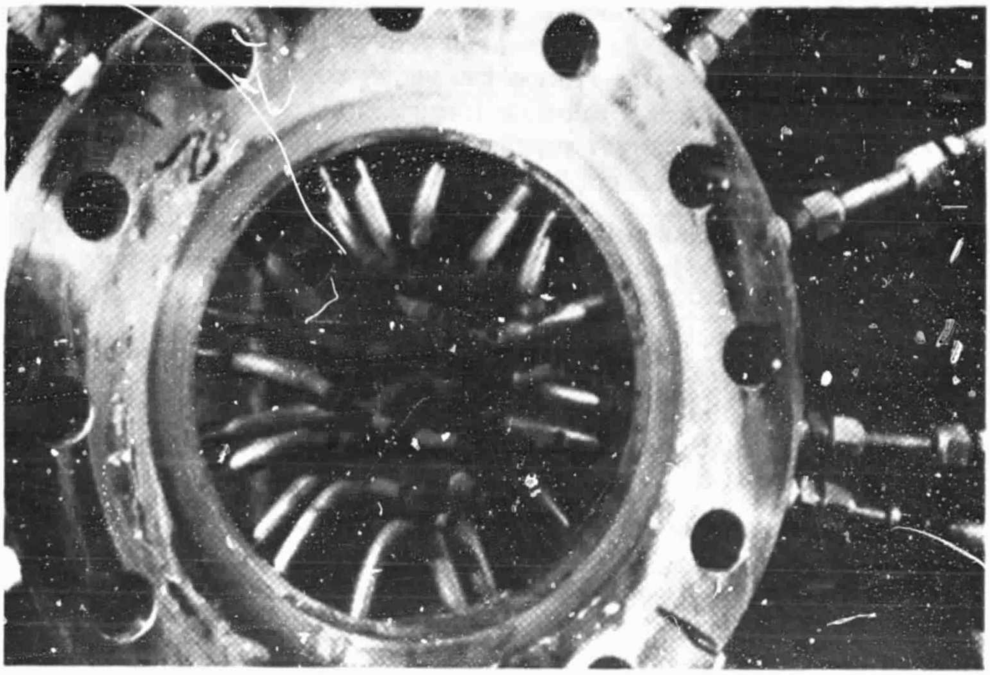


Figure 2. Fuel Gas Inlet Tube Assembly

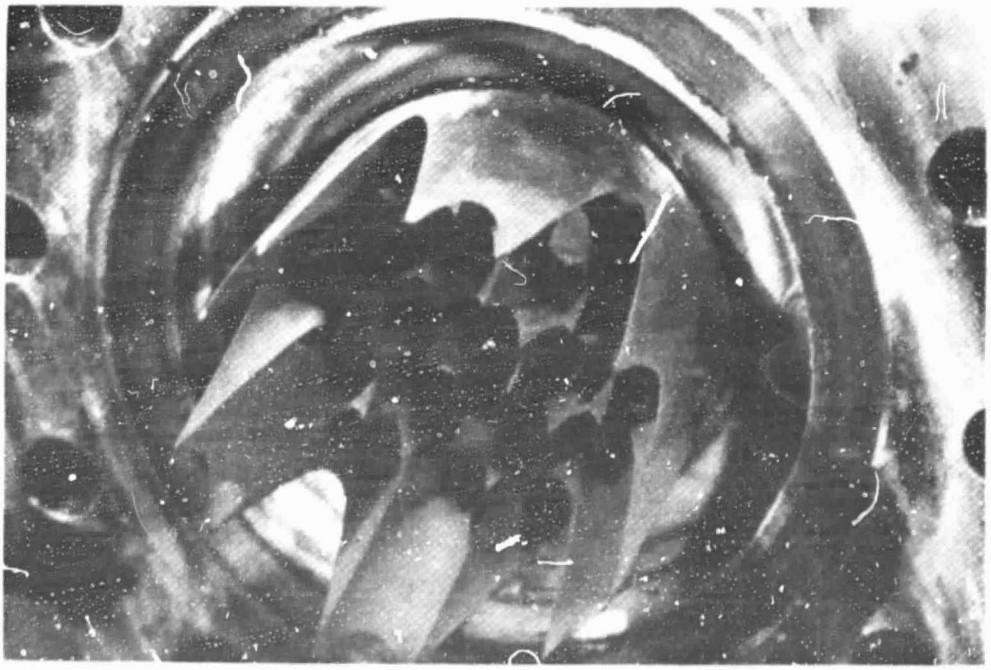


Figure 3. Fuel/Air Mixing and Diffuser Section

The catalytic reactor (see Table 2) consisted of six 12 cm diameter and 2.5 cm thick honeycomb monolithic catalyst elements arranged in series (see Figure 1).

Figure 4 shows a photograph of the test cell with the catalytic reactor installed. The large hexagonal tube assembly is the fuel supply manifold with radial inlet tubes to the injector flange. Air enters axially from the left through a 10.2 cm (4 in.) I.D. pipe. The water-cooled nozzle-and-pintel back pressure assembly is at lower right. Quench water is also injected at this location.

Table 2

DESCRIPTION OF CATALYST ELEMENTS

Element	Catalyst	Loading kg/m^3	Manufacturer
1	Platinum	5.3	Johnson Mattney
2	Platinum	5.3	Johnson Mattney
3	Platinum	5.3	Johnson Mattney
4	Platinum	3.6	Met-Pro, Inc.
5	2 Pd/1 Pt	3.6	Met-Pro, Inc.
6	2 Pd/1 Pt	3.6	Met-Pro, Inc.

(a) Catalyst Bed #1

Element	Catalyst	Loading kg/m^3	Manufacturer
1	2 Pd/1 Pt	1.8	Met-Pro, Inc.
2	2 Pd/1 Pt	1.8	Met-Pro, Inc.
3	2 Pd/1 Pt	1.8	Met-Pro, Inc.
4	2 Pd/1 Pt	3.6	Met-Pro, Inc.
5	2 Pd/1 Pt	3.6	Met-Pro, Inc.
6	2 Pd/1 Pt	3.6	Met-Pro, Inc.

(b) Catalyst Bed #2

Notes: 1) Numbered from inlet.
2) Substrate-Corning Cordierite, 46.5 cells/cm^2.
3) Open area 63%

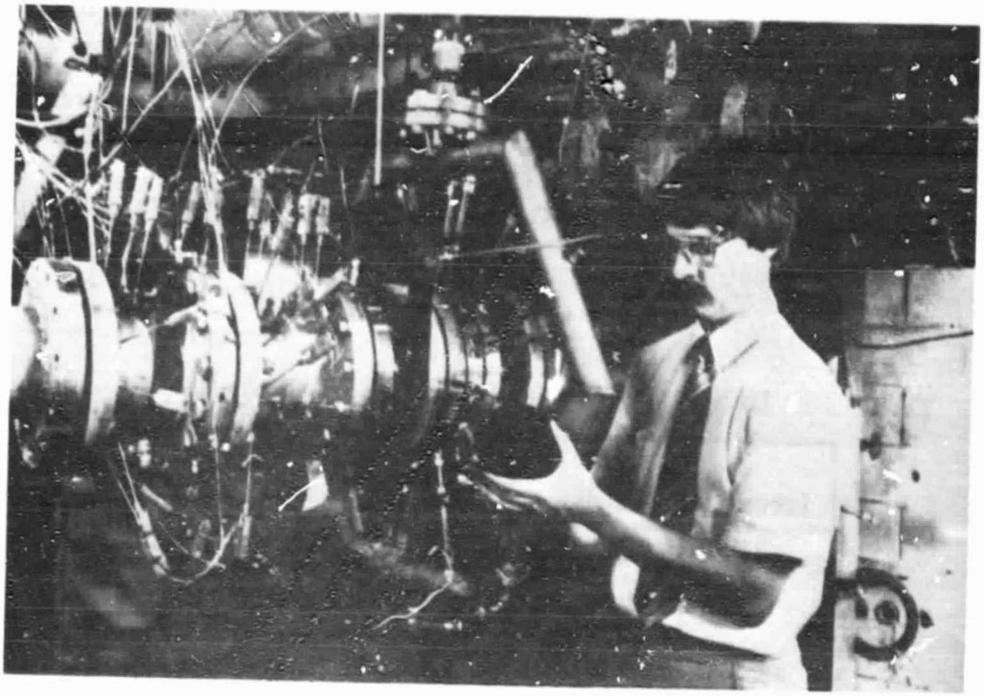


Figure 4. NASA Catalytic Reactor Test Cell

ORIGINAL PAGE IS OF POOR QUALITY

4. EXPERIMENTS

4.1 TEST PLANS

The test plan called for two groups of low-Btu coal gas tests. The first group would consist of two test sets each and would serve as a checkout of the facility operation. The fuel for this period would not be resaturated with condensed liquors at the cleanup exit, and would be relatively dry (~9% H_2O) and free of lighter hydrocarbons and ammonia. The conditions for this group of tests are listed in Table 3.

The second group of tests was to consist of a matrix of thirteen test groups, as shown in Table 4. During this period the PEF cleanup facility would be operated with reinjected condensates to achieve an overall balance of liquids entering and exiting the facility. The balance was to have produced a fuel gas with a molar fraction of H_2O of approximately 21%.

The minimum data acquisition and calculations requirements proposed for the low-Btu gas tests are listed in Tables 5 and 6. In addition to these, on-line instrumentation was used to monitor the fuel gas for quantities of the species listed in Table 7.

Table 3

CHECK-OUT TEST CONDITIONS

Inlet Temperature (K ±20)	Pressure (10^5 Pa ±0.1)	Reference Velocity (M/S ±2)	Ad. Flame Temperature (K ±25)
600	5	20	1300
600	5	20	1350
600	5	20	1400
600	5	20	1450
600	5	20	1500
600	10	20	1300
600	10	20	1350
600	10	20	1400
600	10	20	1450
600	10	20	1500

4.2 DATA ANALYSIS

The entire air and fuel gas supply and catalytic reactor systems were extensively instrumented to provide temperature, pressure, and flow data.

The air supply system was provided with the appropriate thermocouples and pressure transducers so that the temperature, pressure, and mass flow rate of air supplied to the reactor could be determined. The fuel supply line was similarly instrumented.

The catalytic reactor had 36 individual thermocouples installed for measurement of reactor bed temperatures and gas temperatures. Static pressure taps upstream and downstream of the reactor were also provided. A water-cooled gas sampling probe at the reactor exit was used to draw gas samples for emissions analysis.

The exhaust gas analysis was performed using a special mobile gas turbine emissions sampling unit. This unit contained appropriate instrumentation for obtaining and analyzing gas samples for concentrations of carbon monoxide, unburned hydrocarbons, oxides of nitrogen, free oxygen, and carbon dioxide. A detailed description of this system is given in Appendix B.

ORIGINAL PAGE IS
OF POOR QUALITY

Table 4

LOW-Btu GAS TEST 2 CONDITIONS

Inlet Temperature (K ± 20)	Pressure (10^5 Pa ± 0.1)	Reference Velocity (M/S ± 1)	Ad. Flame Temperature (K ± 25)
500	10	10	1300
500	10	10	1350
500	10	10	1400
500	10	10	1450
500	10	10	1500
500	10	20	1300
500	10	20	1350
500	10	20	1400
500	10	20	1450
500	10	20	1500
600	5	10	1300
600	5	10	1350
600	5	10	1400
600	5	10	1450
600	5	10	1500
600	5	20	1300
600	5	20	1350
600	5	20	1400
600	5	20	1450
600	5	20	1500
600	5	30	1300
600	5	30	1350
600	5	30	1400
600	5	30	1450
600	5	30	1500
600	10	10	1300
600	10	10	1350
600	10	10	1400
600	10	10	1450
600	10	10	1500
600	10	20	1300
600	10	20	1350
600	10	20	1400
600	10	20	1450
600	10	20	1500
600	10	30	1300
600	10	30	1350
600	10	30	1400
600	10	30	1450
600	10	30	1500
600	15*	10	1300
600	15	10	1350
600	15	10	1400
600	15	10	1450
600	15	10	1500
600	15	20	1300
600	15	20	1350
600	15	20	1400
600	15	20	1450
600	15	20	1500
600	15	30	1300
600	15	30	1350
600	15	30	1400
600	15	30	1450
600	15	30	1500
700	10	20	1300
700	10	20	1350
700	10	20	1400
700	10	20	1450
700	10	20	1500
700	10	30	1300
700	10	30	1350
700	10	30	1400
700	10	30	1450
700	10	30	1500

*For all pressures of 15×10^5 Pa, tolerance is ± 0.2×10^5 Pa

Table 5

DATA TO BE RECORDED

Inlet Air Temperature, K

Inlet Rig Pressure, Static, Pa

Airflow Rate, Kg/Sec

Fuel Flow Rate, Kg/Sec

Catalytic Reactor Pressure Drop, Static, Pa

Fuel Injector Pressure Drop, Static, Pa

Catalyst Bed Temperature, K

Catalytic Reactor Temperature, K

Gaseous Exhaust Emissions, ppm by Volume of:

- NO_x (Sum of NO + NO_2)
- CO
- CO_2
- O_2
- Unburned Hydrocarbons as CH_4

Table 6

CALCULATED VALUES

1. ***Reference velocity, m/s*** – The velocity of the inlet face of the catalytic reactor, calculated using the mass flow through the reactor, the reactor inlet pressure, the reactor inlet temperature, and the outside diameter of the reactor.
2. ***Fuel/air ratio (weight)*** – The fuel/air ratio shall be computed both from the fuel and air flame measurements and from a carbon balance using the exhaust-gas concentration measurements.
3. ***Combustion Efficiency*** – Computed from the exhaust gas concentration measurements.
4. ***Adiabatic Reaction Temperature*** – K.

Table 7

FUEL ANALYSIS DATA

Lower Heating Value, Btu/scf
Concentrations of Major Constituents, including:

H_2	CH_4
CO	H_2O
CO_2	NH_3
N_2	H_2S

The fuel gas analysis was performed on-line using three instruments. The hydrogen, carbon monoxide, carbon dioxide, methane, and nitrogen concentrations were determined using a mass spectrometer (Perkin Elmer 1200 Multiple Gas Analyzer). The ammonia concentrations were determined using a NO_x sampler with an oxidized gas sample (ThermoElectron Model 10 with model 900 diluter). The hydrogen sulfide concentrations were determined using an SO_2 sampler with an oxidized gas sample (ThermoElectron series 40 with model 340 converter). The water content of the fuel gas was computed from the partial pressure obtained from the resaturater exit temperature.

The air and fuel gas mass flow rates reported were measured using an ASME square-edged orifice plate with flanges and taps supplied by Daniels Industries, Inc. The actual mass flow rates were computed in real time by the data acquisition computer with the appropriate consideration for the gas composition and properties according to ASME *Fluid Meters,* 6th ed., 1971. These measurements also yielded a measure of the fuel-to-air ratio.

In order to make meaningful comparisons of the emissions data, each of the volume concentrations was corrected to a wet basis. The NO_x and unburned hydrocarbons (UHC) data were already on a wet basis. The O_2 and CO_2 were measured after cooling the gas to 0°C. The CO measurements were made in the cool gas after CO_2 removal. These values must thus be corrected to the proper water content of the exhaust products, which can be calculated easily for known fuel composition, fuel-to-air ratio, and assuming complete combustion. In reality, there is some uncertainty in all three of the above points, particularly, in these experiments, in the fuel-to-air ratio.

There are at least three possible methods of determining the fuel-to-air ratio. The most direct is from the measured air and fuel mass flow rates, as pointed out earlier in this section. The other two are from oxygen and carbon balances using the measured exhaust O_2 and CO_2 mole fractions, respectively. This calculation can be made with any of three levels of sophistication. The simplest is to assume complete combustion occurs. The second, and in this case probably the most accurate, would be to include the measured CO, UHC, and NO_x emissions in the oxygen and carbon balances. The third, and most complex, would be to use a chemical equilibrium analysis (such as described in NASA SP-273) routine to determine the proper fuel-to-air ratio to yield the measured O_2 and/or CO_2 emissions.

The results reported here use the fuel-to-air ratios determined from the oxygen balance and correcting for CO and NO_x emissions. The following constituents are used:

fuel: H_2, CO, CH_4, CO_2, N_2, H_2O
air: O_2, N_2, Ar
products: CO_2, O_2, H_2O, N_2, Ar, CO, CH_4, and NO_x

The fuel-to-air ratio is adjusted in a model of the above reaction until the O_2 concentration matches that measured in the test (corrected to wet conditions using the water fraction from the model). The resulting water fraction then corrects the measured emissions so that comparisons can be made on a wet basis.

The emissions indices express the quantities of the emissions on the basis of grams of pollutant per kg of fuel burned. The appropriate relation is

$$EI_i = \frac{[\ ]_i\,(\text{ppmv})}{1000}\,\frac{1+f}{f} * \frac{MW_i}{MW_{prod}}$$

where

$[\ ]_i$ = concentration of species i in products (wet)
f = fuel-to-air ratio by weight
MW_{prod} = molecular weight of products,
MW_i = molecular weight of species i

The fuel/air mixture temperature represents the adiabatic mixing temperature of the two gases. The gas compositions are as described above and the temperatures are measured by thermocouples just prior to the mixing section.

The reference velocity is the calculated average gas velocity at the inlet face of the reactor. The measured fuel and air mass flows are used, and the mixture density is determined from the adiabatic mixing analysis as used above.

The combustion efficiency is determined relative to a complete combustion reaction, and thus the heating value of the product CO and UHC (assumed to be CH_4) are subtracted. The appropriate relation is thus

$$\eta_c(\%) = 100 - \frac{EI_{UHC}}{10}\left[\frac{LHV_{CH4}}{LHV_{fuel}}\right] - \frac{EI_{CO}}{10}\left[\frac{LHV_{CO}}{LHV_{fuel}}\right]$$

The fuel lower heating value is determined assuming CO, H_2, and CH_4 are the volatile species.

The adiabatic reaction temperature is calculated from the air and fuel compositions, the respective temperatures, and the fuel/air ratios. Three values are reported corresponding to three values of the fuel/air ratio, calculated as described previously. Again, complete combustion was assumed in performing the carbon and oxygen balances, with corrections applied to account for CO, CH_4, and NO_x in the combustion products.

4.3 TEST RESULTS

4.3.1 Test Histories

Chronological documentation of the important events of the low-Btu tests may be found in Appendix C. These notes were exerpted from the operators' test log and were edited where necessary for clarity.

Two separate reactor beds were used in the program. The first set of elements were used in the initial group of low-Btu tests (checkout runs), but were then destroyed before testing was completed. All of the data reported for the second group of low-Btu tests were obtained using a second set of catalyst elements.

For a number of different reasons, not all of the points in the test plan were achieved. Table 8 shows the two test matrices, indicating which points were achieved and documenting the reasons why the others could not be realized. Some of these difficulties are expanded on below. Descriptions of the individual test point conditions and group identifiers are shown as the first few lines in Table 9.

