

FINAL REPORT
VOLUME 2: PROJECT PERFORMANCE
AND ECONOMICS

PULSE COMBUSTOR DESIGN QUALIFICATION TEST
AND
CLEAN COAL FEEDSTOCK TEST

PREPARED FOR:

U.S. Department of Energy
National Energy Technology Laboratory
(Under Cooperative Agreement No. DE-FC22-92PC92644)

PREPARED BY:

ThermoChem, Inc.
6001 Chemical Road
Baltimore, Maryland 21226

Draft Report Issued on: February 18, 2002

Final Report Issued on: March 29, 2002

Appendix G, Data Trends Added on: January 22, 2003

DISCLAIMER

This is a report of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their support contractors, make any warranty, express or implied; or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed; or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, mark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of the authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

This report was prepared by ThermoChem, Inc. pursuant to a cost-shared Cooperative Agreement (No. DE-FC22-92PC92644). ThermoChem, its employees, officers or its subcontractors, nor any person acting on behalf of either:

- (a) *Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or*

- (b) *Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendations, or favoring by ThermoChem*

FORWARD

This work was performed under Cooperative Agreement No. DE-FC22-92PC92644 between the United States Department of Energy ("DOE) and ThermoChem, Inc (TCI). The work was carried out by (TCI) at its development testing and manufacturing facilities located at 6001 Chemical Road, Baltimore, Maryland 21226. Participants associated with this project are given below:

ThermoChem, Inc.

Project Manager/Chief Engineer – W. G. Steedman
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 43
Fax: (410) 354-9894
E-mail: wstedman@tchem.net

ThermoChem Business Official

Vice President – L. Rockvam
ThermoChem, Inc.
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

U.S. Department of Energy

Project Manager – Leo E. Makovsky
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, Pennsylvania 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

ABSTRACT

For this Cooperative Agreement, the pulse heater module is the technology envelope for an indirectly heated steam reformer. The field of use of the steam reformer pursuant to this Cooperative Agreement with DOE is for the processing of sub-bituminous coals and lignite. The main focus is the mild gasification of such coals for the generation of both fuel gas and char for the steel industry. An alternate market application is also presented for the substitution of metallurgical coke.

This project was devoted to qualification of a scaled-up 253-tube pulse heater module. This module was designed, fabricated, installed, instrumented and tested in a fluidized bed test facility. Several test campaigns were conducted. This larger heater is a 3.5 times scale-up of the previous pulse heaters containing 72 tubes each. The smaller heater was part of previous pilot field test of the steam reformer at Weyerhaeuser's pulp mill in New Bern, North Carolina.

The project also included collection and reduction of mild gasification process data from operation of the process development unit (PDU) in Baltimore. The operation of the PDU was aimed at conditions required to produce char (and gas) for the Northshore Mining in Silver Bay, Minnesota. Northshore supplied the coal for the process unit tests.

ACKNOWLEDGEMENTS

TCI wishes to acknowledge the contributions of the DOE Project Managers on this project namely, Mr. William Mundorf, Mr. Art Baldwin, the late Mr. Steve Heinz, Mr. Bob Kornosky, Mr. Mike Eastman, Mr. Doug Gyorke, Dr. Tom Sarkas, Mr. Gary Stats and Mr. Leo Makovsky. TCI also wishes to acknowledge the contribution of our cost sharing partners during the course of this project, namely Mr. Denny Hunter of the Weyerhaeuser Paper Company, Mr. Lance Ahearn of the Heartland Development Corporation, and Mr. Frank Tenore of ThermoChem Recovery International (TRI). Furthermore, TCI also acknowledges the contributions of Mr. Jack Siegel of Energy Resources International, Mr. Dan Burciaga of Industria and the support by Javan and Walters Engineering Group.

POINT OF CONTACT

ThermoChem, Inc.

Leland (Lee) Rockvam
Vice President
ThermoChem, Inc.
6001 Chemical Road
Baltimore, MD 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

DOE

Leo E. Makovsky
Project Manager
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, PA 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

TABLE OF CONTENTS

		<u>Page No.</u>
Introductory Material		
	Cover Page	
	Disclaimer.....	i
	Forward.....	ii
	Abstract.....	iii
	Acknowledgements.....	iv
	Point of Contact.....	v
	Table of Contents.....	vi
	List of Tables.....	viii
	List of Figures.....	ix
	List of Abbreviations.....	x
	List of Units.....	xii
	Glossary of Terms.....	xiii
	Executive Summary.....	xiv
1.0	Project Overview.....	1-1
1.1	Purpose of the Project Performance and Economics Report.....	1-1
1.2	Overview of the Project.....	1-1
	1.2.1 Background and History of Project.....	1-1
	1.2.2 Project Organization.....	1-2
	1.2.3 Project Description.....	1-2
	1.2.4 Site.....	1-2
	1.2.5 Project Schedule.....	1-4
1.3	Objectives of the Project.....	1-4
	1.3.1 Qualification Test Objectives.....	1-4
	1.3.2 PDU Test Objectives.....	1-4
1.4	Significance of the Project.....	1-5
1.5	Management and DOE's Role in the Project.....	1-6
	1.5.1 Department of Energy.....	1-6
	1.5.2 Project Management and Execution.....	1-7
	1.5.3 Project Organization Chart.....	1-7
2.0	Technology Description.....	2-1
2.1	Description of the Demonstrated Technology.....	2-1
2.2	Description of the Demonstrated Facilities.....	2-2
	2.2.1 Combustor Design Qualification Test Facility.....	2-2
	2.2.2 PDU Test Facility.....	2-3
2.3	Proprietary Information.....	2-10
2.4	Simplified Process Flow Diagram.....	2-10
	2.4.1 Combustor Design Qualification Test Facility.....	2-11
	2.4.2 PDU Test Facility.....	2-11
2.5	Stream Data.....	2-15

TABLE OF CONTENTS (Continued)

	<u>Page No.</u>
2.5.1 Mass and Energy Balance for the Combustor Design Qualification Test Facility.....	2-15
2.5.2 Mass Balance for the PDU Test Facility.....	2-15
2.6 Process and Instrumentation Diagrams.....	2-15
2.6.1 P&ID for the Combustor Design Qualification Test.....	2-15
2.6.2 P&ID for the PDU Test.....	2-15
3.0 Update of the Public Design Report.....	3-1
3.1 Design and Equipment Changes.....	3-1
3.2 Demonstration Plant Capital Costs Update.....	3-1
4.0 Demonstration Program.....	4-1
4.1 Test Plans.....	4-1
4.1.1 Combustor Qualification Tests.....	4-1
4.1.2 Coal Characterization Tests.....	4-3
4.2 Operating Procedures.....	4-5
4.2.1 Instrumentation and Data Acquisition.....	4-5
4.3 Test Methods.....	4-6
4.4 Analyses of Feedstocks and Products.....	4-7
4.5 Data Analysis Methodology.....	4-9
4.6 Data Summary.....	4-10
4.6.1 Qualification Test.....	4-10
4.6.2 PDU Tests.....	4-22
5.0 Technical Performance.....	5-1
5.1 Effects of Operating Variables on Results.....	5-1
6.0 Environmental Performance.....	6-1
7.0 Economics.....	7-1
7.1 Estimated Process Capital Costs.....	7-1
8.0 Commercialization Potential and Plans.....	8-1
8.1 Market Analysis.....	8-1
8.1.1 Applicability of the Technology.....	8-1
8.1.2 Market Size.....	8-2
8.1.2.1 Market Size for Metallurgical Coke Replacement.....	8-2
8.1.2.2 Market Size for Compliance Coal.....	8-2
8.1.2.3 Synthesis Gas for Power Production.....	8-3
8.1.2.4 Synthesis Gas for Industrial Feedstocks.....	8-4
8.1.3 Market Barriers.....	8-4
8.2 Commercialization Plan.....	8-5

APPENDIX A: Test Plan

APPENDIX B: Operating Checkout Procedures

APPENDIX C: Test Input Data

APPENDIX D: Property Data

APPENDIX E: Pulse Combustor Test Data Analysis

APPENDIX F: Macros Reference

APPENDIX G: Data Trends

LIST OF TABLES

	<u>Page No.</u>
Table 2-1: Mass and Energy Balance for the Combustor Design Qualification Test Facility.....	2-16
Table 2-2: Mass Balance for the PDU Test Facility.....	2-17
Table 4-1: Test Matrix.....	4-2
Table 4-2: Coal and Solid Product Analyses.....	4-7
Table 4-3: Gas Analyses.....	4-8
Table 4-4: Condensate Analyses.....	4-8
Table 4-5: Data Summary – Test Operations.....	4-17
Table 4-6: Flue Gas Analysis.....	4-18
Table 4-7: Calculated Results.....	4-19
Table 4-8: Mass Balance for 1,000°F Test.....	4-22
Table 4-9: Mass Balance for 1,100°F Test.....	4-23
Table 4-10: Mass Balance for 1,200°F Test.....	4-24
Table 4-11: Mass Balance Closure for 1,000°F Test.....	4-24
Table 4-12: Mass Balance Closure for 1,100°F Test.....	4-25
Table 4-13: Mass Balance Closure for 1,200°F Test.....	4-25
Table 4-14: VOC in the Product Gas Stream.....	4-26
Table 4-15: SVOC in the Product Gas Stream.....	4-26
Table 5-1: Product Distribution for 1,000°F Test.....	5-1
Table 5-2: Product Distribution for 1,100°F Test.....	5-1
Table 5-3: Product Distribution for 1,200°F Test.....	5-2
Table 6-1: Effluent BOD.....	6-1
Table 7-1: Major Equipment List.....	7-3
Table 7-2: Major Equipment Costs.....	7-5
Table 7-3: Project Total Installed Cost.....	7-7

LIST OF FIGURES

		<u>Page No.</u>
Figure 1-1:	Site Area Map.....	1-3
Figure 1-2:	Organization Chart.....	1-7
Figure 2-1:	PDU Test Facility.....	2-4
Figure 2-2:	Coal Metering and Injection.....	2-5
Figure 2-3:	Pulse Combustor Combustion Air Plenum.....	2-6
Figure 2-4:	Second Cyclone Catch Pot.....	2-7
Figure 2-5:	Steam Boiler and Feedwater RO Unit.....	2-8
Figure 2-6:	Superheaters.....	2-9
Figure 2-7:	Steam Reformer Controls.....	2-10
Figure 2-8:	Block Flow Diagram.....	2-12
Figure 2-9:	PDU Process Flow Diagram.....	2-14
Figure 2-10:	Legend Sheet No. 1 for the Piping and Instrumentation Diagrams.....	2-18
	Legend Sheet No. 2 for the Piping and Instrumentation Diagrams.....	2-19
Figure 2-11:	Process and Instrumentation Diagram for the Combustor Design Qualification Test.....	2-20
Figure 2-12:	Pulse Combustor Cooling Circuit P&ID for Combustor Design Qualification Test.....	2-21
Figure 2-13:	Process and Instrumentation Diagram for the PDU Test.....	2-22
Figure 4-1:	Gas Chromatograph.....	4-6
Figure 4-2:	Firing Rate.....	4-11
Figure 4-3:	Average Bed Temperature.....	4-12
Figure 4-4:	Plenum Pressure.....	4-13
Figure 4-5:	Combustion Chamber Temperatures.....	4-13
Figure 4-6:	O ₂ Concentration in Flue Gas.....	4-14
Figure 4-7:	NO _x Concentration in Flue Gas.....	4-14
Figure 4-8:	CO Concentration in Flue Gas.....	4-15
Figure 4-9:	THC Concentration, ppm.....	4-15
Figure 4-10:	SO ₂ Concentration in Flue Gas.....	4-16
Figure 4-11:	CO ₂ Concentration in Flue Gas.....	4-16
Figure 4-12:	Variation of Combustion Efficiency with Gas Firing Rate.....	4-20
Figure 4-13:	Variation in Combustion Efficiency with Excess Air.....	4-20
Figure 4-14:	Effect of Bed Temperature on Combustion Efficiency.....	4-21
Figure 4-15:	Heat Transferred to the Fluidized Bed and the Water Jacket.....	4-21

LIST OF ABBREVIATIONS

ASME	---	The American Society of Mechanical Engineers
BMCS	---	Burner Management Control System
BMS	---	Burner Management System
BOD	---	Biological Oxygen Demand
CCT	---	Clean Coal Technology
COD	---	Chemical Oxygen Demand
DOE	---	Department of Energy
DRI	---	Direct Reduction of Iron
EIA	---	Environmental Impact Assessment
EPA	---	Environmental Protection Agency
EPC	---	Engineering Procurement Construction
FFT	---	Fast Fourier Transform
FGD	---	Flue Gas Desulfurization
FGR	---	Flue Gas Recirculation
FR	---	Firing Rate
G&A	---	General and Administration
GC	---	Gas Chromatograph
GHG	---	Greenhouse Gas
GRI	---	Gas Research Institute
HRSG	---	Heat Recovery Steam Generator
IRR	---	Internal Rate of Return
LPG	---	Liquefied Petroleum Gas
MCC	---	Motor Control Center
MTCI	---	Manufacturing and Technology Conversion International, Inc.
NERC	---	National Electric Reliability Council
NGCC	---	Natural Gas Combined Cycle
NPCC	---	New England
PC	---	Pulse Combustor
PDU	---	Process Development Unit
PFD	---	Process Flow Diagram
P&ID	---	Piping & Instrumentation Diagrams
PLC	---	Programmable Logic Controller
O&M	---	Operation & Maintenance
R	---	Reactor

LIST OF ABBREVIATIONS (Continued)

RDF	---	Refuse Derived Fuel
RO	---	Reverse Osmosis
ROI	---	Return On Investment
SCR	---	Selective Catalytic Reduction
SNCR		Selective Non-Catalytic Reduction
SS	---	Stainless Steel
SVOC	---	Semi-Volatile Organic Compounds
TC	---	Thermocouple
TCI	---	ThermoChem, Inc.
THC	---	Total Hydrocarbons
TRI	---	ThermoChem Recovery International, Inc.
VOC	---	Volatile Organic Compounds

LIST OF UNITS

acfm	---	Actual Cubic Feet per Minute
Btu	---	British Thermal Unit
C	---	Degrees Celsius
dia.	---	Diameter
F	---	Degrees Fahrenheit
ft	---	Feet
gal	---	Gallon
gpm	---	Gallons Per Minute
GW	---	Gigawatts
hp	---	Horsepower
h	---	Hour
Hz	---	Hertz
kW	---	Kilowatt
kWh	---	Kilowatt-hour
lb	---	Pound
MM	---	Million
MW	---	Megawatt
ppm	---	Pounds per Minute
psig	---	Pounds per Square Inch
scfm	---	Square Cubic Feet per Minute
sq. ft.	---	Square feet

GLOSSARY OF TERMS

C: Carbon

CO: Carbon Monoxide

CO₂: Carbon Dioxide

Coke: Coke is made by baking a blend of selected Bituminous coals (called Coking coal or Metallurgical Coal) in special high temperature ovens without contact with air until almost all of the volatile matter is driven off. Metallurgical coke provides the carbon and heat required to chemically reduce iron ore to molten pig iron (hot metal). For coke to have the proper physical properties to perform this function, it must be carbonized at temperatures between 900 and 1095°C. The most important physical property of metallurgical coke is its strength to withstand breakage and abrasion during handling and its use in the blast furnace. The most common process currently used to manufacture metallurgical coke is the by-product process.

H₂S: Hydrogen Sulfide

NO_x: Nitrogen Oxides

NaHS: Sodium Hydrasulfide

O₂: Oxygen

S: Sulfur

SO₂: Sulfur dioxide

THC: Total Hydrocarbons

EXECUTIVE SUMMARY

Brief Description of the Project

TCI and its affiliate, MTCI, have developed the PulseEnhanced™ Steam Reforming Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled-up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications. TCI and its subsidiary, TRI, are the project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project and has title to all equipment purchased or fabricated under the project.

The project includes two areas of emphasis:

- (i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and,
- (ii) process characterization through coal feedstock tests in a Process Development Unit (PDU).

The 61- and 72- tube heater bundles, which were previously demonstrated, are too small in capacity for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require the larger 253-tube heater bundles. For example, a 7-heater (253-tube) reformer can mild gasify over 1,100 short tons of coal per day. If the smaller 72-tube heater modules were used, the reformer would require 25 such units, each with its own fuel train, combustion air and flue gas connections.

Project History

On October 27, 1992, the DOE and TCI entered into a Cooperative Agreement for a Demonstration project under the Clean Coal IV solicitation. Preliminary design and engineering work was conducted for a series of potential sites for a demonstration facility, and a scaled-up 253-tube pulse heater bundle was designed and fabricated. On

September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

Technology Being Employed

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost. The project has qualified the design of the 253-resonance tube pulse heater, which is the technology envelope and the heart of a commercial-scale system.

Project Location

The project is located at TCI's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor installation within the Company premises, and the PDU is located indoors in the Company's Development and Manufacturing plant.

Summary of Test Program

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields and composition, char yields and composition and endothermic heat requirements were determined in the PDU Test Facility.

Project Costs

The total cost of this project was \$8.6 million, with DOE providing fifty percent of this cost.

Based on the test data, it is projected that a commercial-scale facility capable of processing 40 US tons per hour in a mild gasification mode will have an installed capital cost of \$28,184,000.

1.0 PROJECT OVERVIEW

1.1 Purpose of the Project Performance and Economics Report

The purpose of the Project Performance and Economics Report is to consolidate, for the purpose of public use, all performance information on the project at the completion of the project. The report provides an overview of the project, the salient performance features and data, and the role of the pulse combustor design qualification test project in commercialization planning.

1.2 Overview of the Project

TCI and its affiliate, MTCL, have developed the PulseEnhanced™ Steam-Reforming Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications.

The project includes two areas of emphasis:

- (i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and,
- (ii) process characterization through coal feedstock tests in a PDU.

The 61- and 72-tube heater bundles, which were previously demonstrated, are too small for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require the larger 253-tube heater bundles.

1.2.1 Background and History of Project

On October 27, 1992, DOE and TCI entered into a Cooperative Agreement for a Demonstration project under the Clean Coal IV solicitation. Preliminary design and engineering work was conducted for a series of potential sites for a demonstration facility, and a scaled-up 253-tube pulse heater bundle was designed and fabricated. On

September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

1.2.2 Project Organization

TCI and its subsidiary, TRI, are the revised project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project and has title to all equipment purchased or fabricated under the project.

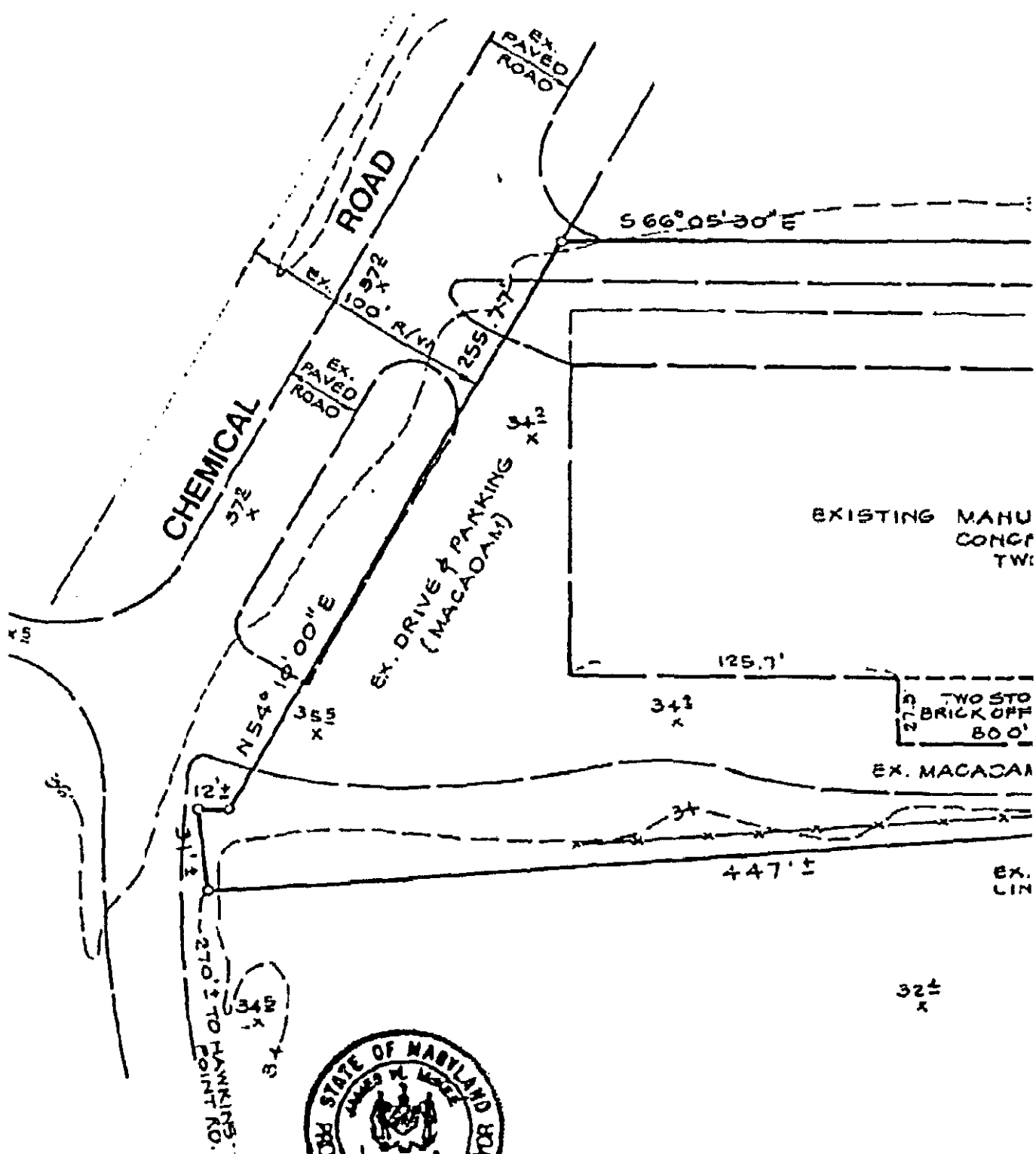
1.2.3 Project Description

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost.

The project will qualify the design of the 253-resonant tube pulse heater, which is the technology envelope and the heart of a commercial-scale system.

1.2.4 Site

The project is located at TCI's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor area within the Company premises, and the PDU is located indoors in the Company Development and Manufacturing plant (see Figure 1-1 on page 1-3).

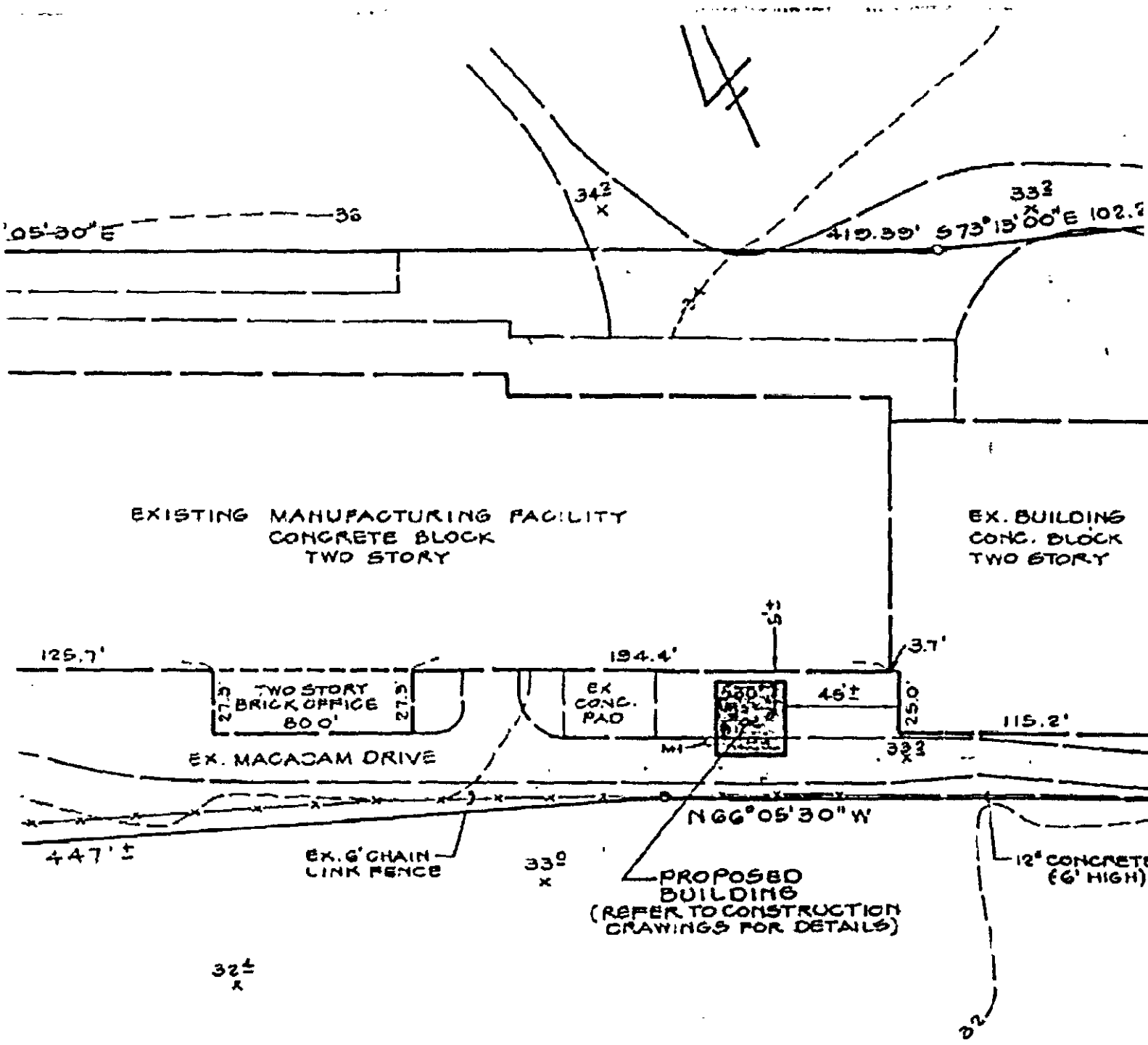


ASSOCIATES, INC.
 LAND SURVEYORS
 5 SHAWAN ROAD
 D 21038
 1-1555
 CHECKED: J.D.G.



JAMES W. MCKEE
 MARYLAND REGISTRATION NO. 9012
 DATE 9/10/99

FIGURE 1-1: SITE AREA MAP



SITE PLAN

6001 CHEMICAL ROAD
 LOTS 24 & 24A
 WARD 25 SECTION 9 BLOCK 7
 BALTIMORE CITY, MARYLAND
 SCALE - 1" = 50' DATE - 9/17/00

! SITE AREA MAP (Note: Drawing is reproduction and may not be to scale.)

1.2.5 Project Schedule

Shakedown and qualification testing of the scaled-up combustor was conducted from October, 2000 through early June 2001. The coal testing in the PDU was conducted in April, 2001.

1.3 Objectives of the Project

The purpose of the revised project is to qualify the design of a scaled-up 253-tube pulse heater as an essential step for the commercialization of this technology. The 61- or 72-tube heater bundles, as previously used, are too small in capacity for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units employing the technology will require the larger 253-tube heater bundles.

1.3.1 Qualification Test Objectives

The principal objectives of this program are to perform design qualification testing of a 253-tube pulse heater and to demonstrate its ability to operate in the pulse combustion mode for commercial deployment. The specific objectives include verification and demonstration of:

- Full-scale pulse heater performance and operability; and
- Emissions (NO_x, THC, CO) determination.

1.3.2 PDU Test Objectives

The objectives of the PDU test will be to evaluate the operability and performance of the system. Specifically, the targets will be:

- Safe, stable and reliable operation,
- Material balance analysis,
- Energy balance analysis,
- Heat of reaction determination,
- Char production and composition determination,

- Product gas composition and yield,
- Bed solids characterization, and
- Cyclone catch solids characterization.

The process data generated from the test will be used for preliminary system design for the full-scale commercial plant.

1.4 Significance of the Project

The design qualification of the 253-tube heater bundle will enable TCI to establish the design parameters of the scaled-up heater in order to meet the requirements of the overall system performance for commercial use. Process fluid mechanics, heat transfer, mass transfer and mixing must be preserved in the scale-up to achieve good system performance. For example, the combustion chamber aspect ratio (height-to-diameter) decreases with an increase in pulse heater module size due to acoustic and geometric considerations. This reduced aspect ratio could affect lateral mixing of the fuel and air, temperature uniformity in the resonance tubes, and proper mass flow distribution of the flue gas across the resonance tube-sheet. In addition, the scaled-up heater must be designed to achieve heat addition that is substantially in phase with pressure oscillations. Appropriate controls and instrumentation must also be used to demonstrate the efficacy of the technology in full-scale commercial applications to TCI's EPC partners and bonding/insurance companies.

Qualifying the design of the 253-tube pulse combustor is an enabling measure for the commercial introduction of the MTCI technology in a wide spectrum of end use applications. The MTCI steam-reforming technology is unique with regards to the wide spectrum of feedstocks it can process.

In the area of coal applications, the MTCI steam reformer has the following end use application opportunities:

- Complete steam reforming of sub-bituminous coal and lignite at the mine mouth and producing power with combined cycle gas turbines and Fuel Cells.

In fact, the MTCI technology is the most suitable technology today for the production of reformat gas from coal and waste (combined) in the world.

- Mild gasification of coal for production of char, tars and fuel gas for the U.S. steel industry. In the case of Northshore Mining, the char is used for a DRI process. The tar would be sold to a company the makes asphalt, and the exported gas would be used for taconite processing.

In addition, the MTCI steam reformer technology can process a wide spectrum of coal and wastes (RDF, chicken waste, sewage sludge, hog waste, biomass waste and essentially any liquid or solid material that contains carbon or hydrocarbons (i.e. tires, plastics, etc.).

The target is to use sub-bituminous and lignite coals that are underutilized and also have highly reactive char and wastes to produce clean power and/or other products (ethanol, methanol, acetic acid, etc.).

This is very significant application and would be enabled by the qualification of the pulse combustor (the technology envelope) scale-up design qualification.

The MTCI technology is unique in the broad spectrum of its end use applications. In other applications, the MTCI process is the leading technology for processing biomass based feedstocks (black liquor, bark, pistachio nut shells [with 4% sulfur], toxic wastes from industrial sources and low level as well as low level mixed wastes).

1.5 Management and DOE's Role in the Project

1.5.1 Department of Energy

DOE provided 50% of the funds for this project and monitored project progress and results.

1.5.2 Project Management and Execution

TCI Project Manager is responsible for project execution and cost/schedule monitoring and control. The Project Manager was also responsible for supervising the project team including consultants and subcontractors.

1.5.3 Project Organization Chart

As depicted by Figure 1-2, the project organization chart, the TCI project manager, Mr. Lee Rockvam, is the interface with the DOE project manager.

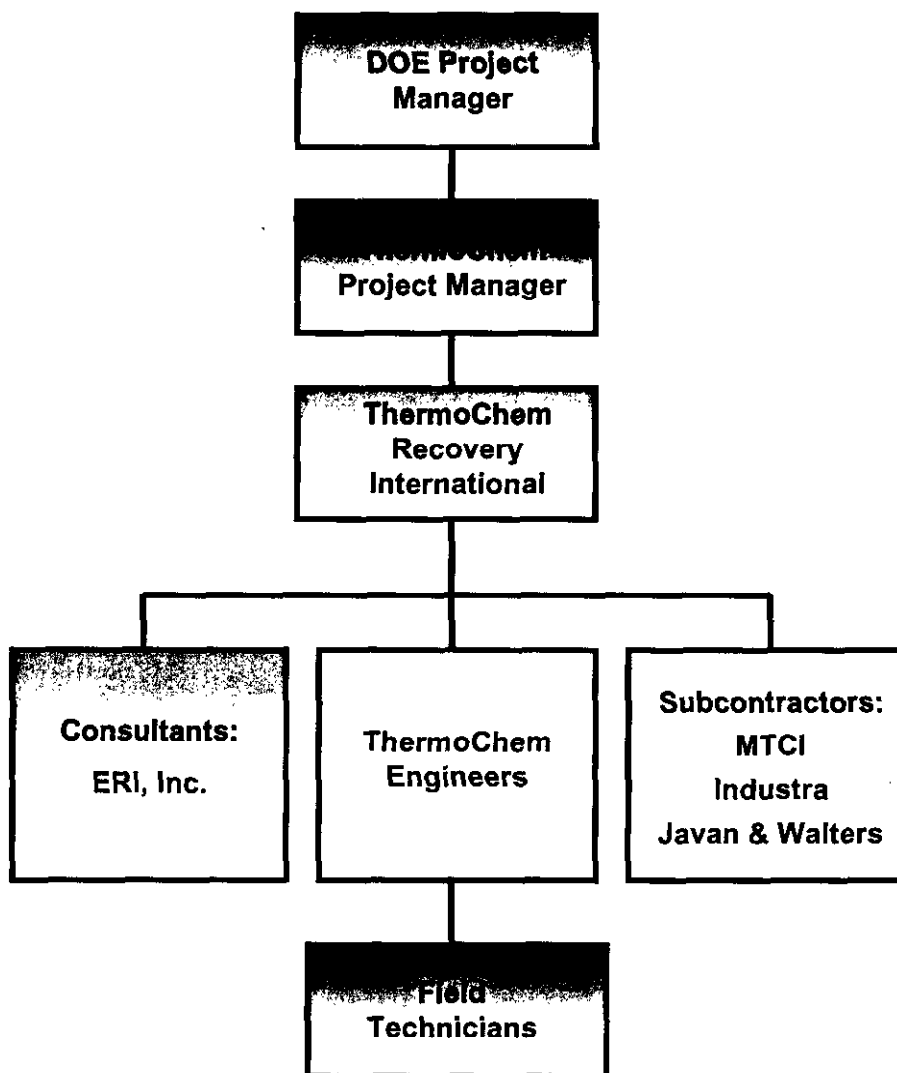


FIGURE 1-2: ORGANIZATION CHART

TRI is the private sector cost sharing entity on this project for the Pulse Combustor Design qualification test and the process investigations conducted using the PDU.

The technical project team is comprised of TCI engineers, MTCI engineers, engineers from Industra and Javan & Walters. In addition, MTCI supplied fabrication and site erection personnel as part of the team.

MTCI also augmented the TCI Engineers with test operation personnel. Temporary Field Technicians were also employed on as needed basis to support electrical, welding and test operation activities.

2.0 TECHNOLOGY DESCRIPTION

2.1 Description of the Demonstrated Technology

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor.

In the TCI steam-reforming system, the multiple resonance tube pulse combustor is employed in which the resonance tubes serve as the heat exchanger to deliver heat indirectly to the fluid bed reactor. At any significant firing rate, a single resonance tube will not have sufficient surface area to transfer all the heat necessary to the fluid bed. Therefore, multiple parallel resonance tubes must be employed. In scaling up the multiple resonance tube pulse combustors, the number of the parallel resonance tubes is increased, and the ratio of the combustion chamber depth to its diameter is reduced. It is essential that the oscillatory component of the flow velocity in all the resonance tubes be in phase to achieve strong pulsations and, thus, enhanced heat transfer and heat release rates.

The larger the number of tubes, the more critical is the tuning of these self-induced, combustion-driven oscillations. Therefore, a number of independent aerodynamics valves are employed to introduce the combustion air to various segments of the combustion chamber. When tuning a multiple resonance tube pulse combustion system, it is necessary to achieve high pulsation amplitudes in order to ensure a more even distribution of the hot flue gases between the resonance tubes. Such distribution is critical given the high-temperature range required for the heat duty to which the resonance tubes are subjected.

2.2 Description of the Demonstrated Facilities

2.2.1 Combustor Design Qualification Test Facility

The full scale test facility consists of the following equipment:

- Reformer Vessel

The reformer consists of a one-inch thick carbon steel plate, reinforced in a rectangular vessel configuration. The vessel is insulated with thermal board and overlaid with 1/16-inch stainless liner.

- Pulse Combustor

The combustor consists of a 253-tube bundle complete with refractory-lined combustion chamber, aerovalve plate assembly, inlet air plenum and exhaust expansion bellows.

- Fuel train and Burner Management System

The fuel train consists of a natural gas pressure reducing station, double block and bleed, modulating control valve and orifice metering station.

- Combustion Air System

The combustion air system includes 5 forced draft fans, damper control and flow measurement pitot tube.

- PC Cooling Water Circuit

The pulse combustor cooling water circuit consists of a steam drum, recirculation pump, balancing valving and feedwater makeup.

- Cyclone

The cyclone is a single stage unit complete with dipleg isolation valve and catch drum.

- Water injection system

The water injection system is supplied with plant water and consists of eight injection nozzles that enter the reformer through the floor of the vessel. Water flow is controlled by a modulating control valve. Purge air prevents pluggage of the injection system in the event that the water is turned off.

- Flue Gas Recycle

Flue gas recycle is an induced system that consists of ductwork connected to the stack, complete with control damper and flow measurement pitot tube. Recycle flue gas enters the process through the suction of the forced draft combustion air fans.

- Flue Gas Quench

The hot combustor flue exhaust is quenched by a water injection system prior to entering the stack. High pressure water with air assist is injected into the stack prior to the muffler.

- Controls System

A dedicated control room complete with a Allen Bradley PLC, PC computers and WinTelligent™ operating software provides control of the Test Facility.

2.2.2 PDU Test Facility

The PDU facility has a nominal feedstock capacity of 30 to 50 pounds per hour. Coal will be fed to the reformer reactor by a metering and injection screw system. Fluid bed temperatures are maintained at the desired levels by regulating the pulse combustor firing rate. At these temperatures, the feedstock undergoes high rates of heating, pyrolysis and steam reformation. In the absence of free oxygen, the steam reacts endothermically with the feedstock to produce a medium-Btu syngas rich in hydrogen.

The bed temperature is the variable that is controlled to maximize char production. As the bed temperature is lowered, the carbon/steam reaction rate slows and more char is produced. On the other hand, a reasonably high temperature is needed to reduce the sulfur content of the char and to produce lighter condensable hydrocarbons.

A description of the PDU components and subsystems is provided below. The PDU consists of the following subsystems:

- The steam reformer reactor and two-stage cyclone subsystem,
- Coal metering and injection subsystem,
- Steam boiler and feedwater reverse osmosis (RO) unit,

- Two stages of steam superheater,
- Gas chromatograph (GC) dry gas sampling and measurement,
- Instrumentation and controls.

An overall view of the steam reformer, the two stage cyclone, the second stage cyclone catch pot and the coal metering and injection subsystem is provided in Figure 2-1.

The bed area of the PDU reformer is an 8-inch diameter stainless steel vessel. Fluid bed height is approximately 6 feet. The pulse combustor resonance tubes are installed vertically through the bottom of the reformer vessel in a “U” shape. The resonance tubes are made of 1-½ inch pipe approximately 10 feet in length, identical to those used in the full-scale combustor. Since the resonance tubes are installed in a “U” shape, they occupy only five feet of the bed height.

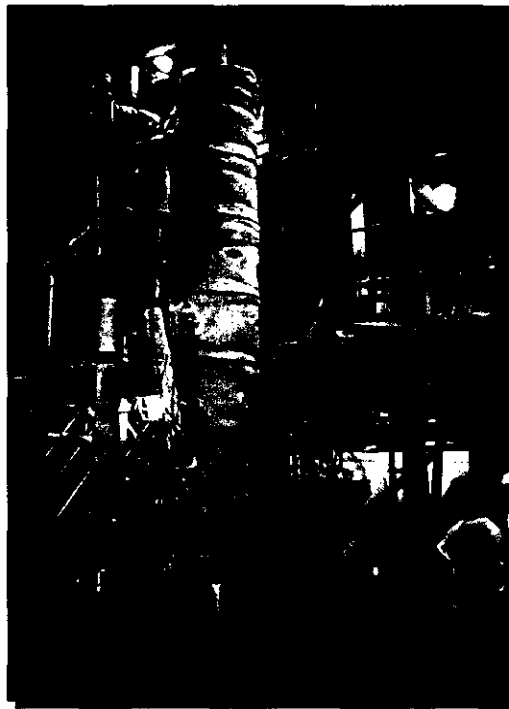


FIGURE 2-1: PDU TEST FACILITY

The reformer operates slightly above atmospheric pressure. The startup fluid bed material consists of silica sand and is fluidized with low pressure (15 psig or 1 bar) superheated nitrogen. The reformer operates in the “bubbling” regime with a low

superficial velocity of 0.5 to 1.0 foot per second. The low velocity ensures sufficient gas residence time. The two-tube pulsed heater supplies indirect heat for the steam reforming reactions.

A close-up view of the metering and feed system is provided in Figure 4-10. Coal is loaded into the bin at the top. A lockhopper is required because of the pressure differential between the fluid bed reactor and the metering bin. The feed rate control box is also shown in Figure 2-2. The lockhopper utilizes a Dezurik brand knife gate valve and a hemispherical valve to provide a seal between the feed hopper and the

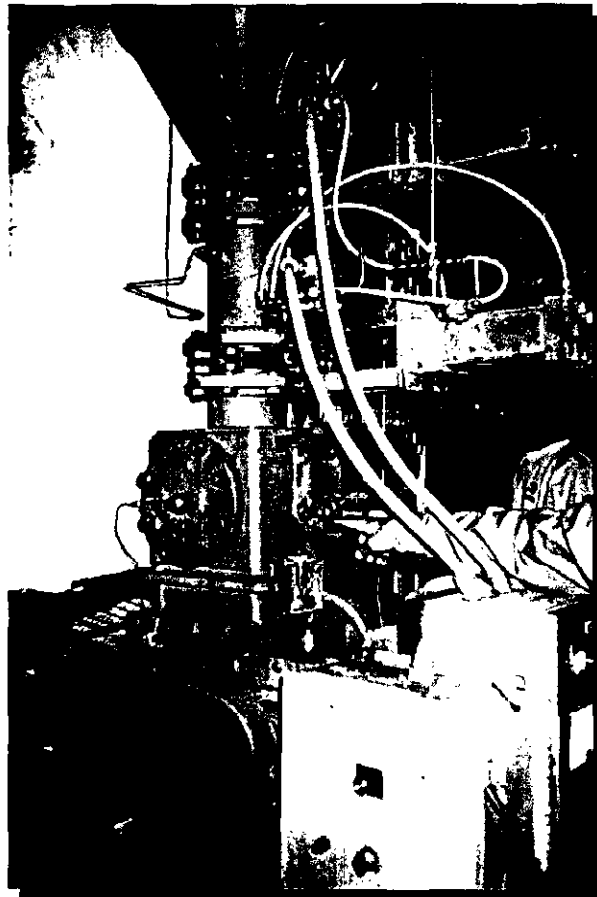


FIGURE 2-2: COAL METERING AND INJECTION

metering cavity. Three variable speed, parallel-drive metering screws provide volumetric flow control of the feedstock to the injection screw. The injection screw is operated at a constant speed and transfers the feed to the bottom section of the

reformer vessel. The feed injection point is located near the bottom to increase product gas residence time in the bed.