Table 8

DATA AVAILABILITY

PT[1]	Status[2]	PT[1]	Status[2]	PT[1]	Status[2]	PT[1]	Status[2]	PT[1]	Status[2]
1	√	6	√	11		16	√	21	√
2	√	7	√	12		17	√	22	√
3	√	8	√	13	X(b)	18	√	23	√
4	√	9	√	14		19	X(a)	24	X(a)
5	X(a)	10	X(a)	15		20	X(a)	25	X(a)
26		31	√	36	√	41		46	√
27		32	√	37	√	42		47	√
28	X(b)	33	√	38	X(c)	43	X(b)	48	√
29		34	X(a)	39	X(a)	44		49	√
30		35	X(a)	40	X(a)	45		50	X(a)
51		56	√	61					
52		57	√	62					
53	X(d)	58	√	63	X(b)				
54		59	X(e)	64					
55		60	X(a)	65					

[1] Data point conditions are detailed in Table 9

[2] Status code:

√ achieved point
X did not achieve point

Failure code:

a catalyst temperature limit
b combustor stability process
c data acquisition problem
d air supply limit
e preheat temperature limit

ORIGINAL PAGE IS
OF POOR QUALITY

Table 9
TEST RESULTS

Group	I				II				IV			V			VII			VIII		X				XII		
Point Number	1	2	3	4	6	7	8	9	16	17	18	21	22	23	31	32	33	36	37	46	47	48	49	56	57	58
Mixed Inlet Temp, K	502	501	498	496	506	504	504	502	593	587	582	594	592	592	613	589	606	591	588	606	602	598	596	687	685	682
Reactor Pres, MPa	1.01	1.04	1.04	1.08	0.95	0.98	0.99	1.03	0.48	0.48	0.48	0.53	0.55	0.54	1.01	0.99	0.98	0.99	1.01	1.47	1.49	1.51	1.53	0.97	0.97	0.97
Ref. Velocity, m/s	10.6	10.4	10.4	9.99	19.3	19.2	19.1	18.8	20.3	19.9	19.6	31.6	31.2	21.1	20.4	21.0	21.6	30.4	30.1	20.2	19.9	19.7	19.5	21.4	21.2	21.2
Exit Temp, K	1300	1341	1401	1458	1299	1344	1388	1450	1289	1334	1394	1300	1337	1392	1307	1348	1400	1325	1330	1293	1352	1393	1452	1293	1357	1405
Air Flow, kg/s	.650	.648	.618	.618	1.075	1.079	1.074	1.068	.522	.511	.497	.849	.845	.832	1.038	1.070	1.046	1.556	1.546	1.504	1.492	1.483	1.478	.955	.933	.924
Air Temp, K	531	531	533	531	539	540	540	540	644	642	640	659	661	661	671	645	671	645	646	661	658	657	656	756	761	765
Fuel Flow, kg/s	.141	.145	.174	.176	.263	.286	.297	.334	.093	.100	.103	.202	.217	.216	.209	.235	.241	.332	.360	.316	.329	.356	.367	.169	.181	.193
Fuel Temp, K	409	411	411	412	409	410	413	417	388	387	387	401	403	406	409	410	410	416	416	424	425	426	426	405	406	407
Reactor ΔP, kPa	9.4	10.2	13.8	16.3	27.4	31.1	32.4	37.7	14.4	15.9	18.2	37.6	39.7	40.9	22.7	24.0	25.8	59.2	60.6	32.8	35.6	39.6	40.5	27.2	31.2	32.0
Fuel Inj. ΔP, kPa	24.9	25.0	27.2	28.3	50.6	53.5	57.5	62.4	35.6	35.5	36.1	79.9	79.8	77.4	41.9	42.1	44.2	82.9	86.9	69.0	68.3	68.2	70.5	63.2	63.4	63.3
Cat. Temp #1, K	1470	1413	—	1435	—	—	—	—	1443	1484	1529	1516	1541	1571	1276	1311	1378	—	—	1407	1447	1477	[illegible]	1247	1288	1367
Cat. Temp #2, K	1283	1251	1422	1370	1346	1341	1382	1424	1307	1350	1383	1448	1472	1497	1195	1223	1292	1219	1214	1389	1432	1468	1495	1213	1257	1328
Cat. Temp #3, K	1166	1132	1290	1313	1207	1216	1267	1308	1185	1215	1267	1286	1293	1321	1168	1228	1276	1197	1207	1235	1278	1313	1334	1136	1183	1242
Cat. Temp #4, K	1112	1080	1234	1345	1131	1154	1211	1266	1147	1175	1248	1203	1206	1232	1116	1174	1223	1175	1166	1129	1176	1228	1257	1117	1162	1193
Cat. Temp #5, K	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	1168	1226	1265
Cat. Temp #6, K	1211	1206	1391	1465	1207	1226	1286	1378	1182	1227	1327	1215	1230	1280	1245	1292	1375	1273	1288	1199	1269	1321	1365	1198	1283	1330
Fuel H_2 Fraction	.1435	.1471	.1392	.1382	.1463	.1399	.1392	.1395	.1459	.1465	.1489	.1359	.1433	.1439	.1475	.1450	.1504	.1466	.1455	.1464	.1437	.1416	.1424	.1468	.1496	.1429
Fuel CO Fraction	.1395	.1278	.1268	.1149	.1438	.1338	.1356	.1218	.1304	.1279	.1369	.1250	.1173	.1213	.1312	.1304	.1346	.1422	.1248	.1269	.1323	.1353	.1331	.1303	.1383	.1258
Fuel CH_4 Fraction	.0272	.0339	.0246	.0422	.0281	.0313	.0238	.0336	.0350	.0325	.0324	.0324	.0274	.0318	.0265	.0296	.0302	.0300	.0318	.0323	.0314	.0313	.0324	.0284	.0266	.0370
Fuel CO_2 Fraction	.0514	.0518	.0552	.0558	.0466	.0504	.0508	.0530	.0546	.0555	.0536	.0550	.0535	.0568	.0556	.0563	.0548	.0528	.0557	.0582	.0580	.0581	.0594	.0562	.0540	.0582
Fuel N_2 Fraction	.3073	.3042	.3240	.3186	.3094	.3175	.3198	.3225	.3197	.3222	.3180	.3179	.3193	.3171	.3154	.3159	.3092	.3070	.3199	.3089	.3073	.3086	.3089	.3217	.3108	.3170
Fuel H_2O Fraction	.3310	.3352	.3303	.3303	.3259	.3270	.3307	.3296	.3145	.3153	.3102	.3339	.3392	.3290	.3216	.3229	.3206	.3214	.3222	.3273	.3273	.3251	.3239	.3166	.3206	.3150
Fuel Mole. Wt.	21.5	21.3	21.8	21.6	21.4	21.6	21.7	21.6	21.6	21.6	21.6	21.7	21.5	21.6	21.6	21.6	21.5	21.5	21.6	21.5	21.6	21.6	21.6	21.6	21.5	21.7
Fuel LHV, kJ/kg	3840	3950	3555	3975	4104	3800	3642	3800	3998	3894	4021	3753	3740	3941	3841	3834	3958	4008	3848	4044	4050	[illegible]	[illegible]	3793	3860	3973
Measured $(F/A)_1$	.217	.224	.281	.285	.245	.265	.276	.313	.178	.196	.208	.238	.257	.259	.201	.220	.231	.213	.233	.210	.221	.240	.249	.177	.194	.209
Adiab. Temp. $(T_F)_1$	1165	1201	1233	1321	1276	1268	1245	1340	1179	1203	1245	1273	1281	1320	1227	1243	1306	1259	1273	1252	1271	1309	1327	1234	1285	1329
O_2 Balance $(F/A)_2$	.358	.379	.461	.438	.347	.382	.425	.456	.231	.261	.290	.253	.294	.299	.223	.228	.278	.239	.260	.232	.259	.285	.293	.145	.166	.186
Adiab. Temp. $(T_F)_2$	1412	1472	1479	1555	1425	1457	1461	1542	1288	1325	1400	1296	1337	1382	1267	1256	1391	1306	1320	1292	1340	1386	1403	1162	1223	1281
C Balance $(F/A)_3$	.266	.284	.363	.367	.256	.288	.325	.375	.211	.237	.264	.226	.255	.268	.226	–	.283	.230	.267	.197	.226	[illegible]	.268	.130	.164	.185
Adiab. Temp. $(T_F)_3$	1245	1306	1355	1455	1236	1287	1309	1433	1210	1256	1345	1201	1233	1300	1251	–	1399	1275	1315	1188	1258	1323	1346	1106	1209	1278

ORIGINAL PAGE IS
OF POOR QUALITY

Table 9 (Cont'd)

TEST RESULTS

Group	I				II				IV			V		
Point Number	1	2	3	4	6	7	8	9	16	17	18	21	22	23
CO Emissions ppmv	1973	1621	238	26	2726	2524	2126	476	2744	2504	1096	3016	2887	2722
UHC Emissions ppmv	69	39	14	12	1258	407	24	7	2033	918	79	3177	2802	1619
NO_x Emissions ppmv	385	376	534	497	394	394	405	485	331	380	389	386	390	406
O_2 Emissions %V	5 55	5 77	6 74	7 09	5 26	5 75	6 19	7 01	4 55	5 03	5 88	4 48	4 66	5 31
CO_2 Emissions %V	8 22	7 27	6 41	5 67	8 29	7 52	7 08	5 81	11 53	10 74	9 70	11 20	10 21	9 78
EI_{CO} gm/kgfuel	7 48	6 04	76	09	10 59	9 17	7 14	1 53	14 58	12 07	4 94	15 02	12 81	11 89
EI_{UHC} gm/kgfuel	15	08	02	02	2 80	85	05	01	6 18	2 54	2 06	9 07	7 12	4.05
EI_{NO_x} gm/kgfuel	2 37	2 24	2 78	2 67	2 51	2 38	2 25	2 56	2 86	3 04	2 76	3 13	2 83	2 89
Comb Efficiency	975	981	997	9996	946	963	976	995	904	941	984	870	895	929
NO_x Yield	0 30	0 32	0 46	0 43	0 29	0 29	0 32	0 41	0 33	0 36	0 37	0 35	0 43	0 37
No Data Points	17	17	24	11	21	16	13	17	12	13	14	14	8	10
No Pts with NO_x Data	6	10	18	7	10	6	8	9	7	6	6	8	7	5

Group	VII			VIII		X				XII		
Point Number	31	32	33	36	37	46	47	48	49	56	57	58
CO Emissions ppmv	2655	2751	188	2127	2529	2779	2665	2192	1889	2557	1181	192
UHC Emissions ppmv	272	14	2	112	202	1350	298	77	48	196	49	39
NO_x Emissions ppmv	379	527	524	-	-	236	273	282	241	274	334	385
O_2 Emissions %V	4 94	-	6 31	5 28	5 60	4 27	5 02	5 72	5 94	2 99	3 96	4 49
CO_2 Emissions %V	12 04	11 90	10 13	11 35	10 85	11 61	10 82	10 05	9 76	14 77	13 93	13 00
EI_{CO} gm/kgfuel	14 56	14 82	87	11 00	12 30	14 79	13 01	9 90	8 39	20 16	8 22	1 22
EI_{UHC} gm/kgfuel	87	04	005	33	56	4 12	84	20	12	90	20	14
EI_{NO_x} gm/kgfuel	3 52	4 69	3 90	-	-	2 05	2 13	2 10	1 68	3 57	3 60	4 04
Comb Efficiency	947	953	997	964	957	922	955	969	974	924	971	995
NO_x Yield	0 34		0 47	0 19	0 23	0 20	0 20	0 20	0 18	0 43	0 45	0 51
No Data Points	18	20	16	1	8	12	21	18	8	17	15	19
No Pts with NO_x Data	9	13	9	0	0	5	8	5	1	9	9	9

With consideration to the reactor bed materials, an upper temperature limit of approximately 1530 K (2300 °F) was set for the test section. This prevented the attaining of any test points at the 1500 K exit temperature and in some cases limited reaching 1450 K.

Three of the test groups could not be performed because the combustion system would not operate stably at the test conditions. Extreme temperature oscillations were observed at the premixer exit position. The nature and magnitude of these oscillations were such that the expected cause was the presence of condensed liquids in the gas. This was certainly a possibility, because the fuel gas delivered from the PEF system was approximately 20 K superheated and the gas temperature drops did occur in the delivery lines. The line pressure drop, tends however, to increase the superheat. The average fuel dew point temperatures corresponding to reactor pressures of 0.5, 1.0, and 1.5 MPa are approximately 387 K, 409 K, and 424 K, respectively. These temperatures are all well below the reactor inlet (mixed fuel and air) temperatures, but the fuel delivery temperature itself ranged from 387 to 426 K in the tests. If, for a specific case, the fuel delivery temperature was below the dew point temperature, then condensed liquids would be present in the fuel. If the fuel/air mixing was not sufficient to completely vaporize these liquids, then there would be liquid present at the premixer exit. This apparently was occurring in test groups III, VI, and IX. These groups were all at the lower reference velocity level of 10 m/s, which result in lower gas mass flow rates. When the fuel flow rates are cut back to the lower levels, the delivery temperature at the rig is lower, and condensation problems result. These problems would be more acute at higher pressures, as pointed out above. Group I was performed at a 10 m/s reference velocity and no problems were encountered. This was due to the low pressure and to the fact that the fuel flow rates and thus the delivery temperature were higher because of the reduced inlet temperature, therefore, a higher reactor temperature rise was required.

Test group XI was not performed because, at the time the attempt was made, insufficient airflow (2.25 kg/s at 1.5 mPa) could be obtained from the air supply system. This was a temporary facility limitation problem but could not be resolved during the test period. This group represented the highest loading on the reactor.

Limitations in the air preheat system preempted one point in group XII and all points in group XIII. These points were to be performed at a nominal inlet temperature of 700 K. Since the typical fuel inlet temperature was about 400 K, the required air inlet temperatures were 750 K and higher. The resulting gas temperatures in the preheater and air outlet temperature at the preheater were very close to the rated maximums.

The loss of the two reactor beds occurred under very different circumstances. The first bed had been somewhat damaged during the checkout runs (see Appendix C) and the first catalyst element had been replaced. Figure 5 depicts the damaged element. The indentations in the element appear to be the type that might have been caused by the impact of some foreign object, although none was found in the vessel The damage could also have resulted from liquid droplet impaction. The loss of the entire catalyst bed occured during operation at 1.0 MPa reactor pressure and was signalled by a sudden loss of about 35% of the reactor pressure. All of the reactor bed thermocouples were lost and no reactor pressure differential was measurable. There remained, however, a seemingly stable combustion. The system was shut down shortly afterward. There was no catalyst structure left in the combustor (see Fig. 6).

The second catalyst bed was lost in a somewhat different manner. Attempts were being made to reach some of the unobtained points in groups XII and XIII when it was noted that the temperature distribution at the reactor exit was becoming very uneven. The system was shut down and disassembled, revealing that the rear elements were fractured. The bed had not, however, been swept away as before. Figure 7 shows the inlet of the fractured catalyst bed (foreign objects in the reactor are from disassembly).