As shown in Figure 2-3, the two-tube pulse combustor has one aerovalve that is supplied with combustion air from the air plenum.

To achieve sufficient oscillations at part load, the natural gas has provisions for air dilution.

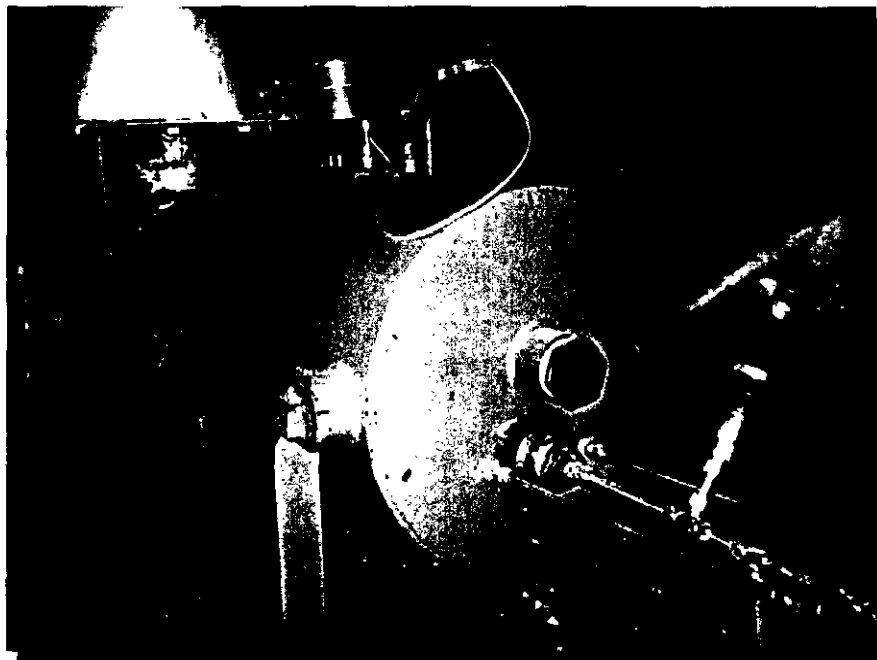


FIGURE 2-3: PULSE COMBUSTOR COMBUSTION AIR PLENUM

A close up view of the second stage cyclone catch pot is provided in Figure 2-4.



FIGURE 2-4: SECOND CYCLONE CATCH POT

A thermostatically controlled heating shell is provided to avoid steam condensation and refluxing near the end of the cyclone dip leg. A valve allows isolation of the pot for removal. A hydraulic table arrangement is used for moving the pot when disconnected from the dip leg allowing the catch to be sampled and weighed.

Figure 2-5 shows the boiler, which generates the steam used by the steam reformer, and the RO unit and storage tank for feedwater treatment.

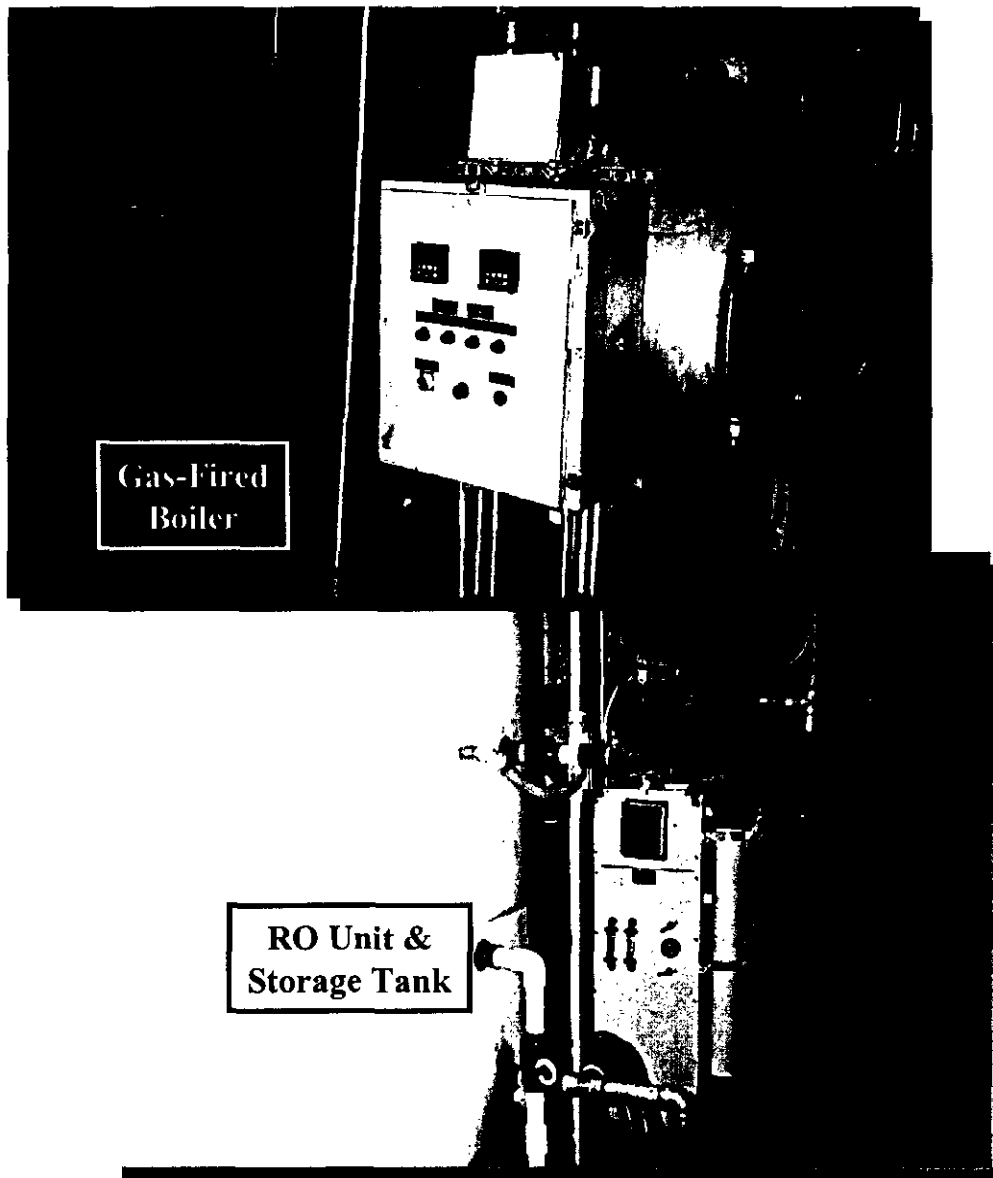
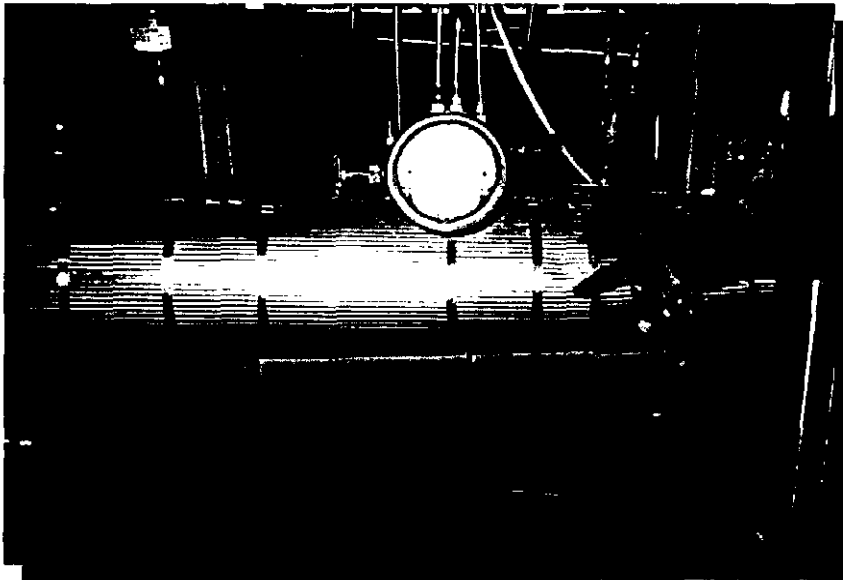


FIGURE 2-5: STEAM BOILER AND FEEDWATER RO UNIT

The natural gas fired boiler provides the supply steam at a nominal 100 psig (6.9 bar) pressure for operation of the PDU plant.

The superheaters employed are depicted in Figure 2-6. The first stage is a Watlow electrical heater which preheats the saturated steam from the boiler. The second stage is a coiled tube heat exchanger inserted in the PDU pulse combustor exhaust where it receives final superheat before being piped into the fluid bed.



**Second Stage
Superheater**

**First Stage
Electric
Superheater**

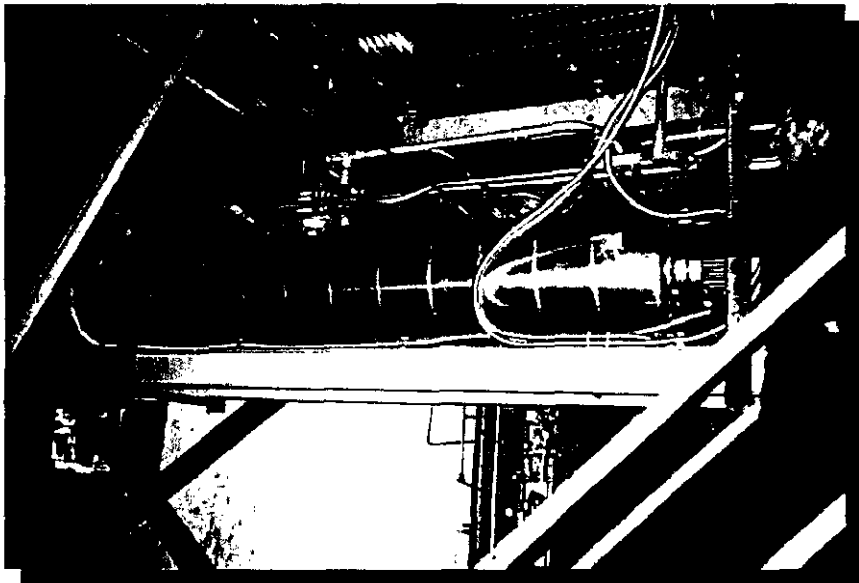


FIGURE 2-6: SUPERHEATERS

Typically, the steam temperature in the steam plenum is maintained at a temperature in the range of 950°F to 1,050°F.

Then the dry gas sample is passed through the GC for analysis (shown in the bottom picture of Figure 2-6). The GC operation is computer controlled with the GC data archived on the computer's hard disk.

Local analog controls (Figure 2-7) are utilized for startup, safe operation, process monitoring and control as well as for orderly startup and shutdown.

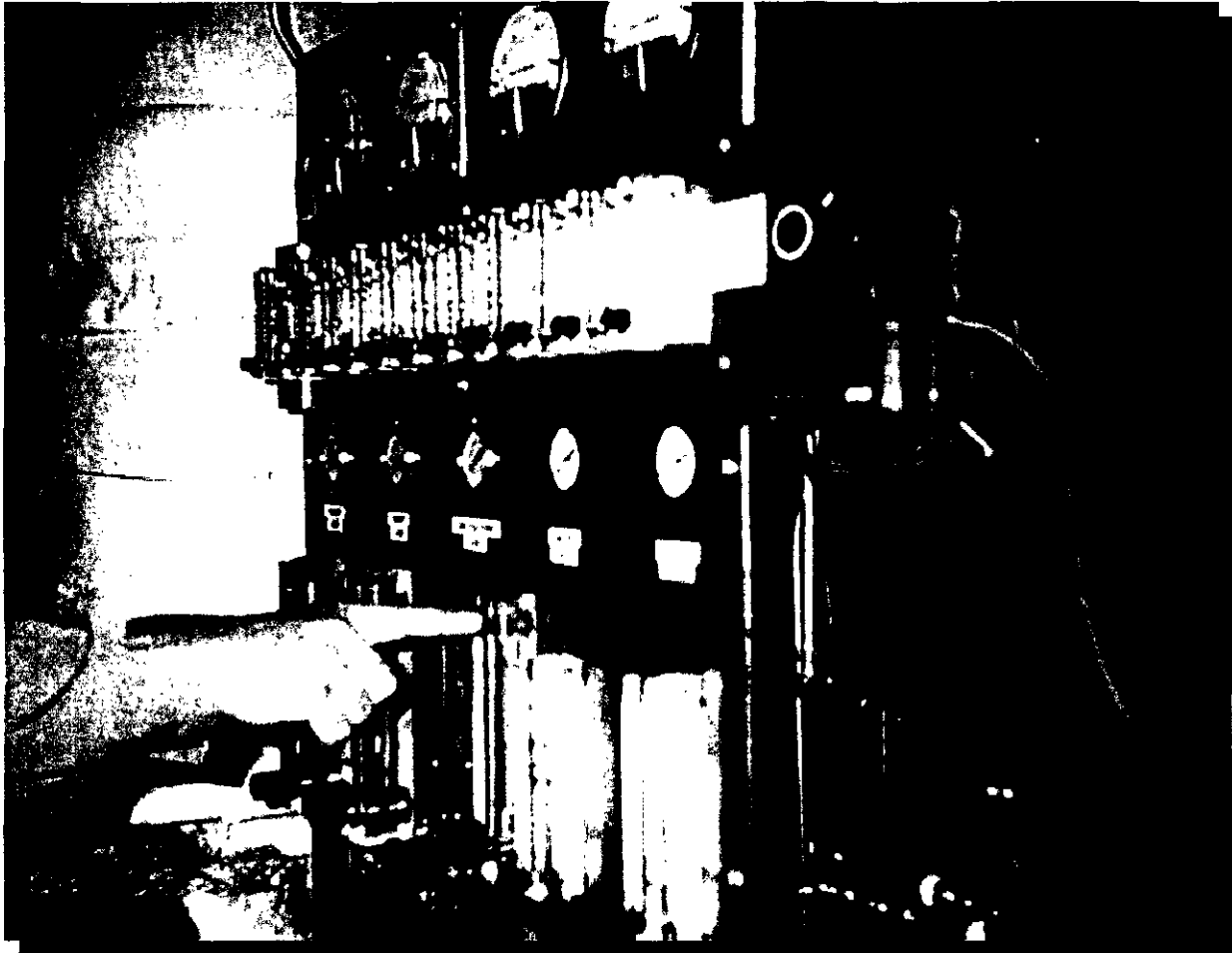


FIGURE 2-7: STEAM REFORMER CONTROLS

2.3 Proprietary Information

Proprietary data is data developed at private expense and embodies trade secrets. Clean Coal Protected Data is data first produced in the performance of this Agreement and is available to DOE. Form fit and function data or aggregated costs and performance information will be furnished in lieu of detailed proprietary information.

2.4 Simplified Process Flow Diagram

2.4.1 Combustor Design Qualification Test Facility

Figure 2-8 presents the project block flow diagram for the combustor design qualification test facility

Sand is used as the fluid bed medium. The sand is fluidized with air from five rental diesel compressors (stream no. 1). Water (stream no. 2) is injected into the bed to impose a heat load on the system to maintain the desired bed temperature. The fluidized bed off-gas (stream no. 3), comprising air used for fluidization and steam generated in the fluid-bed, passes through a cyclone for particulate collection before exiting (stream no. 4). The cyclone catch (stream no. 5) is collected in a drum for disposal.

The combustion air (stream no. 6) for the 253-tube pulse heater is delivered to the combustor by five combustion air fans. The combustor is fueled with natural gas (stream no. 7). A water spray (stream no. 9) cools the combustor flue gas (stream no. 8). The quenching spray is generated by a dual fluid atomizer using air (stream no. 10).

The cooled flue and steam are vented (stream no. 11) through a muffler.

The cooling water for the water jacket of the pulse combustor tubesheets and the arovalve plate cooling loop is circulated via a forced circulation pump, and the water makeup is provided by stream no. 12. Steam is vented from the steam drum (stream no. 13) to maintain a desired operating pressure of approximately 450 psig.

2.4.2 PDU Test Facility

The block flow diagram for the PDU study is presented in Figure 2-9.

In this PDU, the coal is fed into the steam reformer (stream no. 1) near the bottom of the reactor to provide sufficient residence time in the fluid-bed.

The feeder is comprised of a feed bin with a lock hopper below it, which discharges into a live-bottom-metering bin with three metering screws.

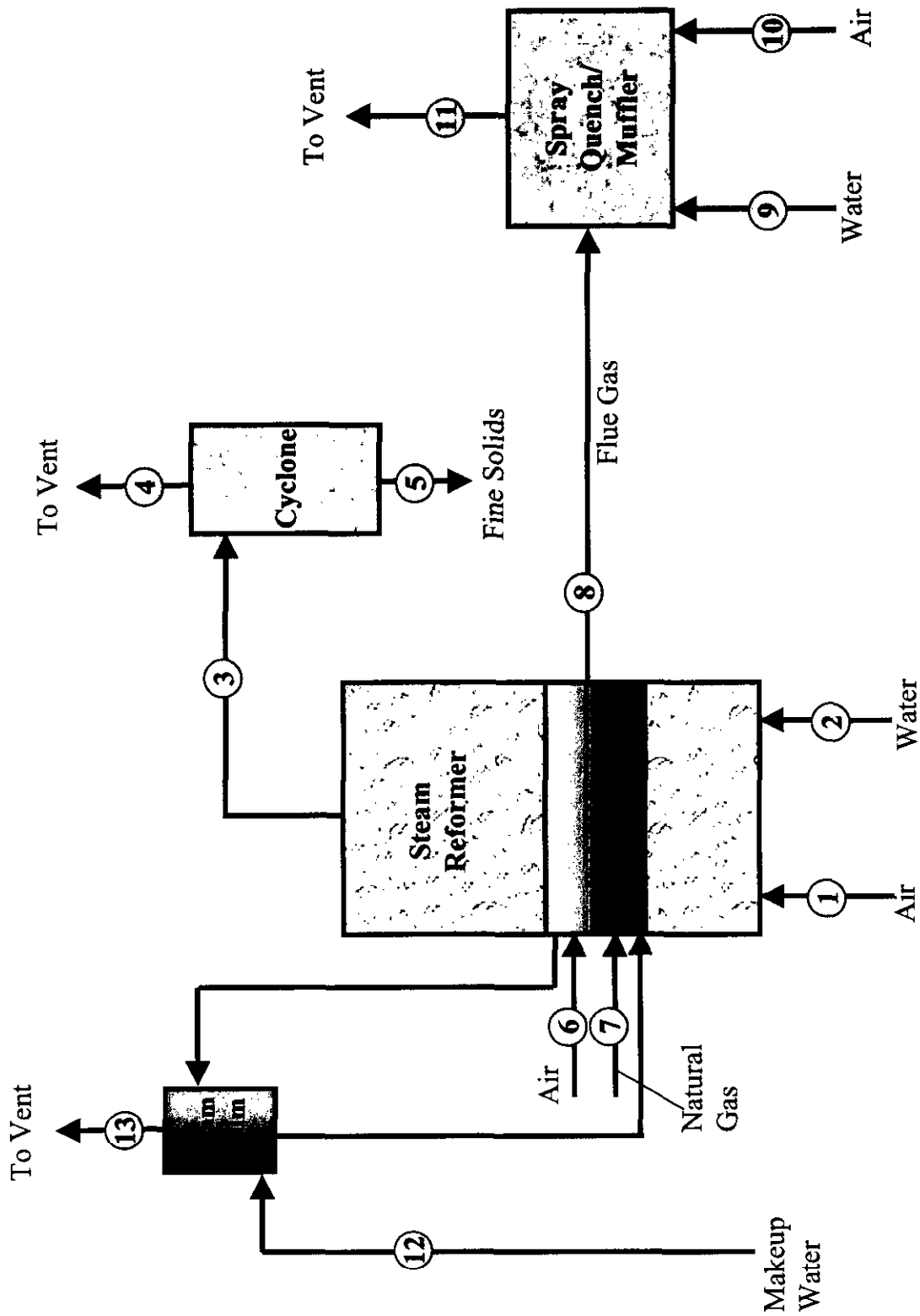


FIGURE 2-8: BLOCK FLOW DIAGRAM

Three variable speed screws meter the coal to a constant speed auger that transfer the coal into the fluid bed.

Superheated steam (stream no. 2) from the superheater is used to fluidize the reformer (R). All instrument penetrations in the reformer are purged by nitrogen (stream no. 3).

Char (stream no. 4) is extracted from the fluid-bed steam reformer and constitutes the reductant for the DRI process.

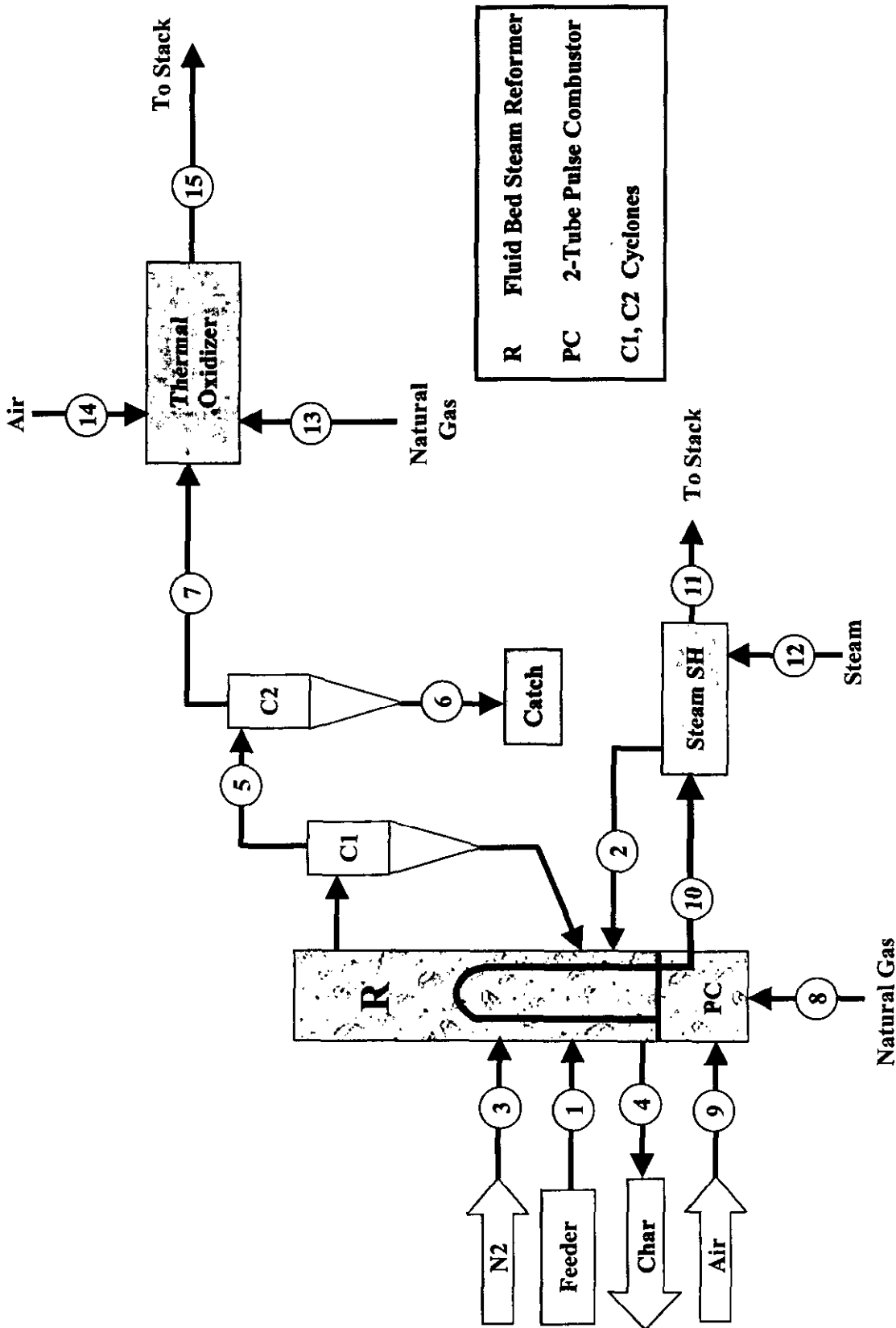
The product gas from the steam reformer passes through two stages of high efficiency cyclones (C1 and C2) and continues on to a Thermal Oxidizer (streams no. 5 and 7).

The first cyclone (C1) catch is returned to the fluid bed via a dip leg. The second cyclone fines catch (stream no. 6) is collected in a catch pot.

Natural gas (stream no. 8) is employed to fire a twin-resonance tube pulse combustor (PC). The combustion air (stream no. 9) is provided through an air plenum to the single aerodynamic valve of the pulse combustor.

The flue gas from the pulse combustor (stream no. 10) passes through the steam superheater which provides superheated steam (stream no. 12) for fluidization of the bed. The flue is sent to the stack (stream no. 11).

The thermal oxidizer employs a duct burner concept with natural gas (stream no. 13) and air (stream no. 14).



R Fluid Bed Steam Reformer
 PC 2-Tube Pulse Combustor
 C1, C2 Cyclones

FIGURE 2-9: PDU PROCESS FLOW DIAGRAM

2.5 Stream Data

2.5.1 Mass and Energy Balance for the Combustor Design Qualification Test Facility

Table 2-1 presents a Mass and Energy Balance for the Combustor Design Qualification Test Facility. This is based on a test performed on March 2, 2001 without flue gas recycle.

2.5.2 Mass Balance for the PDU Test Facility

Table 2-2 presents a Mass Balance for the PDU Test Facility.

2.6 Process and Instrumentation Diagrams

2.6.1 P&ID for the Combustor Design Qualification Test

Figure 2-10 presents the legend sheets for the P&I Diagrams. Figures 2-11 and 2-12 present the P&ID for the Combustor Design Qualification Test. Figure 2-11, the Process and Instrumentation Diagram (P&ID), outlines the controls and instrumentation used in the Combustor Design Qualification Test facility. An ALLEN BRADLEY 5/10 Programmable Logic Controller (PLC) controlled the test facility. The PLC, in conjunction with a Fireye burner management system (BMS), tied in all the process and control loops required to operate the facility efficiently and safely. Figure 2-11 shows all the associated instrumentation utilized for the reformer including all instrumentation that was interlocked to the BMS. Figure 2-12 is the Pulse Combustor Cooling Circuit P&ID.

2.6.2 P&ID for the PDU Test

Figure 2-13 presents the P&ID for the PDU Test.

TABLE 2-1: MASS & ENERGY BALANCE FOR THE COMBUS

TEST DATE: 3/2/2

STREAM NO ->		1	2	3	4	5	6
		Air to Reformer	Water to Reformer	Gas to Cyclone	Gas to Vent	Fines to Catch Drum	Natural Gas to PC Heater
PRESSURE	PSIG	5.9	50	0.3	0	0	1.71
	IN WC						
TEMPERATURE	F	151	45	932	911	865	55
VOLUMETRIC FLOW	QPM		6.0				
	SCFM	2,856		3,907	3,907		287
	ACFM	2,393		10,256	10,301		255
COMPONENT							
CH4	LB/HR						683
C2H6	LB/HR						52
C2H4	LB/HR						
C3H6	LB/HR						
C3H8	LB/HR						25
H2S	LB/HR						
CH3SH	LB/HR						
(CH3)2S	LB/HR						
(CH3)2S2	LB/HR						
H2	LB/HR						
CO	LB/HR						
CO2	LB/HR	6		6	6		12
H2O (v)	LB/HR	83		3,082	3,082		
NH3	LB/HR						
O2	LB/HR	2,999		2,999	2,999		
N2	LB/HR	9,909		9,909	9,909		6
SO2	LB/HR						
H2O (l)	LB/HR		2,999				
NO	LB/HR						
HCl	LB/HR						
C	LB/HR						
Na2CO3	LB/HR						
NaCl	LB/HR						
Na2SO4	LB/HR						
Na2SO3	LB/HR						
NaHSO3	LB/HR						
Na2S	LB/HR						
NaHS	LB/HR						
NaHCO3	LB/HR						
NaOH	LB/HR						
MF COAL	LB/HR						
Inerts	LB/HR			11.3	0.2	11.1	
TOTAL MASS	LB/HR	12,997	2,999	16,007	15,996	11	781
TOTAL CARBON	LB/HR	0	0	2	2	0	578
TOTAL SULFUR	LB/HR	0.000	0.000	0	0	0	0
TOTAL SODIUM	LB/HR	0	0	0	0	0	0
TOTAL CHLORINE	LB/HR	0.0	0.0	0.0	0.0	0.0	0.0
HHV	BTU/HR	0	0	0	0	0	18,075,376
ENTHALPY	BTU/HR	320,716	-95,863	7,263,600	7,157,645	1,922	-8,651
TOTAL HEAT	BTU/HR	320,716	-95,863	7,263,600	7,157,645	1,922	18,066,725

COMBUSTOR DESIGN QUALIFICATION TEST FACILITY

DATE: 3/2/2001

6 Flue Gas to Heater	7 Combustion Air to PC Heater	8 Flue Gas to Spray Quench	9 Water to Atomizer	10 Air to Atomizer	11 Flue Gas to Vent	12 Makeup Water to Steam Drum	13 Steam to Vent
1.71			115	100		450	397
	7	2			0		
55	55	1232	45	55	700	45	447
			4.0			2.2	
287	4,200	4,496		103	5,309		382
255	4,089	14,559		13	11,842		24
685		0.0			0.0		
52		0.0			0.0		
25		0.0			0.0		
		0.9			0.9		
12	9	2,127		0	2,127		
	122	1,796		3	3,823		1,091
	4,411	1,392		108	1,500		
6	14,573	14,579		357	14,936		
			2,024			1,091	
		1.7			1.7		
781	19,115	19,896	2,024	468	22,388	1,091	1,091
578	2	581	0	0	581	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
075,376	0	4,558	0	0	4,558	0	0
-8,651	26,590	8,277,469	-64,688	651	8,011,307	-34,880	1,333,341
066,725	26,590	8,282,027	-64,688	651	8,015,865	-34,880	1,333,341

TABLE 2-2: MASS BALANCE FOR TI

COMPONENT	UNITS	FORMULA	1000°F TEST					COAL	S
			COAL	STEAM	NITROGEN PURGE	PRODUCT GAS	CHAR		
Hydrogen	Lb/Hr	H2				0.569			
Nitrogen	Lb/Hr	N2			19.518	19.691			
Methane	Lb/Hr	CH4				2.324			
Carbon Monoxide	Lb/Hr	CO				0.825			
Carbon Dioxide	LB/Hr	CO2				10.955			
Ethylene	Lb/Hr	C2H4				0.561			
Ethane	Lb/Hr	C2H6				0.625			
Acetylene	Lb/Hr	C2H2				0.000			
Hydrogen Sulfide	Lb/Hr	H2S				0.083			
Propylene	Lb/Hr	C3H6				0.365			
Propane	Lb/Hr	C3H8				0.000			
Steam	Lb/Hr	H2O		23.361		40.941		27.	
Coal	Lb/Hr		52.000				45.000		
Char	Lb/Hr						30.645		
Condensables	Lb/Hr					0.331			
TOTAL MASS	Lb/Hr	----	52.000	23.361	19.518	77.270	30.645	45.000	27.

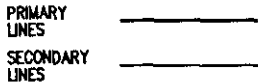
TABLE 2-2: MASS BALANCE FOR THE PDU TEST FACILITY

F TEST			1100°F TEST							12
COGEN	PRODUCT	CHAR	COAL	STEAM	NITROGEN	PRODUCT	CHAR	COAL	STEAM	
URGE	GAS				PURGE	GAS				
	0.569					0.634				
18	19.691				13.308	13.458				1
	2.324					1.814				
	0.825					0.988				
	10.955					9.462				
	0.561					0.466				
	0.625					0.369				
	0.000					0.002				
	0.083					0.054				
	0.365					0.238				
	0.000					0.000				
	40.941			27.117		41.963			18.618	
			45.000					32.000		
		30.645					25.826			
	0.331					0.268				
518	77.270	30.645	45.000	27.117	13.308	69.716	25.826	32.000	18.618	

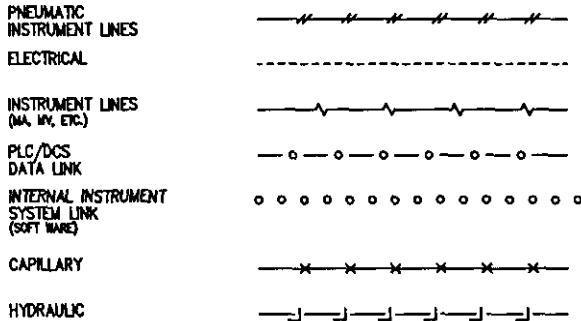
FLOW DESIGNATIONS:

STOCK FLOW	00TPO/100/GPM/F	} NORMAL FLOW (DESIGN FLOW)
LIQUID FLOW	-/-/OPM/F	
STEAM & CHEMICAL GAS FLOW	LB PER HR /PSIG/F	
GAS FLOW	ACFM/PSIG/F	

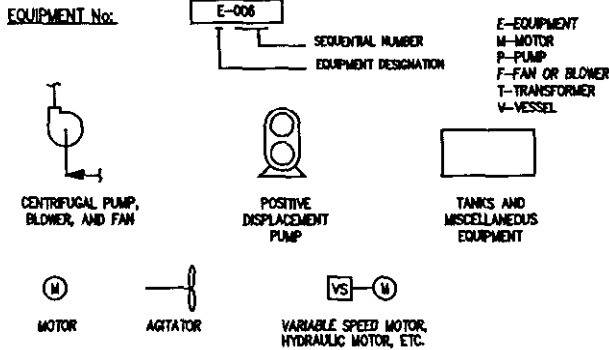
PROCESS LINES:



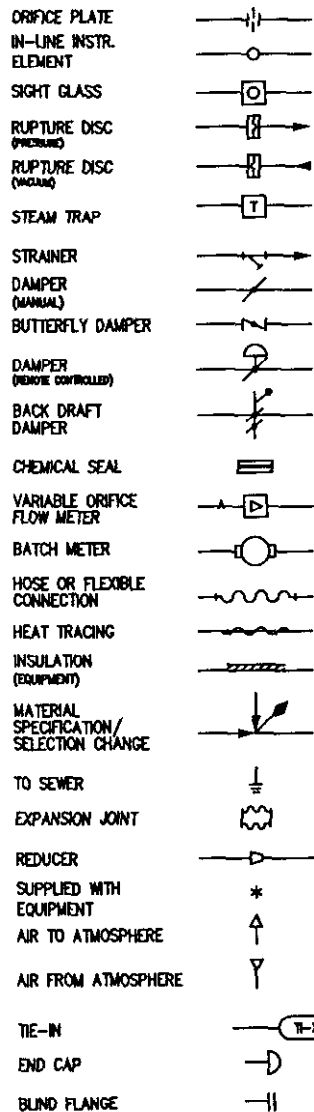
INSTRUMENT LINES:



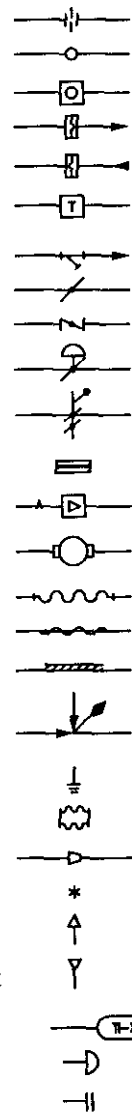
EQUIPMENT:



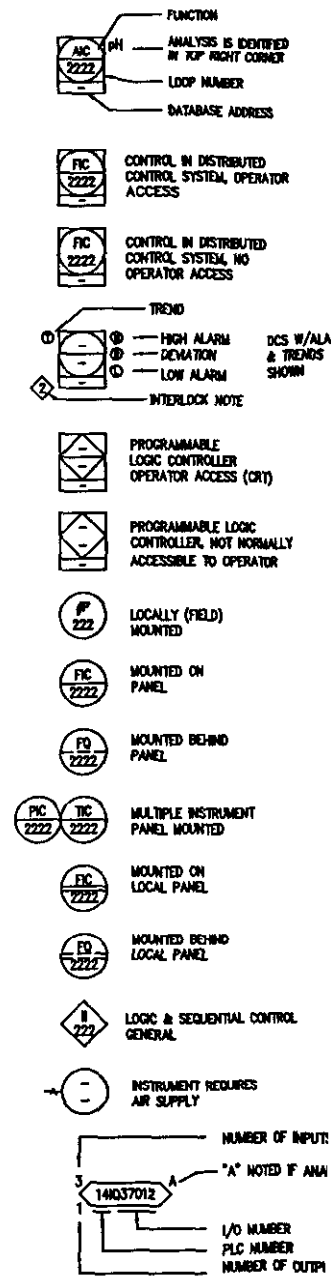
PIPING SYMBOLS:



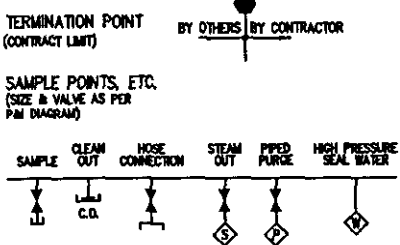
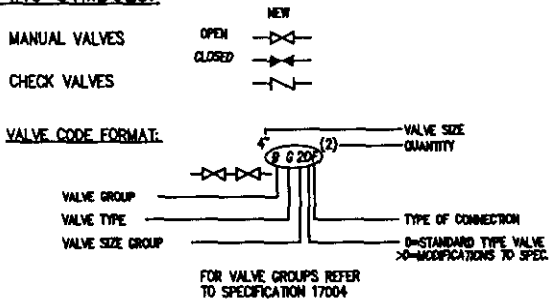
CONT.



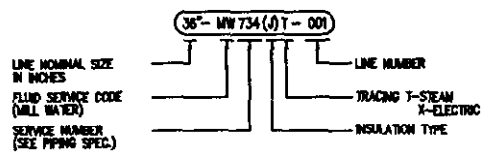
INSTRUMENTATION SYMBOLS:



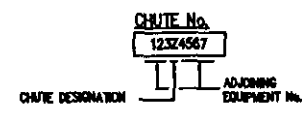
PIPING SYMBOLS:



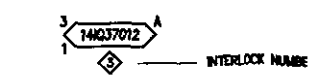
LINE NUMBER SYSTEM:



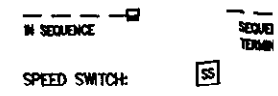
CHUTE NUMBER SYSTEM:



INTERLOCK NOTATION:



NON DRIVE ELECTRICAL INTERLOCK:



CAUTION: FILE IN 17000000

ION SYMBOLS:

- FUNCTION
- ANALYSIS IS IDENTIFIED IN TOP RIGHT CORNER
- LOOP NUMBER
- DATABASE ADDRESS
- CONTROL IN DISTRIBUTED CONTROL SYSTEM OPERATOR ACCESS
- CONTROL IN DISTRIBUTED CONTROL SYSTEM, NO OPERATOR ACCESS
- TRENDS
- HIGH ALARM
- DEVIATION
- LOW ALARM
- INTERLOCK NOTE
- PROGRAMMABLE LOGIC CONTROLLER OPERATOR ACCESS (ORT)

DCS W/ALARMS & TRENDS SHOWN

PROGRAMMABLE LOGIC CONTROLLER, NOT NORMALLY ACCESSIBLE TO OPERATOR

LOCALLY (FIELD) MOUNTED

MOUNTED ON PANEL

MOUNTED BEHIND PANEL

MULTIPLE INSTRUMENT PANEL MOUNTED

MOUNTED ON LOCAL PANEL

MOUNTED BEHIND LOCAL PANEL

DCS & SEQUENTIAL CONTROL SERIAL

INSTRUMENT REQUIRES AIR SUPPLY

NUMBER OF INPUTS
"A" NOTED IF ANALOG

I/O NUMBER
PLC NUMBER
NUMBER OF OUTPUTS

ICM#

INTERLOCK NUMBER

CRITICAL INTERLOCK:



MISC. ABBREVIATION & ACRONYMS

- A — ANALOG SIGNAL
- AC — AIR TO CLOSE
- AE — ABANDON EXISTING
- AO — AIR TO OPEN
- AVG — AVERAGE
- CASC — CASCADE
- DCS — DISTRIBUTED CONTROL SYSTEM
- DIFF — SUBTRACT
- DIR — DIRECT-ACTING
- E/I — VOLTAGE/CURRENT
- EO — ENERGIZE TO CLOSE
- EC — ENERGIZE TO OPEN
- ES — ELECTRIC SUPPLY
- ESD — EMERGENCY SHUTDOWN
- FC — FAIL CLOSED
- FL — FAIL LOCKED OR LAST
- FO — FAIL OPEN
- H — HYDRAULIC SIGNAL
- HS — HYDRAULIC SUPPLY
- I — INPUT OF INTERLOCK
- I/A — INSTRUMENT AIR SUPPLY
- I/P — CURRENT/CURRENT
- MA — MILL AIR SUPPLY
- MO — MOTOR OPERATED
- NC — NORMALLY CLOSED
- NO — NORMALLY OPEN
- No. — NUMBER
- O — OUTPUT OR OPENED
- P — PNEUMATIC SIGNAL OR PROPORTIONAL CONTROL MODE
- P/I — PNEUMATIC/CURRENT
- PLC — PROGRAMMABLE LOGIC CONTROLLER
- R — AUTOMATIC-RESET CONTROL MODE, RESET OF FAIL-LOCKED DEVICE, OR RESISTANCE (SIGNAL)
- RE — REPLACE EXISTING
- REV — REVERSE-ACTING
- RTD — RESISTANCE TEMPERATURE DETECTOR
- S — SOLENOID ACTUATOR
- SP — SET-POINT
- SQ. RT. — SQUARE ROOT
- SS — STEAM SUPPLY
- T — TRAP
- TC — THERMOCOUPLE
- TW — THERMOWELL
- WS — WATER SUPPLY
- X — CLOSED

ANALYSIS ABBREVIATIONS

- COMB. — COMBUSTIBLES
- GC — GAS CHROMATOGRAPH
- H₂ — HYDROGEN
- O₂ — OXYGEN
- CO x — CARBON OXIDES
- NO x — NITROGEN OXIDES
- SO x — SULFUR OXIDES
- CL x — CHLORINE
- H₂S — HYDROGEN SULFIDE
- BRITE — BRIGHTNESS
- LEL — LOWER EXPLOSIVE LIMIT
- pH — pH
- TDC — TOTAL ORGANIC CARBON
- TC — TOTAL CARBON
- 800 — BIOLOGICAL OXYGEN DEMAND
- DO — DISSOLVED OXYGEN
- FL — FLUORIDE
- ORP — OXIDATION/REDUCTION POTENTIAL
- RES — RESIDUAL CHEMICAL
- BMS — BURNER MANAGEMENT SYSTEM
- BF — BURNER FLAME
- MOIS — MOISTURE

SERVICE DESIGNATIONS

- APG — PLANT AIR
- ASH — ASH
- COI — CONDENSATE, 150# CLASS
- GF — FLUE GAS
- GP — PRODUCT GAS
- NGA — NATURAL GAS
- NGI — NITROGEN
- SOI — STEAM, 150# CLASS
- SAN — SAND
- WBI — WATER, BOILER FEED, 150# CLASS
- WCR — WATER, CHILLED, RETURN
- WCS — WATER, CHILLED, SUPPLY
- WHA — WATER, HOT
- WMA — WATER, MILL
- WSR — WATER, RAW

INSTRUMENTATION ABBREVIATIONS:

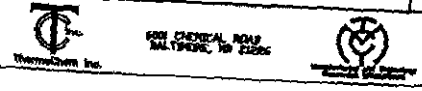
FIRST LETTER		SUCCEEDING LETTERS	
MEASURED OR INITIATED VARIABLE	MODIFIER	READOUT PASSIVE & OUTPUT FUNCTION	MODIFIER
A	ANALYSIS	ALARM	
B	BURNER FLAME	USER'S CHOICE	
C	CONDUCTIVITY	CONTROL	CLOSED
D	DENSITY	DEVIATION/DRIVE	
E	VOLTAGE/EVENT	SENSOR (PRIMARY ELEMENT)	
F	FLOW	RAWD	
G	GAUGE PRESSURE	CLASS GAUGE	
H	MANUAL, HAND		
I	CURRENT	INDICATE	HIGH
J	POWER (WATTS)	SCAN	
K	TIME	CONTROL STATION	
L	LEVEL	LIGHT	LOW
M	MOISTURE, HANIDTY	MONITOR	INTERMEDIATE
N	CONSISTENCY	USER'S CHOICE	
P	USER'S CHOICE, OPACITY	SHRICE	OPEN
R	PRESSURE OR VACUUM	POINT (TEST) CONNECTION	
S	QUANTITY	INTEGRATOR, TOTALIZER	
T	RESTRICTION/RESISTANCE	RECORD OR PRINT/REGULATOR	
U	SPEED	SWITCH/SELECTOR	
V	TEMPERATURE/TORQUE	TRANSMITTER	
W	MULTI-VARIABLE	MULTI-FUNCTION	MULTI-FUNCTION
X	VISCOSITY/VIBRATION/WEAR	VALVE, DAMPER OR LOUVER	
Y	WEIGHT OR FORCE	WELL	
Z	MANUAL ON/OFF (VARS)	UNCLASSIFIED	UNCLASSIFIED
	USER'S CHOICE	RELAY, COMPUTE, OR CONVERT	
	POSITION, LIMIT	ACTUATOR, DRIVER	

B LOCAL INDICATION (P-PRESSURE, L-LEVEL, F-FLOW, T-TEMPERATURE)

INSTRUMENT NOTES:

1. ALL DCS POINTS WILL BE TRENDED.
2. ALL DCS POINTS WILL HAVE HIGH & LOW ALARMS.
3. ALL MOTOR START/STOP FROM DCS UNLESS INDICATED OTHERWISE.

D	10MAY08	ISSUED FOR DESIGN	GR
C	12NOV08	ISSUE FOR APPROVAL	PC
B	05NOV08	ISSUE FOR REVIEW	EL
A	26OCT08	ISSUE FOR REVIEW	EL
REV	DATE	DESCRIPTION	B



**DEMONSTRATION PLANT
P & I DIAGRAM
LEGEND-SHEET 1**

INDUSTRA
Engineers & Consultants

SEATTLE WA PORTLAND OR GREENVILLE SC

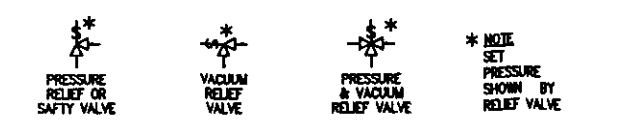
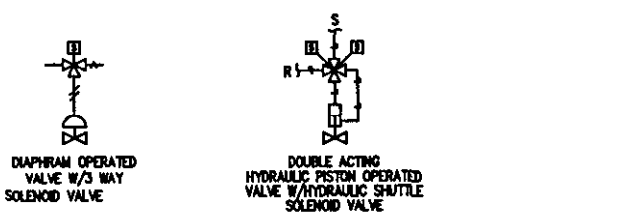
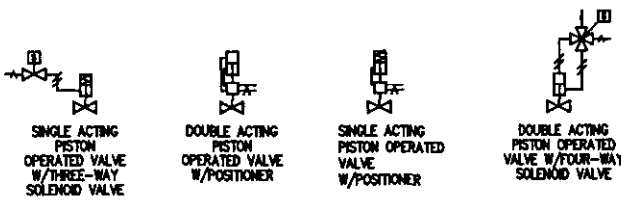
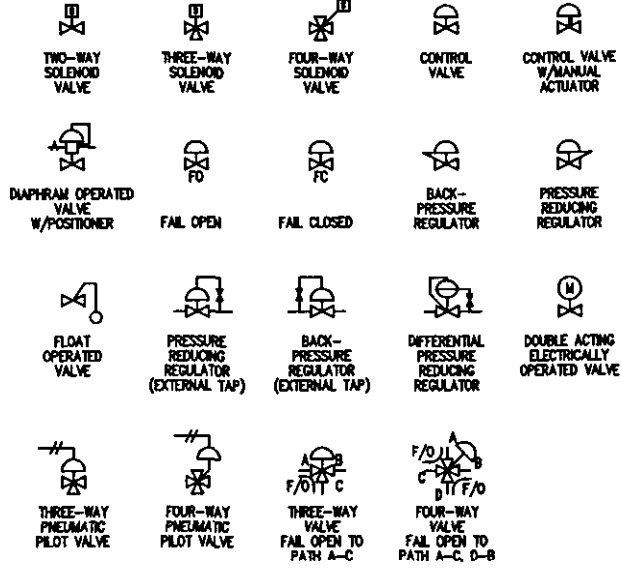
PROJECT NO. 11805

SCALE	DATE	DRAWING NO.
NONE	23OCT08	D-11805-F-001
DR. BY	PROJ. NO.	
ELM	11805	

Final Report
DOE Cooperative Agreement No. DE-FC02-07-OR-21400

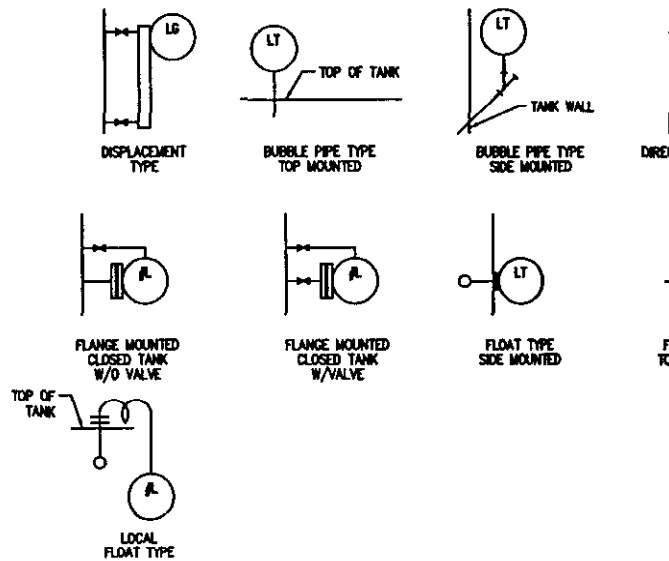
PIPING SYMBOLS:

VALVES W/ACTUATORS

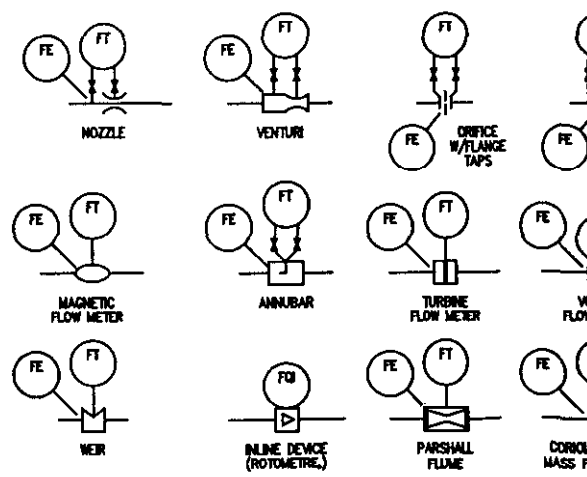


INSTRUMENTATION SYMBOLS:

LEVEL:



FLOW ELEMENTS W/TRANSMITTERS:



ANALYTICAL:

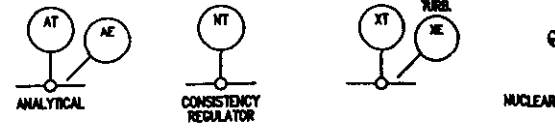
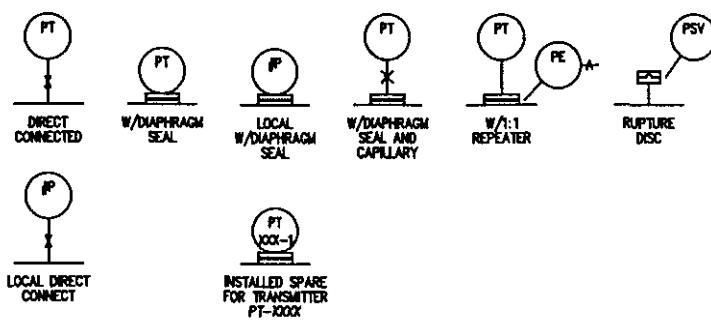
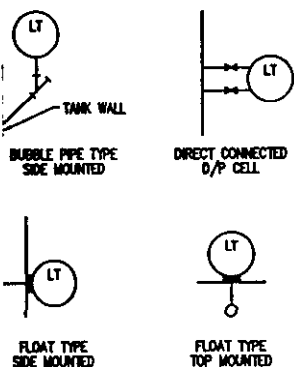


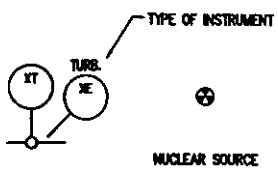
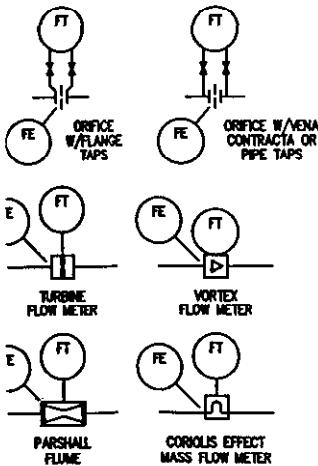
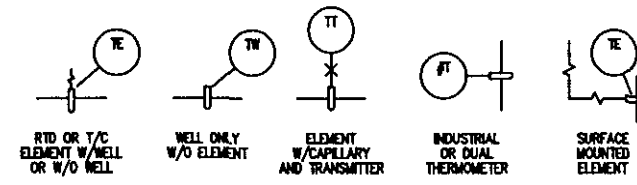
FIGURE 2-10 (continued): Legend Sheet No. 2 for the P&I

INSTRUMENTATION SYMBOLS: CONT.

PRESSURE:



TEMPERATURE ELEMENTS:



INSTRUMENT NOTES:

1. ALL DCS POINTS WILL BE TRENDED.
2. ALL DCS POINTS WILL HAVE HIGH & LOW ALARMS.
3. ALL MOTOR START/STOP FROM DCS UNLESS INDICATED OTHERWISE.
4. ALL IN-LINE INSTRUMENT DEVICES WILL HAVE DEVICE SIZE SHOWN NEXT TO INSTRUMENTS.

D	10MAR00	ISSUED FOR DESIGN	G
B	05NOV98	ISSUE FOR REVIEW	E
A	26OCT98	ISSUE FOR REVIEW	E
REV	DATE	DESCRIPTION	



DEMONSTRATION PLANT
P & I DIAGRAM
LEGEND-SHEET 2

SCALE	DATE	DRAWING NO.
NONE	23OCT98	D-11805-F-002
DR. BY	PROJ. NO.	
ELM	11805	

INDUSTRA
Engineers & Consultants

SEATTLE WA PORTLAND OR GREENVILLE S.C.

PROJECT NO. 11805

for the P&I Diagram

F102_1.DWG
LAST EDIT DATE: 15DEC98
LAST EDIT BY: RE
11903 ZPC REFORMER
D-11905-F-102
11903 ZPC REFORMER
P & I DIAGRAM
D-11905-F-102

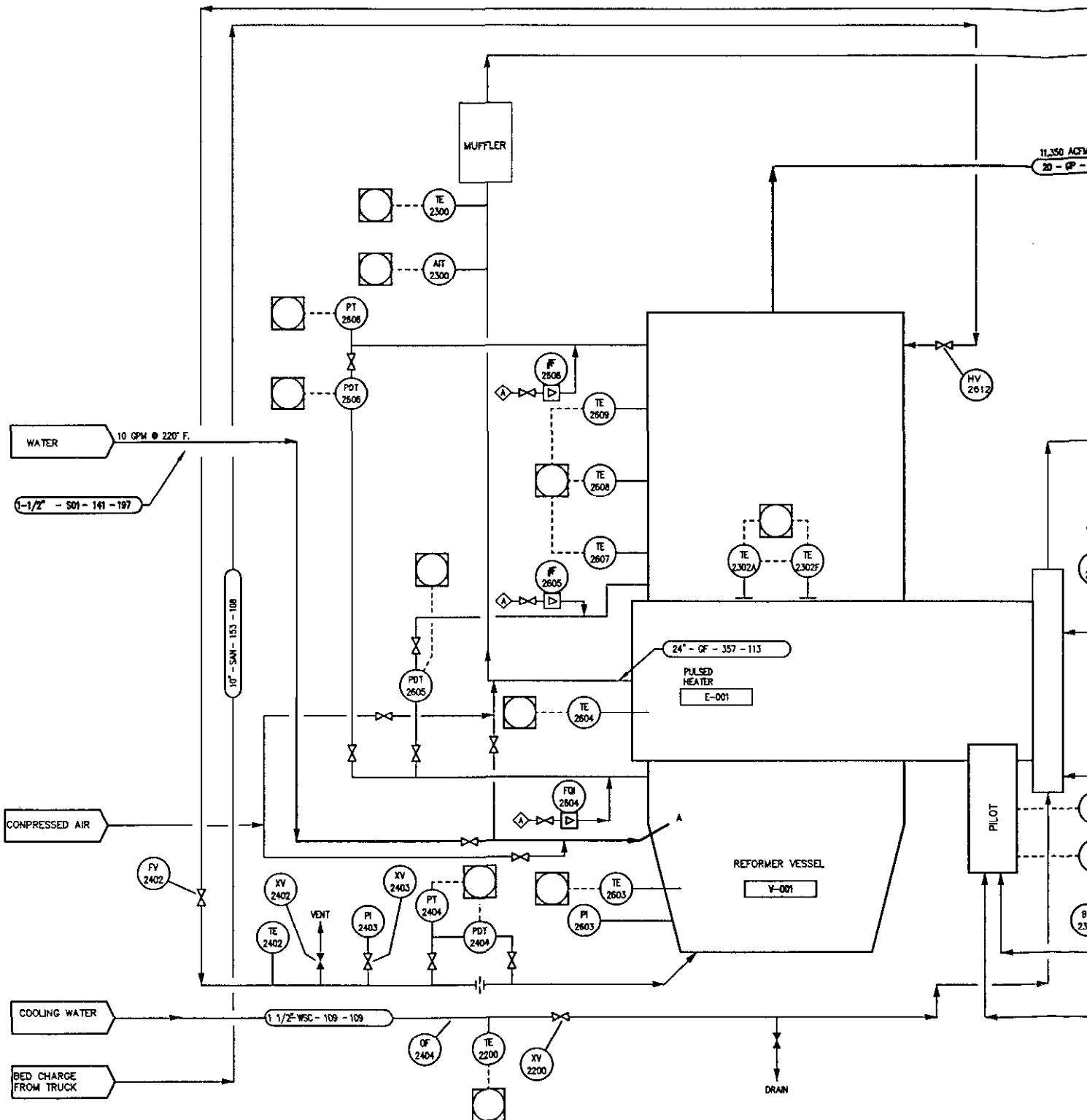
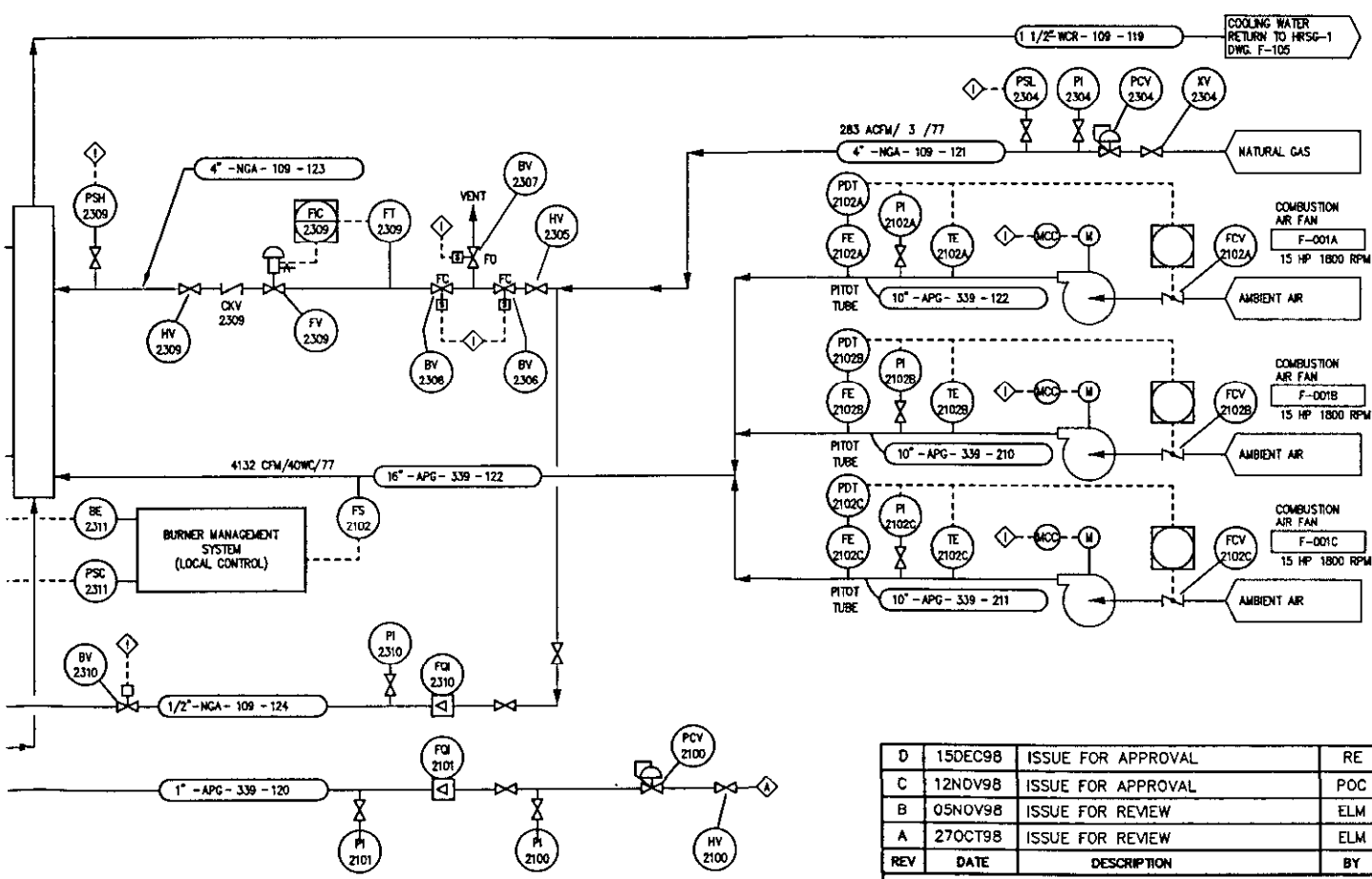
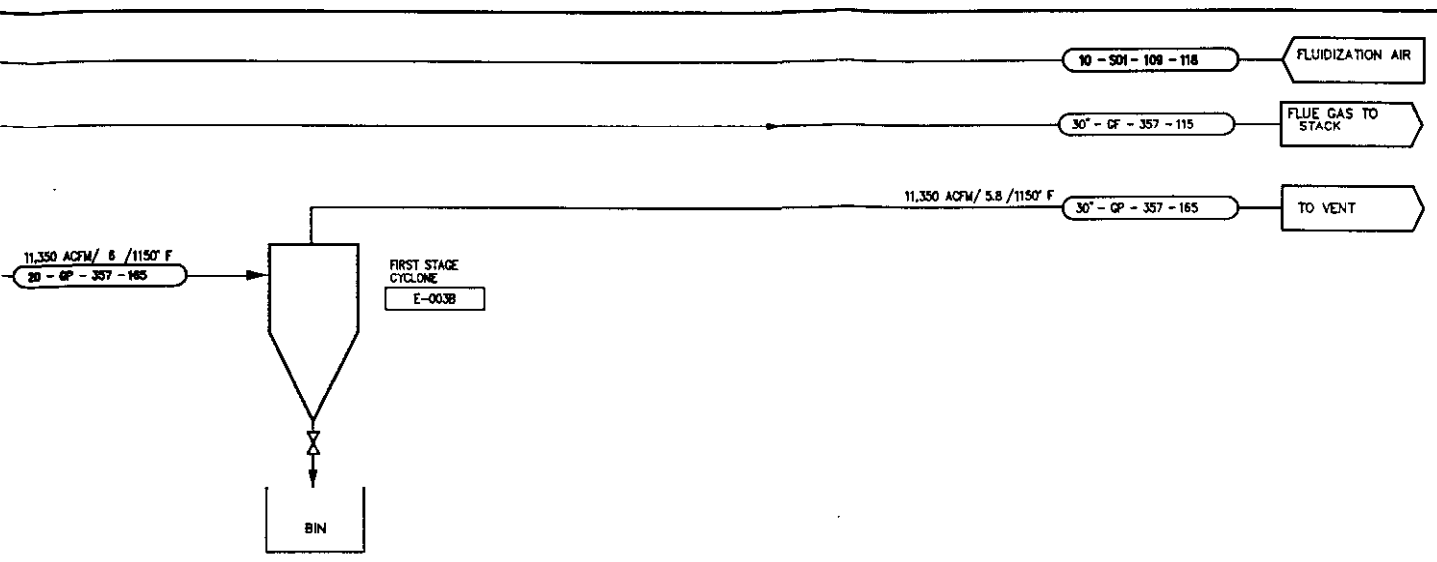
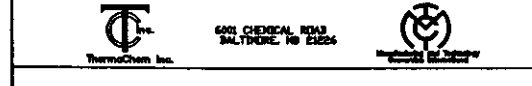


FIGURE 2-11: Process and Instrumentation Diagram for the Combustion Reformer



REV	DATE	DESCRIPTION	BY
D	15DEC98	ISSUE FOR APPROVAL	RE
C	12NOV98	ISSUE FOR APPROVAL	POC
B	05NOV98	ISSUE FOR REVIEW	ELM
A	27OCT98	ISSUE FOR REVIEW	ELM



DEMONSTRATION PLANT P & I DIAGRAM REFORMER

SCALE	DATE	DRAWING NO.	REV.
NONE	23OCT98	D-11805-F-102	A
DR. BY	PROJ. NO.		
ELM	11805		

Burner Design Qualification Test

INDUSTRA
Engineers & Consultants

SEATTLE WA PORTLAND OR GREENVILLE S.C.

PROJECT NO. 11805

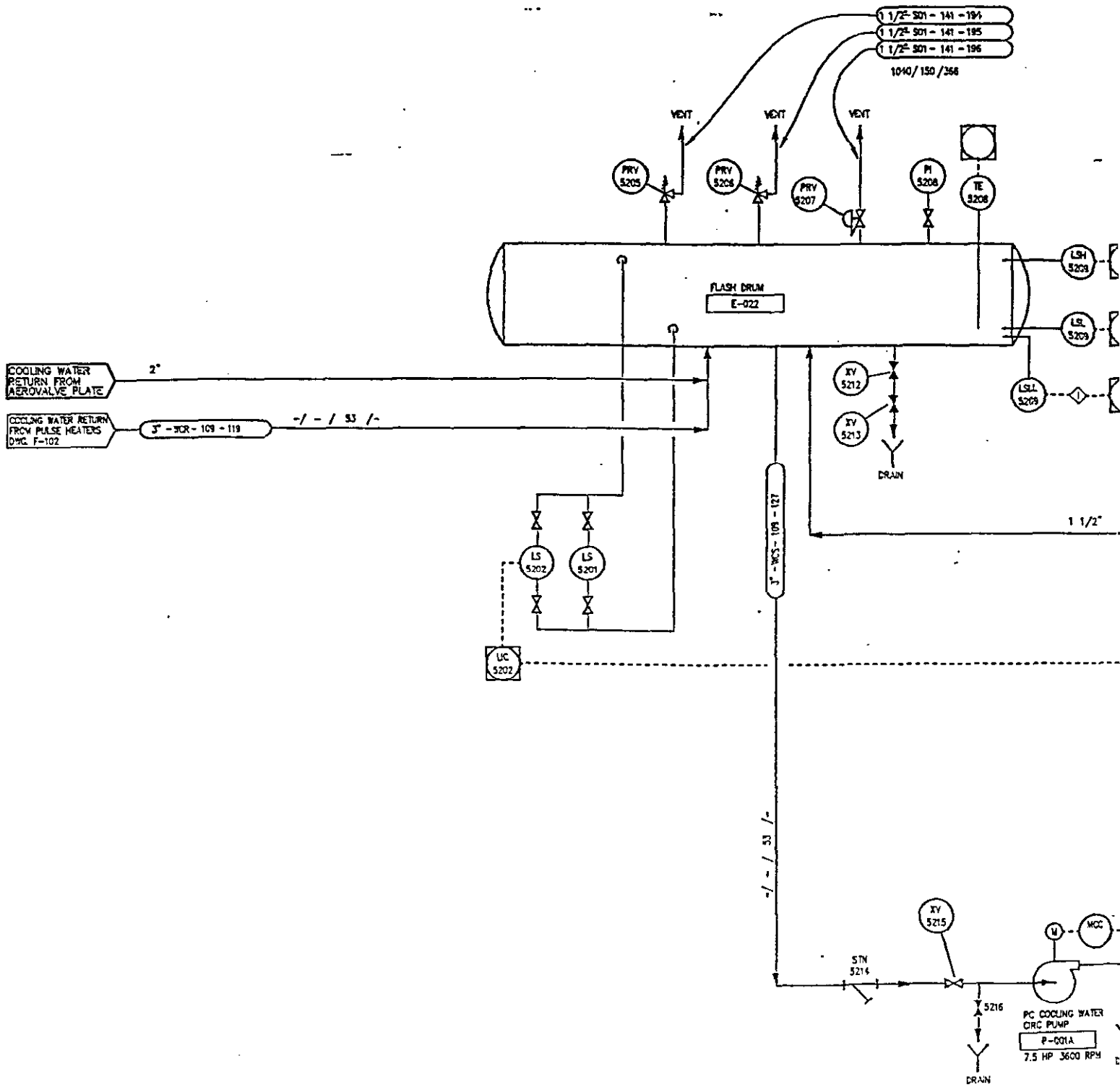
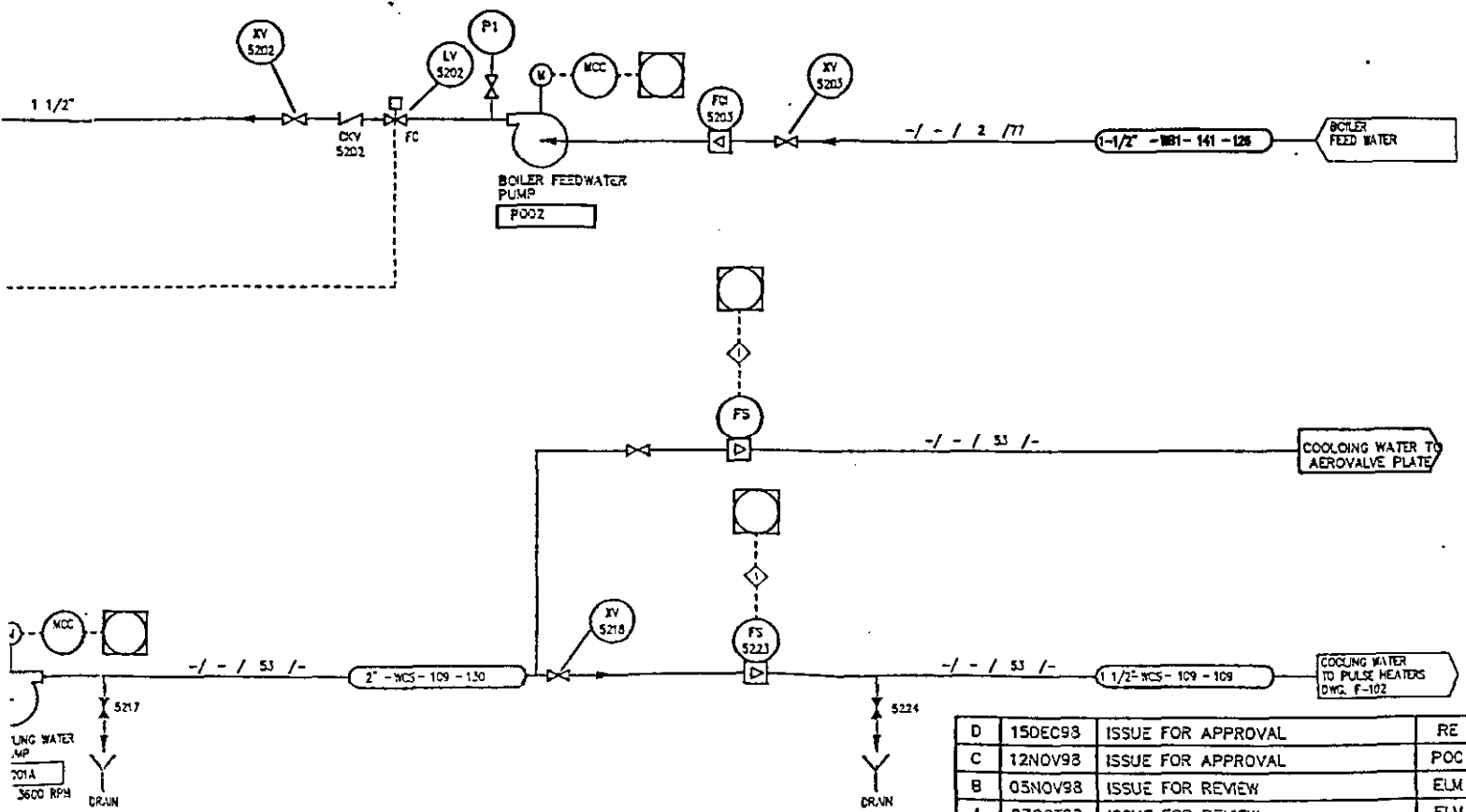
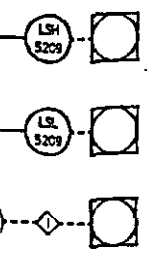


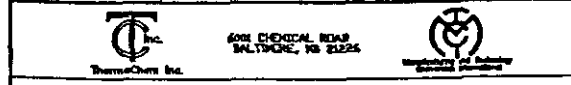
FIGURE 2-12 : Pulse Combustor Cooling Circuit

thermoChem Contract No. 10030

Final Report
 DOE Cooperative Agreement No.
 DE-FC22-92PC92644



REV	DATE	DESCRIPTION	BY
D	15OEC98	ISSUE FOR APPROVAL	RE
C	12NOV98	ISSUE FOR APPROVAL	PCC
B	05NOV98	ISSUE FOR REVIEW	ELM
A	27OCT98	ISSUE FOR REVIEW	ELM



Circuit P&ID for Combustor Design Qualification Test

INDUSTRA
 Engineers & Consultants
 SEATTLE WA PORTLAND OR GREENVILLE S.C.
 PROJECT NO. 11805

**DEMONSTRATION PLANT
 P & I DIAGRAM
 PRODUCT GAS HEAT RECOVERY**

SCALE NONE	DATE 23OCT98	DRAWING NO. D-11805-F-105	REV. A
DR. BY ELM	PROJ. NO. 11805		

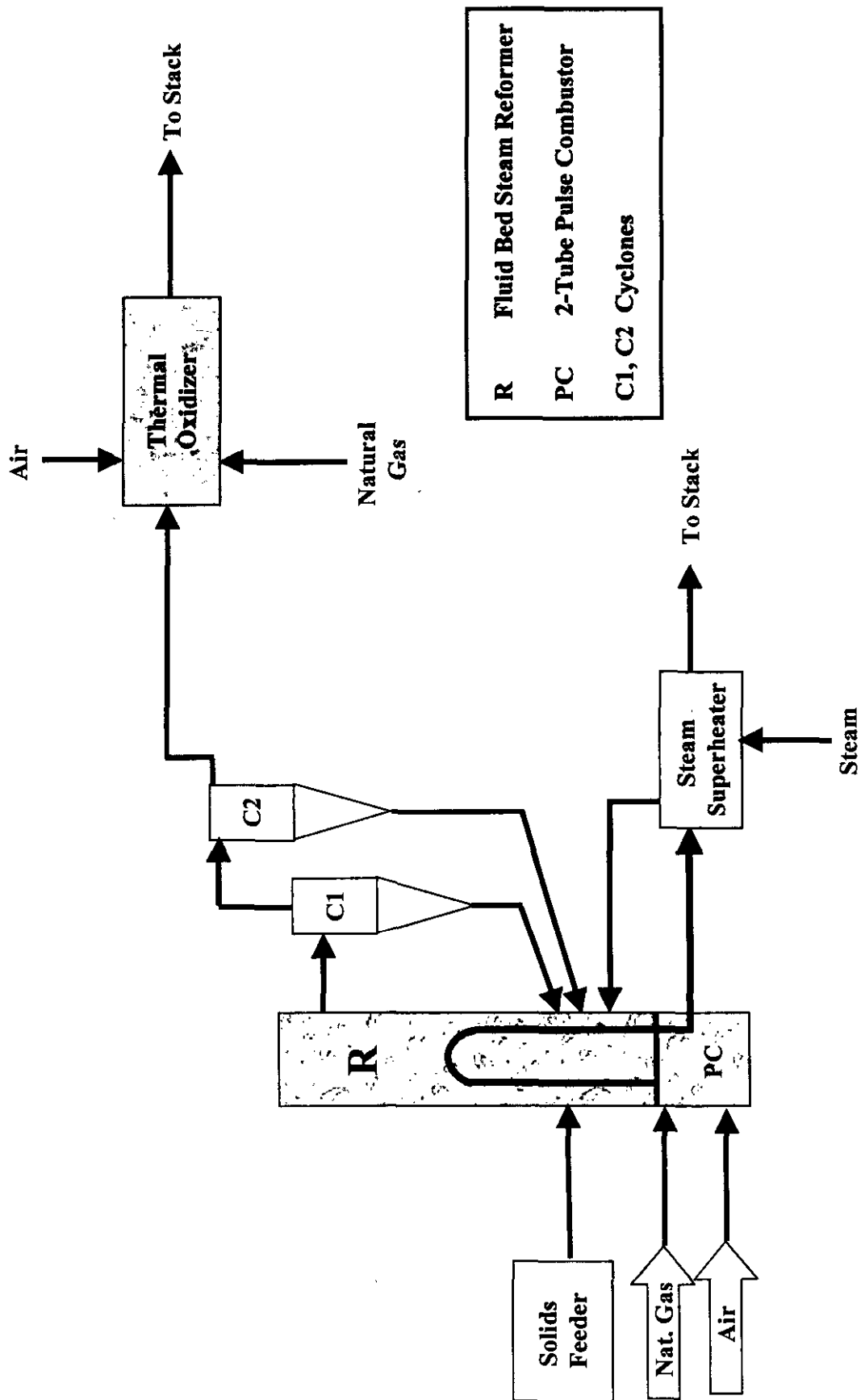


FIGURE 2-13: Process and Instrumentation Diagram for the PDU Test

3.0 UPDATE OF THE PUBLIC DESIGN REPORT

3.1 Design and Equipment Changes

The design and equipment are unchanged from the original Public Design Report, Volume I.

3.2 Demonstration Plant Capital Costs Update

The capital cost analysis presented in Volume I is unchanged.

4.0 DEMONSTRATION PROGRAM

4.1 Test Plans

The principal objectives of this program were to perform qualification testing of a 253-tube pulsed heater and to demonstrate its readiness for commercial deployment.

The specific objectives included verification and demonstration of:

- Full-scale pulsed heater performance and operability,
- Steam reformer system performance and operability,
- Thermal and gasification efficiency with coal feed into the PDU,
- Emissions (SO₂, NO_x, THC and CO) determination, and
- Waste stream (effluent) regulatory compliance for samples from the PDU.

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields and composition, char yields and composition and endothermic heat requirements were determined in the PDU.

4.1.1 Combustor Qualification Tests

Performance of a full-scale multiple resonance tube pulse combustor was determined in the test facility constructed as part of this project.

The test plan is presented in Appendix A.

The pulse combustor's role in the reformer is to provide the process heat required. The combustor was test fired on natural gas. The amount of heat that can be supplied by the pulse combustor will be determined at various operating conditions. Combustor firing rate and excess air levels are the variables to be examined with respect to the combustor. Of course, the amount of heat that can be transferred to the fluidized bed is also dependent upon the conditions within the bed (bedside heat transfer coefficient)

and the tube-to-bed temperature difference. The tube temperatures and bed temperatures were monitored and used in conjunction with energy balance data to determine the bedside heat transfer coefficient. Combustor efficiency and emissions were determined at various firing rates (up to 25 million Btu/hr), excess air levels (20% to 60%), and fluidized bed operating temperatures (1,100°F to 1,400°F). The test matrix is presented in the following table.

Table 4-1: Test Matrix

NUMBER OF TEST SERIES PERFORMED: 6

VARIABLE	VALUE OR RANGE
<u>PULSED HEATER:</u>	
FIRING RATE, MMBTU/H	4 - 23
FLUE GAS RECYCLE	NO; YES
INNER SHIELD TUBE	LONG (26 INCH LENGTH); SHORT (5 INCH LENGTH)
FUEL	NATURAL GAS; H2 - RICH SYN GAS
<u>HEAT SINK:</u>	
- AIR FLUIDIZED BED BED TEMPERATURE, F	50 - 1,350
- WATER BATH TEMPERATURE, F	212

The fluidized bed test facility was filled with sand and fluidized with air. Water was injected into the bed to impose a heat load, thereby controlling the bed temperature independently of combustor firing rate. Gas flow and combustion airflow rates were measured for each test. The pulse combustor flue gas was analyzed to determine the concentration of oxygen, carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxides, and hydrocarbons. This data was used to assess combustion efficiency at various firing rates and excess air levels and provided the basis for the commercial configuration system using this general combustor design.

The fluidized bed temperature, fluidizing air flow, water flow for bed temperature control, pulse combustor exhaust temperature, resonance tube temperatures, combustion air temperature and combustor cooling circuit steam generation were measured for each test. This data permitted projections of an energy balance and quantification of the amount of heat transferred to the bed and the tube-to-bed heat transfer coefficient.

Performance of a full-scale multiple resonance tube pulse combustor was determined in the test facility constructed as part of this project. The combustor was fired on natural gas for most of the testing program.

The amount of heat that can be supplied by the pulse combustor was determined at several firing rates and excess air levels. The tube temperatures and bed temperatures were monitored and used in conjunction with energy balance data to determine the bed-side heat transfer coefficient. Combustor efficiency and emissions (SO_2 , NO_x , THC and CO) were determined at various firing rates, excess air levels, recycle flue gas rates, and fluidized bed operating temperatures.

4.1.2 Coal Characterization Tests

The production of char in the PDU for DRI is the basis for selecting the coal to be tested in the PDU. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant.

In the char production application, the primary variable will be operating temperature. The goal is to identify the lowest temperature at which satisfactory sulfur and volatile matter content reduction is achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby increasing product yield. The lower operating temperature also provides a higher tube-to-bed temperature differential, which improves the amount of heat transfer into the reformer and increases throughput.

The objective of these tests, conducted in an existing PDU, was to identify the lowest temperature at which a char suitable for use as a reductant for DRI production could be achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby maximizing solid product yield. Three operating temperatures were evaluated: 1000, 1100, and 1200 °F.

Mass and energy balances were performed for each steady state PDU test to verify mass closure and to determine the process heat requirement. The coal feed rate, fluidizing steam rate, and instrument purge (nitrogen) rates were measured for each test. A slipstream of product gas was collected in an EPA Method 5 impinger train and the steam and condensable hydrocarbons are collected for analysis. Fixed gas composition was determined by on-line gas chromatography. Product char was collected and analyzed for comparison. The fluid-bed temperature distribution was monitored by thermocouples inserted in thermal wells, so as to permit replacement of thermocouples during operation. The locations of the thermocouples were selected to span the fluid bed such that any maldistribution in fluidization and bed temperature uniformity can be detected.

Since the fluid bed removes heat from the resonance tubes of the pulse combustor, uniform bed fluidization is important in maintaining uniform tube temperatures and efficient heat flux and heat transfer conditions from the resonance tubes to the bed. The bed height was measured by two sets of pressure differential measurements. The pressure differential between two locations at a known height between the two pressure-monitoring taps in the bed were employed to monitor the expanded bed density (pressure drop per unit bed height).

Samples of the product gas condensate were submitted to an independent laboratory for analysis. On-line gas chromatography was utilized to determine product gas composition, yield and heating value. Employing the PDU's semi-automated data acquisition system, all process variables were data logged every thirty (30) minutes to develop trend information. The product gas composition (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, methane, acetylene, ethylene, ethane, propylene, and propane) were determined on line with the MTI M-200 gas chromatograph. Draeger tubes were employed to monitor ammonia and hydrogen sulfide in the product gas. Utilizing an EPA Method 5 gas sampling train, product gas condensate samples were collected, quantified and submitted to an independent laboratory for analysis. Laboratory determinations included volatile organic compounds (VOC's), semi-volatile organic compounds (SVOC's), Chemical Oxygen Demand (COD), Biological Oxygen Demand (BOD), chloride, sulfur and nitrogen compounds.