ORIGINAL PAGE IS
OF POOR QUALITY

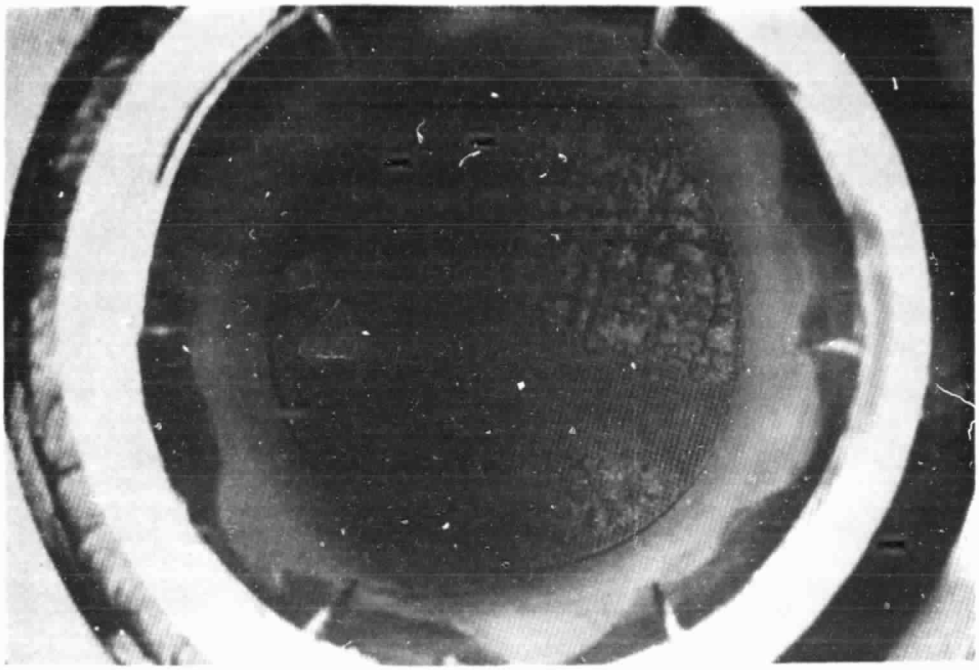


Figure 5. Damaged Catalyst Element #1

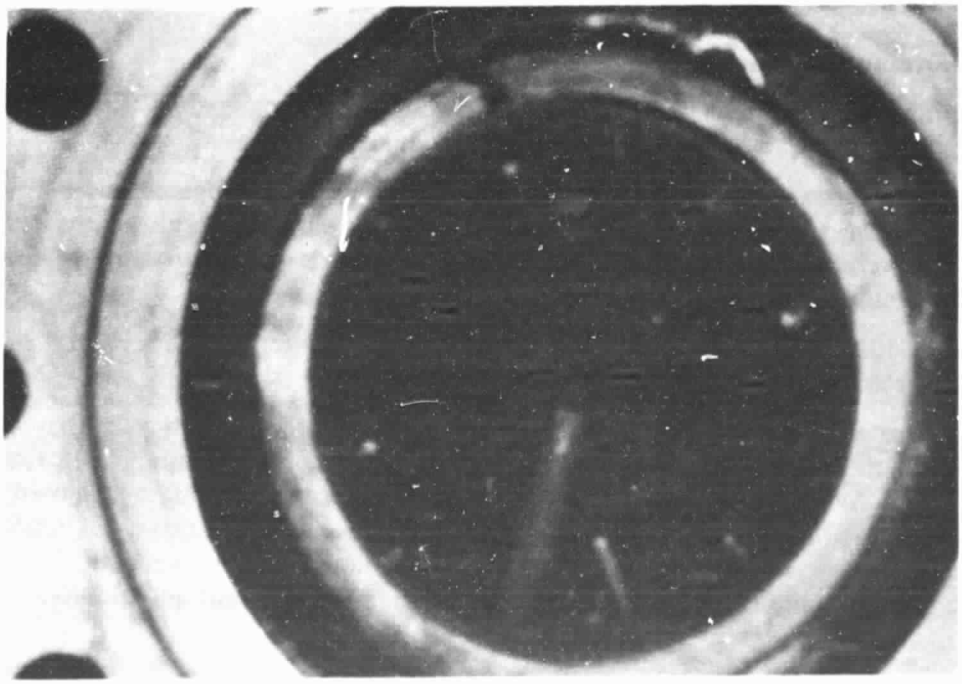


Figure 6. View from Aft End Showing Lost Catalyst Bed

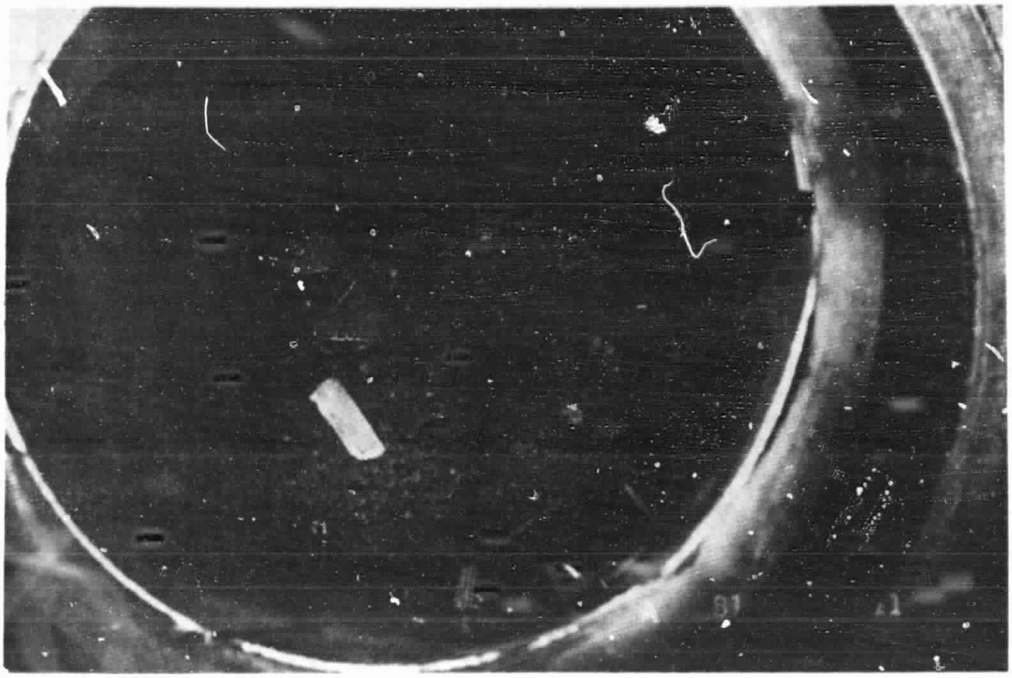


Figure 7. View from Inlet Showing Damaged Catalyst

4.3.2 Performance Results

The complete set of data from the low-Btu tests is summarized in Table 9. Each data point given represents an average of up to 24 individual data samples.

The first four rows in each column summarize the important operational parameters for that point. These are the reactor inlet (mixed fuel and air) temperature, the reactor inlet pressure, the reference velocity, and the average reactor exit temperature. These are the important variables defined by the test matrix (see Table 4).

The remainder of the data is measured or calculated as described in Section 4.2. (In cases where data were not available, a dash (−) appears).

One of the very unfortunate circumstances of the test operation was that because of instrument malfunction no on-line analysis of ammonia concentration in the fuel gas was obtained. The NO_x yield fractions in Table 9 were determined using a constant ammonia content of 3500 ppm. This value was determined from a post-test analysis of aqueous liquor samples using the Kjeldahl method. This should be kept in mind when interpreting these results, as the ammonia content of the gas is by no means a constant quantity over time.

5. TECHNICAL DISCUSSION

5.1 DISCUSSION OF RESULTS

5.1.1 Parameter Variations

Table 10 contains a listing of the number of test points taken tabulated to reveal what parametric variations were accomplished. The three principal variables characterizing each test group – reference velocity, bulk inlet temperature, and reactor pressure – are all shown in the table. With the groups displayed in this manner, a parametric variation in one variable, with all other variables held constant, is identifiable. This is perhaps most easily visualized by thinking of the entries under each reference velocity heading as representing the locations on a temperature-pressure plane in a three-dimensional temperature-pressure-velocity test matrix. It can easily be seen then that the test groups IV, VII, and X represent a systematic variation in pressure at 20 m/sec reference velocity and 600 °K inlet temperature. Similarly groups II, VII, and XII represent a variation of inlet temperature for a constant velocity and pressure of 20 m/sec and 1.0 MPa.

Examination of Table 10 also shows that the variation of inlet reference velocity is not as complete as for the variations in temperature and pressure. Groups IV and V and groups I and II illustrate two less extensive variations in reference velocity at two different pressure, inlet temperature conditions.

The primary data describing the combustor emissions performance have been extracted from Table 9 and grouped together, as described in Table 11. A discussion of the effects of each of the principle variables on combustor performance follows.

5.1.2 Effect of Reactor Pressure

From examination of Table 10, it can be seen that data groups IV, VII, and X represent a controlled set at fixed inlet temperature and reference velocity values of (nominally) 600 K and 20 m/s, respectively. The data from these points are taken from Table 9 and retabulated in Table 11. Shown are emission indices for CO, UHC, and NO_x, combustor efficiency, and NO_x yield from NH_3 in the fuel.

There appears to be no clear trend in the data in response to pressure variation.

5.1.3 Effect of Inlet Temperature

Three groups are available to evaluate the effect of inlet temperature variation. These are groups II, VII, and XII, which were performed at a nominal reactor pressure and reference velocity of 1 MPa and 20 m/s, respectively.

Table 10

PARAMETRIC OPERATIONAL DATA VARIATIONS

Reference Velocities (m/s)		10			20			30		
Inlet Temperatures (K)		500	600	700	500	600	700	500	600	700
	0.5	–	0 (III)	–	–	3 (IV)	–	–	3 (V)	–
Pressures (MPa)	1.0	4 (I)	0 (VI)	–	4 (II)	3 (VII)	3 (XII)	–	2 (VIII)	0 (XIII)
	1.5	–	0 (IX)	–	–	4 (X)	–	–	0 (XI)	–

Number of Points in Group (Group Number)

ORIGINAL PAGE IS
OF POOR QUALITY

Table 11

RESULTS OF PARAMETRIC VARIATIONS ON COMBUSTOR PERFORMANCE

	EI_{CO}			EI_{UHC}			EI_{NOx}			η_c			NOX		
Nominal Exit °K Temperature	1300	1350	1400	1300	1350	1400	1300	1350	1400	1300	1350	1400	1300	1350	1400
Reactor Pressure															
IV 0.5 MPa	14.58	12.07	4.94	6.18	2.54	2.06	2.86	3.04	2.76	.904	.941	.984	0.33	0.36	0.37
VII 1.0 MPa	14.56	14.82	.87	.87	.04	.005	3.52	4.69	3.90	.947	.953	.997	0.34		0.47
X 1.5 MPa	14.79	13.01	9.90	4.12	.84	.20	2.05	2.13	2.10	.922	.955	.969	0.20	0.20	0.20
Inlet Temperature															
II 500 K	10.59	9.17	7.14	2.80	.85	.05	2.51	2.38	2.25	.946	.963	.976	0.29	0.29	0.32
VII 600 K	14.56	14.82	.87	.87	.04	.005	3.52	4.69	3.90	.947	.953	.997	0.34		0.47
XII 700 K	20.16	8.22	1.22	.90	.20	.14	3.57	3.60	4.04	.929	.973	.995	0.43	0.45	0.51
Reference Velocity															
IV 20 m/s	14.58	12.07	4.94	6.18	2.54	2.06	2.86	3.04	2.76	.904	.941	.984	0.33	0.36	0.37
V 30 m/s	15.02	12.81	11.89	9.07	7.12	4.05	3.13	2.83	2.89	.870	.895	.929	0.35	0.43	0.37
I 10 m/s	7.48	6.04	.76	.15	.08	.02	2.37	2.24	2.78	.975	.981	.997	0.30	0.32	0.46
II 20 m/s	10.59	9.17	7.14	2.80	.85	.05	2.51	2.38	2.25	.946	.963	.976	0.29	0.29	0.32

The only variables showing evidence of clear dependence on the inlet temperature is the NO_x emissions index and NO_x yield, both of which appear to increase with increasing inlet temperature.

5.1.4 Effect of Reference Velocity

Data illustrating the effect of reference velocity variation were not as complete as that for reactor pressure and inlet temperature. Four groups were incorporated as two sets of two groups each. Groups IV and V were at 600 K, 0.5 MPa inlet temperature and pressure, and had reference velocities of 20 and 30 m/s, respectively. Groups I and II (500 K, 1.0 MPa) had velocities of 10 and 20 m/s, respectively.

The major effect of velocity seems to be on the completeness of the combustion reaction. As velocity increases, the emissions of carbon monoxide and unburned hydrocarbons increases, and hence combustion efficiency decreases. Because of operational problems, group I is the only data set at a reference velocity of 10 m/s, but as can be seen from Table 9 this group has the highest combustion efficiencies.

5.1.5 Effect of Reactor Exit Temperature

Here it is convenient to refer back to Table 9, since the individual data groups are tabulated with reactor exit temperature as the independent variable.

The emissions of carbon monoxide and unburned hydrocarbons both decrease with increased reactor exit temperature, and hence combustion efficiency increases. This would be the expected trend with equivalence ratios more toward unity.

The nitric oxides' emissions show no dramatic dependence on reactor exit temperature. This would suggest that little or no thermal NO_x production from free nitrogen occurs and that the majority of the NO_x observed originates as fuel-bound nitrogen species (principally NH_3). It also seems to indicate that oxidation of the fuel-bound nitrogen is not dependent on the reaction temperature. From earlier results, however, it was postulated that there was dependence on the reactor inlet temperature.

5.1.6 Carbon and Oxygen Balances

A major effort was made in reducing the data acquired to obtain some accurate and reliable method of determining the fuel-to-air ratios for the reaction. For the most part this effort met with little or no success. In most groups there was very poor agreement between the measured fuel/air ratio and the values determined from carbon or oxygen balances. In addition, none of the three values yielded adiabatic reaction temperatures which showed consistent agreement with the measured exit gas temperature. The fuel/air ratios determined by the different methods and the resulting adiabatic reaction temperatures are given in Table 9.

There are a number of reasons why the above difficulties were not entirely unexpected. First, all of the calculations depend on the fuel composition, which is quite variable. The balance and heating value calculations are very sensitive to the fuel composition. Secondly, the measured fuel and airflow rates (by square-edged orifices) may be subject to rather large inaccuracies, especially at the lower flow rates. Thirdly, the gas composition measured at a single point may not be representative of the bulk average conditions.

5.2 CONCLUSIONS AND RECOMMENDATIONS

5.2.1 Conclusions

Sufficient data were collected from the experimental evaluations to make some initial observations regarding the effect of the test parameters on the combustor performance, although more testing would be required to verify these observations.

The trends in combustor performance were examined with respect to variations in four operational parameters: (1) reactor exit gas or adiabatic reaction temperature, (2) bulk inlet temperature of fuel/gas mixture, (3) reactor inlet static pressure, and (4) average gas velocity at inlet face of reactor (reference velocity). The following observations were made from the limited data available:

1. Unburned combustibles (CO, UHC) decreased with increased reaction temperatures, and hence combustion efficiency improved. There was no apparent effect on the NO_x emission index, although the NO_x yields (from fuel-bound nitrogen) appear to increase in an inconsistent fashion.
2. The only performance variable affected by the reactor inlet temperature was the NO_x emissions and yield, both of which increased with increasing temperature.
3. There is no clear-cut trend to any of the data with variations in reactor pressure, although the NO_x yield appears to decrease with pressure increases in an inconsistent fashion. Because of difficulties encountered in determining NO_x yield (see Section 4.3.2), it would be difficult to conclude with certainty that these trends are meaningful.
4. The reference velocity has a very dramatic effect on the unburned combustibles and hence the combustion efficiency. Increased reference velocity results in increases in CO and UHC emissions and reduced combustion efficiency.

In addition to the data obtained and discussed above, a significant amount of operating experience was gained in the course of the program. Extensive and sophisticated computer software for data acquisition and reduction was generated and implemented, and a sensible methodology for test performance was developed.

APPENDIX A

PROCESS EVALUATION FACILITY DESCRIPTION

A.1 OVERALL SYSTEM CONFIGURATION

General Electric's Process Evaluation Facility (PEF) is located at the GE Research and Development Center in Schenectady, New York. This test facility consists of the advanced fixed bed gasifier, a full-flow, low-temperature gas cleanup system, and an advanced computer-based data acquisition, analysis, and control system. Auxiliary systems available to the test facility include a high-flow, high-pressure air supply, indirect air preheaters, and a high-pressure steam boiler. A schematic diagram of the PEF is shown in Figure 8. A photograph of the PEF facility (Figure 9) shows the gasifier tower, gas cleanup facility, and turbine simulator test cell locations at the Combustion and Gas Dynamics Building. The cleanup facility is approximately 100 feet from the gasifier tower; the turbine simulator test cells are about 150 feet from the cleanup area. Individual control rooms, interconnected by radio and hard-wired communications systems, are utilized for each of the subsystem operations.

This section describes in detail the major subsystem components and support facilities available to the test program.

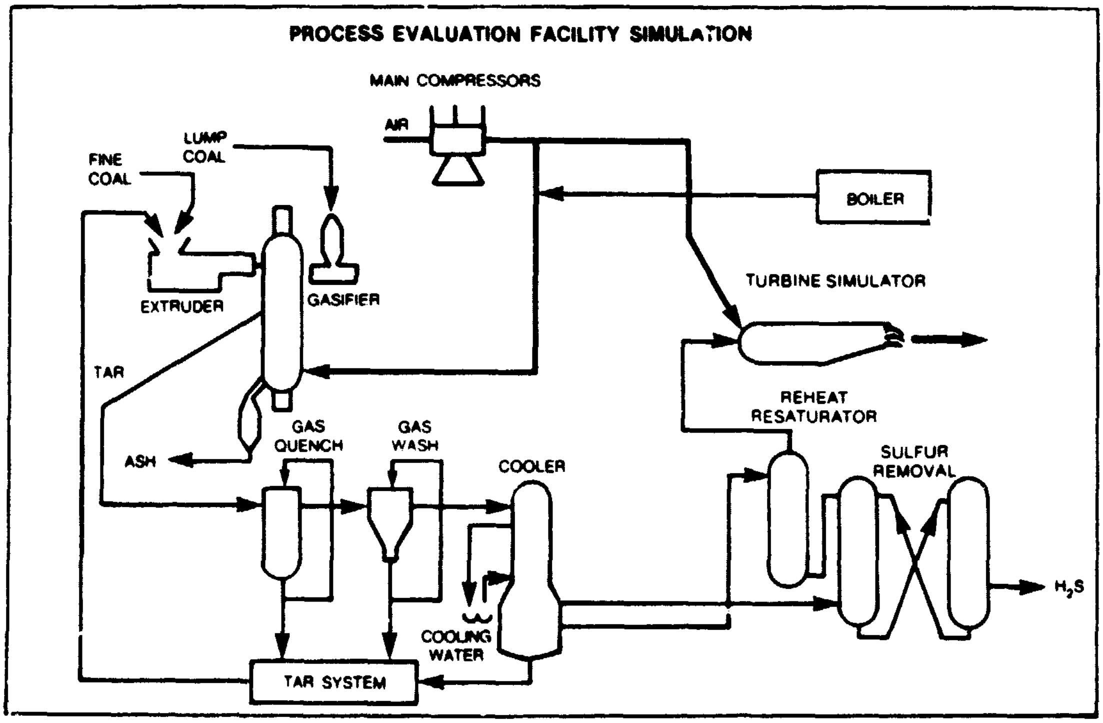


Figure 8. Schematic Drawing of Process Evaluation Facility

ORIGINAL PAGE IS
OF POOR QUALITY

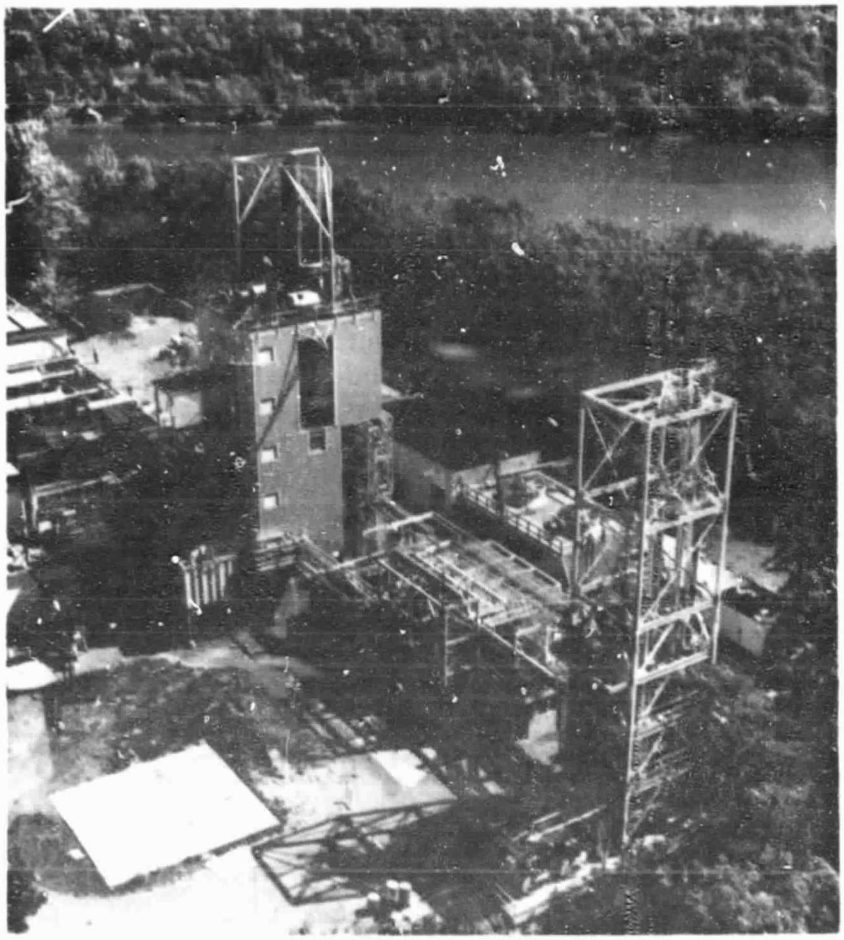


Figure 9. IGCC – Process Evaluation Facility

A.2 COAL GAS FUEL SYSTEM

A.2.1 Advanced Fixed Bed, Coal Gasification System Description

The General Electric gasifier and associated test hardware are mounted in a six-story building shown schematically in Figure 10. Lump coal is fed from the main bin into a weigh bin, lockhoppered up to system pressure, and then fed into the fuel bed through a variable-speed auger. Steam and air enter the base of the gasifier through a distributor located under the grate. Ash is removed through a conventional lockhopper. The hot raw gas exits from the top of the gasifier through a reamed offtake pipe and is immediately quenched in a downflow venturi spray quench. The gas can then be fed directly to a roof-mounted flare, or it can be processed through the gas cleanup system. The quenching-liquor system consists of recirculation and makeup pumps, controls, and a decantation system using settling tanks above and below ground.