4.2 Operating Procedures

Instrumentation and Data Acquisition Systems and Test Methods used in completing the tests are described in this section.

The Design Qualification Test Checkout Procedure is presented in Appendix B.

4.2.1 Instrumentation and Data Acquisition

For the Design Qualification Tests, most of the data was recorded every five minutes in the PLC control and data system. The fluidized bed temperature, fluidizing air flow, pulse combustor exhaust temperature, resonance tube temperature, combustion air temperature, pulse combustor fuel flow, combustion air flow, and recycle flue gas flow were recorded automatically. Water injected into the fluidized bed for temperature control, make-up water for the steam generation circuit, and fluidized bed shell temperatures were measured and recorded manually. Flue gas composition was measured continuously and recorded every five minutes.

For the PDU tests, all temperature and pressure data were recorded manually at thirty-minute intervals. Natural gas and airflow to the pulse combustor and instrument purge nitrogen were measured by rotameters and recorded manually. An approximate instantaneous coal feed rate was determined by observing the metering screw speed. However, the actual coal feed rate is obtained by direct weighing of the coal fed into the loading hopper over time. Cyclone product was collected at the end of each test and weighed to determine a production rate. The bed solids were weighed before and after each test to determine the amount of char that stays in the bed. Product gas composition was measured by an on-line gas chromatograph which stores data every five minutes during the test.

4.3 Test Methods

For the coal characterization tests, an on-line GC was used to analyze a small slipstream of the product gas flow. The sample product gas flow was first passed through a gas cleanup system, shown at the top of Figure 4-1.



FIGURE 4-1: GAS CHROMATOGRAPH

The gas sample is then passed through the dry gas metering pump (middle of Figure 4-1).

Condensate rate was normally determined by measuring the amount of liquid collected per liter of dry gas as measured by a rotameter and dry gas meter. During the PDU tests, however, the amount of water condensed was calculated to achieve a hydrogen balance. This approach is sometimes used because the rotameter and dry gas meter occasionally stick, thereby indicating much lower gas rates than actual.

Samples of the coal feedstock, cyclone products, and bed solids were collected and sent to a qualified independent laboratory for ultimate analysis. The condensate was sent to an independent laboratory for analysis of volatile organics (VOC's), semi-volatile organics (SVOC's), biological oxygen demand (BOD), and chemical oxygen demand (COD).

4.4 Analyses of Feedstocks and Products

Table 4-2 provides the coal and solid product analyses for each of the three temperatures evaluated. This data is used to evaluate performance and mass balance closure for the three tests. (Please see Section 4.6.2).

Table 4-2: Coal and Solid Product Analyses

Solids Analyses				
Component	Coal	Wt%, dry		
		Product 1000F	1100F	1200F
C	72.00%	55.86%	46.64%	89.17%
H	4.87%	0.00%	0.00%	0.00%
N	1.08%	0.78%	0.80%	1.03%
S	0.38%	0.35%	0.07%	0.04%
Ash	6.05%	43.01%	52.49%	9.76%
O	15.62%	0.00%	0.00%	0.00%
As Received Basis				
HHV, Btu/lb	8894			
Fixed Carbon	37.24			
Volatile Matter	31.76			
Moisture	26.56			

Table 4-3 presents the gas analyses for the three tests, and Table 4-4 presents the corresponding condensate analyses. Nitrogen was used as a tie-in element to determine the gas composition reported in Table 4-3. The condensate data furnished in Table 4-4 are the actual raw data reported by the Laboratory. The major constituent or the remainder of the condensate is water.

Table 4-3: Gas Analyses

Gas Analysis (Nitrogen & Moisture Free)	Vol%		
	1000°F	1100°F	1200°F
Hydrogen	37.21	43.98%	53.93%
Oxygen			
Nitrogen	0.00	0.00%	0.00%
Methane	19.14	15.85%	9.40%
Carbon Monoxide	3.89	4.944%	5.54%
Carbon Dioxide	32.90	30.15%	28.96%
Ethylene	2.64	2.33%	1.10%
Ethane	2.75	1.72%	0.61%
Acetylene	0.00	0.01%	0.00%
Hydrogen Sulfide	0.32	0.22%	0.13%
Propylene	1.15	0.79%	0.32%
Propane	0.00	0.00%	0.00%

Table 4-4: Condensate Analyses

Condensate Analysis	1000F	1100F	1200F	
SVOC				
Aniline	7.2	7.1	8.3	mg/L
Phenol	800	800	800	mg/L
2-Methylphenol	290	300	280	mg/L
4-Methylphenol, 3-Methylphenol	900	900	860	mg/L
2,4-Dimethylphenol	110	120	110	mg/L
Naphthalene	1.6	1.4	2.1	mg/L
Acenaphthylene	<0.1	<0.1	0.48	mg/L
Phenanthrene	<0.1	<0.1	0.22	mg/L
Anthracene	<0.1	<0.1	0.13	mg/L
Fluoranthene	<0.1	0.11	<0.1	mg/L
Pyrene	<0.1	0.12	<0.1	mg/L
Bis(2-ethylhexyl)phthalate	0.28	3.4	3.4	mg/L

Table 4-4: Condensate Analyses (continued)

VOC				
Acetone	490	200	290	mg/kg
2-Butanone	140	110	63	mg/kg
Benzene	18	21	17	mg/kg
Toluene	14	13	10	mg/kg
m,p-Xylene	3.1	2.6	2.1	mg/kg
o-Xylene	1.8	1.4	1.2	mg/kg
Styrene	2	1.6	1.7	mg/kg
Naphthalene	1.4	<1.2	2.4	mg/kg
BOD	13	12	9.3	g/L
COD	20	20	16	g/L
Chloride	0.15	0.21	0.14	g/L
Sulfur, total	<0.050	<0.050	<0.050	%

4.5 Data Analysis Methodology

Mass balances were developed for each of the three PDU tests. The balance was developed using the measured amounts of coal fed, cyclone product collected, and starting and final bed weights along with the corresponding chemical analyses. The mass of each constituent (carbon, hydrogen, nitrogen, sulfur, oxygen, and ash) that was fed during the test or was present in the bed at the beginning of the test was determined simply by multiplying the total amount of material (coal and starting bed) by the chemical analysis. Similarly, the amount of each constituent leaving the reformer or remaining in the reformer at the end of the test was determined using the weights and analyses of the cyclone catch and the final bed. The amount of char in the final bed was determined by subtracting the amount of each constituent in the starting bed from that in the final bed. The amount of char was added to the amount of collected cyclone product to determine the amount of solid product generated during each test.

The amount of gas produced was determined by nitrogen balance. The amount of nitrogen used as instrument purge was measured. Using the amount of nitrogen in the dry product gas as determined by the on-line gas chromatograph and the quantity of nitrogen fed, the total amount of dry product gas was calculated to yield a nitrogen balance. Since the rotameter and dry gas meter readings were not stable, the amount of condensate per volume of dry gas was calculated to yield a hydrogen balance.

The energy balance could not be experimentally determined because the heat loss from the small PDU equipment is orders of magnitude greater than the load required for processing. The difference in heat required to maintain temperature with or without feed could not be measured. This is not a significant problem since the heat of reaction can be accurately calculated by thermodynamic principles based on the heat of combustion (or heat of formation) of the products and reactants; all of which are known.

4.6 Data Summary

4.6.1 Qualification Test

A total of 6 test campaigns were conducted for the Qualification Test. The different configurations and conditions tested were:

SERIES 1: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, no flue gas recycle

- bed temperature of up to 1,100 F
- natural gas firing rate of up to 14 MMBtu/h

SERIES 2: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,100 F
- natural gas firing rate of up to 22 MMBtu/h

SERIES 3: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,200 F
- natural gas firing rate of up to 22 MMBtu/h

SERIES 4: Short shield tube (3 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,350 F
- natural gas firing rate of up to 23 MMBtu/h

SERIES 5: Short shield tube (3 inch straight tube length), water bath, natural gas firing, without flue gas recycle

- bath temperature of 212 F
- natural gas firing rate of up to 16 MMBtu/h

SERIES 6: Short shield tube (3 inch straight tube length), water bath, syn gas firing, without flue gas recycle

- bath temperature of 212 F
- syn gas firing rate of up to 11 MMBtu/h

The test measurements and data collection were rather extensive. Data trends are presented in Appendix C. The ensuing discussion targets a specific set of parameters and refers to a 24-h snapshot during operation with the clock starting at 4 AM (0400 h in the attached charts). The test results are presented in Figures 4-2 through 4-15. Data was obtained for both the up and down ramp of the pulse combustor firing rate. During this run, the pulse combustor tripped twice due to air compressor failure. The combustor firing was interlocked with bed fluidization air flow and disruption of this air flow closed the gas solenoid valves. The test was resumed when the air compressor problem was resolved. A bank of five air compressors were used and two different units failed during this test causing the two interruptions.

FIGURE 4-2: FIRING RATE

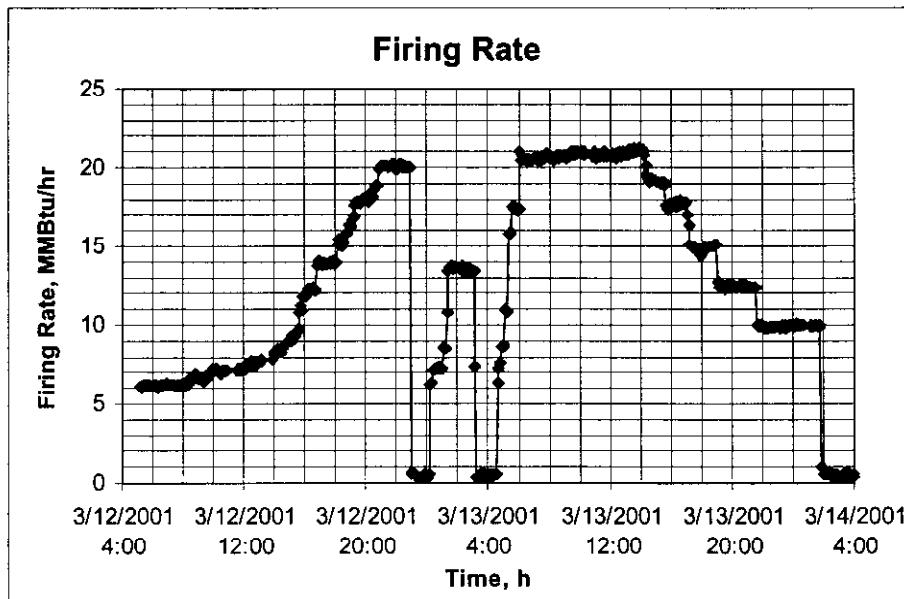


Figure 4-2 indicates the variation in pulse combustor firing rate with time. Natural gas firing rate was ramped up to about 21 MMBtu/h and held steady for about 10 hours. The pulse combustor operation was robust with strong pulsations and air suction with self-aspiration increasing significantly with firing rate.

The dynamic pressure in the combustion chamber was monitored during the test through a HP spectrum analyzer. The pulsation frequency was generally on the order of 58 Hz. The sound pressure level varied from 165 dB (~1.5 psi peak to peak pressure fluctuation) at ~6 MMBtu/h firing rate to about 173dB (~4 psi peak to peak pressure fluctuation) at ~20 MMBtu/h firing rate.

Figure 4-3 depicts the average dense fluid bed temperature. The thermal response of the bed to pulsed heating is quite rapid with bed heatup rates varying between 50 and 200°F per hour. The nominal bed temperature during the run was on the order of 1,000°F, while the peak temperature reached was 1,100°F. Water injection into the bed was started above 1,050°F bed temperature to regulate the bed temperature.

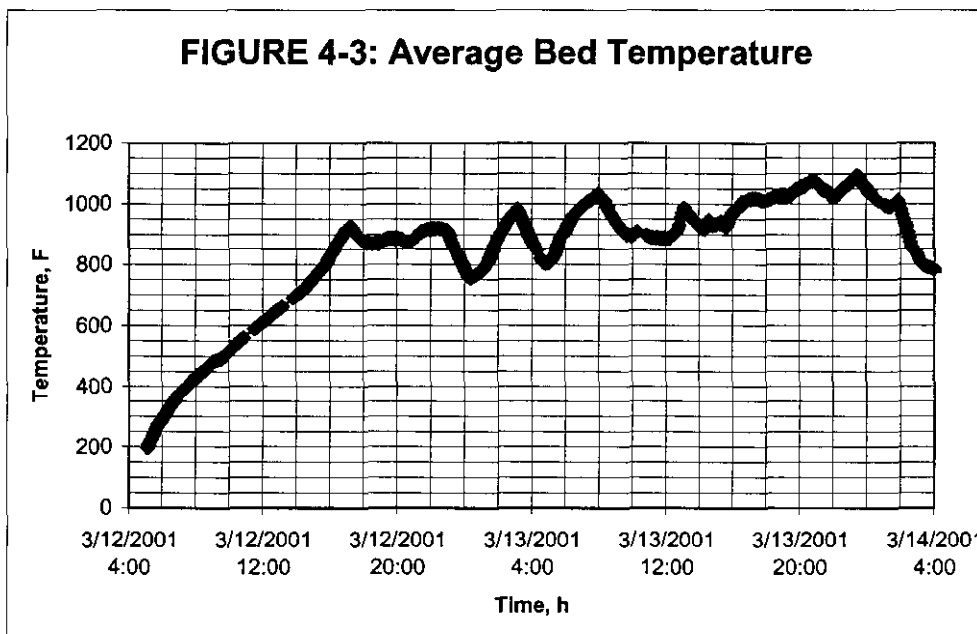
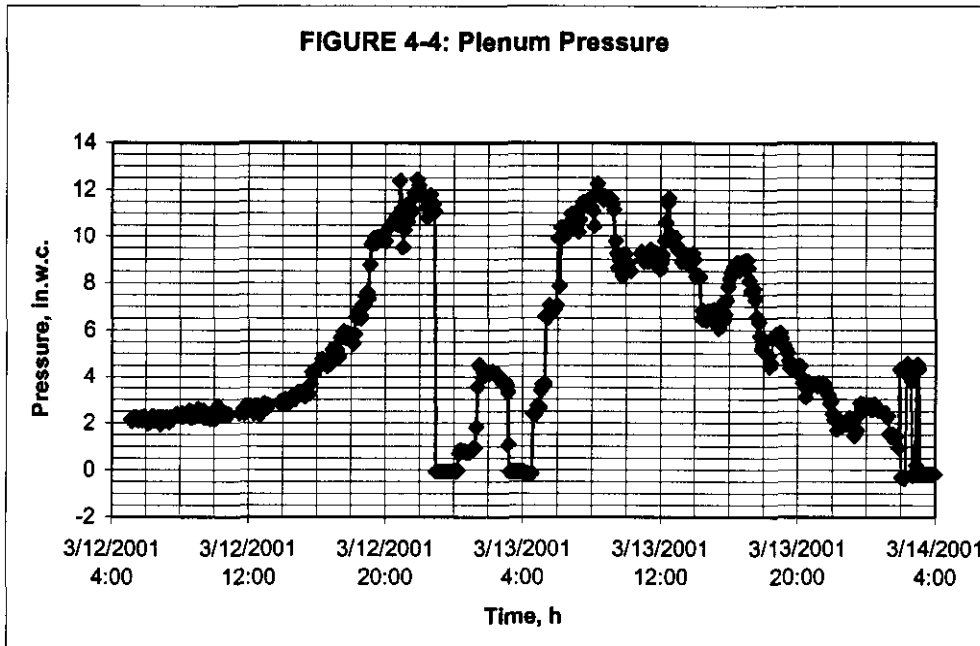
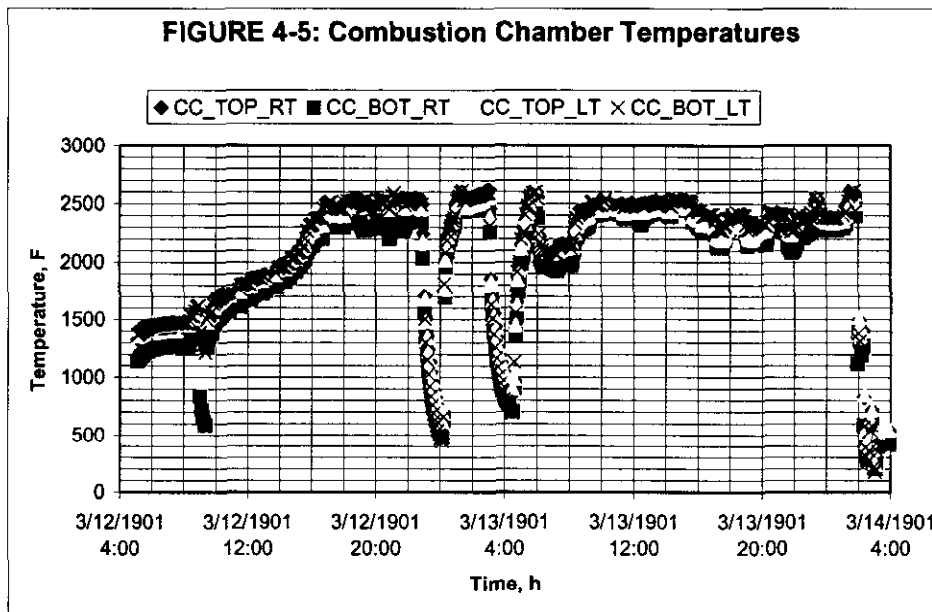


Figure 4-4 shows the static pressure in the air plenum of the pulse combustor. Due to self-aspiration, the demand on static pressure is rather low and is less than 12 inches H₂O at ~21 MMBtu/h firing rate.

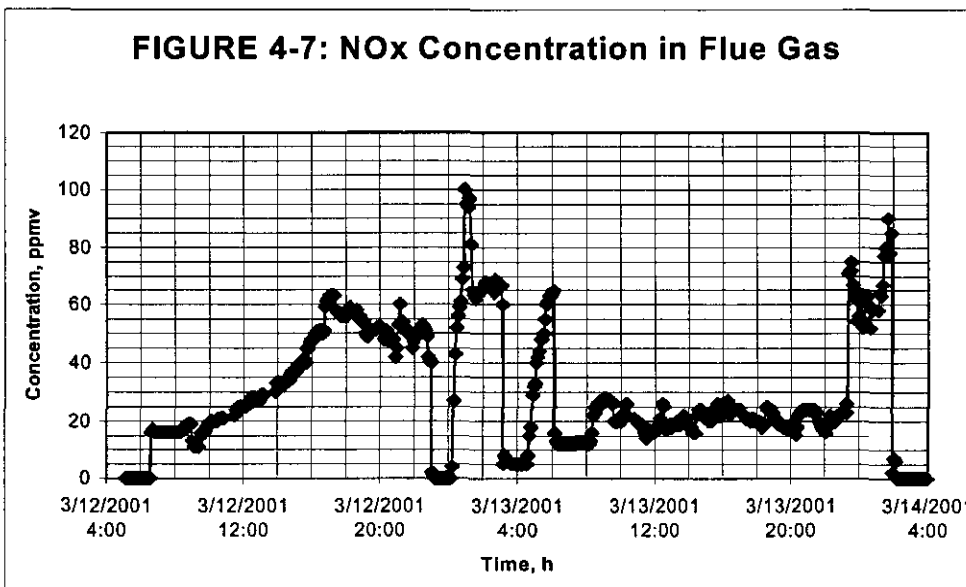
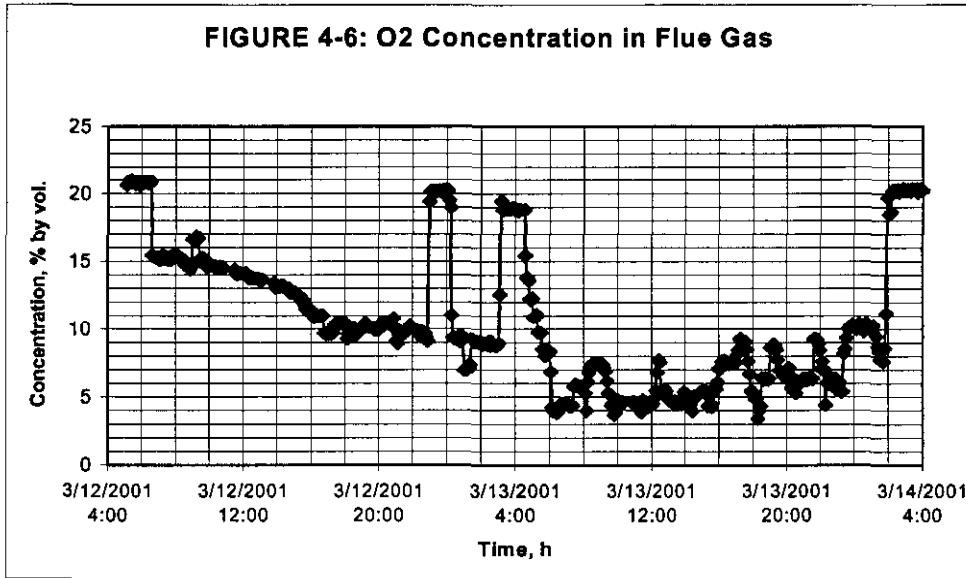


The temperatures registered by four different thermocouples in the pulse combustion chamber are shown in Figure 4-5. The chamber temperature averaged about 2,400°F.

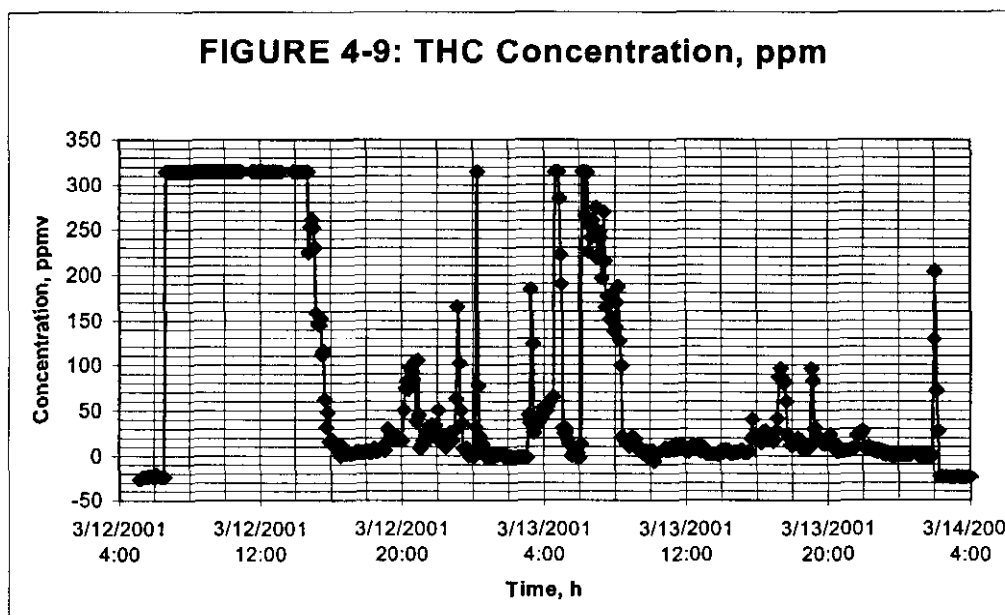
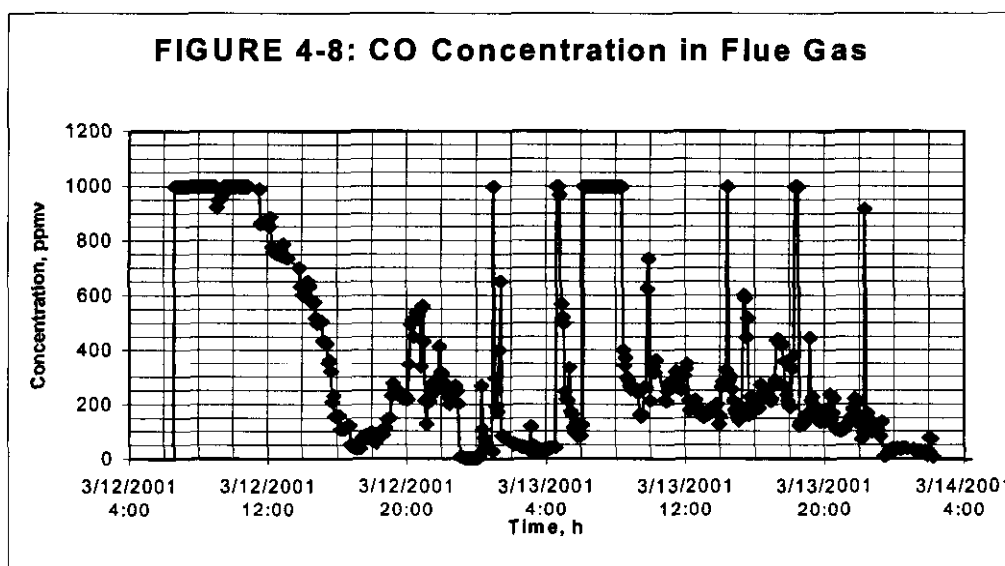


The composition of the flue gas from the combustor was monitored by a continuous emissions monitoring system calibrated and operated by personnel from TRC Environmental Corporation of Connecticut. Figure 4-6 through 4-11 provide the data on a dry basis during this run. The O₂ concentration is in the 4 to 10 % range during stable

firing of the combustor (see Figure 4-6). This corresponds to between 20 and 80% excess air operation. The O₂ concentration was relatively high without flue gas recycle. The high excess air operation was necessary to modulate the combustion chamber temperature. The NO_x emissions were relatively high due to the high O₂ concentration. With flue gas recycle, the O₂ as well as NO_x values reduced significantly. The NO_x concentration was in the 10 to 30 ppmv range (see Figure 4-7).



The CO concentration ranged from 100 to 400 ppmv during stable firing of the combustor (see Figure 4-8). The flow and temperature profiles needed to be established and be stable for the combustion to achieve combustion completion. The THC (total hydrocarbons) emissions are generally low (<20 ppmv) except during transients (see Figure 4-9) indicating high combustion efficiency. Figure 4-10 indicates the measured SO₂ concentration. As is to be expected, the level is very low and stems from the trace amount of mercaptans in natural gas. The CO₂ concentration ranges between 7 and 10% during stable firing (see Figure 4-11), and this is consistent with combustion calculations.



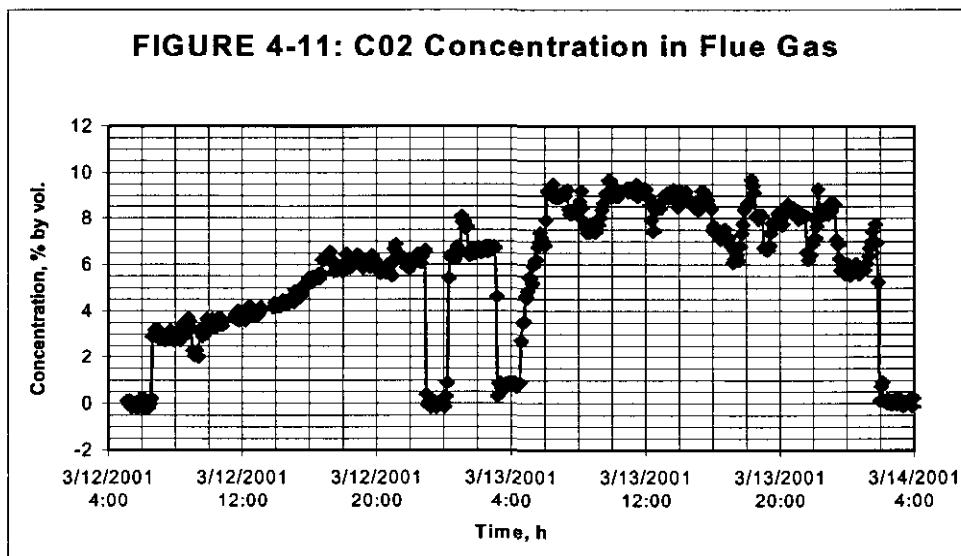
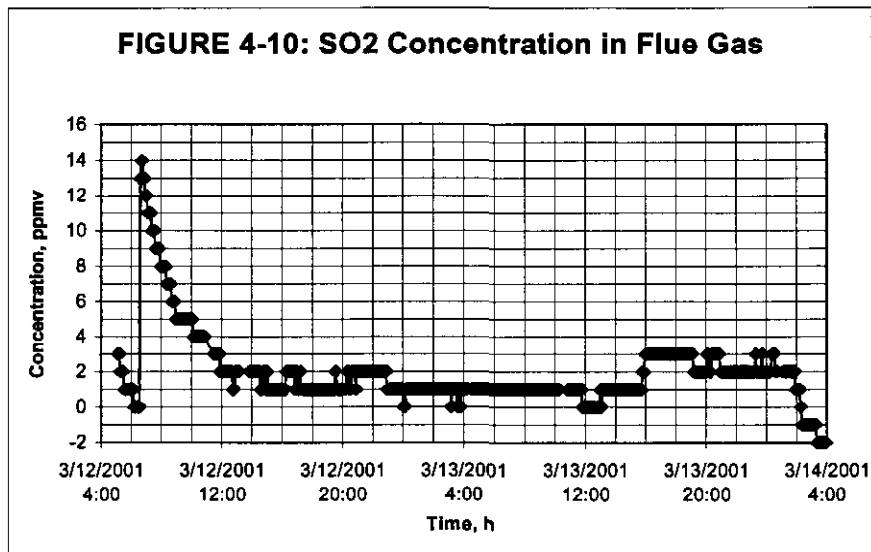


Table 4-5 provides a data summary for test campaigns 2 and 3 long shield tubes. In the flue gas recycle column, 0 denotes no recycle and 1 denotes flue gas recycle. Table 4-6 indicates the measured flue gas composition for the different tests. Table 4-7 presents the calculated results. The spreadsheet used for data analysis and the source code or macros put together are included in the Appendix. These results indicate that high combustion efficiency (99.9+ %) and low emissions including NO_x below 30 ppmv @ 3% O₂ can be obtained with flue gas recycle.

TABLE 4-5: DATA SUMMARY

**LONG SHIELD TUBE
TEST CAMPAIGNS 2 AND 3**

TEST NO.	DATE	TIME	MAIN GAS FIRING RATE MMBTU/H	FUEL DILUTION AIR	FLUE GAS RECYCLE	FRESH AIR	RECYCLE	FAN INLET
						TEMP. F	TEMP. F	TEMP. F
1	3/2/2001	1:49	17.29	YES	0	43		43
2	3/2/2001	3:45	20.61	YES	0	42		42
3	3/2/2001	10:19	20.49	YES	1	43	397	128
4	3/2/2001	12:44	17.50	NO	0	55		55
1	3/12/2001	14:55	8.93	NO	0	55		55
2	3/12/2001	15:58	11.79	NO	0	54		54
3	3/12/2001	17:43	13.88	NO	0	50		50
4	3/12/2001	19:58	18.10	NO	0	46		46
5	3/12/2001	21:57	19.90	NO	0	44		44
6	3/13/2001	2:04	13.69	NO	0	42		42
7	3/13/2001	13:30	21.20	NO	1	43	461	147
8	3/13/2001	15:00	19.24	NO	1	43	377	125
9	3/13/2001	15:55	17.77	NO	1	43	385	125
10	3/13/2001	18:04	14.44	NO	1	43	461	160
11	3/13/2001	20:24	12.37	NO	1	43	332	116
12	3/15/2001	22:49	9.87	NO	1	43	352	127
13	3/15/2001	16:26	3.30	NO	0	43		49
14	3/15/2001	17:01	5.04	NO	0	43		47
15	3/15/2001	17:51	5.99	NO	0	43		44
16	3/15/2001	19:36	17.61	NO	0	43		45
17	3/15/2001	20:36	20.88	NO	0	43		44
18	3/15/2001	21:41	14.98	NO	0	43		44
19	3/15/2001	22:31	17.58	YES	0	43		44

MARY - TEST OPERATIONS

INLET P.	AIR PLENUM PRESSURE	AIR PLENUM TEMP.	PULSE COMBUST. CHAMBER TEMP.	DECOUPLER TEMP.	MUFFLER TEMP.	BED TEMP.	BED HEIGHT	SUPERFICIAL FLUIDIZATION VELOCITY
	INCH H2O	F	F	F	F	F	INCH	FT/S
	8.84	153	2,476	1236	700	983	83.2	0.54
	14.07	165	2,426	1250	700	835	99.8	0.77
	8.59	366	2,445	1187	700	863	91.0	1.17
	5.32	370	2,691	1232	700	932	87.7	1.31
	3.31	119	1,925	1045	630	747	118.8	1.20
	4.37	174	2,101	1154	701	822	123.4	1.28
	5.63	234	2,454	1246	700	893	139.0	1.38
	9.80	278	2,441	1246	694	888	119.7	1.27
	12.19	255	2,483	1234	700	916	134.0	1.14
	4.09	301	2,487	1152	700	890	136.4	1.08
	9.19	463	2,448	1279	700	959	94.2	1.23
	6.71	430	2,494	1228	700	932	89.8	1.19
	7.28	386	2,489	1226	700	962	98.7	1.22
	5.05	433	2,202	1241	700	1012	82.4	1.27
	3.62	354	2,266	1247	700	1065	84.4	1.23
	2.02	357	2,346	1217	700	1060	91.9	1.03
	0.45	73	1,494	644	512	608	82.4	0.52
	0.37	80	2,032	733	576	635	78.9	0.52
	0.72	93	2,229	856	670	715	79.0	0.63
	7.93	318	2,552	1256	701	997	85.8	1.47
	11.11	267	2,545	1356	701	1063	99.0	1.49
	6.42	262	2,432	1260	694	1017	99.7	1.67
	8.76	202	2,537	1275	700	987	86.9	1.64

TABLE 4-6: FLUE GAS ANALYSIS

**LONG SHIELD TUBE
TEST CAMPAIGNS 2 AND 3**

TEST NO.	DATE	TIME	FLUE GAS ANALYSIS				
			O2 %	CO2 %	CO PPMV	NOX PPMV	THC PPMV
2-1	3/2/2001	1:49	10.23	5.59	428	58	44
2-2	3/2/2001	3:45	10.56	5.40	499	56	62
2-3	3/2/2001	10:19	5.07	8.64	228	24	49
2-4	3/2/2001	12:44	7.45	7.50	53	90	2
3-1	3/12/2001	14:55	12.70	4.44	505	37	261
3-2	3/12/2001	15:58	11.32	5.42	152	48	15
3-3	3/12/2001	17:43	10.41	5.91	87	56	4
3-4	3/12/2001	19:58	9.95	6.01	219	52	19
3-5	3/12/2001	21:57	10.10	5.81	316	47	26
3-6	3/13/2001	2:04	8.91	6.74	59	66	1
3-7	3/13/2001	13:30	4.55	9.06	177	19	2
3-8	3/13/2001	15:00	5.37	8.64	150	21	5
3-9	3/13/2001	15:55	6.07	8.40	216	22	24
3-10	3/13/2001	18:04	5.28	8.67	189	20	12
3-11	3/13/2001	20:24	5.83	8.20	143	18	9
3-12	3/15/2001	22:49	5.95	8.45	103	22	4
3-13	3/15/2001	16:26	13.25	4.10	971	19	315
3-14	3/15/2001	17:01	9.49	6.20	69	47	30
3-15	3/15/2001	17:51	9.71	6.05	36	55	10
3-16	3/15/2001	19:36	8.58	6.79	69	57	2
3-17	3/15/2001	20:36	9.10	6.71	81	53	16
3-18	3/15/2001	21:41	9.95	6.15	209	44	1
3-19	3/15/2001	22:31	9.58	6.15	225	52	9

TABLE 4-7: CALCULATED RESULTS

TEST NO.	DATE	TIME	COMBUSTION EFFICIENCY	HEAT TRANSFERRED, %	EX
2-1	3/2/2001	1:49	99.70%	54.5%	
2-2	3/2/2001	3:45	99.62%	56.6%	
2-3	3/2/2001	10:19	99.85%	46.6%	
2-4	3/2/2001	12:44	99.98%	45.9%	
3-1	3/12/2001	14:55	99.10%	55.3%	
3-2	3/12/2001	15:58	99.88%	54.2%	
3-3	3/12/2001	17:43	99.95%	54.8%	
3-4	3/12/2001	19:58	99.86%	53.8%	
3-5	3/12/2001	21:57	99.79%	54.0%	
3-6	3/13/2001	2:04	99.97%	46.7%	
3-7	3/13/2001	13:30	99.93%	48.8%	
3-8	3/13/2001	15:00	99.93%	49.0%	
3-9	3/13/2001	15:55	99.88%	50.1%	
3-10	3/13/2001	18:04	99.91%	49.3%	
3-11	3/13/2001	20:24	99.93%	50.5%	
3-12	3/13/2001	22:49	99.95%	49.7%	
3-13	3/15/2001	16:26	98.57%	37.1%	
3-14	3/15/2001	17:01	99.92%	31.5%	
3-15	3/15/2001	17:51	99.97%	36.6%	
3-16	3/15/2001	19:36	99.97%	49.8%	
3-17	3/15/2001	20:36	99.94%	55.3%	
3-18	3/15/2001	21:41	99.89%	54.1%	
3-19	3/15/2001	22:31	99.87%	53.7%	

EXCESS AIR	<u>CORRECTED TO 3% O2</u>			RECYCLE FLUE GAS TO AIR MASS RATIO
	CO, PPMV	NO _x , PPMV	THC, PPMV	
80.7%	715	97	74	
87.1%	860	97	107	
25.4%	258	27	55	22%
45.5%	70	120	3	
126.0%	1,095	80	566	
98.0%	283	89	28	
82.6%	148	95	7	
76.8%	357	85	31	
79.6%	522	78	43	
60.7%	88	98	1	
21.9%	194	21	2	23%
27.4%	173	24	6	23%
32.6%	260	27	29	23%
25.0%	216	23	14	28%
28.2%	170	21	11	24%
27.2%	123	26	5	27%
124.6%	2,225	44	731	
57.0%	108	74	47	
62.8%	57	88	16	
58.1%	100	83	3	
65.5%	122	80	24	
75.7%	340	72	2	
71.2%	355	82	14	

Figure 4-12 shows the variation in combustion efficiency with natural gas firing rate for the pulse combustor. The combustion efficiency improves with firing rate. This is attributed to enhanced fuel air mixing, more robust pulsations and higher flow field temperatures with an increase in firing rate.

FIGURE 4-12: VARIATION OF COMBUSTION EFFICIENCY WITH GAS FIRING RATE

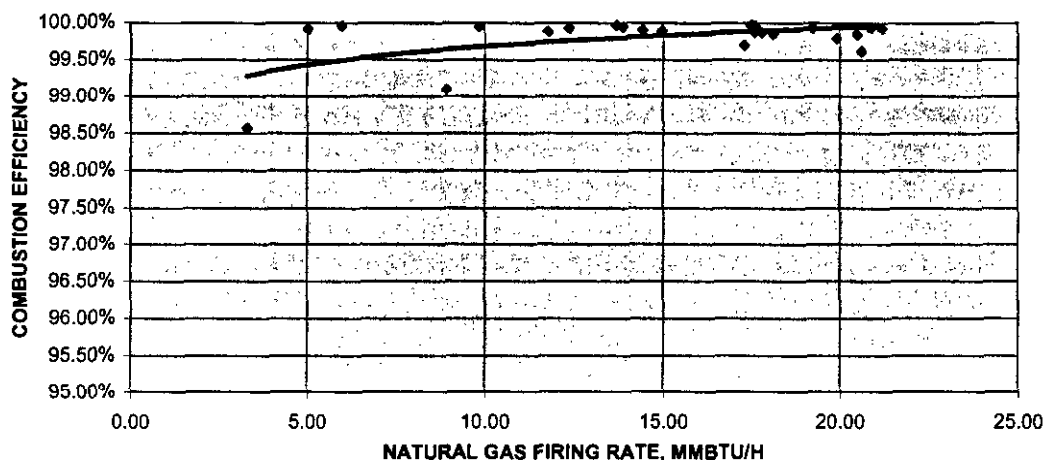


Figure 4-13 indicates the variation in combustion efficiency with excess air. The highest efficiency (i.e. very low CO and hydrocarbon concentrations in the exiting flue gas) is obtained for excess air in the 40 to 60% range. The excess air requirement is rather high (higher than the 15-25% norm in typical burners) due to the low (1,000-1,200°F) resonance tube temperatures. The coal and black liquor steam reforming applications demand low resonance tube temperatures and this in turn requires reasonable O₂ concentration or partial pressure in the flue gas to achieve high combustion efficiency.

FIGURE 4-13: VARIATION IN COMBUSTION EFFICIENCY WITH EXCESS AIR

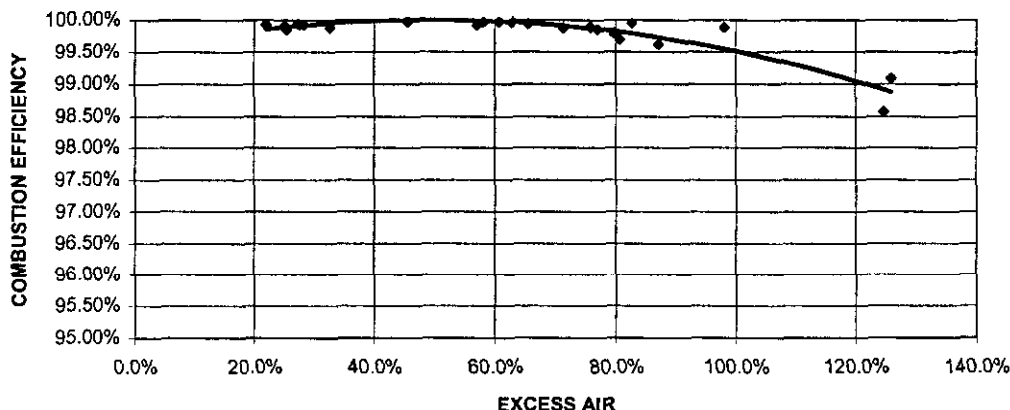


Figure 4-14 depicts the effect of fluidized bed temperature on combustion efficiency. As expected, the combustion efficiency increases with bed temperature. This stems from the concurrent increase in resonance tube temperature and in turn the reaction rate of fuel fragments.