The gasifier reactor vessel, lockhoppers, and associated mechanicals are supported just below the upper gasifier flange in a 60-foot semi-enclosed tower, which was constructed as an integral part of the gasifier (Figure 10). The tower houses the associated coal-handling equipment, coal lockhoppers, coal extruder-feed system, motor control center, and laboratory gas services, as well as work, laboratory, and storage areas. Separators and a shielded gas-piloted flare are located on the roof of the tower and are used to incinerate the coal gas not utilized in downstream combustion tests. The two-story control building and the tar building are adjacent to the tower. The master control panel and a computer-based data acquisition system are housed on the second floor of the control building. The tar building houses the liquor handling system. Four underground liquor storage tanks provide a total storage capacity of 7500 gallons.

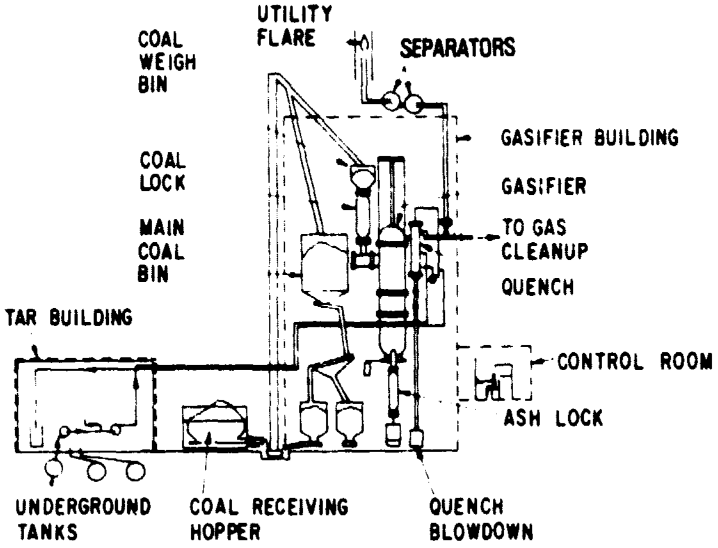


Figure 10. Gasifier System Layout

Coal Gasifier Reactor

The coal gasifier vessel is shown in cutaway side-section in Figure 11. The vessel consists of a 5-foot (o.d.) by 24-foot high shell with 1-inch thick walls and hemispherical caps. It was constructed in four sections joined together with 5-foot flanges, thus allowing easy disassembly for repair or inspection. The steel shell is protected from the high temperatures of the gasification process by two layers of castable refractory: a hardcast, high alumina inner layer 3-3/4 inches thick and an insulating outer layer 8-3/4 inches thick. The effective inner diameter of the vessel is 35 inches.

Mechanicals associated with the gasifier are a grate, an upper bed stirrer, a coal feed auger, and an offtake pipe reamer. The grate stirrer arm can be raised axially to break weakly fused clinkers in the lower portions of the bed. A carbon steel bosh ring is located in the vessel just above the grate pan to provide a hard surface against which the ash clinkers can be crushed. Discharged ash falls into a pit below the pan, from which it is pushed into a chute leading to the ash lockhopper. The grate paddle and all the rabble arms on the stirrer are fully water cooled. The bosh ring is cooled by the incoming air and steam blast. The only other cooled surfaces are certain external flanges (including the auger-, top stirrer-, and gas offtake-flanges). In each case, the cooled metal is insulated from flowing hot gas by refractory.

The overall performance of the coal gasifier is determined by a large number of separate unit operations: coal charging, steam and air charging, bed conditioning, ash residue extraction and discharge, gas cooling, and liquor handling. Subsystems or components to accomplish these operations are described in the following sections.

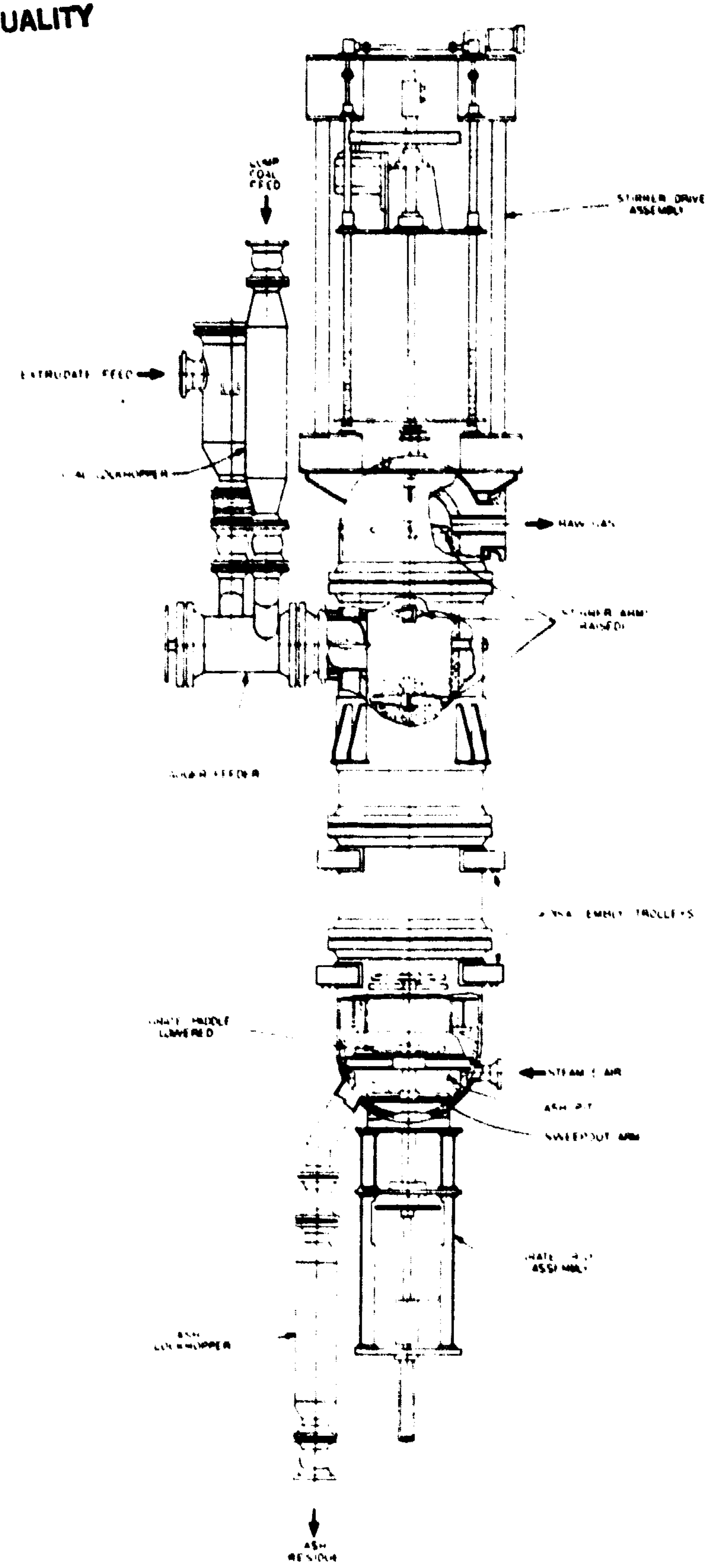


Figure 11. Gasifier Vessel Assembly

Reactor Bed Conditioning

The gasifier top stirrer can penetrate the coal bed to within 3 feet of the grate pan. The stirrer assembly includes three rabble arms, each of which is series water cooled. In normal operation, the stirrer agitates the top 8 feet of the 1 foot bed. Vertical stirrer travel is adjustable from 0 to 2 feet per minute. It is usually set at 0.7 foot per minute going down and at 1.5 feet per minute coming up. The rotation rate is also adjustable but is usually set at about 70 revolutions per hour.

The grate travel covers the bottom 32 inches of the bed, thereby leaving only a 3 to 4 inch zone that cannot be reached by either agitator. The grate is raised and lowered only when the operator decides that the bed is beginning to bridge. This motion is in the range of 0.5 to 1.0 foot per minute, but continuous actuation never occurs for more than a fraction of a minute at a time. Grate rotation rates are maintained in the range of 6 to 40 revolutions per hour

Gas Cooling

The raw gas leaving the gasifier at temperatures between 800 °F and 1200 °F is cooled by direct quenching with a water spray. The close coupled quench vessel is constructed of carbon steel and is 12 feet high and 18 inches in diameter.

The raw gas enters the quench through a 10-inch diameter reamed offtake pipe. The stainless steel reamer rotates continuously in the hot gas stream at about one revolution per minute and is oriented so that deposits are pushed back in the gasifier. Inside the quench, the gas flow is cooled to its saturation state in a 4-inch i.d. water-quenched downflow venturi. After leaving the venturi, the gas makes a 180° turn to flow upward through a baffled section past the inlet venturi, before being turned 180° again and directed from the vessel through a 4-inch offtake pipe located at the backside of the quench. An optional stainless steel demister pad can be installed in the top of the quench vessel to act as a mist eliminator if required.

Recirculation water is supplied to the 1.25-inch spray nozzle by centrifugal pumps which pull water from the quench sump through an internal filter at a rate equivalent to 3 to 3.5 lb water/lb gas. Additional nozzles located just upstream of the venturi throat and in the free gas space near the quench offtake are used to supply makeup and emergency cooling water to the system.

The makeup water is supplied by one of two regenerative turbine pumps that deliver a constant 400 psig head to the makeup control valve. Decanted blowdown liquor from the quench and physical cleanup system is used for makeup water after it has first been filtered through two metal spiral filters (14 mil) located in series. Clean city water can also be utilized for makeup water if needed.

Spray quench liquor is blown down from the system automatically through a 3/8-inch nozzle into a continuous sludge separation vessel located on the first floor of the tower. A 3-inch manually operated sludge lockhopper is also used periodically to remove accumulated sludge from the quench sump. Dry filter cake is discharged from the sludge separator by an operator-actuated hydraulic auger into a 55-gallon drum for analysis and storage. Filtered liquor is drawn from the sump of the sludge separator, metered, and returned to the underground storage tanks through a basket filter for reuse as makeup water.

The gas leaves the quench in a saturated condition and can be directed either to the roof-mounted flare through a backpressure control valve or to the cleanup system for further conditioning.

ORIGINAL PAGE IS
OF POOR QUALITY

Gasification Systems Controls and Data Acquisition

Control of the gasifier is from a console in the main gasifier control room (Figure 12). Local control of the main process functions is available as an option. Data is collected, converted to engineering units, displayed, and stored by a Hewlett-Packard computer data acquisition system. The system can also provide certain process functions such as alarm annunciation. Standard CRT terminals allow the operator to view information available in the computer and to enter commands to change the data acquisition or control tasks.

System variables that are monitored include steam and air flows, coal addition, gas flow rate, quench recirculation rate, differential pressure, system pressures, stirrer and grate position, and various temperatures including bed temperature, vessel shell temperature, and process temperatures. Strip chart recorders are used for continuous monitoring of stirrer and grate torques as well as bed wall temperatures.

Figure 12. Gasifier Control Room

A.2.2 GAS CLEANUP

The gas cleanup facility contains equipment to perform the functional processes and unit operations shown in Figure 13. The cleanup facility receives quenched gas from the gasifier spray quench area through approximately 100 feet of heat-traced and insulated pipe. The washed gas product, cleaned of particulates and gaseous sulfur contaminants and resaturated equipment utilized to perform the various functions shown in Figure 16 is described in detail below.

Particulate Scrubbing

Particulate scrubbing is effected in two stages. The raw gas quench, generally associated with the gasifier operation (and described in Section A.2.1), washes larger particulates from the raw gas stream while cooling the gas to its adiabatic saturation temperature by direct contact with a water spray. The gas is then washed isothermally by a jet venturi fume scrubber to remove fine particulate and tar fog. A centrifugal pump circulates the water stream and provides the liquid head required to achieve a fine liquid spray across the venturi vortex/nozzle contacting section. The temperature of the recirculating liquor stream is matched to the incoming gas temperature by a bypass steam heater. The gas/liquor separator vessel below the venturi contactor is 20 inches (o.d.) by about 55 inches high. The internals of the separator include a baffle plate at the recirculating liquor offtake and a chevron-type mist separator at the gas exit. Blowdown of liquor from the vessel takes place through a throttling orifice to a vented holding tank. City water is added to maintain liquid level. Various nozzles are available to provide recirculating flows of 10, 13, and 17 gpm at a 120 psi differential. A 14-inch (o.d.) vertical separator with a stainless steel mesh mist eliminator is located in the scrubber exit process gas line.

Gas Cooling

Gas cooling is effected by two shell-and-tube heat exchangers, designated E-1 and E-2 (Figure 16). The E-1 exchanger is 530 square foot, type BEM partial condenser utilizing a stainless steel shell and tubes. In the past the gas has been cooled by a recirculating tempered water stream (by control of flow rate and temperature of the recirculating water), but the addition of the chemical cleanup facility introduces the option of cooling the gas by the recirculating condensate stream from the resaturation process. The vessel sump is 24 inches (i.d.) by 32 inches high. Condensate is withdrawn through a restricting orifice to a vented blowdown vessel or directly to a pressurized condensate separation tank. Valving options permit gas and coolant to flow upward or downward through the vessel. Common practice has been to let the gas flow downward and the coolant upward.

The E-2 exchanger, part of the chemical cleanup facility, is a 384 square foot, type CEN partial condenser constructed of carbon steel. The unit is cooled by a tempered water system operating at 120 °F. Both gas and liquid condensates are blown into another pressure vessel for separation and decantation. Each heat exchanger is sized to handle the full heat load required to cool the quenched gas stream to the temperature required by the acid gas removal system.

Acid Gas Removal System

The sulfur-containing gases (H_2S and COS) are removed in the Benfield acid gas removal system. This process utilizes a hot potassium carbonate stream to absorb H_2S from the gas stream. The system employs a split stream configuration to remove about 90 percent of the incoming sulfur gases (the estimated removal efficiency required to meet an emission specification of 1.2 lb $SO_2/10^6$ Btu.) The absorber operates at approximately 180 °F at pressure while the regenerator operates hotter and at about atmospheric pressure. Steam at 55 psia provides the heat for the solution regeneration reboiler.

The acid gas absorber is followed by a gas washer, 18 inches (o.d.) by 27 feet high, which removes any traces of alkali metal carry-over from the absorber. The upper tower section washes the gas with a flow of once-through demineralized water. The lower bed is fed by the downflowing demineralized water and a recirculating liquor stream. Blowdown from the column is used as makeup to the acid gas regenerator system.

Liquid Condensate Separation

Heavy oils and tars are separated from the condensate streams from the E-1 and E-2 gas coolers in separator vessels designated V-2 and V-1, respectively. The liquids pass under and over weirs in a horizontal vessel 36 inches (i.d.) by 6 feet long. A tar boot (12 inches i.d. by about 24 inches long) extends vertically from the bottom of the vessel. Periodically, tar and heavy oils are withdrawn manually. The higher temperature condensate from V-2 is cooled in a 37 square foot double pipe heat exchanger (10 feet long) using the tempered cooling system.

Filters are provided for each condensate stream. The filter assemblies utilize disposable polypropylene elements. Cartridges can be obtained to remove particulates as small as 0.14 micron if desired. The filtered condensate streams are then combined and fed as makeup to the resaturator recirculation liquor.

Reheat Resaturation

The clean gas at about 185 °F is heated to about 240 °F in a 13 square foot double pipe heat exchanger utilizing a 165 psia steam supply.

The resaturator vessel is 24 inches (o.d.) by 34 feet high and contains an 18 foot section of packing. Heat is supplied to the recirculating liquor by the E-1 partial condenser and/or by a 184.5 square foot, type CEN steam heater. The temperature of the gas exiting from the resaturator is about 320 °F. Blowdown liquors from the resaturator are ducted back to storage for use as quench or scrubber makeup.

Cleanup Control

Bypasses have been installed to permit partial utilization of the cleanup functional elements. It is possible to selectively bypass the entire chemical cleanup system, the Benfield and resaturator systems, or the resaturator system. The system backpressure is maintained by a local pressure controller, throttling gas flow to the flare through a backpressure control valve. The fuel gas flow required by the turbine simulator is throttled by a pair of coarse and fine flow control valves operating in parallel. Excess fuel gas passes through the backpressure control valve to the flare system. The cleanup system control panels are located in a control room extension of the physical cleanup pumphouse. Two control panels are used, from which all major flows and temperatures in the cleanup facility may be controlled and/or monitored.

A.2.3 SAMPLING SYSTEMS

Gasifier

Two different sample probes located in the top offtake dome of the gasifier are available for sampling the raw coal-gas composition.

Hot Filter Probe

The hot filter probe consists of a double-piped probe extending approximately six inches into the gasifier through the refractory-lined wall. The probe is electrically heated to about 1000 °F. Once outside the gasifier vessel, the raw gas is filtered through a porous, stainless steel filter element maintained at between 500 °F and 700 °F in order to keep the tars and oils in the vapor phase and to prevent any condensation, which could lead to plugging of the lines. With this system, the fines content of the raw gas can be determined directly by weighing the fines collected in the filter housing.

Reamed Probe

In the reamed probe, the gas samples are obtained through a continuously reamed tube. The inlet end of the probe projects about 6 inches beyond the refractory wall into the gas space. Outside the vessel, the probe is fitted with a T-assembly through which an auger is mounted that continuously reams the sample probe to push tar and fines deposits back into the gasifier.

Sample Conditioning

Outside the vessel the sample gas stream is piped approximately 30 feet to the sample conditioning apparatus shown schematically in Figure 16. All sample lines outside the vessel are heat-traced to 350 °F to maintain the sample stream temperatures above the aqueous dew point. In sample conditioning apparatus No. 1, the gas is passed through two condensers in series located in a chilled water bath. The second condenser is filled with Pyrex* glass wool to form a demister element. Each of the condenser traps is fitted with a siphon to allow periodic removal of the collected condensate while the system is on line. The gas leaves the condensers at a temperature between 36 °F and 46 °F and passes through a few feet of tubing to allow the gas temperature to increase slightly before the gas is passed through a final filter element, a section of 3/8-inch tubing filled with glass wool. The gas is then throttled across a backpressure regulator or pumped during low-pressure or banked gasifier operation and metered across flowrator R1. Downstream of the flowrator, a small portion of the gas is removed, passed through a submicron filter, metered, and piped about 60 feet to the gas analysis laboratory located on the first floor of the tower. Most of the sample gas is vented to the gasifier flare to minimize the delay time between sampling and arrival at the gas chromatographs. Upstream of flowrator R1 an additional slipstream is removed for use in the on-line fuel gas calorimeter.