FIGURE 4-14: EFFECT OF BED TEMPERATURE ON COMBUSTION EFFICIENCY

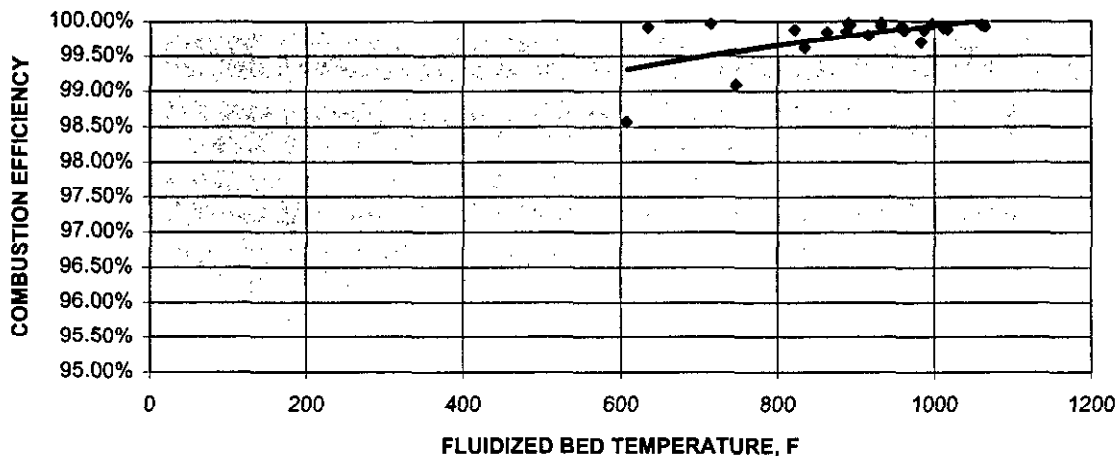
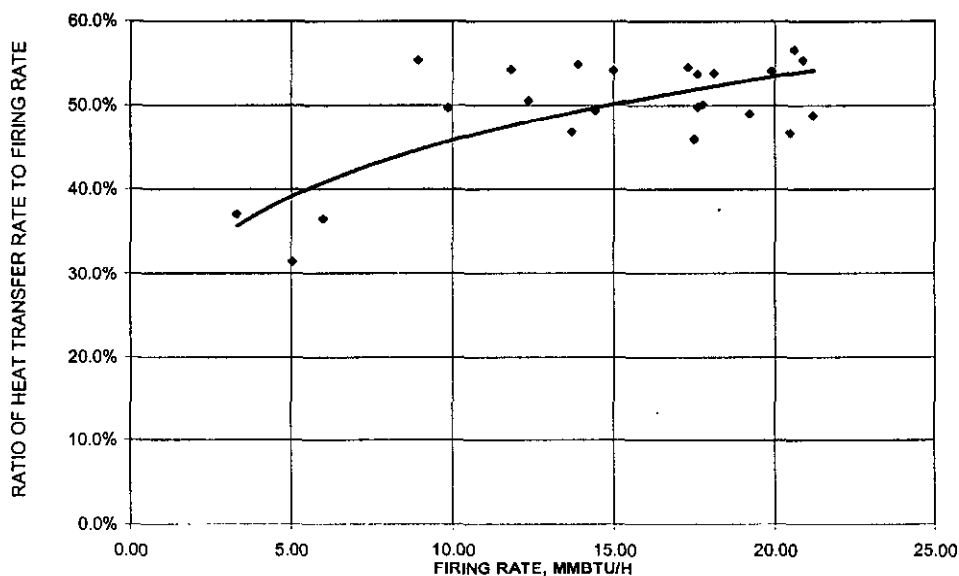


Figure 4-15 exhibits the variations in heat transfer rate to the fluidized bed and the water jacket with firing rate. The ratio of heat transfer rate to the firing rate increases with pulse combustor firing rate. This is attributed to enhancement in pulsations and reduction in excess air with an increase in firing rate.

FIGURE 4-15: HEAT TRANSFERRED TO THE FLUIDIZED BED AND THE WATER JACKET



4.6.2. PDU Tests

The mass balance summaries for each test are presented in Tables 4-8 through 4-10.

Table 4-8: Mass Balance for 1000F Test

		Stream No	1	2	3	4	5
			Coal	Steam	Nitrogen	Product	Char
					Purge	Gas	
Component	Units	Formula					
Hydrogen	Lb/Hr	H2				0.569	
Nitrogen	Lb/Hr	N2			19.518	19.691	
Methane	Lb/Hr	CH4				2.324	
Carbon Monoxide	Lb/Hr	CO				0.825	
Carbon Dioxide	Lb/Hr	CO2				10.955	
Ethylene	Lb/Hr	C2H4				0.561	
Ethane	Lb/Hr	C2H6				0.625	
Acetylene	Lb/Hr	C2H2				0.000	
Hydrogen Sulfide	Lb/Hr	H2S				0.083	
Propylene	Lb/Hr	C3H6				0.365	
Propane	Lb/Hr	C3H8				0.000	
Steam	Lb/Hr	H2O		23.361		40.941	
Coal	Lb/Hr		52.000				
Char	Lb/Hr						30.645
Condensables	Lb/Hr					0.331	
TOTAL MASS	Lb/Hr	--	52.000	23.361	19.518	77.270	30.645

Table 4-9: Mass Balance for 1100°F Test

		Stream No	1	2	3	4	5
			Coal	Steam	Nitrogen	Product	Char
					Purge	Gas	
Component	Units	Formula					
Hydrogen	Lb/Hr	H2				0.634	
Nitrogen	Lb/Hr	N2			13.308	13.458	
Methane	Lb/Hr	CH4				1.814	
Carbon Monoxide	Lb/Hr	CO				0.988	
Carbon Dioxide	Lb/Hr	CO2				9.462	
Ethylene	Lb/Hr	C2H4				0.466	
Ethane	Lb/Hr	C2H6				0.369	
Acetylene	Lb/Hr	C2H2				0.002	
Hydrogen Sulfide	Lb/Hr	H2S				0.054	
Propylene	Lb/Hr	C3H6				0.238	
Propane	Lb/Hr	C3H8				0.000	
Steam	Lb/Hr	H2O		27.117		41.963	
Coal	Lb/Hr		45.000				
Char	Lb/Hr						25.826
Condensables	Lb/Hr					0.268	
TOTAL MASS	Lb/Hr	--	45.000	27.117	13.308	69.716	25.826

Table 4-10: Mass Balance for 1200°F Test

		Stream No 1	2	3	4	5	
		Coal	Steam	Nitrogen Purge	Product Gas	Char	
Component	Units	Formula					
Hydrogen	Lb/Hr	H2			2.301		
Nitrogen	Lb/Hr	N2			18.187	18.326	
Methane	Lb/Hr	CH4				3.186	
Carbon Monoxide	Lb/Hr	CO				3.275	
Carbon Dioxide	Lb/Hr	CO2				26.926	
Ethylene	Lb/Hr	C2H4				0.652	
Ethane	Lb/Hr	C2H6				0.390	
Acetylene	Lb/Hr	C2H2				0.004	
Hydrogen Sulfide	Lb/Hr	H2S				0.097	
Propylene	Lb/Hr	C3H6				0.281	
Propane	Lb/Hr	C3H8				0.000	
Steam	Lb/Hr	H2O		18.618		7.549	
Coal	Lb/Hr		32.000				
Char	Lb/Hr					12.263	
Condensables	Lb/Hr				0.266		
TOTAL MASS	Lb/Hr	--	32.000	18.618	18.187	63.252	12.263

The closure for each constituent is presented in tables 4-11 through 4-13.

Table 4-11: Mass balance closure for 1000F Test.

ELEMENTAL BALANCES							
IN	C	H	N	S	Ash	O	TOTAL
Coal	27.498	3.410	0.411	0.146	2.309	18.227	52.000
Steam		2.619				20.742	23.361
Purge			19.518				19.518
TOTAL	27.498	6.029	19.929	0.146	2.309	38.970	94.879
OUT							
Char	16.983	0.000	0.238	0.106	13.075	0.000	30.402
Cond Organics	0.254	0.02				0.056	0.331
Product Gas	6.375	6.007	19.691	0.078	0.000	44.788	76.939
TOTAL	23.611	6.029	19.929	0.184	13.075	44.844	107.672
Closure	0.859	1.000	1.000	1.262	5.663	1.151	1.135

Table 4-12: Mass balance closure for 1100°F Test

ELEMENTAL BALANCES							
IN	C	H	N	S	Ash	O	TOTAL
Coal	23.796	2.951	0.356	0.126	1.998	15.774	45.000
Steam		3.040				24.077	27.117
Purge			13.308				13.308
TOTAL	23.796	5.991	13.663	0.126	1.998	39.851	85.424
OUT							
Char	11.962	0.000	0.205	0.018	13.464	0.000	25.649
Cond Organics	0.206	0.02				0.046	0.268
Product Gas	5.262	5.973	13.458	0.051	0.000	44.703	69.448
TOTAL	17.430	5.991	13.663	0.069	13.464	44.748	95.365
Closure	0.732	1.000	1.000	0.547	6.739	1.123	1.116

Table 4-13: Mass balance closure for 1200°F Test

ELEMENTAL BALANCES							
IN	C	H	N	S	Ash	O	TOTAL
Coal	16.922	2.098	0.253	0.090	1.421	11.217	32.000
Steam		2.087				16.531	18.618
Purge			18.187				18.187
TOTAL	16.922	4.185	18.440	0.090	1.421	27.748	68.805
OUT							
Char	10.630	0.000	0.123	0.005	1.164	0.000	11.921
Cond Organics	0.203	0.02				0.045	0.266
Product Gas	12.250	4.168	18.326	0.091	0.000	28.152	62.987
TOTAL	23.084	4.185	18.448	0.096	1.164	28.197	75.174
Closure	1.364	1.000	1.000	1.071	0.819	1.016	1.093

The elemental closures are very good for such a small-scale experiment. The ash closure is off more than other constituents due to measuring small differences in large numbers: the starting bed of sand is reported as ash and weighs more than all the ash fed during the combined tests. Nitrogen and hydrogen closure is forced by the calculation procedure described earlier.

Tables 4-14 and 4-15 present a summary of the Volatile Organic Compounds (VOC) and Semi-Volatile Organic Compounds (SVOC) collected in the gas condensate. The gas condensates were collected with an EPA method 5 sampling train utilizing ice-water bath impingers. Since the full-scale, commercial cold gas cleanup equipment does not achieve ice-water bath temperatures and the commercial steam reformer will have reduced freeboard heat losses and higher gas residence times, these captured organic condensate quantities are considered the upper limit or high and worst case values.

Table 4-14: VOC in the Product Gas Stream

VOC	mg/kg of dry feed		
	1,000°F	1,100°F	1,200°F
Acetone	434.05	104.83	39.09
2-Butanone	124.02	57.66	8.49
Benzene	15.94	11.01	2.29
Toluene	12.40	6.81	1.35
Xylenes	4.34	2.10	0.44
Styrene	1.77	0.84	0.23
Naphthalene	1.24	0.00	0.32
TOTAL VOC	593.77	183.25	52.22

Table 4-15: SVOC in the Product Gas Stream

SVOC	mg/kg of dry feed		
	1,000°F	1,100°F	1,200°F
Phenols	1860.23	1111.24	276.33
Naphthalene	1.42	0.73	0.28
Aniline	6.38	3.72	1.12
Others	0.25	1.90	0.57
TOTAL SVOC	1868.28	1117.60	278.30

4.7 Operability and Reliability

There were no operability and reliability issues associated with the PDU testing.

5.0 TECHNICAL PERFORMANCE

5.1 Effects of Operating Variables on Results

The amount of each constituent reporting to each product for all three tests is presented in Tables 5-1 through 5-3.

Table 5-1: Product Distribution for 1000°F Test

Normalized Product Yields Percent Reported			
	To Solids	To Gas	To Condensate
C	72.44%	27.19%	0.37%
H	0.00%	99.88%	0.12%
N	1.19%	98.81%	0.00%
S	57.45%	42.55%	0.00%
Ash	100.00%	0.00%	0.00%
O	0.00%	99.96%	0.04%

Table 5-2: Product Distribution for 1100°F Test

Normalized Product Yields Percent Reported			
	To Solids	To Gas	To Condensate
C	69.13%	30.41%	0.46%
H	0.00%	99.89%	0.11%
N	1.50%	98.50%	0.00%
S	25.86%	74.14%	0.00%
Ash	100.00%	0.00%	0.00%
O	0.00%	99.96%	0.04%

Table 5-3: Product Distribution for 1200°F Test

Normalized Product Yields Percent Reported			
	To Solids	To Gas	To Condensate
C	46.43%	53.51%	0.06%
H	0.00%	99.97%	0.03%
N	0.66%	99.34%	0.00%
S	5.25%	94.75%	0.00%
Ash	100.00%	0.00%	0.00%
O	0.00%	99.99%	0.01%

In these tables, the data presented earlier was normalized, that is, each constituent is adjusted to provide a 100% closure. This helps to eliminate the effect of mass balance accuracy variations. As would be expected, the amount of carbon and the amount of sulfur reported to char decreases with increasing temperature. The condensate appears to receive a lower portion of carbon as temperature increases as would be expected. In order to maximize char production, operation at 1000 or 1100°F would be preferred. Char suitable for Direct Iron Production is generated at either temperature.

6.0 ENVIRONMENTAL PERFORMANCE

A process condensate is the only waste stream generated in this process since the gas is used as fuel and the char is the primary product. Stack emission from combustion of the gas is discussed below.

Biological Oxygen Demand (BOD) is the primary concern with the effluent. Generally, if this is reduced, the individual organic species contributing to the BOD will be reduced. BOD as a function of operating temperature is presented in Table 6-1.

Table 6-1: Effluent BOD

EFFLUENT BOD	1000F	1100F	1200F
BOD, lb/Ton dry coal	13.98	15.27	3.04
BOD, lb/Ton dry char	19.30	22.09	6.55

There is very little difference in effluent quality between the two lower operating temperatures, as one would expect considering there is little difference in char and gas yields between these two conditions. At the higher temperature, gasification appears to begin and the liquid organics that contribute to BOD are being destroyed somewhat.

A facility producing 20 tons of char per hour and operating at 1000 F would produce a raw effluent stream containing approximately five tons of BOD. This raw effluent could not be discharged directly into a stream; however, conventional aerobic digestion technology would adequately treat the stream for discharge. A treatment facility would be required even for the higher temperature operating condition. Although this facility would be smaller than that required for low temperature operation, the cost savings associated with treatment would no doubt be more than offset with reduced product yield.

7.0 ECONOMICS

7.1 Estimated Process Capital Costs

The projected process capital cost provided in this report for a commercial configuration plant is based upon projections only. The information is to be regarded as extrapolations (Scaling Factors) and budget quality engineering estimates. The cost is, of necessity, not based on actual data from a full-scale demonstration project for mild gasification of coal.

Table 7-1 presents the major equipment list for a commercial configuration plant for mild gasification of sub-bituminous coal for the Northshore Mining Company. This configuration is the most likely near term commercial plant since Northshore is still in need of such a plant. The projections are made based on a budget estimate study performed by Industra (dated July 17, 1997) which was adjusted for inflation and other considerations (scale-up from similar systems for spent liquor recovery providing new cost data since July 17, 1997).

The plant is based on a reactor with five 253-tube heaters having a nominal coal processing (mild gasification) capacity of 40 US tons per hour. For the purpose of operating cost calculations (Section 6.0), the plant was assumed to be operating at 36 US tons per hour.

Coal is fed into the steam reformer utilizing a weigh feeder and a water-cooled injection screw feeder. Ash and unreacted char are removed from the reformer via lockhoppers and a cooling conveyor.

A cold gas cleanup train is used to process the raw reformat gas from the steam reformer.

Cyclones provide fundamental particulate control, followed by a venturi scrubber to remove any remaining entrained particulate. A gas cooler with acidic pH control provides the dual purpose of cooling the gas (condensing the steam) as well as ammonia removal.

The H₂S absorber contacts the relatively cool gas (125°F) with caustic to remove the sulfur as a NaHS solution. The sulfide solution will be sold to a local pulp mill as chemical makeup for the cooking process.

Finally, the reformat gas is clean and acceptable for burning as a fuel in the pulse heaters as well as in boilers for steam generation.

Table 7-1 presents the major equipment list for the commercial configuration mild gasification project. The table also indicates the items that are within the normal scope of supply from ThermoChem, and the items that are obtained by the clients' engineers via multiple-vendor quotes.

Table 7-2 presents the major equipment costs.

The plant total installed cost is shown in Table 7-3. The table presents, in addition to the Major Equipment Costs, other costs associated with the field erection of the plant.

TABLE 7-1: MAJOR EQUIPMENT LIST

Item No.	Item Name	Quantity		Unit Capacity	Design Characteristics	Material of Construction	Vendor
		Operating	Spare				
1	Coal-Handling System:			40 ton/h (wet)			
2	Bucket Elevator	1		40 ton/h	Standard	Carbon Steel	Multiple Vendor Quotes
3	Conveyor	1		40 ton/h	Standard	Carbon Steel	Multiple Vendor Quotes
4	Weigh Feeder	1		40 ton/h	Standard	Carbon Steel	Multiple Vendor Quotes
5	Feed Screw	1		40 ton/h	Standard	Carbon Steel	Multiple Vendor Quotes
6	Storage Bin	1		40 ton/h	Cylindrical with 70° Cone Bottom	Carbon Steel	Multiple Vendor Quotes
7	Reactor w/steam distributor	1		36.1 ton/h (wet)	Refractory-lined Rectangular Vessel	Carbon Steel	ThermoChem
8	Pulsed Heater w/Plenum & Aerovalves	5		253-tube 6.0 MMBtu/h each	PulseEnhanced™	321 SS	ThermoChem
9	Pulsed Heater Combustion Air Fan	2		9400 acfm @ 28" WC	75 HP Blower	Carbon Steel	ThermoChem
10	Char-Handling System:			13.5 ton/h (dry)			
11	Lock Hopper	1		1,000 lbs. char	Standard	Carbon Steel	ThermoChem
12	Cooling Conveyor	1		13.5 ton/h	Standard	Carbon Steel	Multiple Vendor Quotes
13	Char-Slurry Mixing Tank	1		27 ton	Cylindrical with Conical Bottom	Carbon Steel	Multiple Vendor Quotes
14	Char-Mixing Tank Pumps	2		66 gpm, 7.5 hp each	Slurry-Handling	Carbon Steel	Multiple Vendor Quotes
15	Char-Mixing Tank Agitator	1		5 hp each	Medium Turbulence	Carbon Steel	Multiple Vendor Quotes
16	First Stage Cyclone	4		5000 acfm	95% Removal	321 SS	ThermoChem
17	Second Stage Cyclone	4		5000 acfm	99.5% Removal	Refractory-lined Carbon Steel	ThermoChem
18	Heat Recovery Steam Generator # 1 (HRSG1)	1		26250 lb/h @ 150 psig	Unfired	Carbon Steel	ThermoChem

TABLE 7-1 (continued): MAJOR EQUIPMENT LIST

Item No.	Item Name	Quantity		Unit Capacity	Design Characteristics	Material of Construction	Vendor
		Operating	Spare				
19	HRSG1 Recirculation Pump	1	1	60 gpm	25 hp High Temp/ Pressure Service	Carbon Steel	ThermoChem
20	Venturi Scrubber	1		20000 acfm	S. Steel Throat	Carbon Steel Body	ThermoChem
21	Venturi Scrubber Pump	1	1	160 gpm, 10 hp each	Slurry-Handling	Carbon Steel	ThermoChem
22	Gas Cooler Column w/pH control	1		20000 ACFM	5.5' D X 19' H Packed	Carbon Steel	ThermoChem
23	Gas Cooler Tank	1		5000	Cylindrical w/Dished Bottom	Carbon Steel	ThermoChem
24	Gas Cooler Heat Exchanger	1		2 MM Btu/h	Plate Heat Exchanger	Carbon Steel	ThermoChem
25	Gas Cooler Recirculation Pump	1	1	760 gpm, 20 hp each	Centrifugal	Carbon Steel	ThermoChem
26	H ₂ S Absorber	1		20000 acfm	5.5' D X 24' H Packed	Carbon Steel	ThermoChem
27	H ₂ S Absorber Recirculation Pump	1	1	110 gpm, 2 hp each	Centrifugal	Carbon Steel	ThermoChem
28	Superheater	1		4.2 MM Btu/h	Standard	304 SS	ThermoChem
29	Heat Recovery Steam Generator 2 (HRSG2)	1		39,000 lb/h @ 150 psig	Fired with off-gas or Natural gas	Carbon Steel	Multiple Vendor Quotes
30	Air Heater	1		9 MM Btu/h	Standard	Carbon Steel	Multiple Vendor Quotes
31	Stack	1		20000 acfm	83' H	Carbon Steel	Multiple Vendor Quotes
32	SS Duct Work	1 lot		6700 sq. ft.	3/16" Different Sizes	304 SS	Multiple Vendor Quotes
33	Carbon Steel Duct Work	1 lot		3300 sq. ft.	3/16" Different Sizes	Carbon Steel	Multiple Vendor Quotes

TABLE 7-2: MAJOR EQUIP

Item No.	Item Name	F.O.B. Cost/ Unit	Sales Tax	Freight Cost	Installing Cost	Total Cost Ea.
1	Coal-Handling Systems:					
2	Bucket Elevator	100,000		2,000	5,000	107,000
3	Conveyor	155,000		3,100	5,000	163,100
4	Weigh Feeder	50,000		1,000	2,500	53,500
5	Feed Screw	75,000		1,500	2,500	79,000
6	Storage Bin	300,000		6,000	12,500	318,500
7	Reactor w/Steam Distributor	401,000		8,020	110,000	519,020
8	Pulsed Heater w/ Plenum & Aerovalves	507,800		10,156	10,000	527,956
9	Pulsed Heater Combustion Air Fan	12,500		250	6,790	19,540
10	Char-Handling System:					
11	Lock Hopper	2,000		40	1,500	3,540
12	Cooling Conveyor	50,000		1,000	2,500	53,500
13	Char-Mixing Tank	5,000		100	950	6,050
14	Char-Mixing Tank Pumps	2,000		40	2,500	4,540
15	Char-Mixing Tank Agitator	2,000		40	1,000	3,040
16	First Stage Cyclone	36,250		725	2,500	39,475
17	Second Stage Cyclone	37,500		750	2,500	40,750
18	Heat Recovery Steam Generator # 1	300,000		6,000	14,900	320,900
19	Recirculation Pump	3,500		70	3,100	6,670
20	Venturi Scrubber w/Throat	13,000		260	2,300	15,560
21	Venturi Scrubber Pump	4,500		90	4,100	8,690
22	Gas Cooler Column w/pH control ¹	12,000		240	2,500	14,740

¹ Ammonia removal

AJOR EQUIPMENT COSTS

Total Cost Ea.	No. of Units	Totals			Total Cost
		Equipment	Freight	Installation	
107,000	1.0	100,000	2,000	5,000	107,000
163,100	1.0	155,000	3,100	5,000	163,100
53,500	1.0	50,000	1,000	2,500	53,500
79,000	1.0	75,000	1,500	2,500	79,000
318,500	1.0	300,000	6,000	12,500	318,500
519,020	1.0	401,000	8,020	110,000	519,020
527,956	5.0	2,539,000	50,780	50,000	2,639,780
19,540	2.0	25,000	500	13,580	39,080
3,540	1.0	2,000	40	1,500	3,540
53,500	1.0	50,000	1,000	2,500	53,500
6,050	1.0	5,000	100	950	6,050
4,540	2.0	4,000	80	5,000	9,080
3,040	1.0	2,000	40	1,000	3,040
39,475	4.0	145,000	2,900	10,000	157,900
40,750	4.0	150,000	3,000	10,000	163,000
320,900	1.0	300,000	6,000	14,900	320,900
6,670	2.0	7,000	140	6,200	13,340
15,560	1.0	13,000	260	2,300	15,560
8,690	2.0	9,000	180	8,200	17,380
14,740	1.0	12,000	240	2,500	14,740

TABLE 7-2(continued): MAJOR EC

Item No.	Item Name	F.O.B. Cost/Unit	Sales Tax	Freight Cost	Installing Cost	Total Cost Ea.
23	Gas Cooler Tank	2,500		50	1,000	3,550
24	Gas Cooler Heat Exchanger	4,000		80	1,000	5,080
25	Gas Cooler Recirculation Pump	11,000		220	3,100	14,320
26	H ₂ S Absorber (sulfur removal)	13,000		260	2,500	15,760
27	H ₂ S Absorber Recirculation Pump	2,500		50	3,100	5,650
28	Superheater	35,000		700	1,500	37,200
29	Heat Recovery Steam Generator 2	708,000		14,160	24,800	746,960
30	Air Heater	150,000		3,000	2,500	155,500
31	Stack	25,000		500	2,500	28,000
32	St. Steel Duct Work (one lot)				188,000	188,000
33	C. Steel Duct Work (one lot)				188,00	188,000
34	Equipment Paint (one lot)				21,000	21,000
35	Insulation Including Duct (one lot)				81,000	81,000
36	Miscellaneous Materials				209,000	209,000

Major Equipment Cost Totals

ed): MAJOR EQUIPMENT COSTS

Total Cost Ea.	No. of Units	Totals			Total Cost
		Equipment	Freight	Installation	
3,550	1.0	2,500	50	1,000	3,550
5,080	1.0	4,000	80	1,000	5,080
14,320	2.0	22,000	440	6,200	28,640
15,760	1.0	13,000	260	2,500	15,760
5,650	2.0	5,000	100	6,200	11,300
37,200	1.0	35,000	700	1,500	37,200
746,960	1.0	708,000	14,160	24,800	746,960
155,500	1.0	150,000	3,000	2,500	155,500
28,000	1.0	25,000	500	2,500	28,000
188,000	1.0	25,000	500	2,500	28,000
188,000	1.0	0	0	188,000	188,000
21,000	1.0	0	0	21,000	21,000
81,000	1.0	0	0	21,000	21,000
209,000	1.0	0	0	209,000	209,000
		5,333,500	106,670	755,830	6,196,000

TABLE 7-3: PROJECT TOTAL INSTALLED COST

Item No.	Item Description	Unit Cost		Item Total Cost	Remarks
		Equipment/ Material	Installation/ Subcontract		
Direct Costs:					
1	Major Equipment	\$5,440,170	\$755,830	\$6,196,000	
2	Piping	\$1,170,000	\$1,013,000	\$2,183,000	
3	Electrical	\$170,000	\$250,000	\$420,000	
4	Instrumentation & Control	\$670,000	\$530,000	\$1,200,000	
5	Site Preparation	\$20,000	\$130,000	\$150,000	
6	Civil/Structure	\$25,000	\$100,000	\$125,000	
7	Building	\$600,000	\$660,000	\$1,260,000	
8	Operation & Startup Spares			\$700,000	Includes one Pulse Heater
9	10% Escalation			\$1,250,000	3-yrs since 98 Estimate
10	Land			\$500,000	
11	Preliminary Expenses/Project Fees			\$2,250,000	
12	Insurance and Permits			\$2,100,000	
13	Warranty & Licensing Fees			\$1,800,000	
14	10% Execution Contingency			\$1,950,000	
Direct Cost Total		\$8,095,170	\$3,438,830	\$22,084,000	
Indirect Cost:					
15	8% Detailed Engineering			\$1,500,000	
16	Project and Construction Management			\$1,700,000	
17	Commissioning and Start-Up			\$650,000	Includes Training Support
18	General & Administrative Expenses			\$1,500,000	
19	General Contingency			\$750,000	
Indirect Cost Total				\$6,100,000	
PROJECT TOTAL INSTALLED COST				\$28,184,000	

8.0 COMMERCIALIZATION POTENTIAL AND PLANS

8.1. Market Analysis

Under the CCT demonstration program, key components of the technology will be demonstrated at full commercial-scale to test commercial applicability, ability to achieve economies-of-scale and ability to use alternative coal feedstocks. While the demonstration will test the MTCI technology for its char reductant generation potential, the technology can also produce several other products for other market applications.

8.1.1. Applicability of the Technology

The CCT demonstration project carried out by MTCI is to qualify a single 253-tube pulse combustor heater bundle. The heater bundle is the heart of a commercial-scale steam reformer system that has broad commercial applications including:

- black liquor processing and chemical recovery;
- hazardous, low-level mixed waste volume reduction and destruction;
- coal processing for:
 - the production of hydrogen for fuel cell power generation and other uses,
 - production of gas and char for the steel industry,
 - production of solid Clean Air Act compliance fuels,
 - production of syngas that can be used as a feedstock for the chemicals industry, for power generation, for the production of high quality liquid products, and for other purposes,
- coal-pond waste and coal rejects processing for overfiring/reburning for utility NO_x control; and
- utilization of a range of other fuels and wastes to produce a variety of value added products.

Recognizing that the CCT Demonstration Program is intended to expand the markets for coal and improve the competitiveness of coal in domestic markets, especially in the electric power market, a preliminary assessment of the most promising coal applications of the MTCI technology was conducted. These applications used mild gasification of coal (via the MTCI technology) to produce: (1) metallurgical coke replacement, (2) compliance coal for existing power plants, and (3) syngas for use as an industrial feedstock and power production.

8.1.2 Market Size

8.1.2.1 ...for Metallurgical Coke Replacement

Integrated metallurgical coke production in 1996 was approximately 18.5 million short tons¹. Although blast furnace metallurgical coke consumption has declined by almost 1.8 million short tons from 1995 (to 16.7 million tons), there remains a shortage of coke from integrated mills of over 4 million tons. As a result of the planned closing of several coke plants, the shortfall has risen by 265,000 tons in 1998 and an additional 900,000 tons in 1999. This will bring the total shortfall to over 5 million, which is expected to be met by domestic merchant coke plants.

Breeze, a lower quality coke, is also utilized in the iron and steel industry. However, in the U.S., less than 1 million short tons of breeze are consumed. In addition, although the large majority of coke is utilized in blast furnaces, some (less than 10%) are consumed in foundries (U.S. Department of Commerce, Manufacturing Consumption of Energy, 1994).

8.1.2.2 ... for Compliance Coal

The acid rain provisions (Title IV) of the Clean Air Act Amendments of 1990 require existing coal-fired power plants to reduce their SO₂ emissions in two phases, in 1995 and 2000. To comply with the 1995 requirements, many power plants switched coals to those with a sulfur content that complies with the emissions target (below 2.5 lbs. sulfur/MMBtu); this is also known as "compliance coal." Although many utilities are still *assessing options for compliance with the more stringent year 2000 requirements* (1.2

lbs. sulfur/MMBtu), it is expected that coal switching to a low sulfur coal will again be the dominant compliance method. Coal switching is a popular compliance choice due to its relatively low cost because a capital investment in flue gas desulfurization (FGD) or other SO₂ control technology is not required.

8.1.2.3 Synthesis Gas for Power Production

Synthesis gas can be used instead of natural gas or oil in combustion turbines to produce electric power. At present, three U.S. power plants convert coal to syngas via gasification in the Clean Coal Technology Demonstration program. In addition, several industrial (petrochemical) sites are (will be) using refinery bottoms and petroleum coke as feedstocks to a gasifier to produce electricity and other chemical byproducts. The MTCI technology can also produce synthesis gas from coal for use in combustion turbines to produce electric power.

Several market opportunities exist for the use of the MTCI technology for power production. These include (1) new capacity, (2) replacement capacity, and (3) compliance capacity. Each opportunity is discussed in the following.

At present 95,300 megawatts (MW) of combined cycle and combustion turbines in the power sector are fueled by natural gas. These units generate over 80 billion kilowatt-hours, and consume 2.98 trillion cubic feet of natural gas (approximately 3 Quads).

Natural gas is currently the preferred fuel for new electric generating capacity (peaking/intermediate and baseload). This is because: (1) current fuel costs are relatively low, and they comprise 93% (projected to be reduced to 88% by 2005 with the use of advanced NGCC technologies) of the operational costs for a natural gas combined cycle (NGCC) facility; (2) the capital cost of combined-cycle plants is low and the time to install them is relatively short thereby reducing up front capital costs and producing revenues more quickly than other power options; (3) the efficiency of combined cycle plants is high and improving, and (4) the environmental issues associated with gas use are fewer than most economically viable options.

8.1.2.4 Synthesis Gas for industrial Feedstocks

Based upon information obtained from industrial sources, conventional methods for reforming natural gas to synthetic gas are capital intensive. As a result, the cost of synthetic gas derived from natural gas is roughly 1 1/2 to 3 times the price of natural gas feedstock. Considering that natural gas supplied to industrial users in the states where most of the synthetic gas users are located is \$3-\$4/MMBtu, the synthetic gas prices for industrial feedstocks are on the order of \$4.50-\$12/MMBtu. Where a commercial-scale MTCI steam reformer can produce a syngas having comparable chemical properties within or less than this price range, there may be market opportunities for the technology. The price of syngas produced by the MTCI technology is dependent upon the cost of coal used as its feedstock. To compete with \$4.50/MMBtu conventional syngas, a large MTCI plant would have to use \$23-\$25/MMBtu coal. A small MTCI plant would have to use \$5/MMBtu coal and a 15% IRR to be competitive with \$4.50 syngas. At the upper end of the conventional syngas cost range, the MTCI technology would be competitive no matter what the coal price or the IRR considered.

8.1.3 Market Barriers

The U. S. steel industry is currently in an economic downswing. This is probably the single most dramatic barrier to overcome for the DRI and coking applications.

Natural gas pricing will also have a major impact on incentives to proceed with steam reforming projects.

8.2. Commercialization Plan

Current plans are to work with a recognized company such as Midrex who has extensive experience and contacts within the steel and related industries. ThermoChem is currently in contact with Midrex discussing areas of mutual interest. Midrex's technical in-house capabilities would provide the new steam reforming process with valuable design and operating experience for the first operating plant.

APPENDIX A

Test Plan

TEST PLAN

Pulse Combustor Design Qualification Test
Cooperative Agreement DE-FC22-92PC92644

September 11, 2000

The principal objectives of the project are to perform qualification testing of a 253-tube pulse heater and to demonstrate its readiness for commercial deployment. Specific objectives include verification and demonstration of:

- Full-scale heater performance, operability, reliability, and availability;
- Steam reformer system performance, operability, reliability, and availability;
- Thermal and gasification efficiency with coal from the process data unit;
- Emissions (SO_x, NO_x, THC, CO) determination;
- Waste stream (ash and effluent) regulatory compliance from the process data unit; and
- Economic merit of this technology

Tests will be conducted in two separate facilities to develop the data required to commercialize the Steam Reforming technology. Full-scale heater performance will be assessed in the Pulse Combustor Test Facility. Process data, i.e., gas yields and composition; char yields and composition; emissions; and heat requirements will be determined in a Process Data Unit.

Full-Scale Heater Tests

Performance of a full-scale multiple resonance tube pulse combustor will be determined in the test facility constructed as part of this project. The pulse combustor's role in the reformer is to provide the process heat required. The amount of heat that can be supplied by the pulse combustor will be determined at various operating conditions. Combustor firing rate and excess air levels are the variables to be examined within the combustor. Of course, the amount of heat that can be transferred to the fluidized bed is also dependent upon the conditions within the bed (bed-side heat transfer coefficient) and the

tube-to-bed temperature difference. The tube temperatures and bed temperatures will be monitored and used in conjunction with energy balance data to determine the bed-side heat transfer coefficient. Combustor efficiency and emissions will be determined at various firing rates (up to 30 million Btu/hr), excess air levels (20% to 60%), and fluidized bed operating temperatures (1100 °F to 1650 °F).

The fluidized bed test facility will be filled with sand and fluidized with air. Water will be injected into the bed to impose a heat load, thereby controlling the bed temperature independently of combustor firing rate.

Gas flow and combustion air flow rates will be measured for each test. The pulse combustor flue gas will be analyzed to determine the concentration of oxygen, carbon monoxide, nitrogen oxides, sulfur dioxide, and hydrocarbons. This data will be used to assess combustion efficiency at various firing rates and excess air levels.

The fluidized bed temperature, fluidizing air flow, water flow for bed temperature control, pulse combustor exhaust temperature, resonance tube temperature, combustion air temperature, combustor cooling circuit steam generation, and fluidized bed shell temperatures will be measured for each test. This data will permit calculation of an energy balance and quantification of the amount of heat transferred to the bed and the tube-to-bed heat transfer coefficient.

Process Data Tests

It continues to appear that one of the more promising early applications of the technology will be similar to the manufacture of coke; i.e., the production of char for use in direct reduction of iron (DRI). In this application, the char is a direct substitute for metallurgical coke. The purity requirements are easily satisfied by the char produced via mild gasification and the strength requirements for coke used in conventional blast furnace operations are not relevant to the DRI process. This application is the basis for selecting the coal to be tested in the Process Data Unit. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant.

Petroleum coke, which can be used as a DRI reductant has the following specifications:

- 0.5% Sulfur
- 90% Fixed Carbon
- 5-10% Volatiles

A coal-derived char should surpass these specifications in order to be more attractive than petroleum coke. The specifications provided by Northshore mining for the char are:

- 0.3% Sulfur
- 85% Fixed Carbon

Volatile content is not important to Northshore; however, in order to achieve the target of 85% fixed carbon, volatile content will necessarily be fairly low.

The optimum coal for testing is Black Thunder subbituminous coal since this coal is currently used by Northshore as fuel and is therefore readily available at the site. The characteristics of this coal are typical of Powder River Basin coals:

% Moisture	24.0 - 33.0
% Carbon	47.0 - 53.0
% Hydrogen	3.2 - 3.8
% Nitrogen	0.82 - 0.84
% Oxygen	11.1 - 13.4
% Chloride	0.00 - 0.03
% Sulfur	0.21 - 0.47
% Ash	3.2 - 5.6

The primary variable will be operating temperature. The goal is to identify the lowest temperature at which satisfactory sulfur and volatile matter content reduction is achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby increasing product yield. The lower operating temperature also provides a higher

tube-to-bed temperature differential which improves heat transfer into the reformer and increases throughput.

Complete mass and energy balances will be performed for each steady state PDU test to verify mass closure and to determine the process heat requirement. The coal feed rate, fluidizing steam rate, and instrument purge (nitrogen) rate are measured for each test. A slip stream of product gas is collected in a Method 5 impinger train and the steam and condensable hydrocarbons are collected for analysis. Fixed gas composition is determined by on-line gas chromatography. Product char will be collected and analyzed for comparison with the targets provided above.

Data Analysis

The data obtained will form the basis for designing a facility capable of producing 10 tons per hour of char for use in Direct Reduction of Iron. Data from the PDU will be used to identify feed coal requirements (product yields) and waste stream flows and composition. The combustor test facility data will provide information required to determine the number of heaters that must be used to satisfy the reformer heat load and process emissions data.

This preliminary facility design will be used as the basis for completing an economic assessment of the technology

253-tube Pulse Heater Test Parameters and Measurements

Objectives:

- Map out the operational boundary
- Compare performance and temperature profiles with model projections
- Evaluate operability, stability, reliability and safety attributes

Test Parameters:

- Fuel firing rate

- Combustion stoichiometry
- Fuel/air premixing ratio
- Superficial fluidization velocity of the fluidized bed
- Fluidized bed temperature
- Fuel type – natural gas, H₂-rich syn gas

Test Measurements:

- Static pressures
 - air plenum
 - fuel supply
 - premix air supply
 - pulse combustion chamber
 - decoupler
 - exhaust muffler inlet
 - fluid bed air inlet plenum
 - at different elevations of the dense fluidized bed and the freeboard
 - cyclone inlet
 - steam drum
 - compressed air flow to the flue gas spray quench atomizer
 - water flow to the flue gas spray quench atomizer
- Dynamic pressure
 - pulse combustion chamber
 - decoupler exit
 - exhaust muffler inlet
 - exhaust muffler exit
- Temperatures
 - air inlet in duct just upstream of air plenum
 - air plenum
 - pulse combustion chamber
 - flue gas in decoupler

- flue gas at decoupler exit/upstream of water spray
- flue gas at exhaust muffler inlet
- resonance tube skin temperature – 4 outer tubes each @ 3 locations along the tube
- gas temperature just upstream of resonance tube exit – at the center of the tube bundle and in 4 outer tubes in the bundle
- fluidized bed – several locations
- tubesheet at pulse combustion chamber/resonance tube interface – 4 locations
- air inlet into fluidized bed
- freeboard – inlet and exit
- steam drum
- cooling water in to pulse combustor tubesheets
- cooling water out from pulse combustor tubesheets
- Flow rates
 - combustion air
 - fuel
 - premix air
 - fluidization air
 - pilot gas
 - pilot air
 - water circulation rate to the pulse combustor tubesheets (aerovalve and resonance tube)
 - water makeup rate to the steam drum
 - compressed air flow to the flue gas spray quench atomizer
 - water flow to the flue gas spray quench atomizer
- Flue gas composition
 - decoupler exit
 - air plenum
- Cyclone solids collection
 - rate
 - particle size distribution
- Bed solids sample

- initial
- final
- Sound pressure level (dB)
 - at ~3 ft distance from air plenum
 - at ~3 ft distance from decoupler
 - in the vicinity of the fluidized bed
- Strain – gage rosettes at different locations on the fluidized bed vessel
- Heat flux meter on the tubesheet at pulse combustion chamber/resonance tube interface to estimate wall heat flux (?)

APPENDIX B

Operating Checkout Procedures

Clean Coal

*Pulse Combustor
Design Qualification Test*

Check List and Procedure for Startup

ThermoChem, Inc.

October 18, 2000

1. OVERVIEW

The following procedure is to be used for a cold startup of the steam reformer system. It is assumed that the vessel has all associated equipment installed, i.e. pulsed heater, cyclone, instrumentation, etc. It is also assumed that vessel entry procedures have been adhered to and that the manways are open for personnel access to the internals of the vessel and the pulsed heater air plenum.

The goals of a successful steam reformer startup are:

- Safety. The procedures provide for a safe startup of the reformer system for both personnel and equipment.
- Achievement of dry refractory to prolong equipment life. The pulsed heater combustion chamber must be dry and cured properly to minimize maintenance and prolong the life of the refractory.

2. CHECK LIST

2.1. Inspect and secure the reformer vessel

- 2.1.1. *Warning: Vessel entry procedures must be adhered to prior to personnel entering the reformer.*
- 2.1.2. Remove unnecessary equipment, debris and foreign objects, if any, from reformer interior.
- 2.1.3. Carefully inspect the interior reformer walls for the integrity of the insulation boards. Make sure that the walls are fully covered by insulation and there are no bare spots. Also ascertain that the insulation is properly secured to the wall and is not free or loose. Correct deficiencies, if any.
- 2.1.4. Assure that all instrument taps, distributor bubble caps, water injector and bed drains are open and clear. Supplying air and verifying adequate flow from inside the vessel can check the bubble caps and instrument taps. The injector may be checked by temporarily connecting to an air hose and verifying flow. The drains should be visually inspected from inside the vessel using a flashlight. Correct deficiencies, if any.
- 2.1.5. Check all the vessel thermocouples for connectivity and integrity. Replace defective thermocouples, if any.
- 2.1.6. Inspect the resonance tube bundle to make sure that the inter-tube space is clear and there are no obstructions to fluidization. Clear debris, if any.

- 2.1.7. Check all the thermowells mounted on the pulse heater resonance tubes for mechanical integrity and the thermocouples for connectivity and integrity. Correct defects, if any. Verify that the thermowell junctions are located as specified in the drawing. Measure and record the data on the locations of all the thermowell junctions in the logbook.
- 2.1.8. Inspect the rope seal between the pulse heater decoupler and the decoupler housing for tightness of packing. Repack, if necessary.
- 2.1.9. Close and secure manways.
- 2.1.10. Close all bed drain and bed loading valves.
- 2.1.11. Carefully inspect the reformer exterior to make sure that all the ports are connected and there are no openings from the vessel to the outside. Cap the openings, if any.

2.2. Inspect and secure the pulsed heater

- 2.2.1. *Warning: air plenum entry procedures must be adhered to prior to personnel entering the reformer.*
- 2.2.2. Remove unnecessary equipment, debris and foreign objects, if any, from the interior of the air plenum.
- 2.2.3. Inspect the aerovalve plate for proper orientation and alignment with reference to the resonance tubesheet. If incorrect, reorient and realign.
- 2.2.4. Assure that all instrument taps, aerovalves, resonance tubes, gas injection ports, flame sensor port and pilot burner ports are open and clear. Supplying air and verifying adequate flow from inside the air plenum can check the pilot burner ports and instrument taps. The gas injector can be checked by temporarily connecting to an air hose and verifying flow. The aerovalves should be visually inspected from inside the air plenum using a flashlight. Correct deficiencies, if any.
- 2.2.5. Check all the pulsed heater thermocouples for connectivity and integrity. Replace defective thermocouples, if any.
- 2.2.6. Perform a hydrostatic pressure test (535 psig) on the aerovalve plate water jacket. Record the data and the result in the logbook. If the test fails, inform the Project Manager of the result and wait for instructions regarding the next step.
- 2.2.7. Perform a hydrostatic pressure test (535 psig) on the pulse combustion chamber-resonance tube interface tubesheet water jacket. Record the data and the result in the logbook. If the test fails, inform the Project Manager of the result and wait for instructions regarding the next step.
- 2.2.8. Inspect the flame sensor for mechanical and signal integrity and the optical window for cleanliness.
- 2.2.9. Ascertain that a differential pressure transmitter is set up across the air plenum and pulse combustion chamber pressure taps. Correct, if necessary.
- 2.2.10. Ascertain that a differential pressure transmitter is set up across the pulse combustion chamber and the decoupler pressure taps. Correct, if necessary.

- 2.2.11. Use a borescope to inspect the integrity of refractory inside the pulse combustion chamber. Record the observations in the logbook. If there are large cracks or bare areas inform the Project Manager of the result and wait for instructions regarding the next step.
- 2.2.12. Inspect the flexible pipe connectors between the gas supply manifold and the aerovalve plate gas tubesheet for mechanical and flow integrity. The flex connectors can be checked by temporarily connecting to an air hose and verifying leak-free operation. Correct deficiencies, if any.
- 2.2.13. Inspect the water and steam pipe connections to the aerovalve plate water jacket for mechanical and flow integrity. Circulating water and verifying leak-free operation can check the connections. Correct deficiencies, if any.
- 2.2.14. Close and secure manway.
- 2.2.15. Inspect the seating of the flange/weight combination on the pressure relief support flange for proper seal. Correct, if necessary. Assure that the guard bolts are properly secured so that the weight can not fall off and cause injury. Secure the bolts, if necessary.

2.3. Inspect and secure the balance of plant

- 2.3.1. Inspect the Forced Draft fan mounting, electrical and piping connections for safe and leak free operation. Correct, if necessary.
- 2.3.2. Inspect the air compressor electrical and piping connections for safe and leak free operation. Correct, if necessary. If the compressor is diesel engine driven, check all the fluid (engine oil, diesel, etc.) levels. Add fluids as necessary.
- 2.3.3. Check the water and compressed air connections to the atomizer in the spray quench column. Correct, if necessary. Activate the spray and make sure that the atomizer delivers a fine mist with the droplets impinging on the column wall not before a travel of at least 10-ft axial distance from the sprayhead.
- 2.3.4. Assure that the cyclone exhaust vent and the pulsed heater exhaust vent are open and are free/clear from obstructions.
- 2.3.5. Assure that the cyclone catch drum is in place and is properly attached to the cyclone dipleg.
- 2.3.6. Assure that the gas trains (both pilot and pulse burners) and the burner management systems are set up for safe and leak free operation.
- 2.3.7. Assure that the premix air for fuel/air mixture supply to the pulse heater is set up for proper and safe operation.
- 2.3.8. Inspect the steam drum, the pressure relief valve and the piping connections. Correct, if necessary.
- 2.3.9. Verify proper operation of water level control and satisfactory supply of makeup water.
- 2.3.10. Ensure that dynamic pressure transducers are installed on the pulse combustion chamber and decoupler pressure taps and are connected to the Hewlett Packard Spectrum Analyzer.

- 2.3.11. Assure that the instrumentation (pressure transmitters, transducers, thermocouples and flow meters) actually in place are in agreement with those listed in the test plan, have the proper measurement range and are sufficient to provide all the measurements planned. Add if there are missing instrumentation.
- 2.3.12. Assure that the flue gas sampling line at decoupler exit is properly connected to the Continuous Emissions Monitoring System.
- 2.3.13. Assure that the sand to be used as fluid bed material has the particle size distribution specified in the test plan.

3. STARTUP PROCEDURE

3.1. Initialize

- 3.1.1. Instrument purges on air. Verify rotometer flow settings.
- 3.1.2. Start the air compressor.
- 3.1.3. Open the valve on the water line and supply water to the steam drum.
- 3.1.4. Open the steam vent.

3.2. Load sand to the reformer

- 3.2.1. Open the bed loading double block valves at the reformer.
- 3.2.2. Open lockhopper drain valve at media bin discharge.
- 3.2.3. Start bed loading conveying air.
- 3.2.4. Start lockhopper timer sequence to initiate sand flow to the conveying eductor. Sand is now being transferred from the media bin to the reformer.
- 3.2.5. Since the reformer cyclone is designed with sealing trickle valve on its dip leg, fluidization of the bed can be initiated during the bed loading process.
- 3.2.6. Admit fluidization air flow into the distributor and adjust air flow rate to correspond to about 1.4 feet per second of superficial fluidization velocity.
- 3.2.7. Verify that the bed level measurement is functional. This is an indicator of a well-fluidized bed.
- 3.2.8. When the media bin is empty as indicated by the bin level transmitter, shut off lockhopper unloading timer control (Media bin sized to hold only one reformer inventory).
- 3.2.9. Close drain valve at media bin discharge.
- 3.2.10. Shut off bed loading conveying air.
- 3.2.11. Close bed loading double block valves at reformer.

3.3. Preheat pulsed heater refractory with natural gas pilot burners

- 3.3.1. Assure that the water level in the steam drum corresponds to the preset level.

- 3.3.2. Switch on the water circulation pump to circulate water through the pulsed heater tubesheets.
- 3.3.3. Turn on the pulsed heater pilot burners to begin preheat of the combustion chamber refractories to 1,000°F.
- 3.3.4. The automatic Burner Management System (BMS) will purge the pulsed heater and light off the pilot burner automatically.
- 3.3.5. Set pilot fuel/air mixture rotameters to pre-designated (slightly below stoichiometric or slightly rich mixture) settings to maintain a heat-up rate no more than 50°F per hour if curing the refractory for the first time.
- 3.3.6. Follow the refractory curing procedure outlined below:
- 3.3.7. Ramp from ambient temperature up to a combustion chamber temperature of 300 F at a rate not exceeding 50 F per hour.
- 3.3.8. Hold steady at this temperature for six (6) hours.
- 3.3.9. Ramp from 300 F to a combustion chamber temperature of 450 F at a rate not exceeding 50 F per hour.
- 3.3.10. Hold steady at this temperature for six (6) hours.
- 3.3.11. Ramp from 450 F to a combustion chamber temperature of 600 F at a rate not exceeding 25 F per hour.
- 3.3.12. Hold steady at this temperature for six (6) hours.
- 3.3.13. Ramp from 600 F to a combustion chamber temperature of 1,000 F at a rate not exceeding 50 F per hour.
- 3.3.14. Hold steady at this temperature for six (6) hours.
- 3.3.15. *Caution: Heat up rate is not to exceed 25/50°F per hour to protect refractory during curing.*

3.4. Fire pulsed heater on natural gas.

- 3.4.1. After allowing sufficient elapsed time for purging air from the steam drum, close the steam vent to pressurize the pulsed heater water jackets.
- 3.4.2. Open the valves for water and air flow to the atomizer and start the water spray in the spray quench column.
- 3.4.3. With the pulsed heater combustion chamber preheated to 1,000°F by the pilot burners in step 3.3 and the tubes covered with bed material, perform the following:
- 3.4.4. Select natural gas firing in the control logic.
- 3.4.5. Set fuel/air mixture rotameters such that the nominal mixture ratio is 1:1 on a volumetric basis. This requires that the volumetric flow rates of fuel and air are equal to each other. Operational safety mandates that the mixture ratio is far removed from the flammability limit. *Therefore, the air flow rate should never exceed 2 times the natural gas flow rate, on a volumetric basis.*
- 3.4.6. On the pulsed heater control, set tube temperature incrementally (10 to 50°F) and iteratively above the fluid bed temperature and set firing control in "auto". For example, if the bed temperature is 400°F, set heater tube temperature setpoint in the 410 to 450°F range such that the pulsed

heater combustion chamber temperature increase rate does not exceed 100 F per hour.

- 3.4.7. *Caution: Heat up rate is not to exceed 100°F per hour in the pulsed heater combustion chamber to protect refractory.*
- 3.4.8. *Caution: Do not exceed heater tube temperature setpoint of 1,200 °F.*
- 3.4.9. The pulsed heaters will ignite on natural gas.
- 3.4.10. Verify that the heater is ignited by observing that the combustion chamber temperature is rising. Also monitor the dynamic pressure in the chamber.
- 3.4.11. If heater ignition fails, the BMS will automatically purge the heater and reinitiate the light off sequence.

3.5. Continue bed heat-up

- 3.5.1. *Caution: Heat up rate is not to exceed 100°F per hour to protect vessel refractory.*
- 3.5.2. Continue heat-up of the bed to target operating temperature (1,120°F or as desired) by increasing the tube temperature setpoints in increments of 10 to 50°F. This will insure a steady and acceptable rate of temperature rise of the system's refractory.
- 3.5.3. Continue to verify bed temperature uniformity throughout the heat-up process.

3.6. Initiate water feed

- 3.6.1. When the reformer bed temperature reaches operating temperature, perform the following:
- 3.6.2. Open solenoid block valve on the water injectors.
- 3.6.3. Set bed temperature control to 1,120°F (or other setpoint as desired). The control will modulate the total water flow to maintain the fluid bed temperature setpoint.
- 3.6.4. Verify water flow has been established to each injector.
- 3.6.5. Verify that the pulsed heater firing controls are responding properly to the water reaction heat load and are maintaining a constant tube temperature setpoint.
- 3.6.6. Vary the pulsed heater tube temperatures as necessary to map out water throughput. For example, a lower water-processing rate will require less heat load to process. Therefore, a lower tube temperature setpoint will be required.

4. NORMAL SHUTDOWN PROCEDURE

The following procedure is to be used for normal shutdown of the reformer system.

4.1. Shut off water feed to the reformer

- 4.1.1. Close the water injector solenoid supply valves.

4.2. Reduce pulsed heater firing rates

- 4.2.1. Switch pulsed heaters to manual firing control.
- 4.2.2. Reduce firing rate initially by 1.5 MMBtu/h times the water flow rate to the reformer in gpm and in one (1) MMBtu per hour increment afterwards.
- 4.2.3. Continue to reduce firing rates to achieve bed temperature rate of drop no more than 100°F per hour or pulsed heater combustion chamber temperature rate of drop of no more than 100°F per hour to protect refractory.
- 4.2.4. *Caution: Cool down rate is not to exceed 100°F per hour to protect refractory.*

4.3. Turn off pulsed heater

- 4.3.1. Set pulsed heater firing controller to "zero".
- 4.3.2. The BMS will initiate a burner air purge for shutdown.
- 4.3.3. Shut off combustion air supply fan.
- 4.3.4. Turn off water and air flows to the atomizer in the spray quench column.
- 4.3.5. Turn off water circulation pump.

4.4. Shut off fluidization air flow and the purges

- 4.4.1. Turn fluidization air flow off.
- 4.4.2. Turn instrument air purges off.

APPENDIX C
Test Input Data

INPUT

TEST DATE 3/13/01 13:30 HR

INPUTS

DATA TO BE ENTERED IN

CELLS

NO. OF FUEL HEATERS 1

AMBIENT AIR PRESSURE 14.7 PSI
 AMBIENT AIR TEMPERATURE 44.0 F
 RELATIVE HUMIDITY 60.0%

FUEL TYPE:

ENTER IN CELL BELOW: 1 FOR NAT GAS
 2 FOR PROPANE
 3 FOR REFORMATE GAS

	NAT GAS WTR	PROPANE	REFORMATE GAS
	1	2	3
ASH	0.00%	0.00%	0.00%
MOISTURE	0.00%	0.00%	12.48%
CARBON	74.06%	81.68%	24.75%
HYDROGEN	24.01%	18.32%	8.39%
SULFUR	0.00%	0.00%	0.11%
NITROGEN	0.81%	0.00%	0.00%
OXYGEN	1.12%	0.00%	54.28%
CHLORINE	0.00%	0.00%	0.00%
TOTAL	100.00%	100.00%	100.00%
HHV, BTU/LB	23,133	21,500	5,913
SPECIFIC HEAT OF FUEL, BTU/LB-F	0.532	0.407	0.50
MOLECULAR WEIGHT, LB/LB MOLE	17.19	44.11	14.92
STANDARD DENSITY, LB/FT3	0.045	0.116	0.039
HHV, BTU/SCF	1,050	2,504	233

IF FUEL TYPE IS 3 ABOVE,
 ENTER VALUES BELOW:

REFORMATE GAS	LB/MOL GAS	LB/LB	HHV	LHV	SPEC HEAT
H2	1.19	8.00%	4,890	4,132	0.274559
CO	2.17	14.51%	631	631	0.036137
CO2	9.44	63.25%	-	-	0.128389
CH4	0.18	1.20%	288	259	0.00641
C2H6	0.02	0.12%	27	25	0.000517
C2H4	0.03	0.21%	45	42	0.00085
C3H8	0.02	0.11%	24	22	0.000451
H2S	0.00	0.00%	-	-	0
CH3SH	0.00	0.00%	8	7	0.000286
(CH3)2S	0.00	0.00%	-	-	0
(CH3)2S2	0.00	0.00%	-	-	0
HCl	0.00	0.00%	-	-	0
H2O (v)	1.86	12.48%	-	-	0.055523
100.0000%	14.92	100.00%	5,913	5,118	0.50
HHV, Btu/SCF	233		BTU/LB		
LHV, Btu/SCF	201				
LHV, Btu/Lb	5,118				

INPUT

PERCENT EXCESS AIR 20.28

FUEL(+AIR?) INJECTION: 08 0.000

AIR PREHEAT NO

FUEL GAS SUPPLY TEMPERATURE, F 50

COMBUSTION AIR TEMPERATURE, F 46

BED TEMPERATURE, F 35

COMBUSTION AIR SUPPLY PRESSURE, INCH WC 0.33 PSIG

DESIGN FIRING RATE PER HEATER, MMBTU/H 21.57 10 MAIN 0.57 PULS

RECYCLE FLUE GAS TEMPERATURE, F 461

FLUE GAS INLET TEMP TO FAN, F 147

TEST NO.	DATE	TIME	FIR RATE MMBTU/H	DILUTION AIR RECYCLE	FRESH AIR T	RECYCLE T	FAN INLET T	AIR PLENUM P
3-7	3/13/01	13:30	21.20	NO	43	461	147	9.19
			463	2,448	1279	700	94.2	1.23

AIR PLENUM T CHAMBER T DECOUPLER T MUFFLER T BED T

FLUE GAS ANALYSIS

O2 % 4.55 9.06 177

CO PPMV 19

NOX PPMV 2

THC PPMV

BED HEIGHT INCH

FL VELOCITY

APPENDIX D

Property Data

PROPRTS

THERMODYNAMIC & TRANSPORT DATA

Heat Capacity

Units = cal/(gmole)(K)
 Form: $C_p = a + b*t + c*t^2 + d*t^3$

	a	b	c	d
N2	7.07	-0.00132	3.31E-06	-1.26E-09
CO2	5.14	0.0154	-9.94E-06	2.42E-09
H2O (v)	8.1	-0.00072	3.63E-06	-1.16E-09
SO2	5.85	0.0154	-1.11E-05	2.91E-09
O2	6.22	0.00271	-3.7E-07	-2.2E-10

Thermal Conductivity

Units = microcal/s/cm/K
 Form: $K_g = a + b*t + c*t^2 + d*t^3$

	a	b	c	d
N2	0.9359	0.2344	-0.000121	3.591E-08
CO2	-17.23	0.1914	1.308E-05	-2.514E-08
H2O (v)	17.53	-0.0242	0.00043	-2.173E-07
SO2	-19.31	0.1515	-0.000033	5.5E-09
O2	-0.7816	0.238	-8.94E-05	2.324E-08

Gas Viscosity

Units = micropoise
 Form: $\mu = a + b*t + c*t^2$

	a	b	c
N2	30.43	0.4989	-0.000109
CO2	25.45	0.4549	-8.65E-05
H2O (v)	-31.89	0.4145	-8.27E-06
SO2	-3.793	0.4645	-7.28E-05
O2	18.11	0.6632	-0.000188

Molecular Weights & Heating Values

	Lb/LbMole	HHV Btu/Lb	LHV Btu/Lb
O2	32		
N2	28.01		
H2	2.02	61095	51623
CO	28.01	4347	4347
CO2	44.01		
CH4	16.05	23875	21495
C2H6	30.08	22323	20418
C2H4	28.06	21636	20275
C3H6	42.09	21048	19687
C3H8	44.11	21669	19937
H2S	34.08	7097	6537
CH3SH	48.11	13599	12820
(CH3)2S	62.14	15103	14198
(CH3)2S2	94.20	11317	10721
HCl	36.46		
H2O (v)	18.02		
SO2	64.06		
C4H10	58.14	21296	19653

PROPRTS

Fuel Gas Heat Capacities	a	b	c	d
H2	6.88	-0.000022	2.1E-07	1.3E-10
CO	6.92	-0.00065	0.0000028	-1.14E-09
CO2	5.14	0.0154	-9.94E-06	2.42E-09
CH4	5.04	0.00932	8.87E-06	-5.37E-09
C2H6	2.46	0.0361	-0.000007	-4.6E-10
C2H4	0.934	0.0369	-1.93E-05	4.01E-09
C3H8				
H2S	7.2	0.0036		
H2O	8.10	-7.20E-04	3.63E-06	-1.16E-09

ORIFICE FLOW COEFFICIENT

BETA	CO	CO -	0.59181
		+	0.02244 *BETA
0.2	0.5969		0.5963
0.25	0.5975		0.5974
0.3	0.5983		0.5985
0.35	0.5992		0.5997
0.4	0.6003		0.6008
0.45	0.6016		0.6019
0.5	0.6031		0.6030
0.55	0.6045		0.6042
0.6	0.6059		0.6053
0.65	0.6068		0.6064
0.7	0.6069		0.6075

ASME HANDBOOK, CURVE-FIT
PAGE 3-65

BETA	C1	C1 -	91.70803517
		+	BETA ²
0.2	5.486		5.486
0.25	8.106		8.106
0.3	11.153		11.153
0.35	14.606		14.606
0.4	18.451		18.451
0.45	22.675		22.675
0.5	27.266		27.266
0.55	32.215		32.215
0.6	37.513		37.513
0.65	43.153		43.153
0.7	49.129		49.129

ASME HANDBOOK, CURVE-FIT
PAGE 3-65

PROPRTS

LN(BETA)	LN(C1)	LN(C1) - + 1.74996 *LN(BETA)
		4.51861
-1.609	1.702	1.702
-1.386	2.093	2.093
-1.204	2.412	2.412
-1.050	2.681	2.681
-0.916	2.915	2.915
-0.799	3.121	3.121
-0.693	3.306	3.306
-0.598	3.472	3.472
-0.511	3.625	3.625
-0.431	3.765	3.765
-0.357	3.894	3.894

CURVE-FIT

PROPRTS

<u>TUBE SIZES</u>				
<u>ID, INCH</u>	<u>OD, INCH</u>	<u>WALL THK</u>	<u>BWG GAUGE</u>	
0.206	0.269	0.25	0.022	24
0.305	0.364	0.375	0.035	20
0.402	0.493	0.5	0.049	18
0.495	0.622	0.625	0.065	16
0.606	0.824	0.75	0.072	15
0.709	1.049	0.875	0.083	14
0.81	1.38	1	0.095	13
1.032	1.61	1.25	0.109	12
1.282	2.067	1.5	0.109	12
1.76	2.469	2	0.12	11
2.204	3.068	2.5	0.148	9

<u>PIPE SIZES</u>					
<u>NOMNL, IN</u>	<u>ID, INCH</u>	<u>OD, INCH</u>	<u>WALL THK</u>	<u>SCHEDULE</u>	
0.125	0.269	0.405	0.068	40	
0.25	0.364	0.54	0.088	40	
0.375	0.493	0.675	0.091	40	
0.5	0.622	0.84	0.109	40	
0.75	0.824	1.05	0.113	40	
1	1.049	1.315	0.133	40	
1.25	1.38	1.66	0.14	40	
1.5	1.61	1.9	0.145	40	
2	2.067	2.375	0.154	40	
2.5	2.469	2.875	0.203	40	
3	3.068	3.5	0.216	40	
3.5	3.548	4	0.226	40	
4	4.026	4.5	0.237	40	
5	5.047	5.563	0.258	40	
6	6.065	6.625	0.28	40	
8	7.981	8.625	0.322	40	
10	10.02	10.75	0.365	40	
12	12	12.75	0.375	40	
14	13.25	14	0.375	STD	
16	15.25	16	0.375	STD	
18	17.25	18	0.375	STD	
20	19.25	20	0.375	STD	
22	21.25	22	0.375	STD	
24	23.25	24	0.375	STD	
26	25.25	26	0.375	STD	
28	27.25	28	0.375	STD	
30	29.25	30	0.375	STD	
32	31.25	32	0.375	STD	
34	33.25	34	0.375	STD	
36	35.25	36	0.375	STD	
42	41.25	42	0.375	STD	
48	47.25	48	0.375	STD	

PROPRTS

VISCOSITY OF STEAM

TEMPERATURE K	VISCOSITY NS/M2 *10 ⁷	TEMPERATURE F	VISCOSITY LB/FT-H	MU = + 4.849E-05 *TEMP	0.01988	CORRELATION A24:D33
380	127.1	224	0.0307		0.0308	0.0301
400	134.4	260	0.0325		0.0325	0.0321
450	152.5	350	0.0369		0.0369	0.0370
500	170.4	440	0.0412		0.0412	0.0419
550	188.4	530	0.0456		0.0456	0.0468
600	206.7	620	0.0500		0.0500	0.0517
650	224.7	710	0.0544		0.0543	0.0566
700	242.6	800	0.0587		0.0587	0.0615
750	260.4	890	0.0630		0.0630	0.0664
800	278.6	980	0.0674		0.0674	0.0712
850	296.9	1070	0.0718		0.0718	0.0761
					CURVE-FIT	

VISCOSITY OF AIR

TEMPERATURE K	VISCOSITY NS/M2 *10 ⁷	TEMPERTR F	VISCOSITY LB/FT-H	MU = + 4.029E-05 *TEMP	0.04725
300	184.6	80	0.0447		0.0505
350	208.2	170	0.0504		0.0541
400	230.1	260	0.0557		0.0577
450	250.7	350	0.0606		0.0614
500	270.1	440	0.0653		0.0650
550	288.4	530	0.0698		0.0686
600	305.8	620	0.0740		0.0722
650	322.5	710	0.0780		0.0759
700	338.8	800	0.0820		0.0795
750	354.6	890	0.0858		0.0831
800	369.8	980	0.0895		0.0867
850	384.3	1070	0.0930		0.0904
900	398.1	1160	0.0963		0.0940
950	411.3	1250	0.0995		0.0976
1000	424.4	1340	0.1027		0.1012
1100	449.0	1520	0.1086		0.1085
1200	473.0	1700	0.1144		0.1157
1300	496.0	1880	0.1200		0.1230
1400	530.0	2060	0.1282		0.1303
1500	557.0	2240	0.1347		0.1375
					CURVE-FIT

PROPERTS

THERMAL CONDUCTIVITY OF STEAM

TEMPERATURE K	THERMAL CONDUCT W/M-K *10 ³	TEMPERATURE F	TH CONDUCT BTU/H-FT-F	K = + 0.0000267 *TEMP
380	24.6	224	0.0142	0.0140
400	26.1	260	0.0151	0.0149
450	29.9	350	0.0173	0.0173
500	33.9	440	0.0196	0.0197
550	37.9	530	0.0219	0.0221
600	42.2	620	0.0244	0.0245
650	46.4	710	0.0268	0.0269
700	50.5	800	0.0292	0.0293
750	54.9	890	0.0317	0.0317
800	59.2	980	0.0342	0.0341
850	63.7	1070	0.0368	0.0365

CURVE-FIT

THERMAL CONDUCTIVITY OF AIR

TEMPERATURE K	THERMAL CONDUCT W/M-K *10 ³	TEMPERATURE F	TH CONDUCT BTU/H-FT-F	K = + 0.0000181 *TEMP
300	26.3	80	0.0152	0.0165
350	30.0	170	0.0173	0.0181
400	33.8	260	0.0195	0.0197
450	37.3	350	0.0216	0.0214
500	40.7	440	0.0235	0.0230
550	43.9	530	0.0254	0.0246
600	46.9	620	0.0271	0.0262
650	49.7	710	0.0287	0.0279
700	52.4	800	0.0303	0.0295
750	54.9	890	0.0317	0.0311
800	57.3	980	0.0331	0.0328
850	59.6	1070	0.0344	0.0344
900	62.0	1160	0.0358	0.0360
950	64.3	1250	0.0372	0.0376
1000	66.7	1340	0.0385	0.0393
1100	71.5	1520	0.0413	0.0425
1200	76.3	1700	0.0441	0.0458
1300	82.0	1880	0.0474	0.0490
1400	91.0	2060	0.0526	0.0523
1500	100.0	2240	0.0578	0.0556

CURVE-FIT

APPENDIX E

Pulse Combustor Test Data Analysis

STOICHIOMETRY

FUEL TYPE:			
ASH	0.00%	LB AIR/LB COMPONENT	
MOISTURE	0.00%		
CARBON	74.06%	11.43	8.466
HYDROGEN	24.01%	33.98	8.158
SULFUR	0.00%	4.28	0.000
NITROGEN	0.81%		
OXYGEN	1.12%	-4.29	-0.048
CHLORINE	0.00%		
STOICHIOMETRIC AIR (LBS DRY AIR/LB FUEL)			16.575
HUMIDITY RATIO			
STOICHIOMETRIC AIR (LBS WET AIR/LB FUEL)	0.0132	LB WATER/LB DRY AIR	16.793
WATER IN AIR (LB WATER/LB FUEL)			0.218

HHV OF FUEL: 23,133 BTU/LB FUEL
 MOISTURE IN FLOE: 2.14 LB/LB FUEL
 LATENT HEAT: 2,245 BTU/LB FUEL
 LHV OF FUEL: 20,888 BTU/LB FUEL

QUICK OVERALL BALANCE

INLET AIR PRESSURE	15.03	PSIA		
INLET AIR TEMPERATURE	43	F		
INLET AIR COMPOSITION				1.02
-OXYGEN	3.864	LB O2/LB FUEL		0.23
-NITROGEN	12.712	LB N2/LB FUEL		0.76
-WATER	0.218	LB WATER/LB FUEL		0.01
INLET AIR THETA FN FOR CP	2.79			2.79
SPECIFIC HEATS				3.00
-OXYGEN	0.221	BTU/LB O2-R		1.744
-NITROGEN	0.249	BTU/LB N2-R		3.339
-WATER	0.448	BTU/LB WTR-R		1.492
COMBUSTION STOICHIOMETRY	121.92%			
TOTAL INLET FLOW			26.246	LB TOTAL/LB FUEL
INLET ENTHALPY				
-OXYGEN	-38.47	BTU/LB FUEL		
-NITROGEN	-142.53	BTU/LB FUEL		
-WATER	-4.40	BTU/LB FUEL		
FRACTN HEAT REL FROM FUEL	100.00%			0
EFFEC HEAT REL FROM FUEL	100.00%			
TOTAL HEAT LOSS	51.21%			
TOTAL INLET ENTHALPY			23,562	48.8%

COMBUSTION PRODUCTS
EXIT TEMPERATURE 1
THETA FUNCTN FOR CP
SPECIFIC HEATS

1,279 F	1,279	9.66	3.00
9.66			
0.241 BTU/LB O2-R		3.393	1.790
0.261 BTU/LB N2-R		5.125	3.390
0.489 BTU/LB WTR-R		4.841	1.584
0.256 BTU/LB CO2-R		2.122	0.414
0.263 BTU/LB CO-R		5.504	3.752
3.479 BTU/LB H2-R		-166.448	-189.614
0.798 BTU/LB CH4-R		11.198	5.883
0.196 BTU/LB HCL-R		1.919	0.614
0.252 BTU/LB NO-R		0.409	-1.268
0.167 BTU/LB SO2-R		1.508	0.397
0.159 BTU/LB SO3-R			
0.250 BTU/LB ASH-R			

LB COMP/LB FUEL	MOL	VOL PCT WET	VOL PCT DRY
0.970	0.030	3.07 %	4.18 %
17.502	0.625	63.33 %	86.24 %
4.722	0.262	26.56 %	
3.049	0.069	7.02 %	
0.004	0.000	132.89 PPMV	9.56 %
0.000	0.000	0.00 PPMV	180.95 PPMV
0.000	0.000	0.00 PPMV	0.00 PPMV
0.000	0.000	1.50 PPMV	2.04 PPMV
0.000	0.000	0.00 PPMV	0.00 PPMV
0.000	0.000	14.26 PPMV	19.42 PPMV
0.000	0.000	0.00 PPMV	0.00 PPMV
0.000	0.000	0.00 PPMV	0.00 PPMV
0.000	0.000	100.00	100.00
0.000	0.987	26.60	
0.000		MOL WT	

EXIT ENTHALPIES

BTU/LB FUEL	
279.8	
5466.7	
2769.9	
937.4	
1.2	
0.0	
0.0	
0.0	
0.0	
0.1	
0.0	
0.0	
0.0	
0.0	
0.0	
23,562	

FIRING RATE:
AIR REQUIREMENT FOR
COMBUSTION:
FUEL FLOW RATE:
TOTAL AIR FLOW:

2.18E+07 BTU/HR	0.57
25.25 LB air/LB fuel	346 scfm
941 LB/HR	5,351 scfm
23,757 LB/HR	

EXIT ENTHALPIES

-OXYGEN	154.1
-NITROGEN	2793.1
-WATER	5183.9
-CO2	445.6
-CO	0.3
-HYDROGEN	0.0
-CH4	0.0
-HCL	0.0
-NO	0.1
-SO2	0.0
-SO3	0.0
-ASH	0.0
TOTAL	22,328

BTU/LB FUEL

WATER QUENCH FOR FLUE GAS RECIRCULATION

INLET WATER PRESSURE
 INLET WATER TEMPERATURE
 INLET WATER FLOW RATE, LB/H
 INLET AIR FLOW RATE

60.00 PSIA
 38 F
 0.531 LB/H
 2.69 LB/LB FUEL
 0.00 LB/H
 0.00 LB/LB FUEL

5.06 GPM
 0.00 SCFM

SPRAYING SYSTEMS CO.
 FINE SPRAY HYDRAULIC ATOMIZING SPRAY NOZZLE

TOTAL INLET FLOW

INLET ENTHALPY

-FLUE GAS
 -WATER
 -AIR

22528.10 BTU/LB FUEL
 -112.95 BTU/LB FUEL
 0.00 BTU/LB FUEL
 22,415

42.700 LB/LB FUEL

TOTAL INLET ENTHALPY

COMBUSTION PRODUCTS
 EXIT TEMPERATURE 1
 THETA FUNCTN FOR CP
 SPECIFIC HEATS

-OXYGEN
 -NITROGEN
 -WATER
 -CO2
 -CO
 -HYDROGEN
 -CH4
 -HCL
 -NO
 -SO2
 -SO3
 -ASH

461 F	5.11	5.11	3.00
5.11	2.267	2.267	1.790
0.226	3.918	3.918	3.390
0.250	2.547	2.547	1.584
0.455	0.889	0.889	0.414
0.225	4.282	4.282	3.752
0.080	-182.325	-182.325	-189.614
3.446	11.198	11.198	5.883
0.798	1.919	1.919	0.614
0.196	0.409	0.409	-1.268
0.252	0.717	0.717	0.397
0.152			
0.144			
0.250			

EXIT FLOWS	LB COMP/LB FUEL	MOL	VOL PCT WET	VOL PCT DRY
-OXYGEN	1.078	0.034	1.78 %	1.78 %
-NITROGEN	17.859	0.638	33.74 %	33.74 %
-WATER	20.710	1.149	60.81 %	
-CO2	3.049	0.069	3.67 %	3.67 %
-CO	0.004	0.000	132.89 PPMV	132.89 PPMV
-HYDROGEN	0.000	0.000	0.00 PPMV	0.00 PPMV
-CH4	0.000	0.000	1.50 PPMV	1.50 PPMV
-HCL	0.000	0.000	0.00 PPMV	0.00 PPMV
-NO	0.000	0.000	14.26 PPMV	14.26 PPMV
-SO2	0.000	0.000	0.00 PPMV	0.00 PPMV
-SO3	0.000	0.000	0.00 PPMV	0.00 PPMV
-ASH	0.000	0.000	0.00 PPMV	0.00 PPMV
TOTAL	42.700	1.890	100.01	39.20
	100.000%	22.59	MOL WT	

EXIT ENTHALPIES	BTU/LB FUEL
-OXYGEN	92.7
-NITROGEN	1699.6
-WATER	3591.7
-CO2	260.8
-CO	0.1
-HYDROGEN	0.0
-CH4	0.0
-HCL	0.0
-NO	0.0
-SO2	0.0
-SO3	0.0
-ASH	0.0
TOTAL	22,415

0.00

THETA FUNCTN FOR CP
SPECIFIC HEATS

- OXYGEN
- NITROGEN
- WATER
- CO2

3.37
0.220
0.249
0.448
0.206

- BTU/LB O2-R
- BTU/LB N2-R
- BTU/LB WTR-R
- BTU/LB CO2-R

3.37
1.872
3.482
1.750
0.491

3.00
1.790
3.390
1.584
0.414

INLET ENTHALPIES

- OXYGEN
- NITROGEN
- WATER
- CO2

BTU/LB FUEL
71.3
292.0
77.4
4.7

445.4

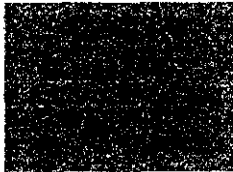
CORRECTED TO 3% O2

3.00

193.66

2.19

20.79



APPENDIX F
Macros Reference

TESTDATA Macro
Macro recorded 2/17/2002 by Ravi Chandran

```
Public itindex As Integer
Private Const itmax As Integer = 10
Private Const refl As String = "B500"
Option Explicit
Option Base 1
Dim ITERTN1 As Integer, ITERTN2 As Integer
Dim flag1 As Integer

Sub TESTDATA()

Range("J451").Select
Selection.Copy
Range("G512").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("D451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G513").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("F451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G514").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("G451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G519").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("H451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G520").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("I451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G521").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("M451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G522").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("N451").Select
Application.CutCopyMode = False
Selection.Copy
Range("G523").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
False, Transpose:=False
Range("R451:V451").Select
Application.CutCopyMode = False
Selection.Copy
```

Module2 - 2

```
Range("G528").Select
Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:=
False, Transpose:=True
Application.Run Macro:="SOLVER"
nd Sub
```

```
SOLVER Macro
Macro recorded 2/17/2002 by Ravi Chandran
```

```
ub SOLVER()
itindex = 0
For ITERTN1 = 1 To itmax
flag1 = Range("D560").Value
If flag1 > 0 Then Exit Sub
Range("C539").Select
Range("C539").GoalSeek Goal:=0, ChangingCell:=Range("G539")
Range("C540").Select
Range("C540").GoalSeek Goal:=0, ChangingCell:=Range("G540")
Range("C541").Select
Range("C541").GoalSeek Goal:=0, ChangingCell:=Range("G541")
Range("C542").Select
Range("C542").GoalSeek Goal:=0, ChangingCell:=Range("G542")
Range("C543").Select
Range("C543").GoalSeek Goal:=0, ChangingCell:=Range("G543")
Range("C548").Select
Range("C548").GoalSeek Goal:=0, ChangingCell:=Range("G548")
Range("C549").Select
Range("C549").GoalSeek Goal:=0, ChangingCell:=Range("G549")
Next ITERTN1
End Sub
```

Sub Recycle()

Recycle Macro

Macro recorded 2/18/2002 by Ravi Chandran

Keyboard Shortcut: Ctrl+Shift+A

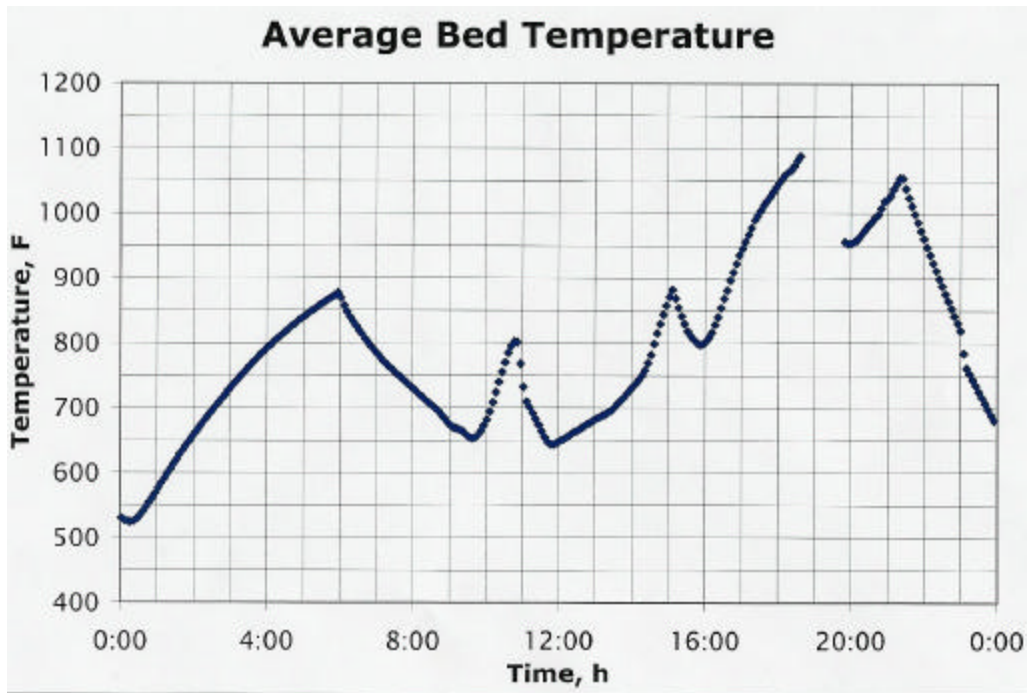
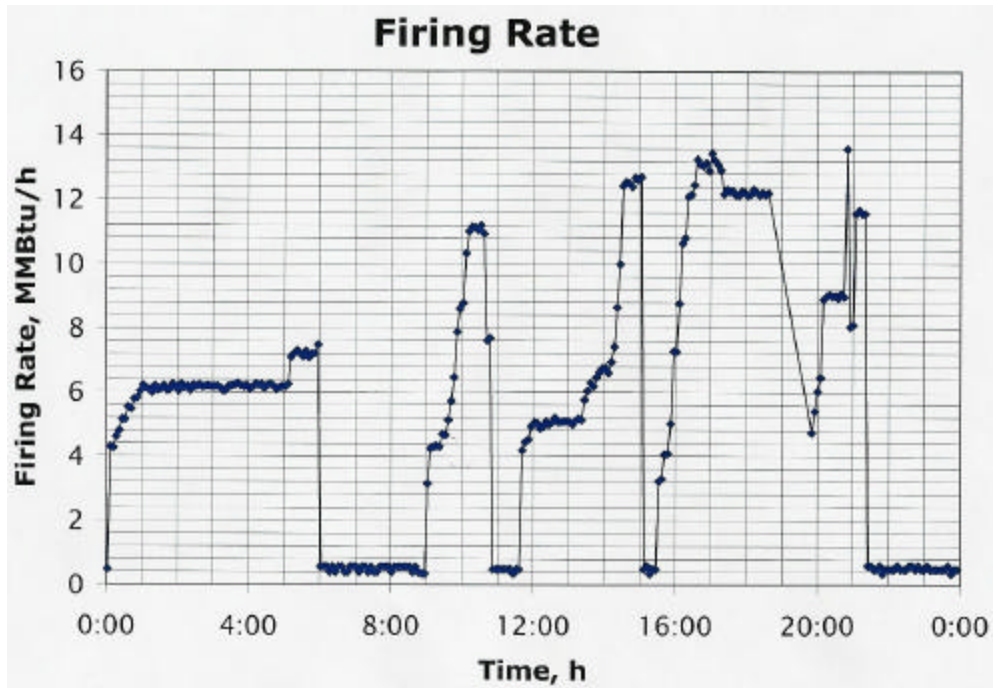
```
Range("D232").GoalSeek Goal:=0, ChangingCell:=Range("B177")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q38").Select
Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
Range("Q36").Select
Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q38").Select
Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
Range("Q37").Select
Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
Range("D232").Select
Range("D232").GoalSeek Goal:=0, ChangingCell:=Range("B177")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q36").Select
Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q37").Select
Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
Range("Q38").Select
Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q36").Select
Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
Range("Q37").Select
Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
Range("Q38").Select
Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q36").Select
Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
Range("Q35").Select
Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
Range("Q36").Select
Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
```