Gas flowrate through the entire system is maintained at about 40 actual cc/sec by adjusting the flow through flowrator R1. Adjustments are made to compensate for gasifier operating pressure and flow to the calorimeter. Average gas residence time in the system is on the reorder of one minute. Total mass flows through the system are roughly proportional to gasifier pressure.

All of the tubing used in the system is either stainless steel or Teflon†-lined flexible steel expansion sections with stainless Swagelok* or JIC‡ fittings. Most valves and auxiliary fittings are also stainless steel.

Condensate is removed from the traps every 20 minutes through a siphon located on each condenser. The condensate is then transferred into a 4-liter separatory funnel to allow an initial separation of water and hydrocarbons. Periodically (approximately every 2 hours) a condensate sample is kept aside as a spot check sample rather than added to the funnel.

Sufficient gravimetric separation of the composite liquor sample in the separatory funnel occurs to produce three distinct layers after a few hours of undisturbed settling time: heavy hydrocarbon, aqueous liquor, and light hydrocarbon. The hydrocarbon fractions are collected and saved, while a sample of the aqueous liquor is taken and the remainder discarded. The cumulative aqueous liquor and the spot check aqueous samples are analyzed for total N as NH_3, total sulfides, and phenols. Ammonia is determined by the Kjeldahl method. Total

---

*** Pyrex is a registered trademark of the Corning Glass Works.**

*** Swagelok is a registered trademark of the Crawford Fitting Company.**

† Teflon is a registered trademark of the E.I. duPont de Nemours & Company.

‡ JIC is a registered trademark of the Chicago Fittings Corporations.

phenol and sulfide determinations are made by a commercial testing laboratory, using standard procedures. The total hydrocarbon fractions, including tars from the spot check samples, are combined and distilled to remove the remaining water. The dry hydrocarbons are then further characterized by a vacuum distillation.

Sampling and analysis of the gaseous and liquid process streams in the cleanup facility are designed to provide necessary data for process and equipment design and for water treatment and effluent control definition. Samples of process blowdown liquors are periodically taken for analysis, but the difficulty of obtaining uniform and representative samples has led to the development of the sample system shown in Figure 17. Gaseous samples are withdrawn through sample probes or taps at appropriate locations between the major vessels and passed through 25 to 75 feet of electrically traced sample lines to the conditioning system. The gas is then passed through a hot filter to a chilled water condenser. Condensate is collected at system pressure in stainless steel bombs for subsequent separation and analysis. The dry gas is then metered and vented or directed to the gas chromatograph laboratory for analysis. The liquid samples collected are analyzed for a variety of physical and chemical properties as defined by the characterization map (Figure 18).

Fuel gas from the E-1 exit, E-2 exit, wash column exit, and resaturator exit is routed to the CCU gas sampling laboratory via heat-traced sample lines. The sample gas is metered through a heated precision dilution apparatus and/or through a glycol-cooled indirect heat exchanger and liquid collection bomb. The sample gas, diluted with air at an approximate 20:1 ratio, is monitored by on-line continuous gas analyzers to give wet gas concentrations for NH_3, CO_2, and H_2S + COs. The chilled and dried gas stream is sent to the gasifier sampling laboratory for gas chromatographic and/or mass spectrometer analysis. The condensed liquids are collected and combined with sample gas flow measurements to determine condensible insoluble hydrocarbon loadings as well as other oil and water properties. Figure 17 shows a schematic of the gas sampling system.

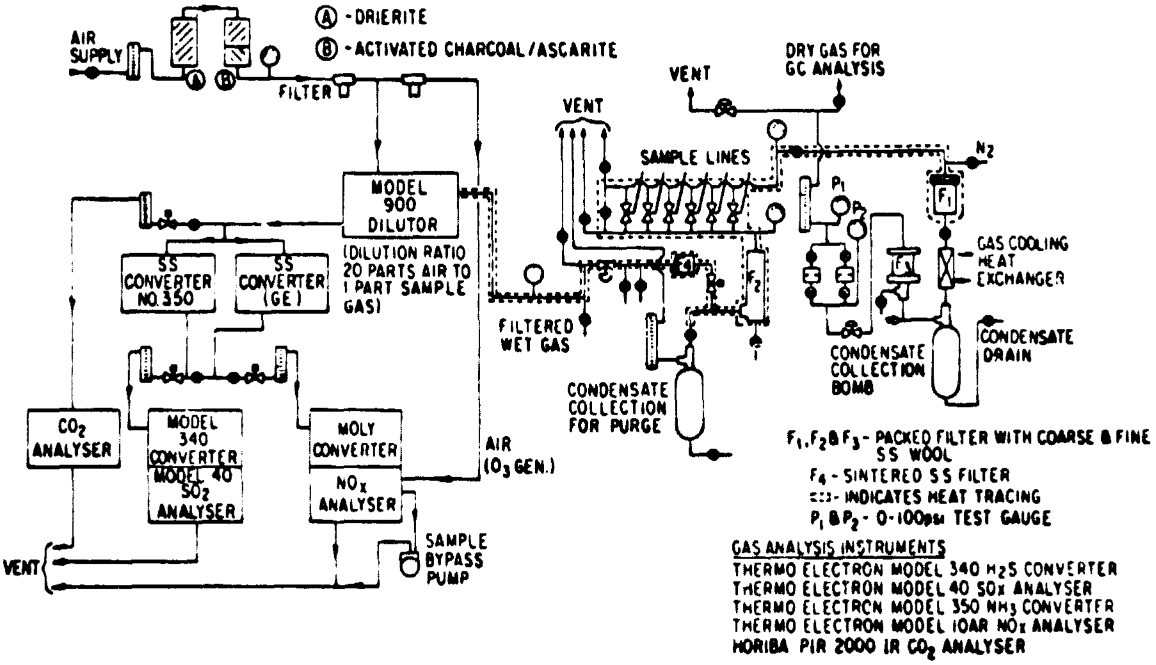


Figure 17. Schematic of Gas Sampling System

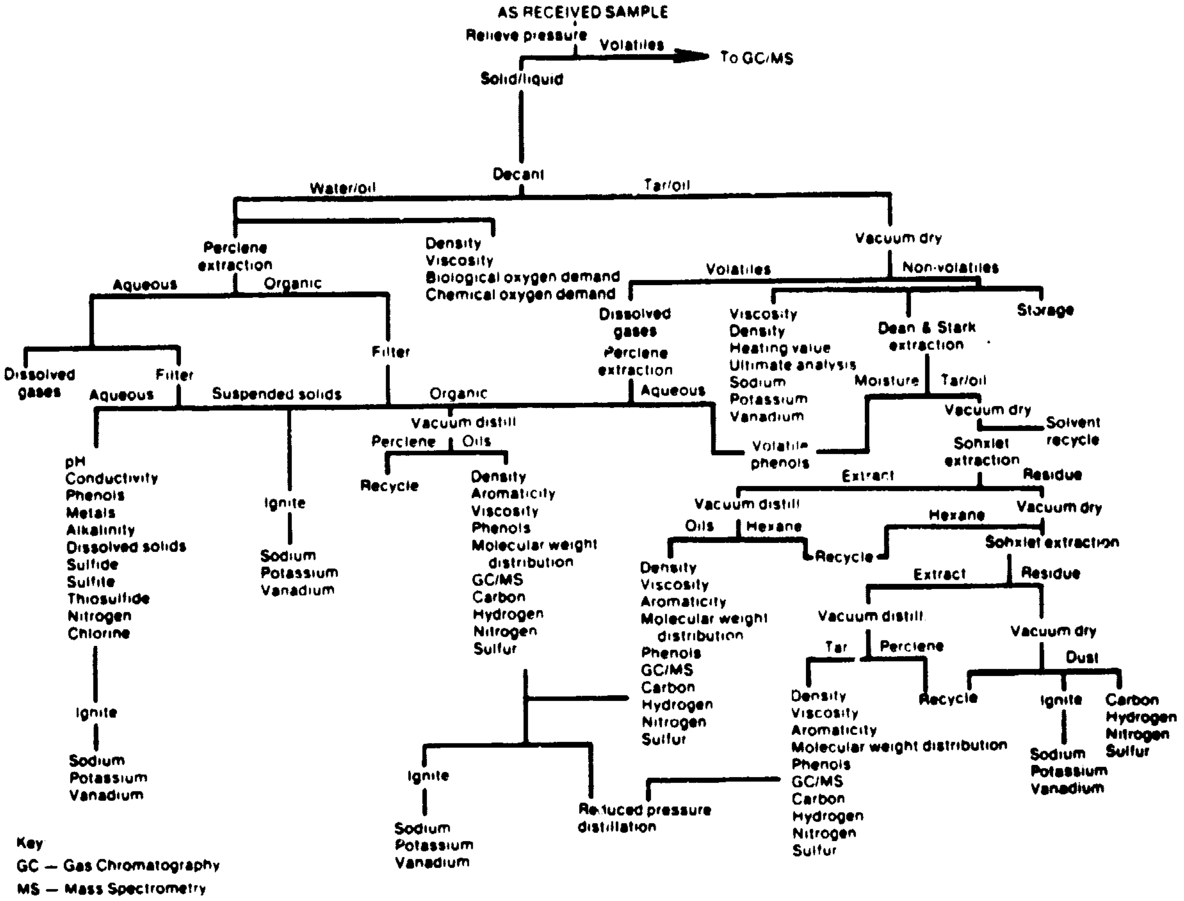


Figure 18. Overall Characterization Map

Process liquor samples are collected from the V-1 tar separator, washer, and resaturator components. These are analyzed for fixed and dissolved sulfur and nitrogen compounds, alkali metal concentrations, total dissolved sulfur and nitrogen compounds, alkali metal concentrations, total dissolved solids, and relative quantities of oils. Where possible, more complete physical and chemical analyses of the hydrocarbon fractions are made.

Samples of the Benfield system lean solution are taken and analyzed for $CO_3^{=}/HCO_3^{-}$ and HS^- ions. This information is used in the evaluation of system performance.

Particulate sampling of the gas streams involves filtration on a submicron pore size Teflon membrane filter. Samples are withdrawn from the main flow stream through an L-shaped sample probe approximately centered and pointing upstream in the main gas path. The slipstream, at system pressure, flows through heat-traced Teflon tubing to the filters housed in a stainless steel, high-pressure filter holder also heated to prevent vapor condensation, and is finally cooled, depressurized, and metered with a wet test meter. The filter is then removed, dried, and weighed for particulate loading, and subsequently washed with a hydrofluoric acid solution to solubilize the alkali metals for analysis by atomic absorption. The desired quantity of gas to be drawn through the filters is based on past experience of the particulate loadings in the sampled stream and designed to provide an adequate weight of collectibles. This quantity is approximately 1, 6, and 20 scf for the scrubber inlet, outlet, and resaturator outlet streams, respectively.

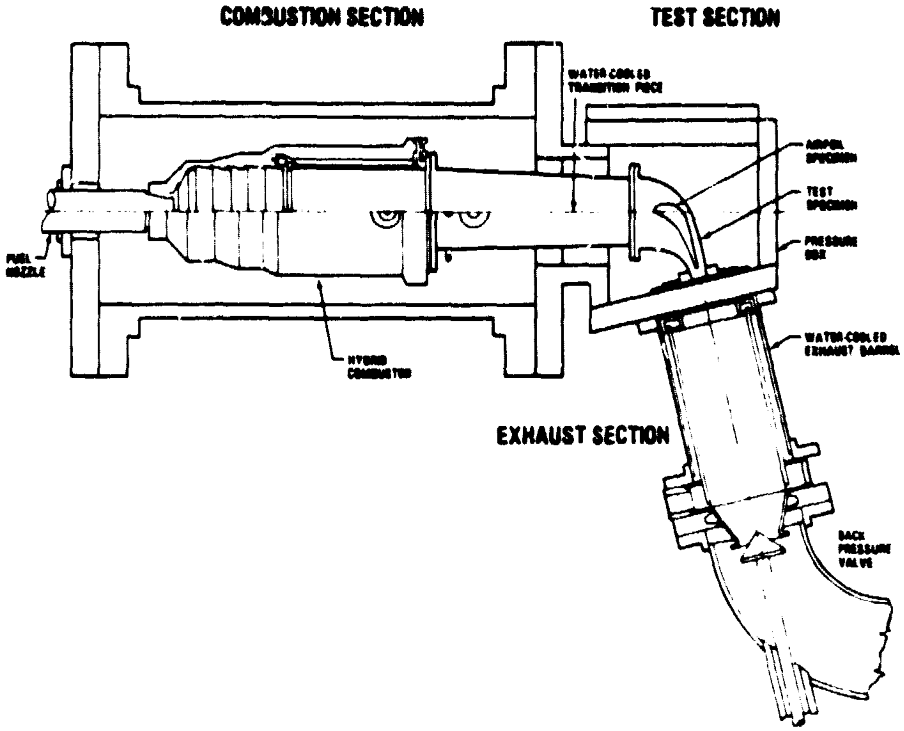


Figure 20. UHT Turbine Simulator

The nozzle or airfoil test specimen is located in the pressure box of the test section. The nozzle is backpressured by a water-cooled nozzle and pintle assembly. All elements of the UHT simulator have been designed to operate with a gas temperature up to 3000 °F and have been tested to 2700 °F. These operating gas temperatures correspond to near-stoichiometric firing conditions for certain low-Btu fuels.

A.2.5 Integrated Gasification and Combustion Control System

The control system for the overall operation of the integrated gasification and gas turbine simulation facility consists of four major control loops: the fuel gas flow to combustor control loop, the loop that controls the airflow split between the gasifier and combustor, the control loop that sets plant pressure, and the loop that controls airflow to the gasifier. The final control valves are indicated by their process identification number. The control equipment was selected to satisfy two objectives: flexibility of operation normally associated with a pilot plant, and realistic simulation of the control strategy proposed for a commercial plant.

Operation of the facility is normally conducted in one of two modes, as shown in Figures 21 and 22. Labeled "open" and "closed" loop, the two modes are identified by whether or not the gas production rate is greater than or equal to the rate of fuel flow to the combustor. In open-loop operation, the gasifier feed rates are held constant and excess fuel is vented and flared. This mode is appropriate for evaluating steady-state performance of the gas producing and cleaning equipment. Closed-loop operation requires that the gasifier feed rates be adjusted so that the manufactured gas flow matches the combustor demand. This match is achieved by using the cleanup system exit pressure for control.

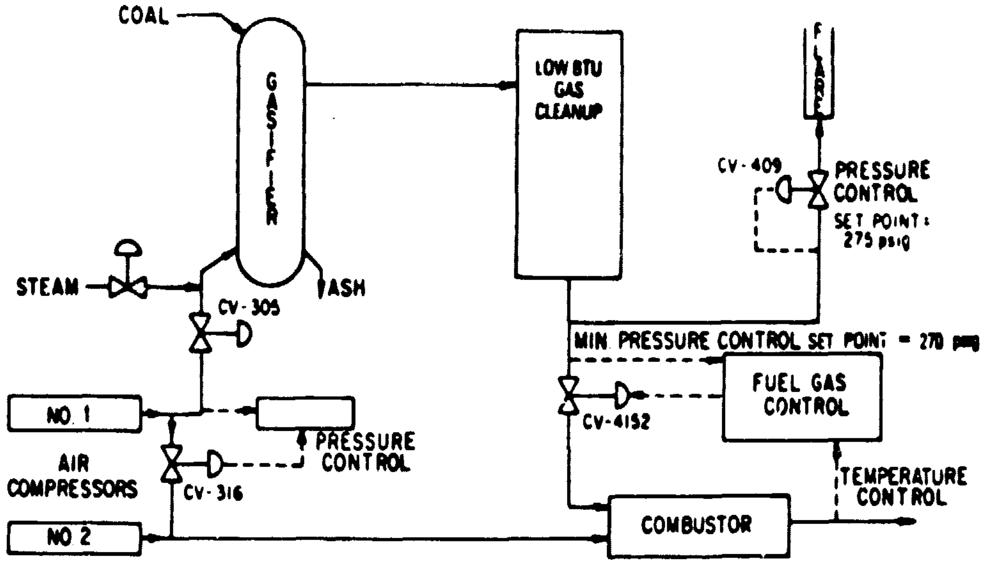


Figure 21. IGCC Pilot Plant Open-Loop Operational Mode

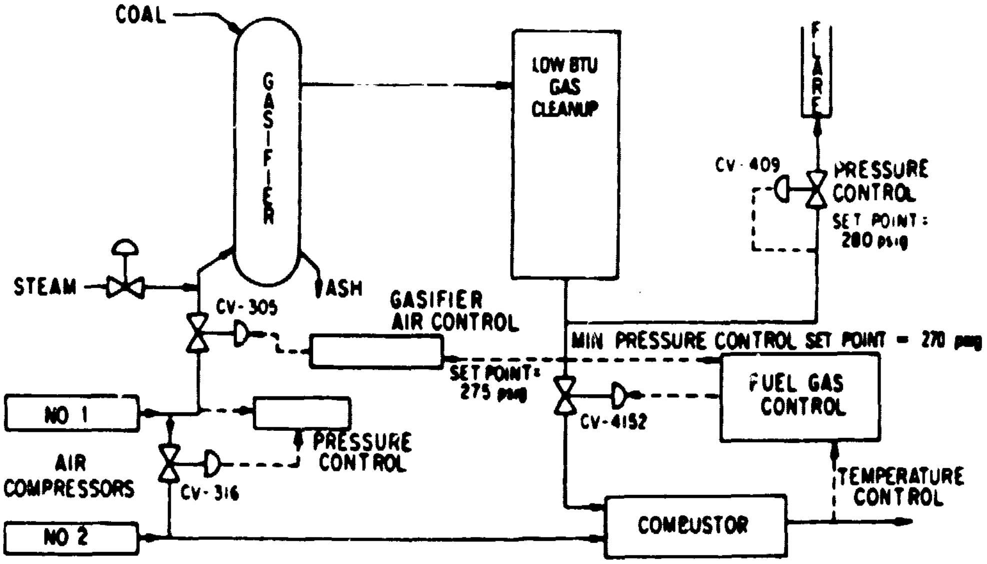


Figure 22. IGCC Pilot Plant Closed-Loop Operational Mode

A.3 SUPPORT EQUIPMENT

A.3.1 Air and Steam Supply Systems

The high-pressure air supply consists of two 800-hp, 3-stage liner-cooled and after-cooled compressors capable of delivering 8 lb/sec of air at 300 psig (Figure 23). Higher pressures (to 500 psig) at somewhat lower flows and higher flows (to 12 lbm/sec) at lower pressures are available; all are capable of convenient adjustment and automatic control. An indirect gas-fired preheater can increase the air temperature at a flow of 8 lbm/sec to 800 °F; temperatures to 1200 °F can be obtained. The whole facility is made compatible with the rest of the

ORIGINAL PAGE IS
OF POOR QUALITY

A.2.4 Turbine Simulator Test Cells

A turbine simulator serves as an experimental power generation simulation which permits realistic interactive studies to be conducted between the fuel plant and the power generation subsystem, and also makes it possible to establish gas quality specifications.