End Sub

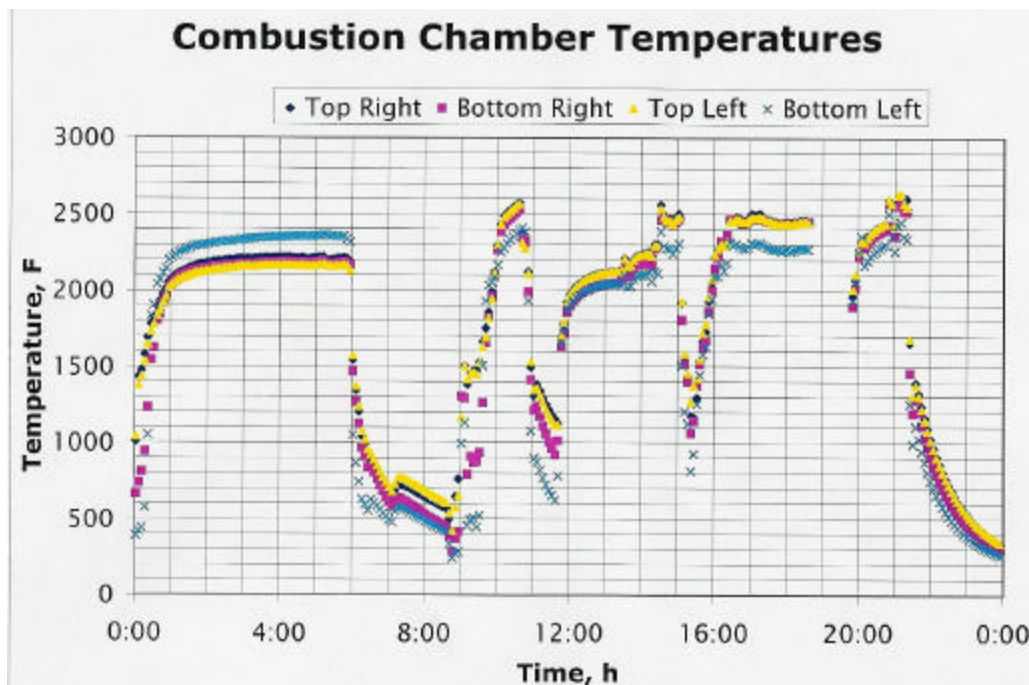
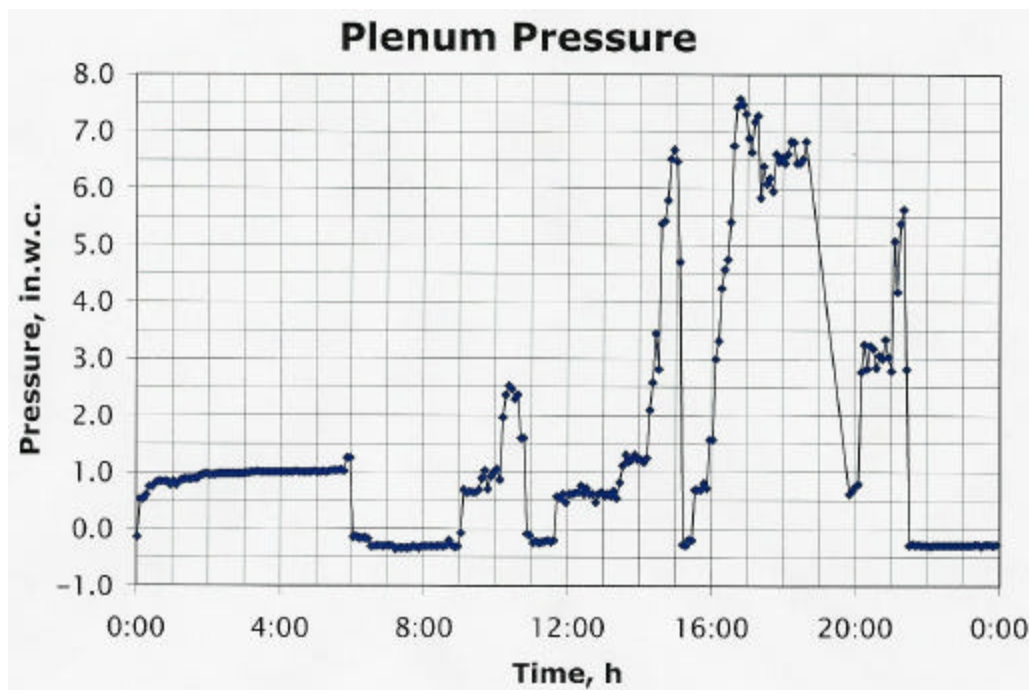
APPENDIX G

Data Trends

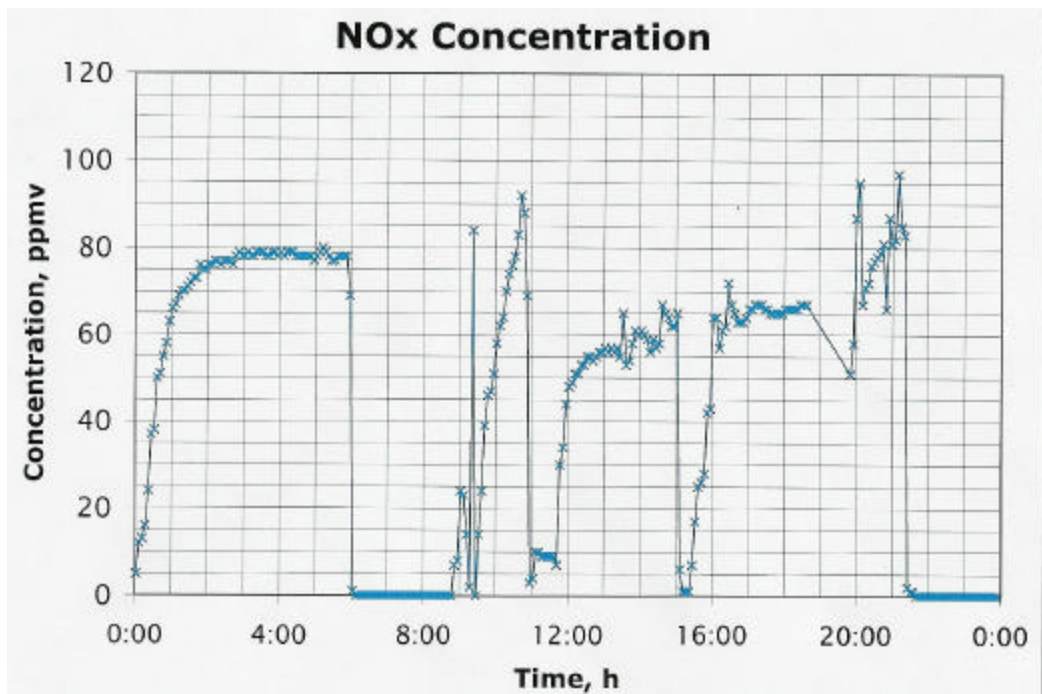
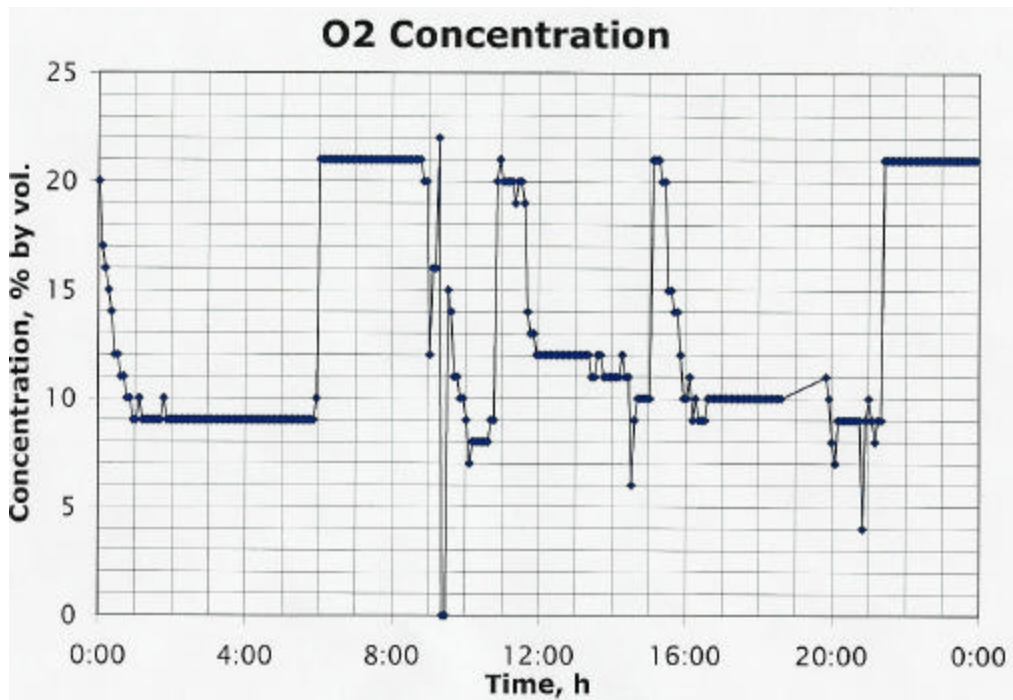
SERIES 1



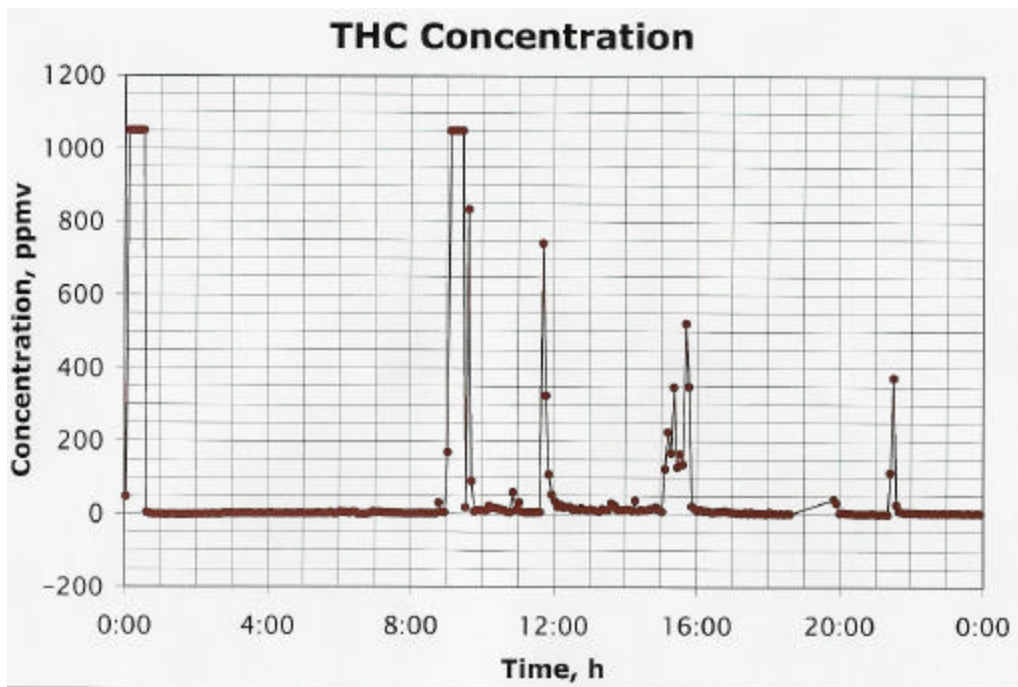
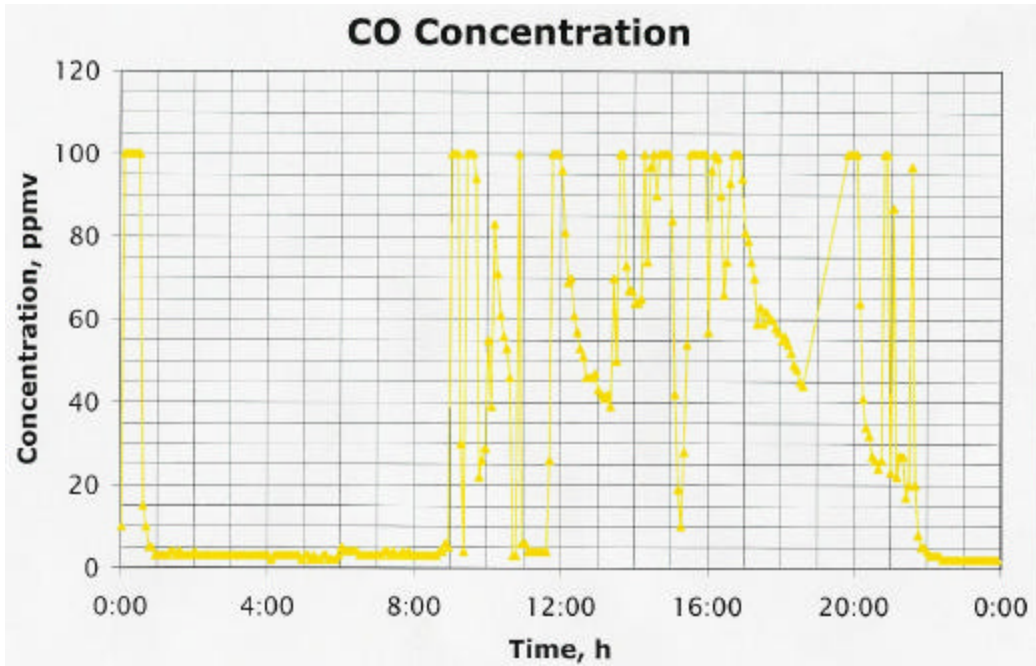
SERIES 1



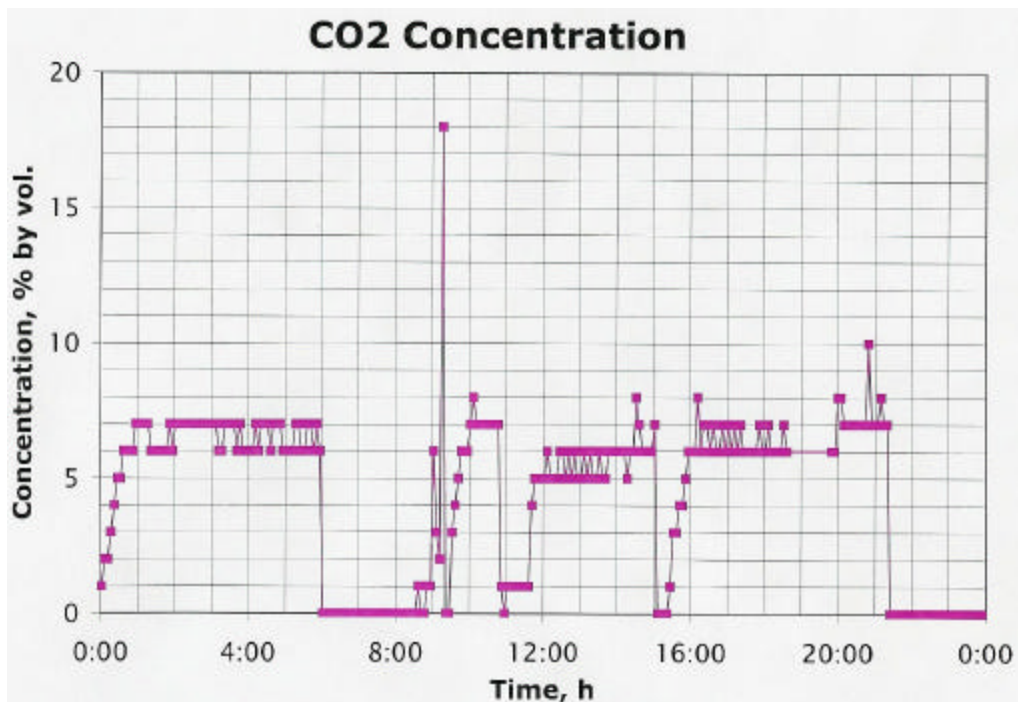
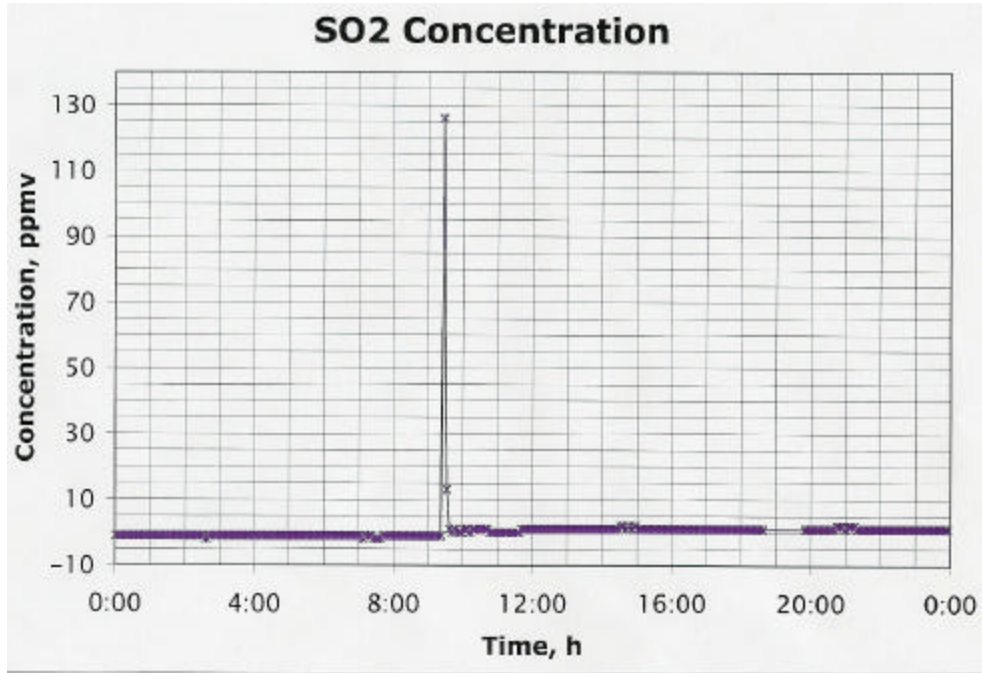
SERIES 1



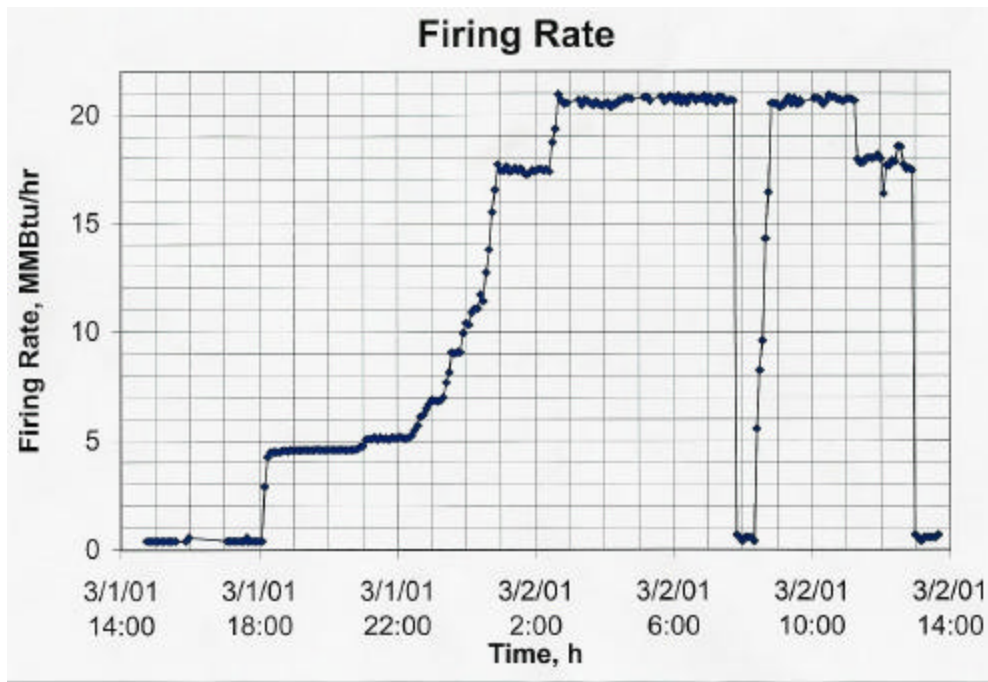
SERIES 1



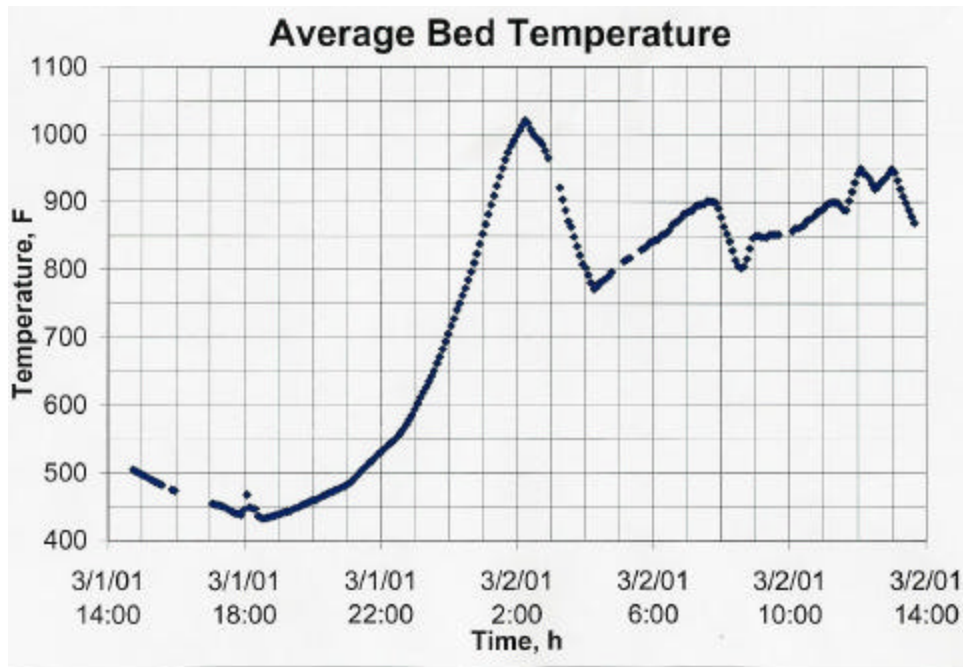
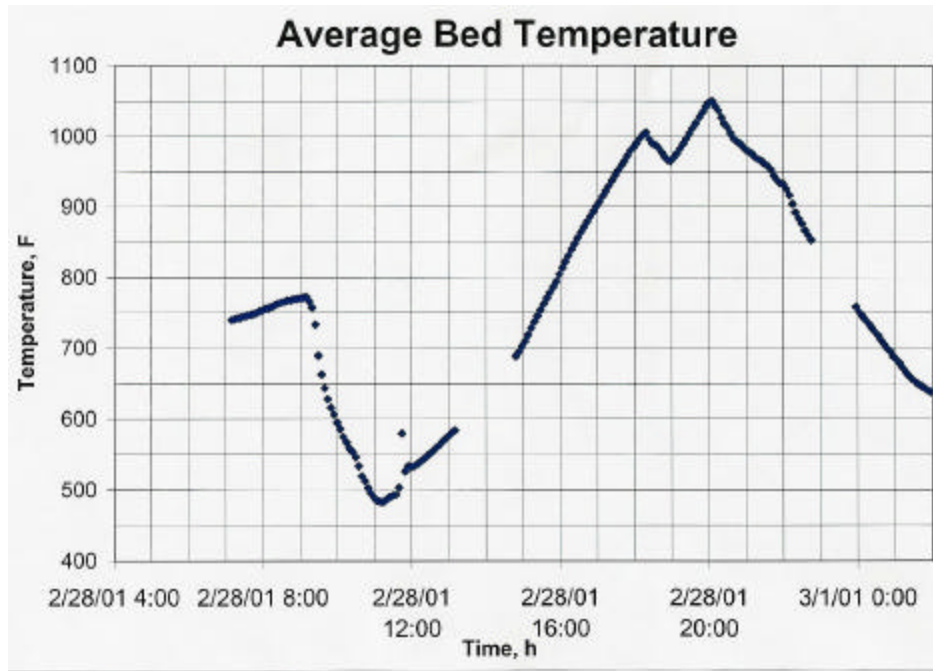
SERIES 1



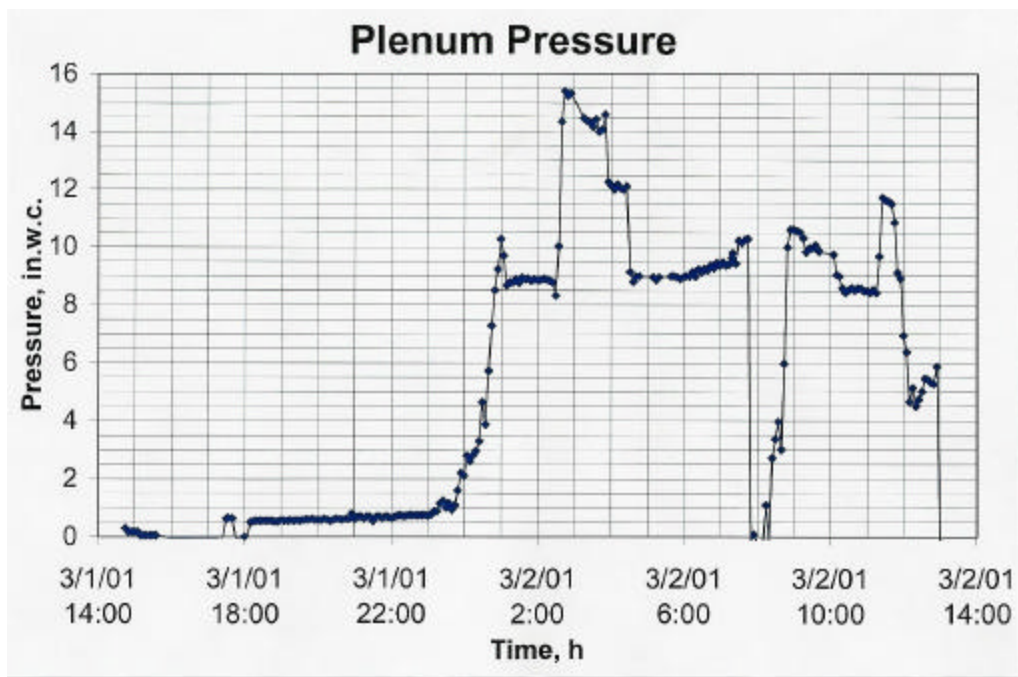
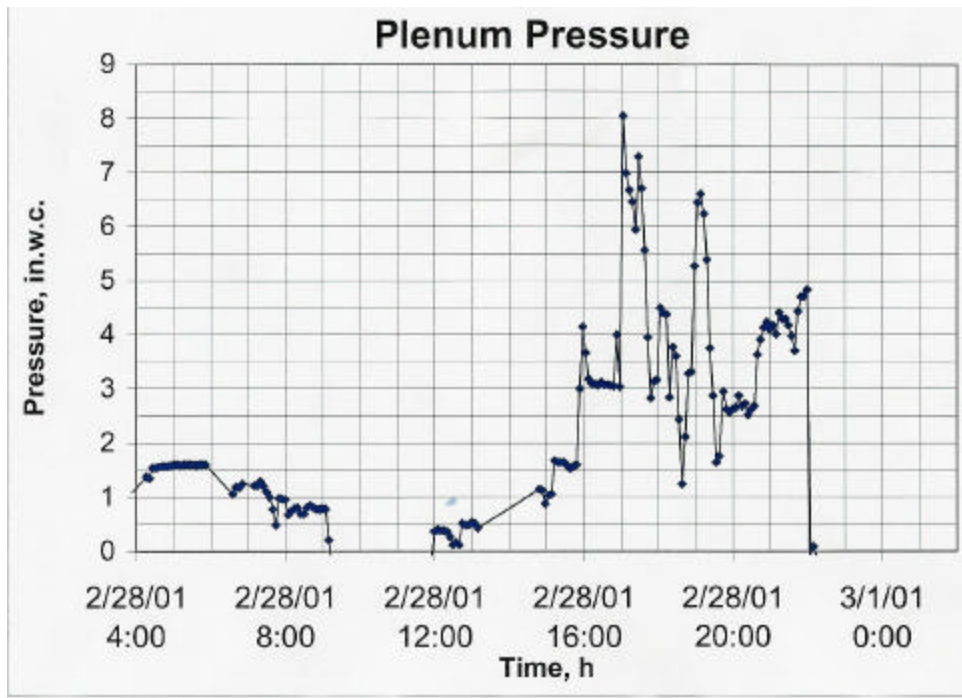
SERIES 2



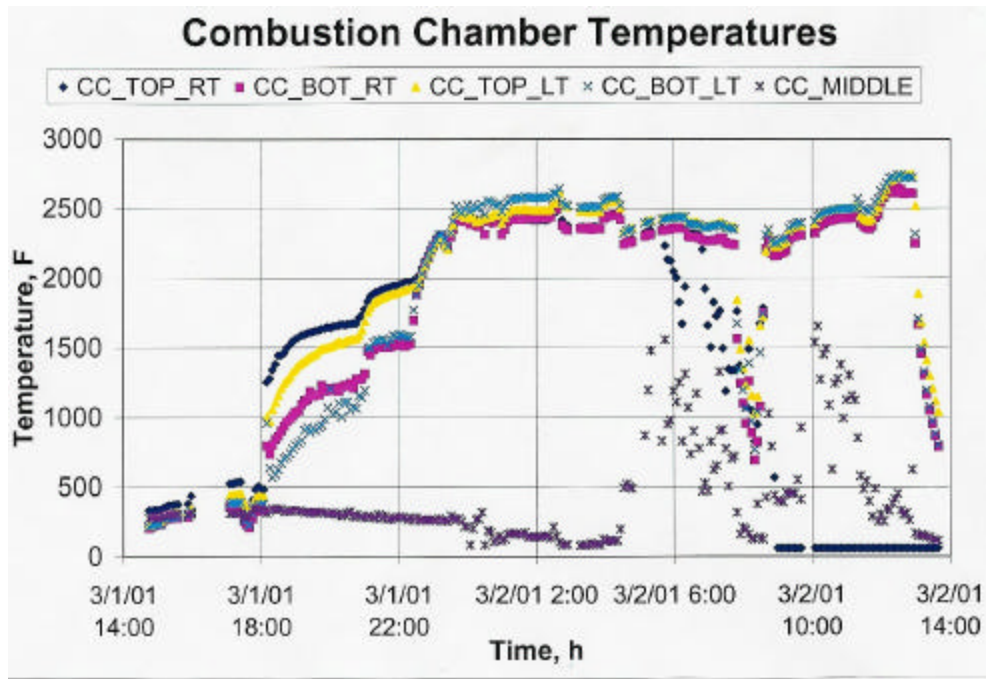
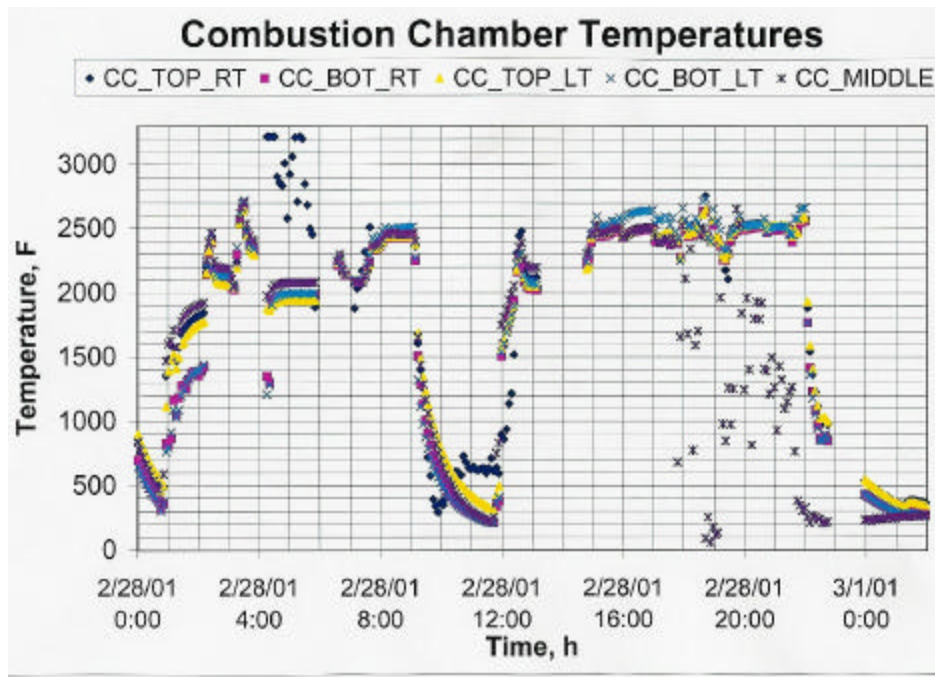
SERIES 2



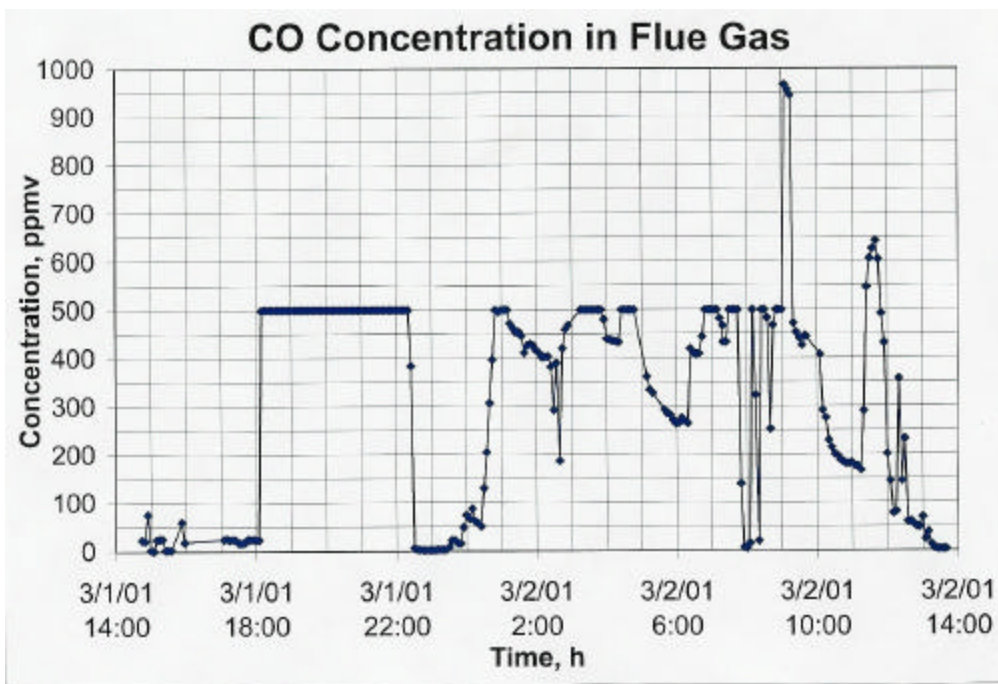
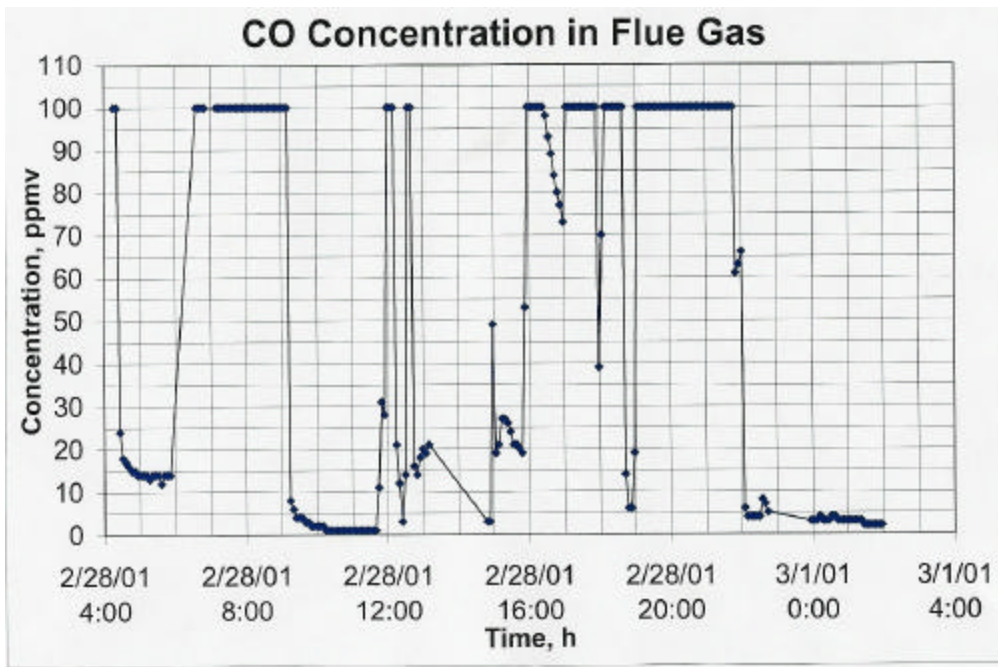
SERIES 2



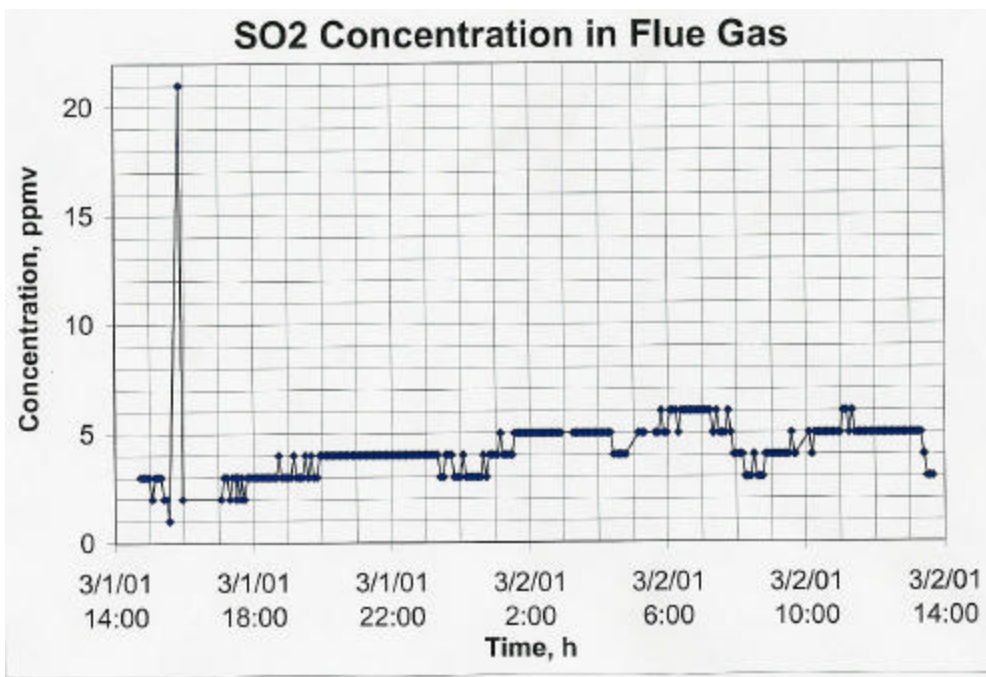
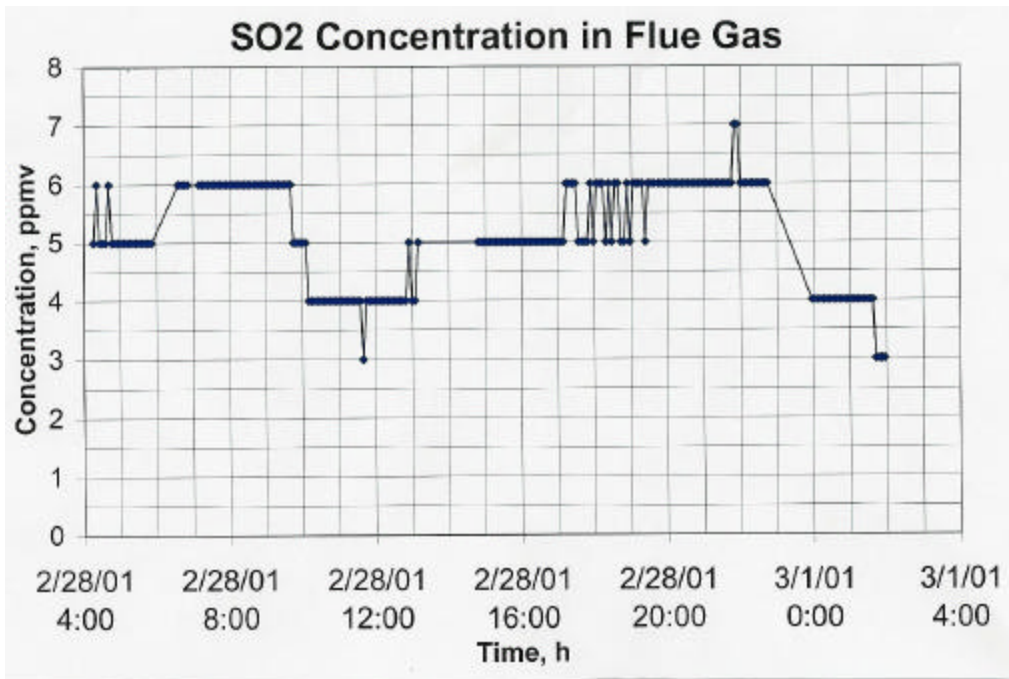
SERIES 2