Several turbine simulator test stand facilities have been developed to duplicate the combustion and first-stage turbine nozzle environment of a gas turbine. The simulators provide the research capability to conduct low-Btu gas and liquid fuel combustion research in short-term experiments and to perform materials evaluations of hot-section components in long-term operations.

Turbine Simulator

The original turbine simulator test stand and gas path layout used during previous PEF tests are shown schematically in Figure 19.

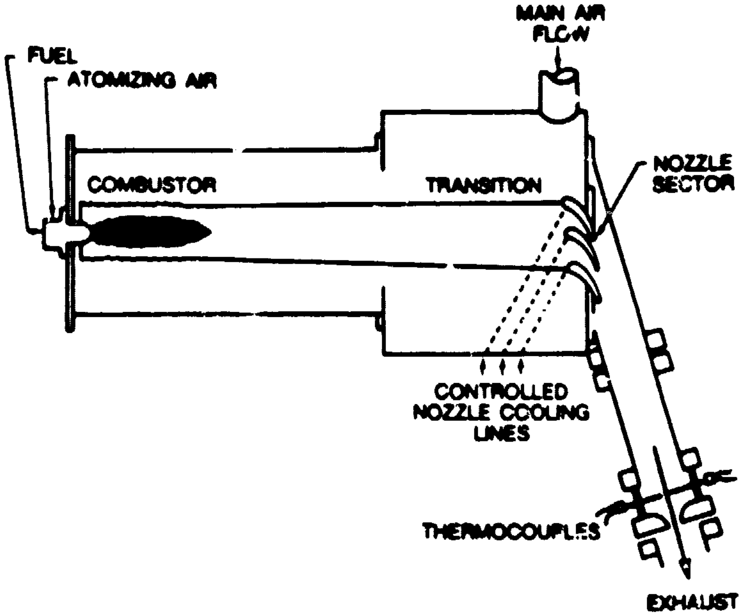


Figure 19. Low-Btu Gas Turbine Simulator (9 atm)

UHT Turbine Simulator

The ultra-high temperature (UHT) turbine simulator, shown in Figure 20, is a high-pressure, high-temperature combustor and nozzle test facility capable of operating at pressures up to 16 atmospheres with a combustor exhaust gas flowrate of 7.5 lbm/sec at temperatures up to 2600 °F. It is composed of three primary sections: the combustor, the (nozzle) test, and the exhaust sections. The combustor section contains a 6-inch diameter, film-cooled can combustor capable of burning liquid or gaseous fuels.

Figure 20 shows a hybrid combustor composed of a metal reaction zone combustor liner followed by a ceramic liner. The circular combustor cross section is connected to a rectangular duct profile by means of a water-cooled transition piece.

ORIGINAL PAGE IS
OF POOR QUALITY

laboratory and its surroundings by use of a large and efficient exhaust system and silencer. Valving is sufficiently versatile to enable the air supply to be adapted to various types of combustion, hot gas path parts evaluation, and gasification test programs.

Low-, medium-, and high-pressure steam supplies are available to the facility. An oil/gas-fired boiler with a capacity of 1.4 lbm/sec at 450 psig is used for the high-pressure steam supply system required for the gasifier blast.

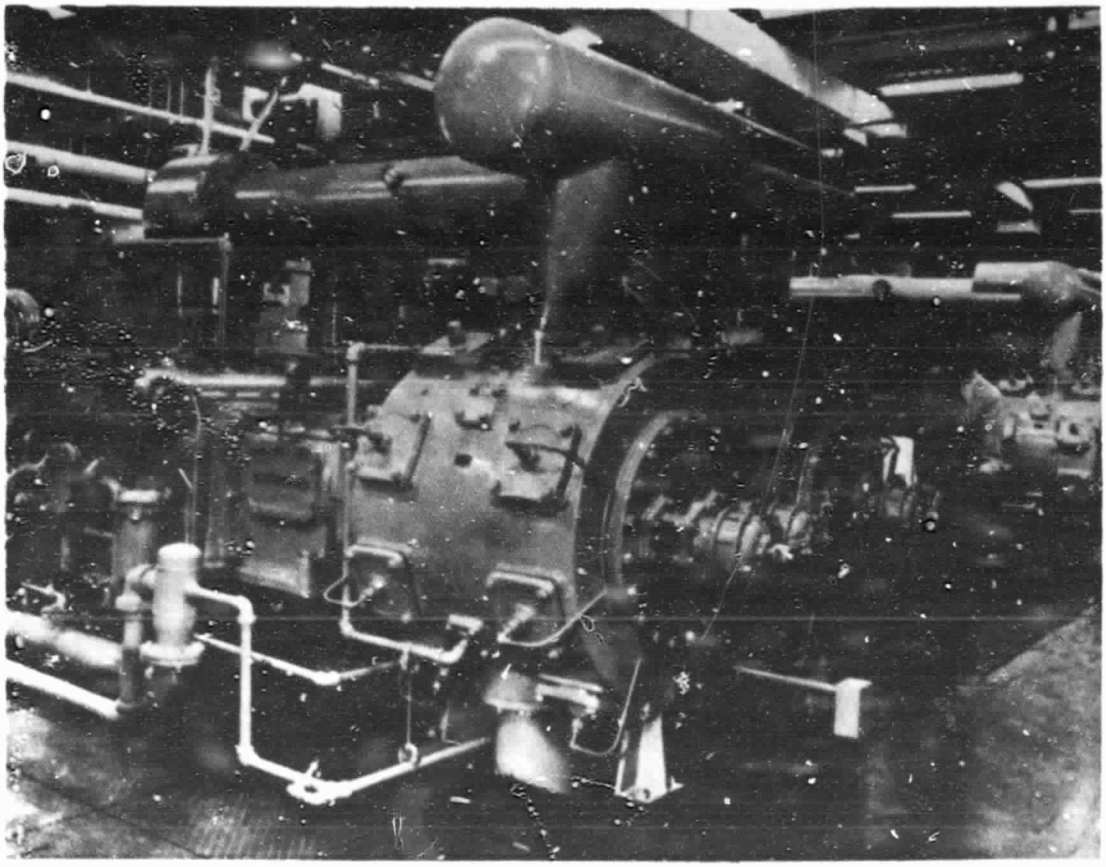


Figure 23. Worthington Compressor

A.3.2 Computerized Data Acquisition and Control System

A hierarchical, multilevel, distributed, real-time, mini/microcomputer-based data acquisition and control system supports the PEF simulation facility. This system provides real-time experimental data acquisition, real-time data analysis, real-time system control, data and calculational result display, test data archiving, post-test data analysis, and real-time and post-test system simulation. The central Hewlett-Packard computer system is shown in Figure 24. The satellite computer and data acquisition system in the gasifier can be seen to the right of center in Figure 15.

Operator interfaces and displays are provided by multiple CRT display terminals supported on RS-232 communication lines to the MUX processor at 9600 baud. Operator selectable alphanumeric displays of up to 20 variables per page are supported throughout the system. These displays are updated with new information as it becomes available in the system with variable update rates ranging from 1 to 20 seconds depending on data acquisition frequency.

ORIGINAL PAGE IS
OF POOR QUALITY

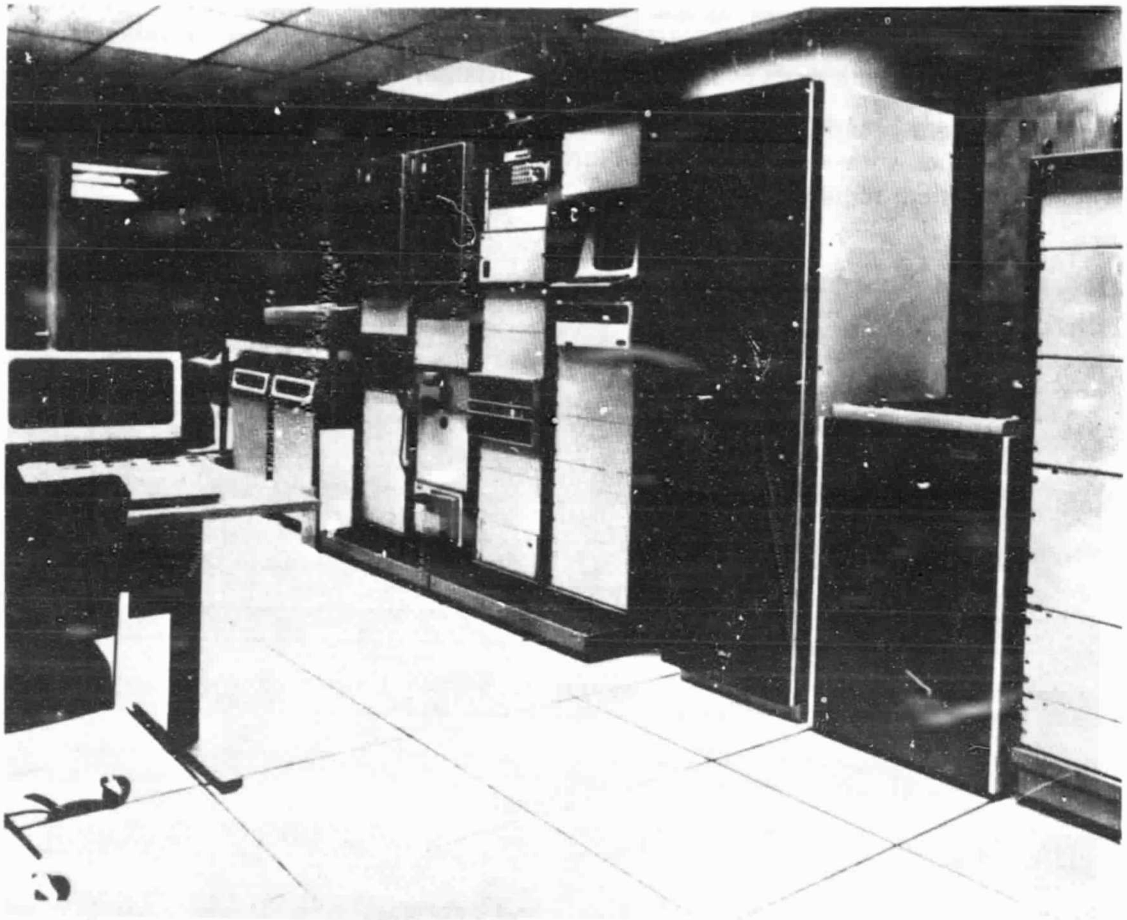


Figure 24. Computer Control System

APPENDIX B*

GAS TURBINE MOBILE EMISSIONS SAMPLING LABORATORY

B.1 SAMPLE PROBES AND SAMPLE LINES

Various sampling probes are used in field measurement. These probes range from lengths of stainless steel tubing to a heavy-duty rail mounted system. The system provides the capability for approximately 9 feet of effective traversing length and accepts either quartz or stainless steel resistively heated liners. Thermocouples are used to monitor stack temperature and liner skin temperature.

The sample is conducted from the probe through a metal T, which contains a thermocouple to monitor sample gas temperature, and then into a resistively heated, large diameter Teflon liner sample hose. The mobile laboratory is equipped with 250 feet of this hose and the main sample pump is sized to provide less than 1 second residence time through 100 feet of hose. Multi-position sampling is accomplished through use of a heated switching box. The large pump and flexible line length permit the sampling of several units in a power block without moving the laboratory. The low residence time, Teflon construction, and temperature control of the liners assure the integrity of all sample species. Leaks are identified by spraying freon degreaser on all joints while operating the sample pump at test flow. Even minute leaks are immediately indicated by a deflection of the hydrocarbon analyzer recorder.

B.2 SAMPLE FLOW AND SAMPLE CONDITIONING

The sample flow (Figure 25) is conducted from the sample line through a heated stainless steel T where it splits into main console flow and auxiliary sample manifold flow. A thermocouple is used to monitor the sample line exit temperature.

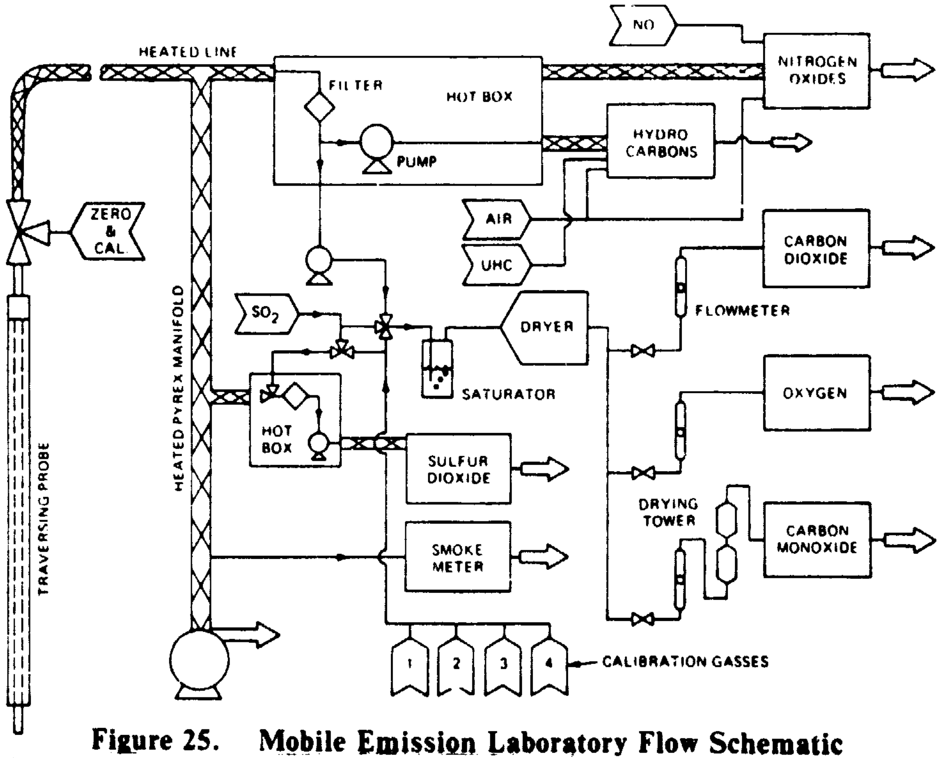


Figure 25. Mobile Emission Laboratory Flow Schematic

---

*Source: "Standard Field Testing Procedure for NO_x Emission Compliance," General Electric Company Gas Turbine Division Report GEK-28172, March 1981.

The main console flow passes through a heated Teflon line to a hot box maintained at 350 °F. The hot sample is filtered and then is split into two flows. One flow stream supplies the heated nitrogen oxides instrument and hydrocarbon instrument, while the other supplies the non-dispersive infrared instruments (NDIR) and the paramagnetic oxygen analyzer. The flow to the heated instruments is pumped via a metal bellows pump within the hot box and conducted via heat traced Teflon lines directly to the instruments. The other flow is cooled and pumped by another metal bellows pump through a saturator and a refrigerated dryer. Both the sample and calibration gases pass through the saturator and dryer. This ensures that the effects of moisture content are identical for sample and calibration gases. With the exception of the flow to the carbon monoxide instrument, the flows pass through a simple flowrater and then directly to the instruments. Because carbon dioxide causes an appreciable interference response from the NDIR measuring CO, the flow to this instrument passes through an Ascarite absorber to remove the CO_2 and then through a Drierite column to remove the water generated by the Ascarite absorption process.

The auxiliary sample manifold is a heated Pyrex section which provides, through ball joint taps, well conditioned samples to any auxiliary instruments used in the test. The sample flow to the sulfur dioxide instrument is also taken from this manifold, filtered, pumped by a heated metal bellows pump and passed through heat traced Teflon tubing to the instrument. The manifold waste flow is cooled by dilution with ambient air, passed through the main sample pump, and vented to atmosphere.

The console is designed so that all piping lengths are kept to a minimum. All materials in contact with the sample are type 316 stainless steel or FEP Teflon. All instruments are vented to atmosphere to eliminate any pressure variation drifts.

B.3 EMISSIONS CONSOLE CALIBRATION

B.3.1 General

The calibration and zero gases are conducted to the instrument via FEP Teflon tubing. Selection of the desired gas is made through a system of manual valves so arranged that the hydrocarbon and nitrogen oxides instruments may be checked for zero and calibration drift independently of each other and the other instruments. The NDIR instruments and the paramagnetic oxygen instrument are calibrated as a group.

B.3.2 Compliance Testing

A calibration system is installed which allows selection and control of calibration gases from within the mobile emissions laboratory to comply with the USEPA sampling method. These calibration gases are routed through Teflon lines to the temperature measurement T at the interface between the probe and the heated sample line. This allows the simultaneous calibration of the entire sampling system and instruments. The response time of the entire system (except the probe) may also be determined.

B.3.3 Certification of Calibration

The calibration and zero gases are subjected to USEPA Protocol I or other USEPA approved analysis by the vendor (Scott Research Laboratories). The nitrogen oxide calibration gas is subjected to analysis using the phenoldisulfonic acid method.

B.4 DESCRIPTION OF CONSOLE INSTRUMENTS

B.4.1 Flame Ionization Total Hydrocarbon Analyzer

Unburned hydrocarbons are analyzed using a Beckman Model 402 flame ionization detector (FID). A flow diagram of this analyzer is shown in Figure 26. This analyzer was designed specifically to determine the total hydrocarbon concentrations in the exhaust of diesel and turbine engines. It consists of a heated inlet sample line, an analyzer module, and an electrometer amplifier module.

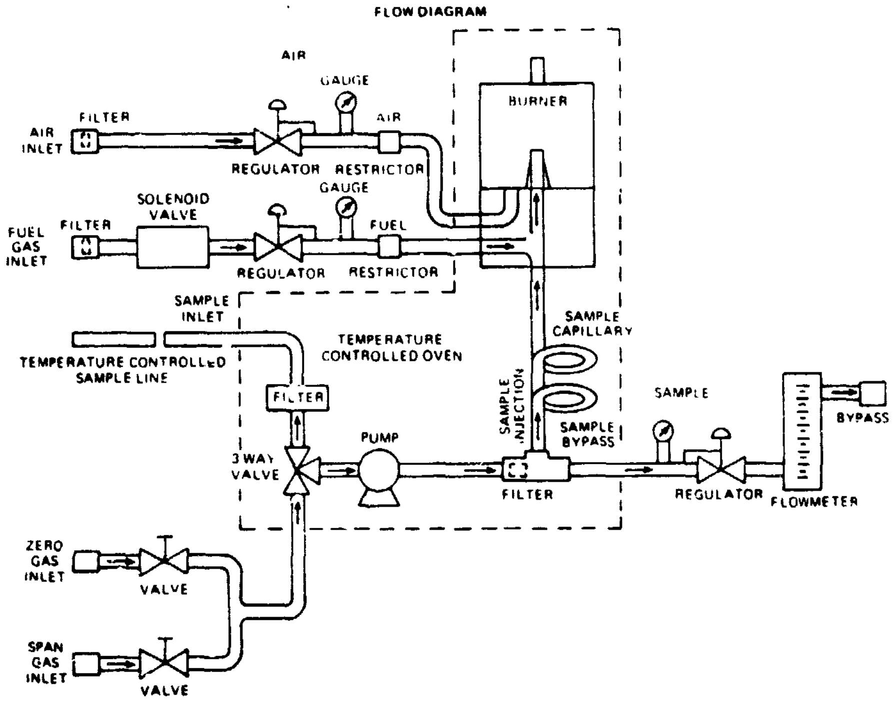


Figure 26. Flow Diagram

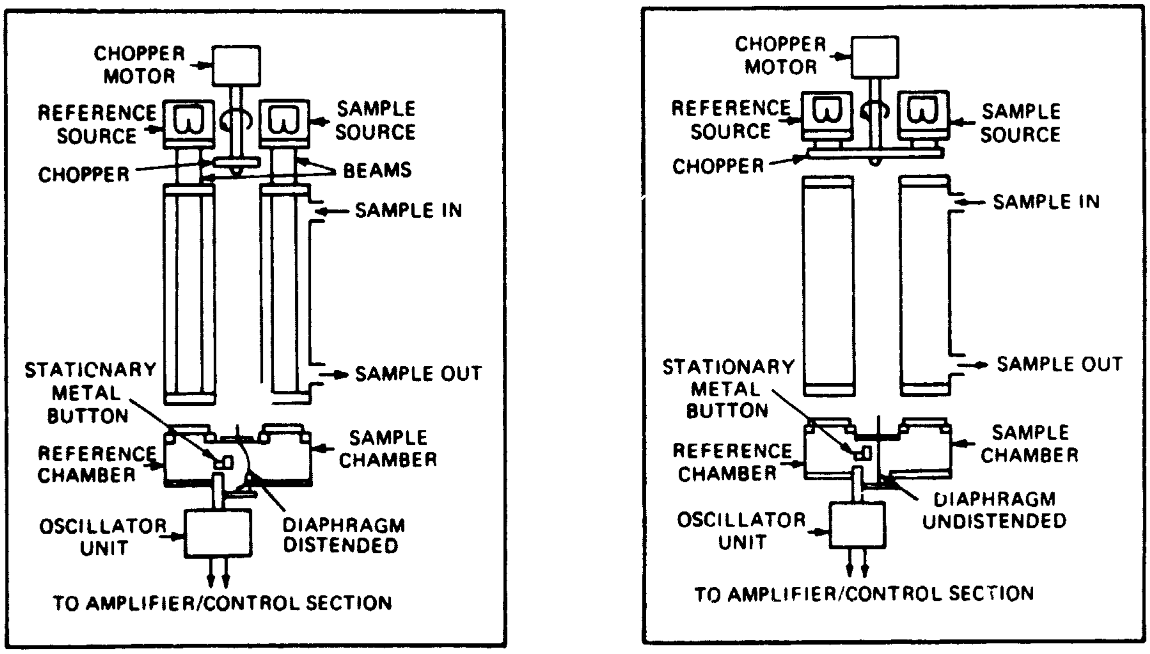
The FID analyzer utilizes the flame ionization method of detection. The sensor element is a burner where a precisely controlled flow of sample gas passes through a hydrogen/air flame sustained by regulated flows of fuel and air. Within this flame, the hydrocarbon components of the sample gas undergo a complex ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing a current to flow through an electronic measuring circuit. This ionization current is proportional to the rate of HC bonded carbon atoms entering the burner and, therefore, is a measure of concentration of hydrocarbons in the sample system.

The exhaust sample is pumped through the temperature-controlled sample line to the analyzer, passed through a glass filter to remove particles, and pumped into the burner. Filter and burner are contained in an oven with a three-way valve that provides selection between the exhaust gas sample and calibration gases. The oven is heated by a resistive heating element. The oven is temperature-controlled by a thermistor and a solid state proportional temperature controller. Thus, the exhaust sample stream can be analyzed without "wall effect" losses of the higher molecular weight components. Oven temperature setpoint is adjustable from 200 °F to 400 °F and maintained at 350 °F.

The electrometer amplifier and output circuitry, housed in a separate enclosure, is mounted in the console. The amplifier has eight range switch positions. A continuous span control permitting a 10-to-1 sensitivity adjustment provides a range of full-scale methane equivalents from 5 ppm to 25,000 ppm, or 50 ppm to 250,000 ppm. Using the lowest full-scale range of 5 ppm, accuracy levels of 1 ppm are available. All other full-scale ranges have 1 percent accuracy or 1 ppm, whichever is greater. The output is recorded on a strip chart recorder and fed directly into the data acquisition system.

B.4.2 Non-Dispersive Infrared CO and CO_2 Analyzers

NDIR analyzers are used to measure the concentrations of CO and CO_2. These analyzers use double-beam optical system to measure the differential absorption of infrared energy (Figure 27). Two infrared sources are used, one for the sample energy-beam and one for the reference energy-beam. The beams are blocked simultaneously ten times per second by a chopper, a two-segment blade rotating at 5 revolutions per second. In the unblocked condition, each beam passes through the associated cell and into the detector. The sample cell is a flow-through tube that contains a continuous stream of the sample gas. The reference cell is a sealed tube filled with reference gas, selected for minimal absorption of infrared energy of those wavelengths absorbed by the sample component.



a. BEAMS NOT BLOCKED BY CHOPPER PASS THROUGH CELLS AND INTO DETECTOR

b. BEAMS BLOCKED BY CHOPPER DO NOT REACH DETECTOR

Figure 27. Functional Diagram of Nondispersive Infrared Analyzer

The detector consists of two sealed compartments separated by a flexible metal diaphragm. Each compartment has an infrared-transmitting window to permit entry of the corresponding energy-beam. Both chambers are filled, to the same subatmospheric pressure, with the vapor of the sample component. Use of this substance as the gas charge in the detector causes the instrument to respond only to that portion of net difference in energy due to the presence of the measured component in the sample cell. When the chopper blocks the beams, temperature and pressure in the two chambers are equal and the diaphragm is in an undistended condition. As the chopper alternately blocks and unblocks the beams, the sample chamber is heated less than the reference due to absorption of infrared energy in the sample path, and the diaphragm pulses, changing the detector capacitance cyclically. The detector is part of an amplitude modulation circuit which has an output proportional to the peak-to-peak variation of the input.

The meter reading is a function of the concentration of the sample component. The instrument is adjusted so that a zero reading or any desired arbitrary reading corresponds to a concentration of zero percent of the sample component while a full-scale reading corresponds to the highest concentration in the operating range. Since the reading is proportional to the difference in absorbed energies in the two cells, and since the absorbed energies are related to the sample concentration by Beer's Law, the logarithm of the signal is proportional to the sample concentration. A passive resistance circuit is used to linearize the input to the recorders. The linearity of the system is verified using a minimum of three calibration gases plus a zero gas.

B.4.3 Chemiluminescence NO and NO_2 Analyzer

General

A chemiluminescence analyzer is used to measure NO and NO_2. (The shorthand $NO_x = NO + NO_2$ will often be used.) NO is measured directly using the following reactions:

$$NO + O_3 \rightarrow O_2 + NO_2^*$$

$$NO_2^* \rightarrow NO_2 + h\nu \text{ (light quantum)}$$

where NO_2^* is NO_2 in an electronically excited state. With the spontaneous emissions of a light quanta ($h\nu$), the NO_2^* returns to its ground state. The total quantum of light emitted within the reaction chamber are proportional to the mass flow rate of NO into the reaction chamber. The light emission is measured by a photomultiplier tube and associated electronics.

A Beckman 955 chemiluminescence analyzer (Figure 28) is utilized. The NO of the sample is measured directly with this instrument. The instrument operates near atmospheric pressure eliminating auxiliary vacuum pumps, and the maintenance associated with oil replacement, air leaks, etc. Internal temperature of the analyzer flowpaths is controlled at about 160 °F-180 °F to prevent moisture condensation within the system. The measurement of the total NO_x concentration of the exhaust gas is accomplished by the use of a catalytic converter. This device reduces the NO_2 in the exhaust sample to NO and oxygen by heating the sample to a prescribed temperature for a given period of time in the presence of carbon and a catalyst, according to the equation:

$$NO_2 + C \xrightarrow{\text{catalyst}} NO + CO$$

If the sample leaving the converter is passed through the NO analyzer, the analyzer will indicate the NO_x concentration (i.e., the sum of the newly formed NO plus the NO present in the original stream).

A 32 °F dewpoint dryer is incorporated in the sample system to eliminate the dilution and interference effects (see below) of water vapor in the sample gas. The dryer is located downstream of the NO_2 to NO converter (Figure 28) because NO_2 is soluble in the condensate and NO is not. It is impractical to pass the entire sample flow through the dryer because of the large flows used to minimize sample system residence time. A valve arrangement allows the instrument to be operated with or without the dryer. All materials used in the dryer are Teflon, 316SS, or Pyrex. The dryer is always used during a compliance test.

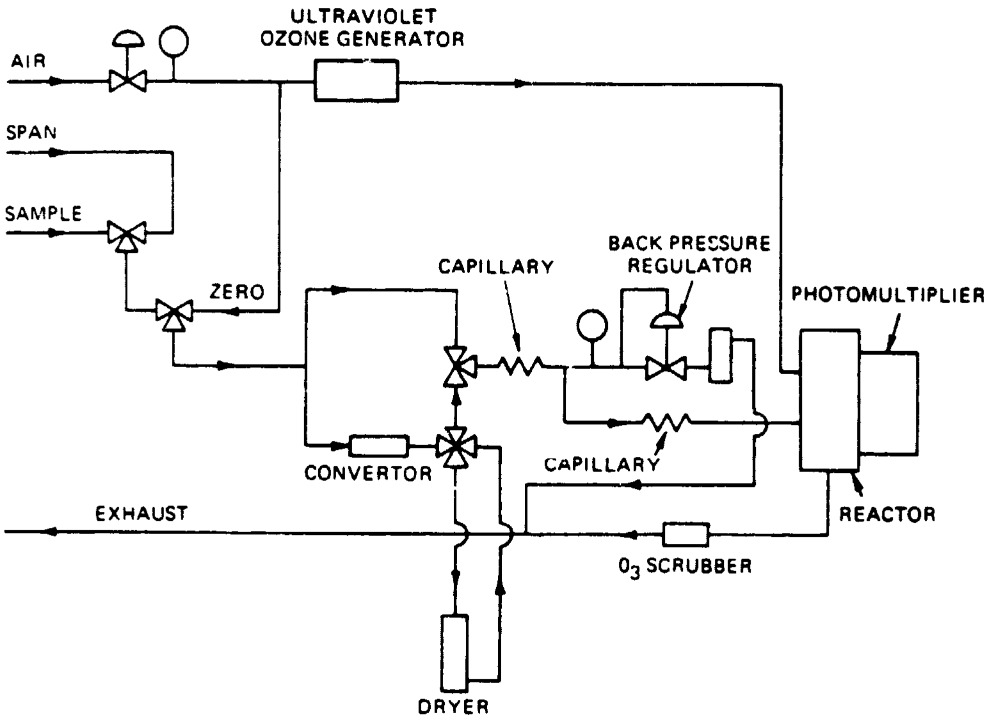


Figure 28. Schematic Diagram of Chemiluminescence Analyzer

Efficiency of Conversion of NO_2 to NO

A check is made before and after each test using a ThermoElectron Model 100 NO_x generator (Figure 29) to ensure that the efficiency of conversion of NO_2 to NO is satisfactory. The NO span gas, which is in nitrogen, is diluted with oxygen or air. The diluting stream is subjected to ultraviolet radiation in the ozonator which generates O_3. The O_3 immediately reacts with the NO in the calibration gas to form O_2 and NO_2. The resulting stream is passed to the chemiluminescence instrument. Any difference between the readings in the NO (no converter) and NO_x (converter) modes of measurement is due to converter efficiency since the flows are balanced (see below). A converter efficiency less than 95% is unacceptable and the converter is replaced. The converter temperature is continuously monitored so that any drift may be detected.

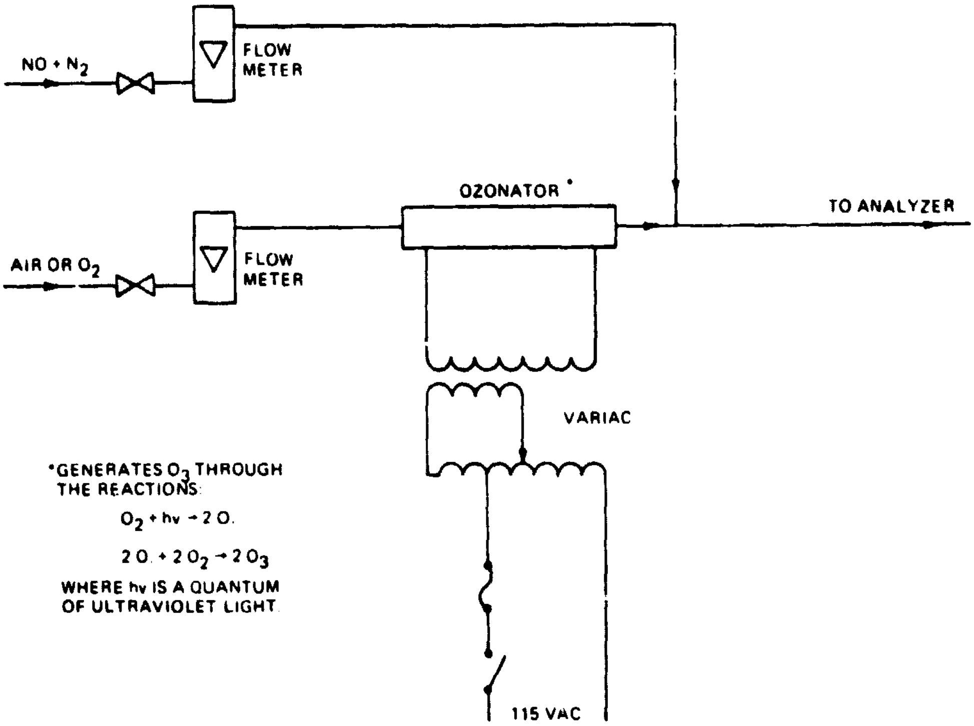


Figure 29. Model 100 NO_2 Generator

Equivalence of NO_x and NO Measurement Modes

Because of the different flow paths, the NO_x and NO measurement modes of operation result in essentially two different instruments with a common detector. The flow in the two modes must be very carefully balanced because the response of the instrument is directly proportional to the sample flow through the detector. The manufacturer's procedure depends upon a "NO_2 free" calibration gas (1.0 ppm NO_2 is the limit of certification). For a 75 ppm gas, this would result in a possible error of 1.3% in the flow balance if the converter efficiency were 100%. The efficiency can not be checked much closer than ± 1.3%. Under these circumstances the accuracy of NO_2 measurements (which is determined by the difference) could be in error by ± 3.9%.

To avoid this error problem, Hastings Model AII-500 mass flowmeter is used to ensure that the flows are balanced. The *repeatability* of measurements of mass flow rate of this instrument is ± 0.5% of F.S. At any given time, the NO mode and the NO_x mode flows may be reliably balanced to within 2.5 standard cubic centimeter/min. for a total flow of 200 sccm.

However, experience has shown that these flows may drift apart by as much as 3% during an 8 hour test. To compensate for this, the NO_x measurement mode and the NO measurement mode are zeroed and calibrated at each calibration point, and separate calibration histories are maintained throughout the test.

Interferences

Because the chemiluminescent method depends upon the measurement of emitted light, there are two routes for direct interference:

1. Positive interference due to a gaseous species which reacts with ozone or some other constituent of the exhaust gas to produce light. This light must lie in the same wavelength range as the NO, O_3 reaction because of the optical filter and photomultiplier characteristics.
2. Negative interference due to a species which depletes either the NO or O_3.

In addition to these direct interferences, there are indirect interferences from species which do not react chemically within the reaction chamber. These species have an effect because most excited NO molecules (NO^*) do not reach their ground state by emitting photons, but instead give up their energy of excitation to another molecule in a collision. These excited molecules are said to be quenched. The efficiency with which the NO^* molecules are quenched depends upon the other molecules participating in the collision. In general, triatomic molecules have higher quenching efficiencies than diatomic. Thus, as H_2O and CO_2 displace nitrogen in a sample gas with constant concentration, the response of the instrument will decrease. Finally, indirect interference may result from sample flow variation due to changes in sample gas composition. In a capillary flow control system, changes in sample gas viscosity cause significant flow variations.

There is no experience to indicate measurable direct interferents (positive or negative) with the chemiluminescent method in the effluent gases from the combustion of residual, crude, or distillate oil, propane, or natural gas. In accord with the USEPA testing procedure, a check of the response to possible interferents is made before each test, and a record kept of the results.

Indirect interferences are more subtle. The major quenching interferents are CO_2 and H_2O. The major interference from the sample flow effect is caused by O_2. During a compliance test, the H_2O is removed by the dryer. In order to eliminate the CO_2 and O_2 interference, modifications must be made to the instrument and to the calibration procedure.

Linearity

Since the reaction of NO with O_3 is a first order reaction, the instrument response is linear to within the limits set by the electronics. This linearity is verified prior to a compliance test, with a minimum of three span gases and a zero gas, and a record is kept of the results.

B.4.4 Paramagnetic Oxygen Analyzer

General

The oxygen analyzer is a Beckman Model F3

The sampling sensor and electronic circuit are shown in Figure 30.

The dumbbell-shaped test body is acted upon by electrostatic and magnetic forces which, in the null position, are balanced and cause the photocells to be equally illuminated. The magnetic force acting upon the test body depends upon the magnetic susceptibility of the gas surrounding it. If the composition of the gas changes, the susceptibility changes. Any

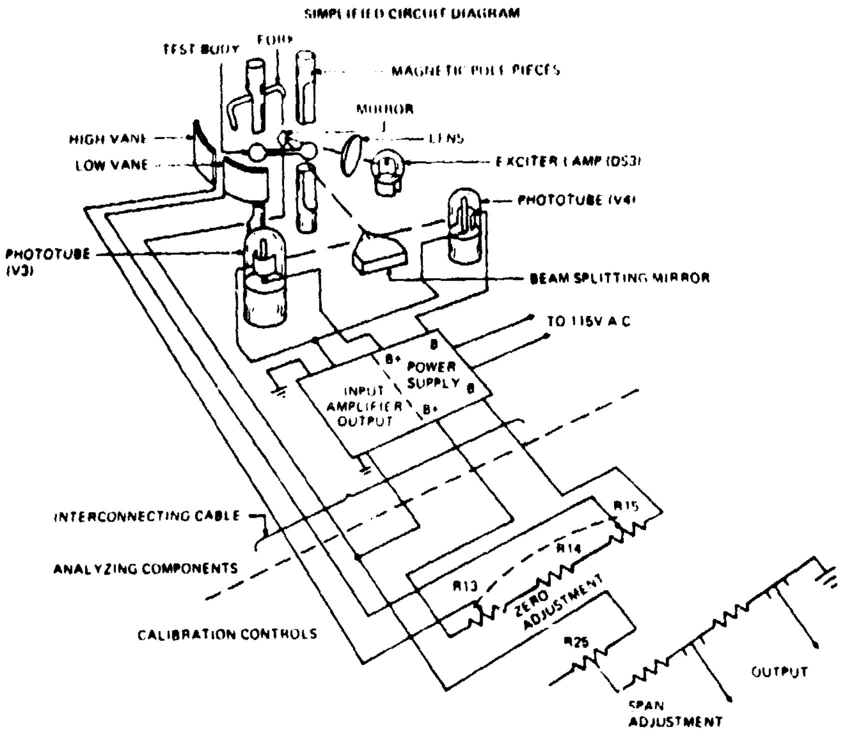


Figure 30. Simplified Circuit Diagram

change causes a rotation of the test body due to the imbalance of the applied magnetic and electrostatic forces. The rotation of the quartz fiber deflects the mirror and unequally illuminates the two photocells. The electrostatic force is then increased to drive the test body back to the null position. The change in voltage necessary to accomplish this is a direct measure of the change in susceptibility.

Interference

The method is specific because of oxygen's highly paramagnetic nature. As shown in Table 12, most other gases with the exception of the nitrogen oxides are weakly diamagnetic. Because of the relative difference in concentrations between nitrogen oxides and oxygen, there is no detectable interference. The most significant interference is due to the change in relative concentration of nitrogen. This interference is taken into account in the data reduction procedure.

Linearity

The null-balance principle of operation of this instrument insures that it will be stable and precise. The linearity of the instrument is better than the agreement among the gases used as a check. The linearity is verified prior to compliance test with at least two span gases plus a zero gas and a record kept of the results.

Table 12

OXYGEN EQUIVALENTS OF COMMON GASES

Gas	Equivalent Percent of Oxygen	Equivalent Partial Pressure of Oxygen (mm Hg)
Acetylene, C_2H_2	−0.612	−4.65
Allene, C_3H_4	−0.744	−5.65
Ammonia, NH_3	−0.479	−3.64
Argon, A	−0.569	−4.32
Bromine, Br_2	−1.83	−13.9
1,2-Butadiene, C_4H_6	1.047	−7.95
1,3-Butadiene, C_4H_6	−0.944	−7.17
n-Butane, C_4H_{10}	−1.481	−11.25
iso-Butane, C_4H_{10}	−1.485	−11.28
1 Butene, C_4H_8	−1.205	−9.15
cis 2-Butene, C_4H_8	−1.252	−9.50
iso-Butene, C_2H_8	−1.201	−9.12
trans 2-Butene, C_4H_8	−1.274	−9.68
Carbon Dioxide, CO_2	−0.623	−4.73
Carbon Monoxide, CO	−0.354	−2.69
Ethane, C_2H_6	−0.789	−5.99
Ethylene, C_2H_4	−0.553	−4.20
Helium, He	−0.059	−0.45
n-Heptane, C_7H_{16}	−2.508	−19.0
n-Hexane, C_6H_{14}	−2.175	−16.5
cyclo-Hexane, C_6H_{12}	−1.915	−14.55
Hydrogen, H_2	−0.117	−0.89
Hydrogen Bromide, HBr	−0.968	−7.35
Hydrogen Chloride, CHI	−0.650	−4.94
Hydrogen Fluoride, HF	−0.253	−1.92
Hydrogen Iodide, HI	−1.403	−10.7
Hydrogen Sulphide, H_2S	−0.751	−5.71
Krypton, Kr	−0.853	−6.48
Methane, CH_4	−0.512	−3.88
Neon, Ne	−0.205	−1.56
Nitric Oxide, NO	+44.2	+336.0
Nitrogen, N_2	−0.358	−2.72
Nitrogen Dioxide, NO_2	+28.7	+218.0
Nitrous Oxide, N_2O	−0.56	−4.26
n-Octane, C_8H_{18}	−2.84	−21.6
Oxygen, O_2	+100.0	+760.0
n-Pentane, C_5H_{12}	−1.81	−13.75
iso-Pentane, C_5H_{12}	−1.853	−14.08
neo-Pentane, C_5H_{12}	−1.853	−14.08
Propane, C_3H_8	−1.135	−8.62
Propylene, C_3H_6	−0.903	−6.86
Water, H_2O	−0.381	−2.90
Xenon, Xe	−1.34	−10.4

B.4.5 Spectroscopic Sulfur Dioxide Analyzer

The SO_2 analyzer is a Lear Seigler Model SM1000 Spectroscopic Analyzer.

Many compounds, both gases and liquids, absorb light. Generally, a compound will absorb light of a particular wavelength and not light of some other wavelength.

The wavelength of radiation determines the energy content of the radiation. Long wavelength radiation, such as infrared or heat, has very low energy content. Visible light has higher energy content and ultraviolet light is very high in energy content. As this energy passes through the gas, it is absorbed by the molecules of the gas. Often, only narrow bands of wavelengths are absorbed for the physics of the molecule demand that only particular energies are allowed to be absorbed. These allowed energies (absorption bands) are different for each molecule (type of gas). The absorbing power of a particular gas is defined through a physical constant called the absorption coefficient, $a(\lambda)$, which is a function of wavelengths. The constant $a(\lambda)$ is zero at those wavelengths where the gas does not absorb and becomes greater than zero at wavelengths where absorption occurs. The larger $a(\lambda)$, the greater the gases strength of absorption. The absorption of light can be measured as follows:

Light of the intensity Io of a particular wavelength λ can be directed through a cell of length b. Gas, inside the cell, at concentration c absorbs some of the light, and that not absorbed exits at intensity I. This exiting intensity is predictable using the formula, known as Beer's Law:

$$I(\lambda) = Io(\lambda)\, e^{-a(\lambda)bc}$$

Io = Incident Intensity

I = Exiting Intensity

c = Concentration of Absorbing Gas

b = Pathlength Through the Gas

$a(\lambda)$ = Absorption Coefficient of the Gas

If the absorption coefficient $a(\lambda)$ is known, the concentration of the gas in the cell can be determined by measuring the incident and exiting intensities. That is

$$C = \frac{1}{a(\lambda)b} \ln \frac{Io}{I}$$

For example, using a 1 Meter cell ($b = 100$ cm), at 3000A, SO_2 has a maximum absorption coefficient value of 20 $(\text{atm-cm})^{-1}$. Beer's Law predicts 10% absorption ($Io/I = 1.1$) at 50 ppm SO_2 and 1% absorption at 5 ppm.

The SM1000 is a tuned second derivative spectrometer coupled with a multipass analysis cell. An optical schematic of the instrument is shown in Figure 31. Radiation from an ultraviolet or visible light source is spectrally dispersed by a grating monochromator so that the radiation leaving the exit slit is monochromatic in wavelength.

The light generated by the ultraviolet source is modulated at 45 hertz by the oscillating entrance slit of the monochromator. This entrance slit is driven by the Wobbler. The wavelength modulation of the light produces the second derivative signal. The monochromator selects the center wavelength about which the modulation occurs. The monochromator wavelength is factory set at the peak of an absorption band belonging to the gas to be measured. The light, after exiting the monochromator, passes through the sample cell. The gas being measured is passed continuously through the sample cell.

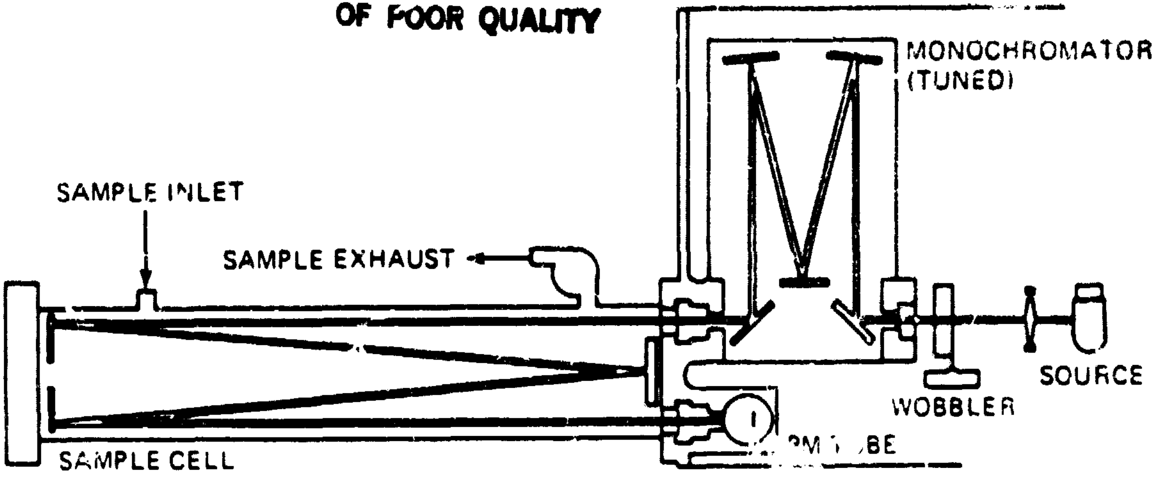


Figure 31. SM1000 Optical Schematic

After exiting the sample cell, the light is focused on the photomultiplier tube detector. The output of the photomultiplier contains a dc voltage proportional to the total light reaching the detector and superimposed on the dc level is an ac "ripple" corresponding to the second derivative (d^2) signal. This second derivative signal is proportional to the concentration of the gas in the sample cell. The output of the photomultiplier tube is fed into the analyzer unit for processing.

The output of the analyzer is recorded on a strip chart and inputted to the digital data acquisition system. The instrument may be operated in a 0 – 100 ppmv, or 0 – 500 ppmv range.

B.4.6 Traveling Tape Smoke Sampler

The basic smoke sampler used is the Von Brand filtering recorder which draws a gas sample through a moving strip of Whatman #4 laboratory filter paper. The system uses a 1/2 inch wide sampling opening with a tape speed of 4 inches per minute. To ensure that sample volume flow is always constant, a Fisher-Porter "Minirator" with a maximum flow of 32 cubic feet per hour, is used to measure the sample flow before it reaches the tape.

The sample passes through the flowrator and then to the sampling head where the carbon particles are filtered out by the filter paper. With the sampling pump and the tape drive motor running, the flow is adjusted to 13.0 cubic feet per hour with a tape speed of 4 inches per minute. Minimum sampling time is two minutes per point with more time preferable to assure steady-state sampling conditions.

The exhaust gas from the machine is drawn through the gaseous emissions probe as described above. The smoke sampler is operated from one of the auxiliary sample manifold taps because there is no probe filter. The use of isokinetic sampling has been tested and seems to be unnecessary.

The Von Brand Reflective Smoke Number (VBRSN) is determined from the soiled tape using a Photovolt Model 610 Reflection Meter which has been calibrated with a set of certified standard reflectance tiles. After calibration, the amount of light reflected from the smoke stain is compared to that reflected from clean tape. The tape is backed with an enamel standard known reflectance to prevent room lighting from affecting the reading. The reflected measurement is obtained through a green tri-stimulus filter to make it equivalent to a grey scale value. A more complete description of this procedure may be found in Appendices A-1 and 2 of the A.S.T.M. tentative smoke measuring method paper (D2157-63T).

APPENDIX C

CHRONOLOGICAL RECORD

DATE	TIME	COMMENTS
8-18-81	1030	First cold airflow through reactor.
	1300	Fix air leaks at fuel injection tube fittings.
	2100	Shut down compressors.
8-20-81	0600	Started airflow through rig.
	0615	Started air preheater.
	1030	Pressurizing fuel supply lines to rig.
	1155	Began passing fuel gas through by-pass at rig.
	1610	First fire in rig.
	1612	Trip due to mixup in overtemp controllers.
	1614	Relight very easily.
	1620	Operating at 1880 °F (1300 K) exit temperature.
	1640	Operating at 2150 °F (1450 K) exit temperature.
	1645	Shut down rig and air supply.
8-21-81	0900	Made minor adjustment in backpressure valve seat setting.
8-26-81	1530	Replaced reactor TC #10.
8-27-81	0800	Started airflow.
	1000	Started preheater.
	1425	Pressurize gas line.
	1430	Bypassing gas.
	1526	Light off.
	1530	Overtemp trip on premixer exit temperature.
	1608	Relight at somewhat reduced airflow.
	1620	Increasing reference velocity at 20 m/sec.
	1640	Flameout
	1655	Relight
	17[illegible]5	Flameout
	1732	Relight at increased air inlet temperature.

---

*Excerpted from Operator's Test Log.

	1822	Flameout while increasing exit temperature from 1640 to 1730 °F.
	1835	Completed test point 16 after relight.
	1844	Completed test point 17.
	1905	Continuing to see erratic behavior in premixer exit temperature.
	2005	Shut down for day. Suspect pre-ignition in premixer section is occurring.
8-28-81	1500	Partially disassembled rig and discovered apparent F.O.D. damage to first catalyst element. Arranged to procure a replacement.
8-31-81	0930	Began installing new #1 catalyst element.
	1500	Began flowing air through rig.
	1730	Pressurized gas line and began bypassing gas.
	2400	Experienced difficulties with compressor controls, now back on line and ready to go.
9-1-81	0004	Light off at 30% water, no problems.
	0134	Flameout — reason unknown.
	0138	Relight.
	0218	Data taken, test point 16.
	0254	Now attempting pt 18, seeing excessive temperature at test section #6 0.25" (255°).
	0259	Now attempting pt 21.
	0307	Lost fire but regained spontaneously. Very large variation in conditions, velocity went up to 50 m/s.
	0313	Flameout due to overtemp at premixer exit.
	0317	Relight.
	0400	Exhaust emissions sampling system is down. Gaining operating experience only.
	0506	Forced to shut down due to problems in fuel plant.
9-2-81	0247	Started airflow through rig. Preheater started.
	0420	Bypassing gas.
	0444	Light off on second try.
	0513	Flameout — reason unknown. Relight.
	0611	Completed pt 16.
	0641	Completed pt 17. Back down to pt 16.

0721	Flameout due to overtemp at premixer exit. Relight.
0734	Completed pt 26.
0827	Flameout due to overtemp at premixer exit.
0830	Relight.
0850	Experiencing wild fluctuations (280-800 °F) in premixer exit temperature.
0857	Flameout due to overtemp at premixer exit.
0902	Relight.
0908	Flameout – premixer overtemp.
0909	Relight.
0916	Still getting wild fluctuations. Shut down intentionally to bleed water traps.
0919	Relight.
0944	Flameout – premixer overtemp.
1006	Relight.
1053	Flameout – reason unknown.
1102	Relight on second try.
1218	Completed pts 21 and 22.
1240	Completed pt 23.
1240	Flameout – reason unknown.
1400	Have installed bleed in bottom of fuel manifold.
1413	Relight.
1503	Flameout – premixer overtemp. Relight.
1628	Flameout – premixer overtemp. Relight.
1658	Lost preheater.
1732	Flameout due to low inlet temperatures.
2035	Preheater fixed.
2058	Airflow restored. Bypassing gas.
2112	Relight.
2130	Many TCs not working and no chamber DP. Is bed gone?
2230	Relight and hold low heat (1400 °F). Looks bad. Shutdown.
2303	Removed exhaust pipe. No bed left.

9-21-81	1400	New combustor arrived by truck and is now being installed.
	1815	Now flowing preheated air.
	2240	Attempted light off.
	2310	Not successful in lighting off. Technician and engineer entered cell to bleed water traps. Ignition apparently occurred at this point and lasted about 2 minutes. Gas was valved off all during this time. This entire sequence was repeated, with the same results. Fire was not as hot the second time, but lasted longer. Gas velocity was increased from 5-10 m/sec to 30 m/sec. This time light off went smoothly.
	2320	Holding steady at low flame temperatures. Still experiencing wild premixer exit temperature variations.
9-22-81	0222	Now operating more or less stably at pt 36 conditions. Having some computer difficulties.
	0315	Have now completed pts 36-38. Cannot go further due to high bed temperature (TS #6 0.25"/345°).
	0622	Completed points 31-33 after solving some problems with CO, CO_2, and O_2 emissions instruments.
	0721	Have redone pts 36-38. Trying for pt 21.
	0745	Flameout due to reactor exit overtemp. Seeing extreme temperature oscillations at the time.
	1024	Relight. Attempt to run at point 6 conditions.
	1235	Just getting stabilized. Must shut down due to gasifier problems.
	1642	Relight.
	1743	Completed pt 6.
	1820	Completed pts 7-9. Everything looks good.
	1842	Completed pt 3.
	1910	Completed pt 4. Having computer problems.
	1930	Completed pts 1 and 2.
	2024	Completed pt 21. Having computer problems.
	2038	Completed pt 22.
	2049	Completed pt 23.
	2107	Completed pt 16.
	2141	Completed pt 17.
	2215	Completed pt 18.
	2244	Trying for pt 11. Much trouble with temperature oscillations.
	2256	Trying for pt 26. Still having problems.

	2342	Flameout – premixer exit overtemp. Relight.
9-23-81	0004	Give up. Go on to point 46.
	0053	Completed pt 46.
	0100	Completed pt 47.
	0107	Completed pt 48.
	0202	Completed pt 49. Go on to point 51.
	0216	Cannot achieve airflow for pt 51. Try to reach pt 41.
	0232	Flameout – premixer exit overtemp. Extreme oscillations. Relight.
	0450	Tried to achieve pt 56 but ran into problems with excessive preheater exit temperature.
	0617	Preheater flameout.
	0640	Preheater restarted.
	0715	Flameout – reason unknown. Relight.
	0730	Tried pt 26 again. Still encountering instabilities.
	1213	Flameout – premixer exit overtemp. Relight.
	1245	Shut down to check instrumentation. Found premixer exit TC was broken (?).
	1320	Relight.
	1410	Down due to contractor blunder unrelated to system but which shut down gasifier.
	1910	Started airflow and preheater.
	2230	Bypassing gas.
	2307	Light off on second try.
	2347	Trying to get pt 56. Having trouble with preheater dropping out.
9-24-81	0100	Completed pts 56-58.
	0130	Can't quite get to pt 59 due to preheater temperature limit.
	0227	Tried to do pts 61-64 but preheat was a little low at each point. Shut down system.
	0910	Started airflow and preheater.
	1009	Relight. Try to redo pt 56.
	1057	Catalyst bed exit temperatures look strange.
	1103	Shut down system.