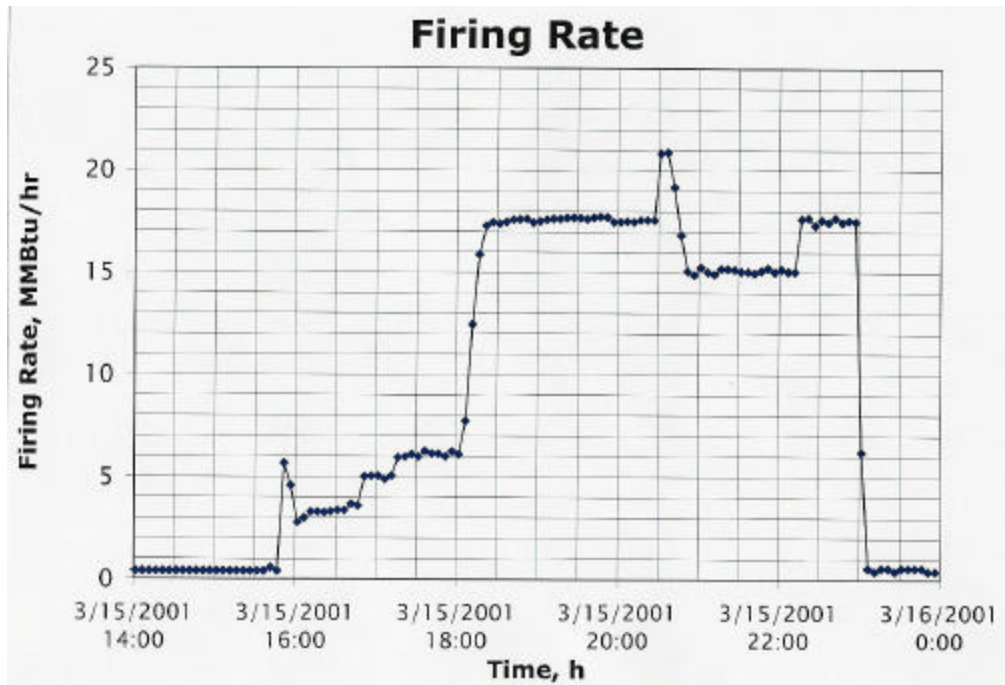
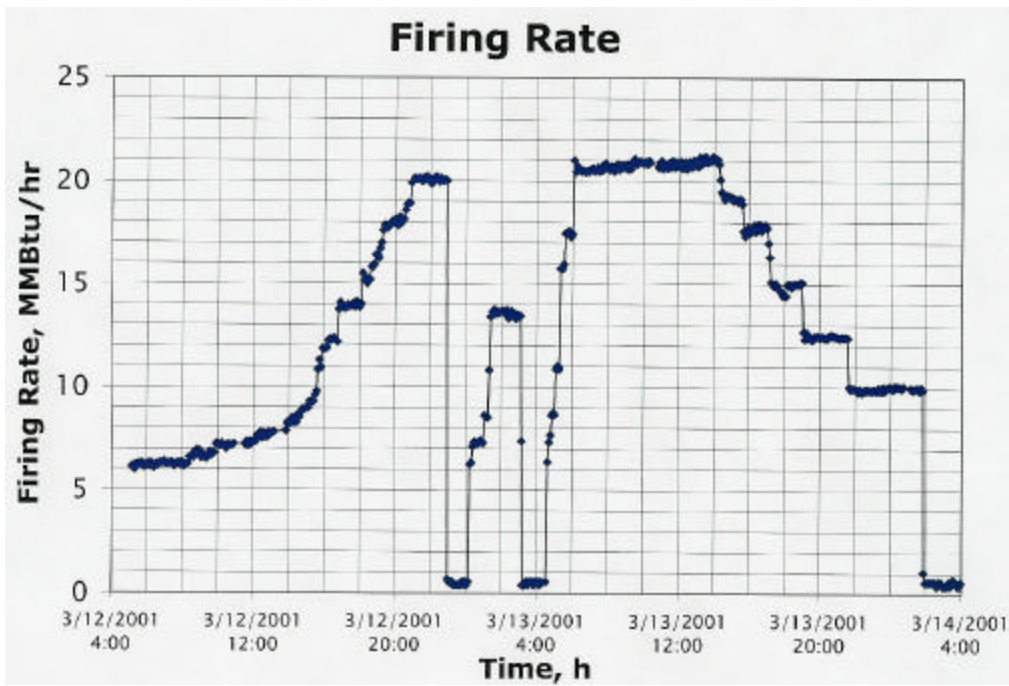
SERIES 2



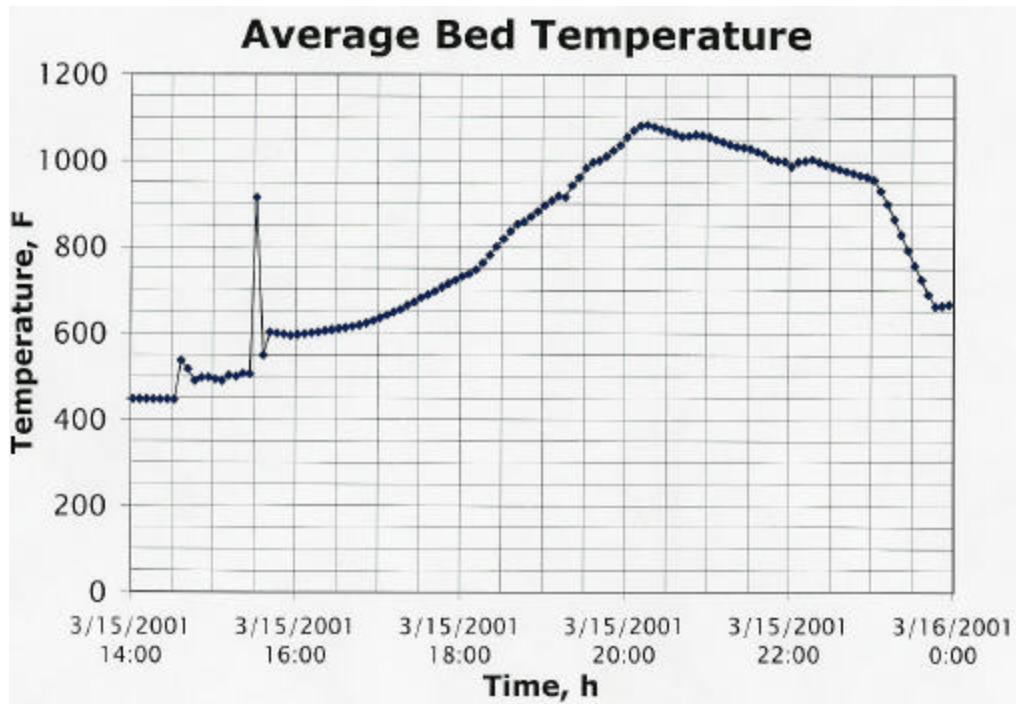
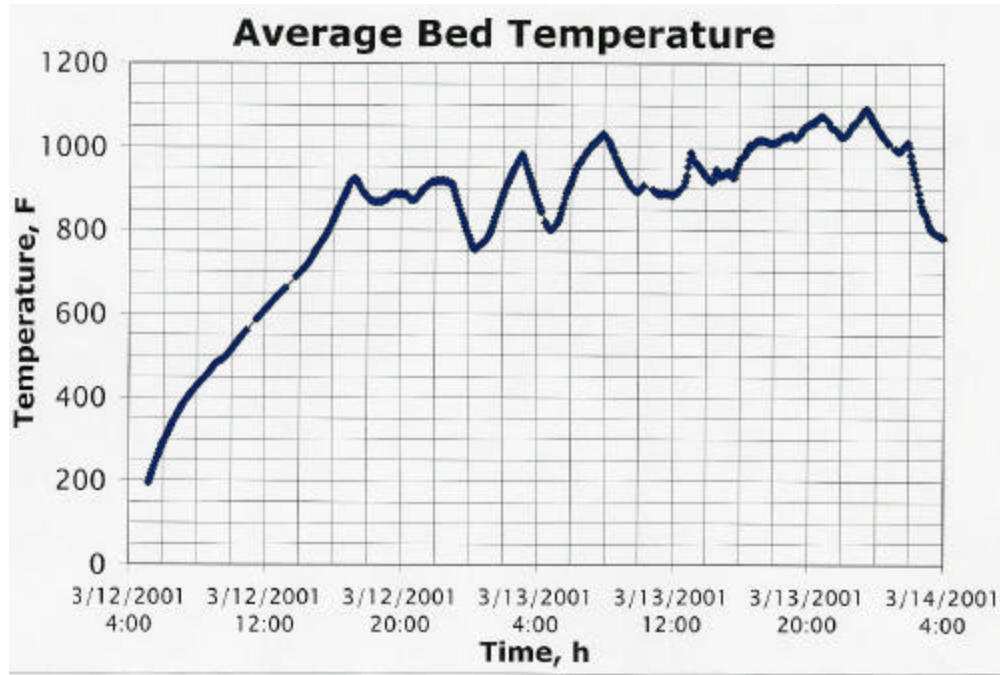
SERIES 2



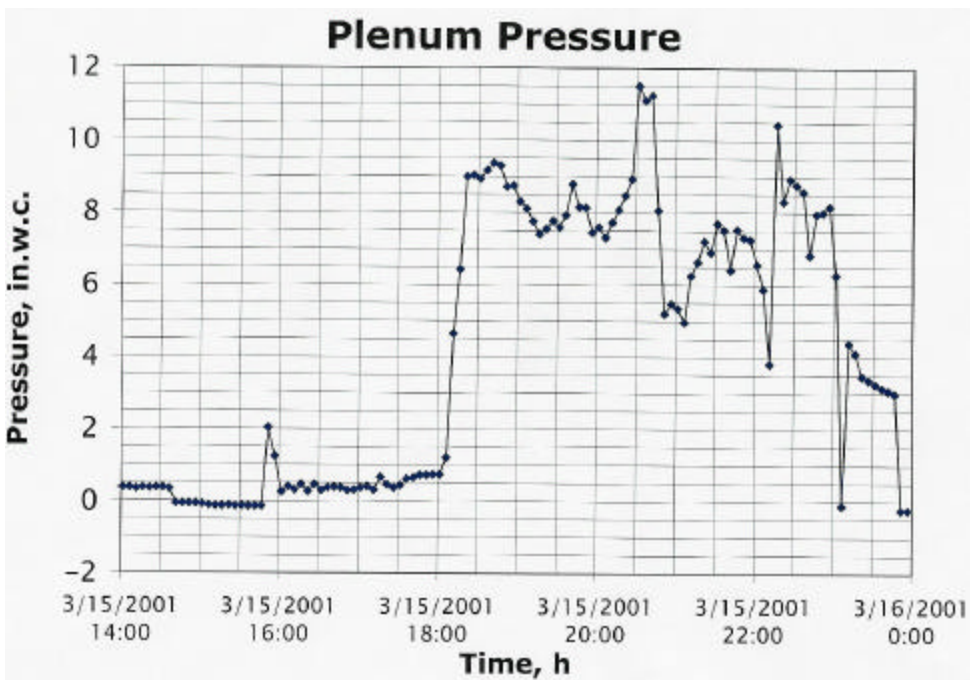
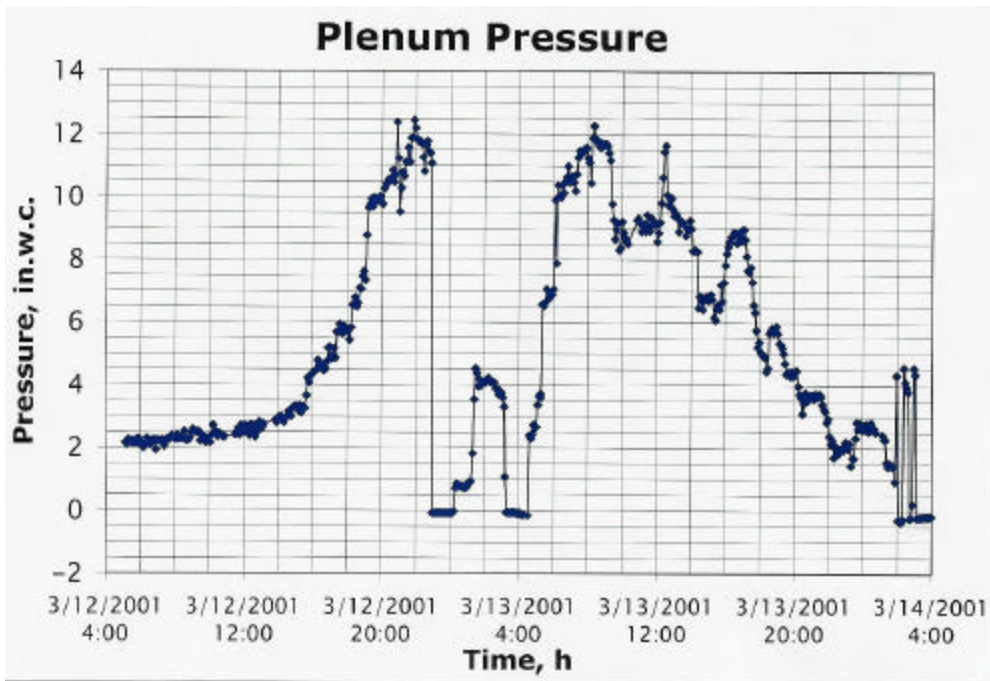
SERIES 3



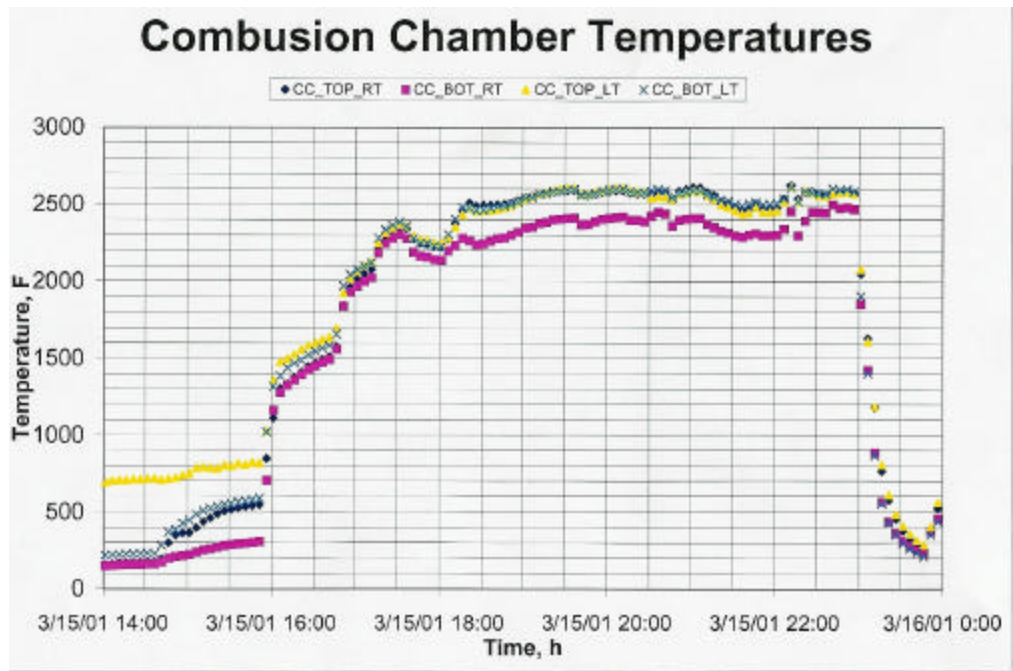
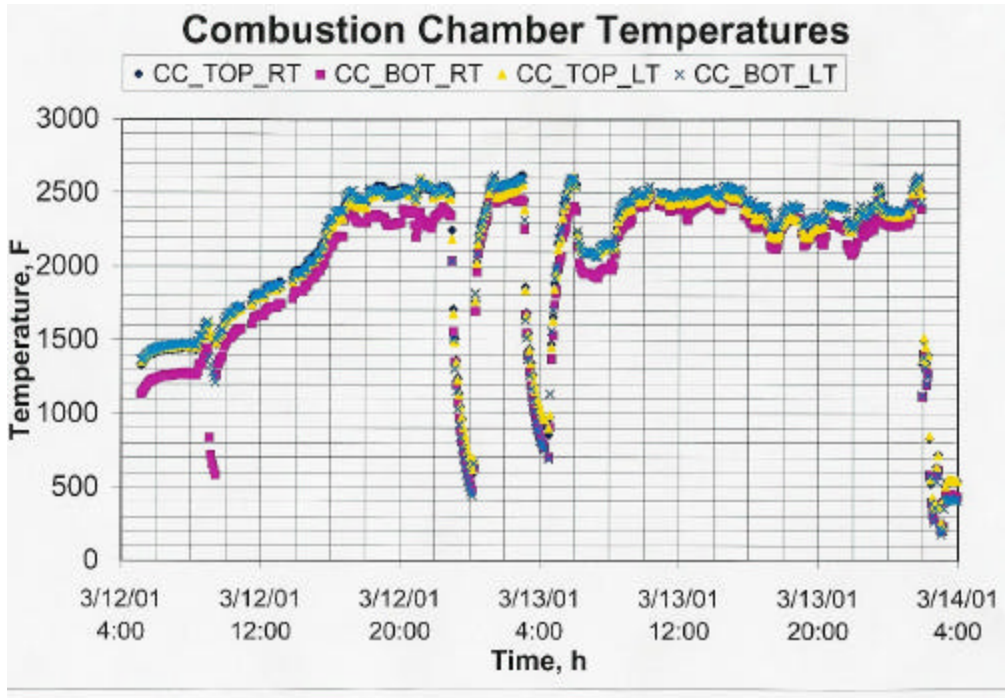
SERIES 3



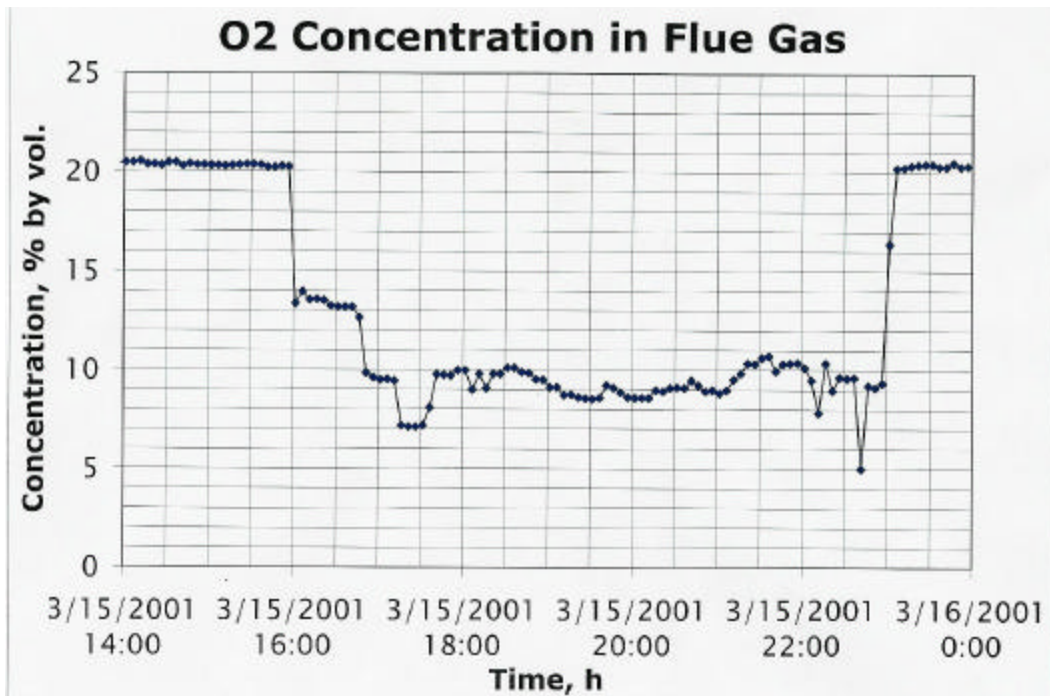
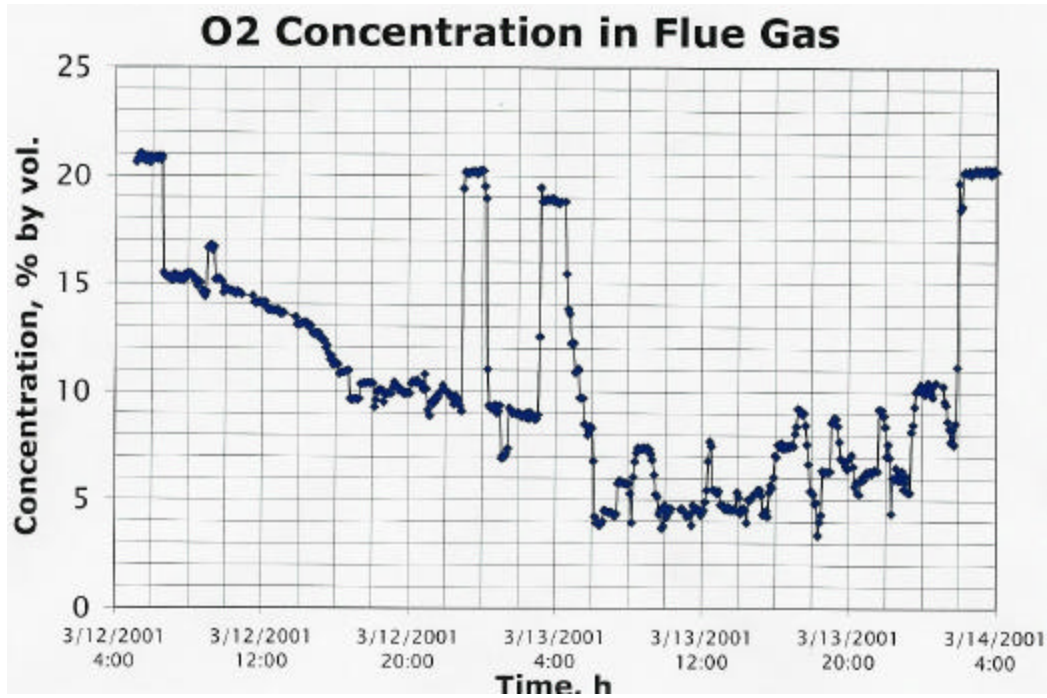
SERIES 3



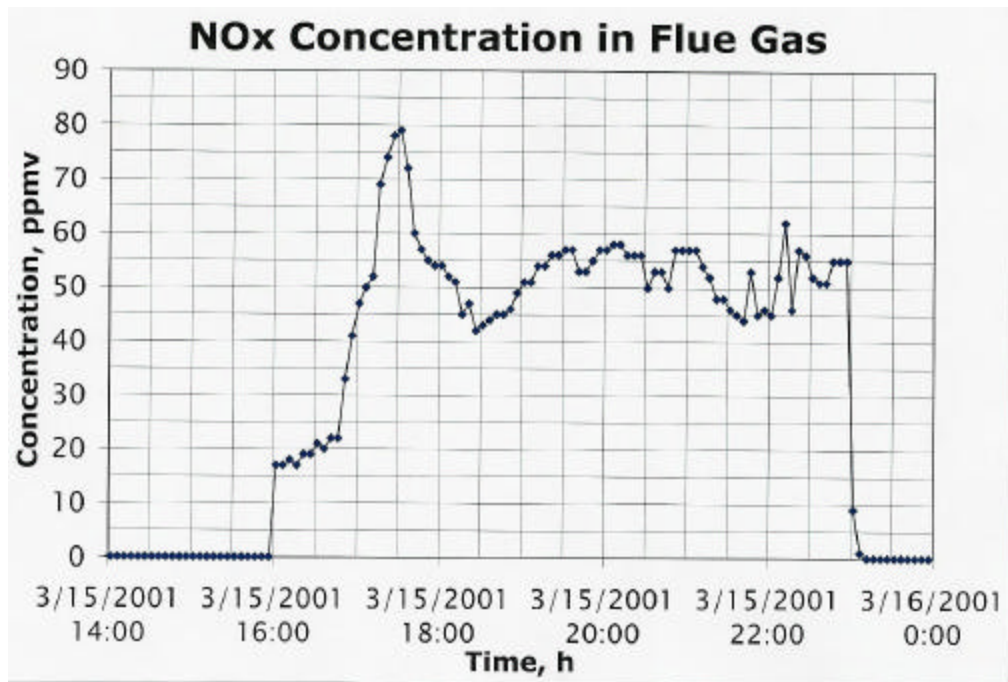
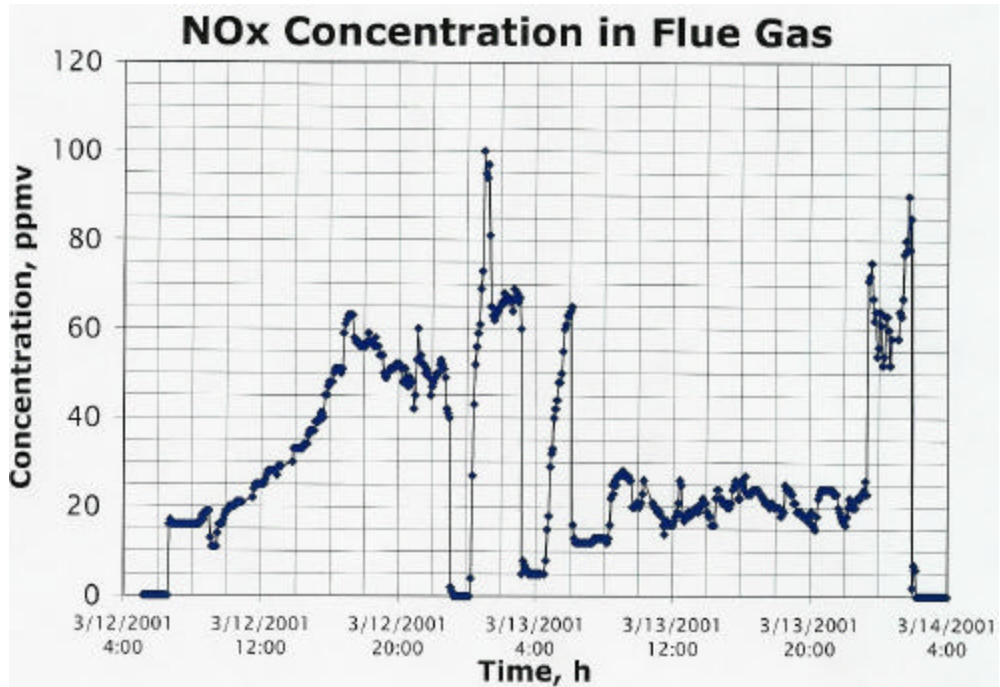
SERIES 3



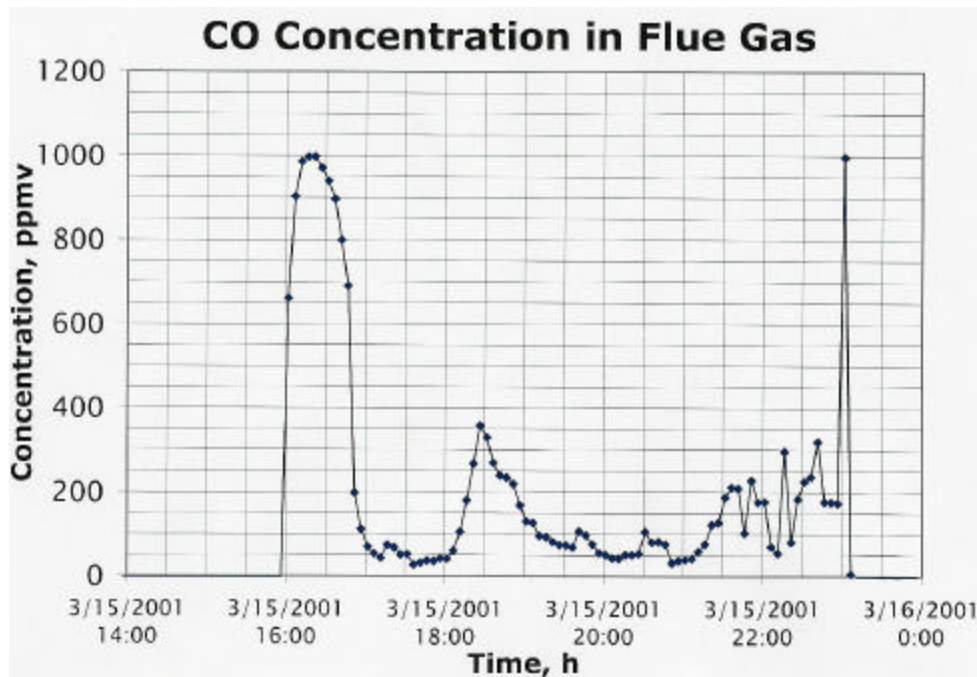
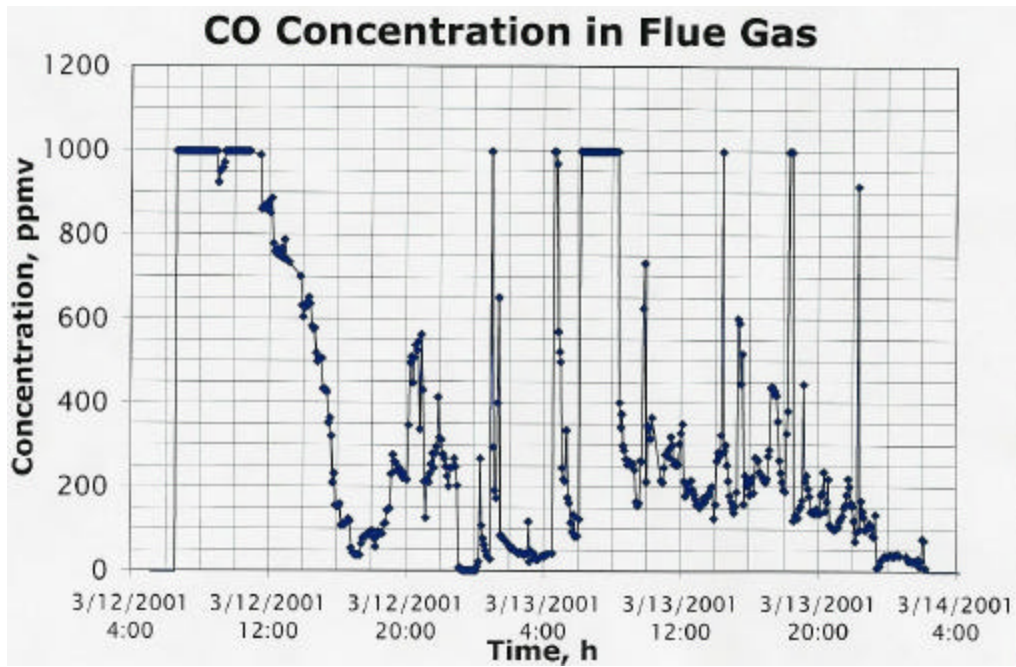
SERIES 3



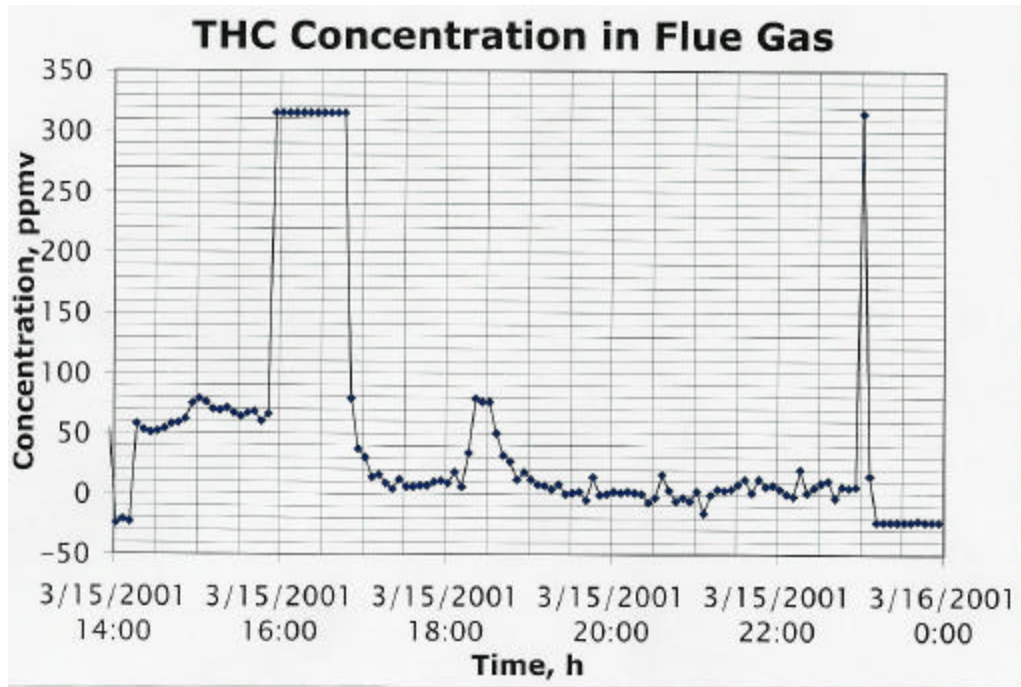
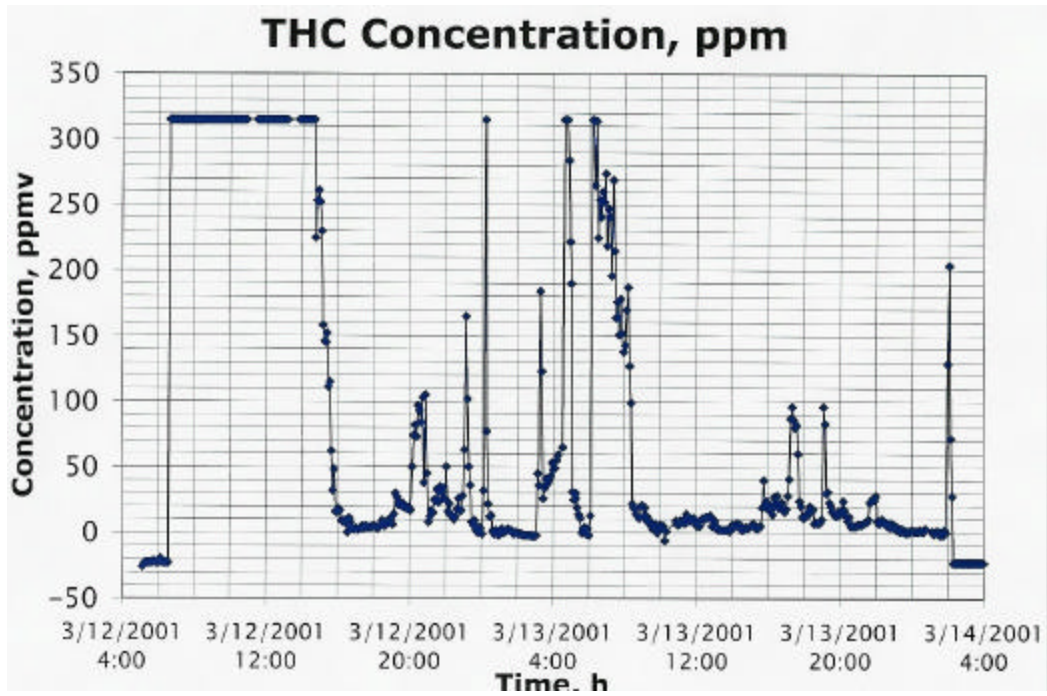
SERIES 3



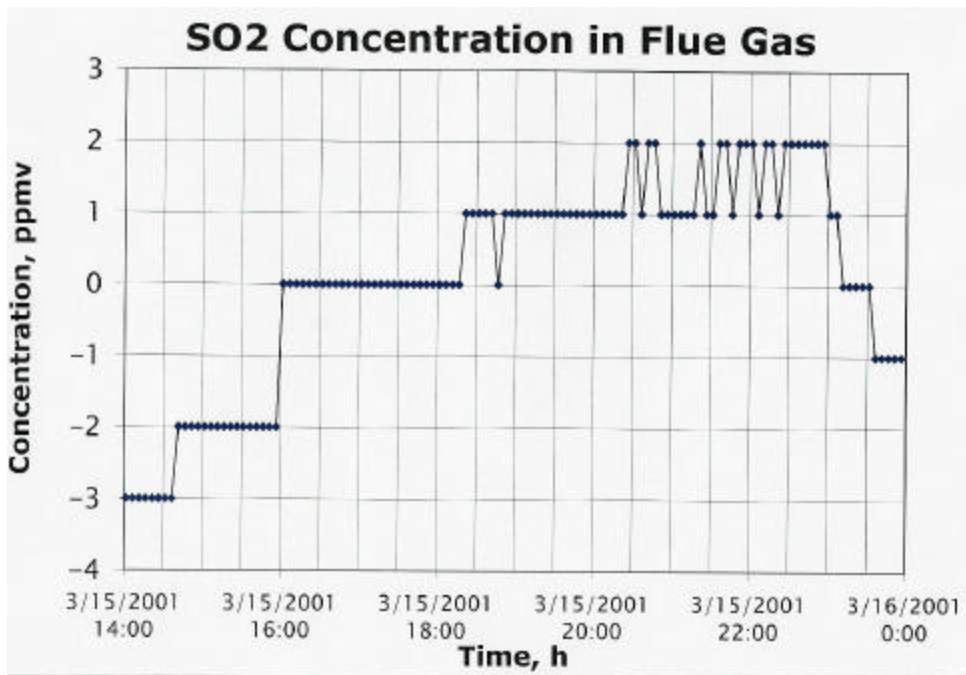
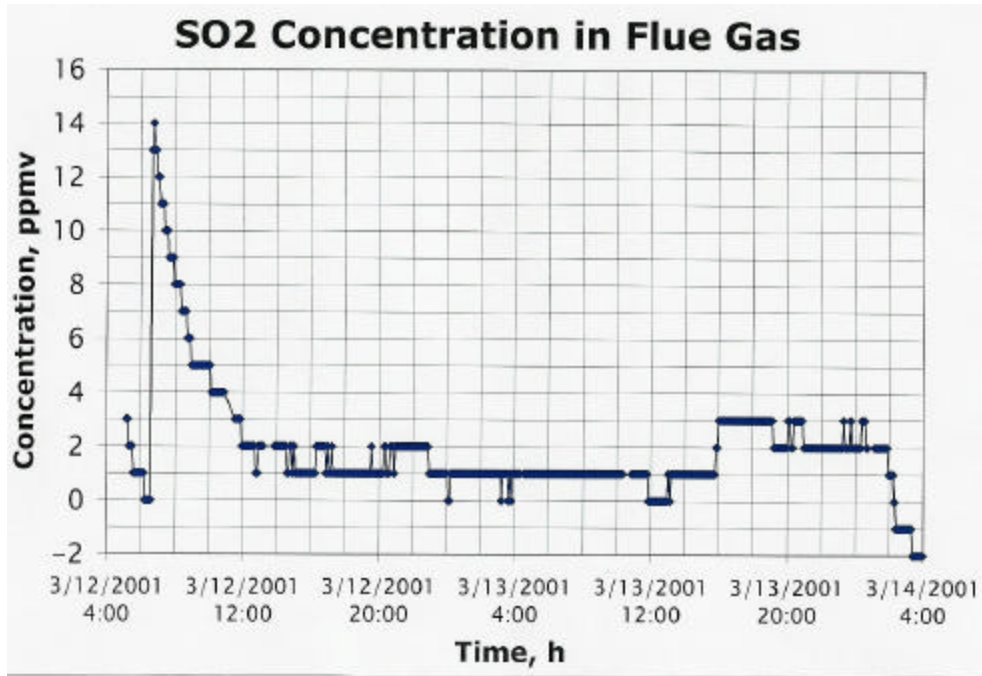
SERIES 3



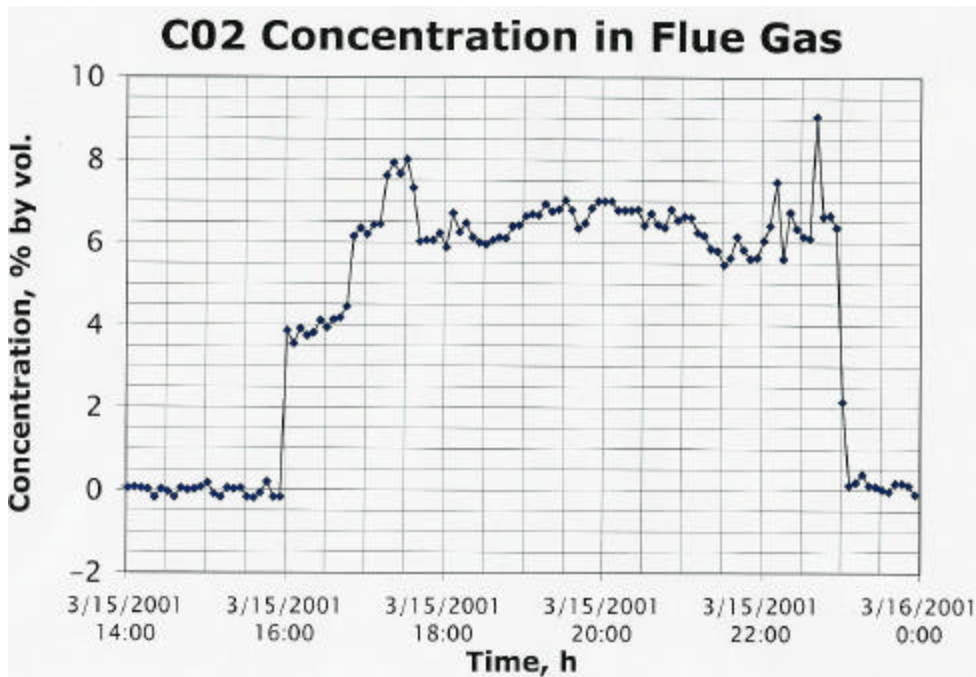
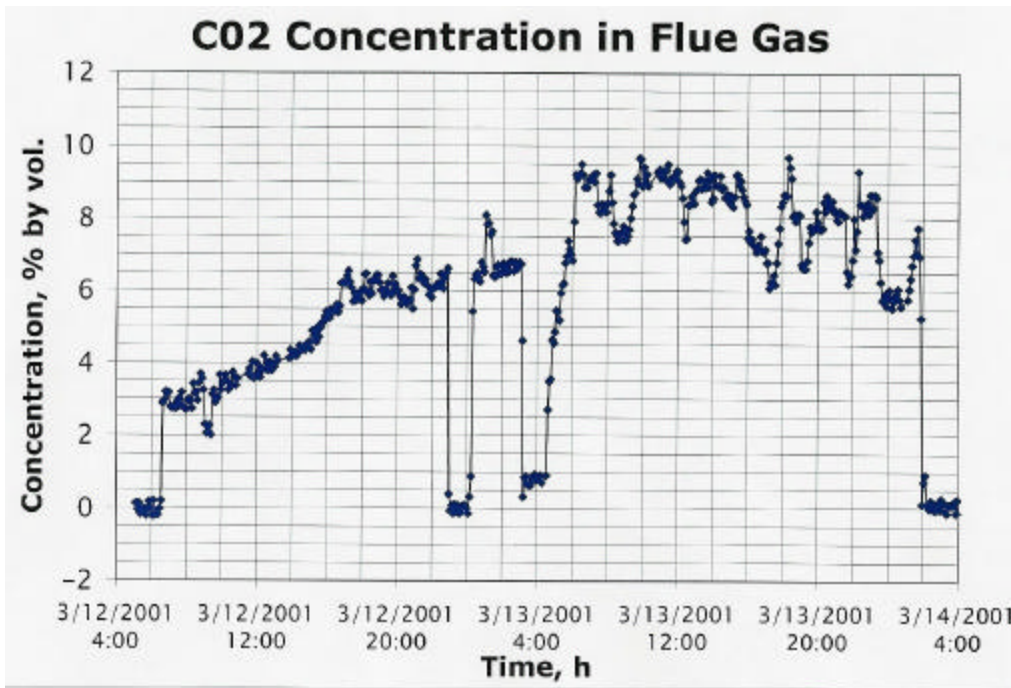
SERIES 3



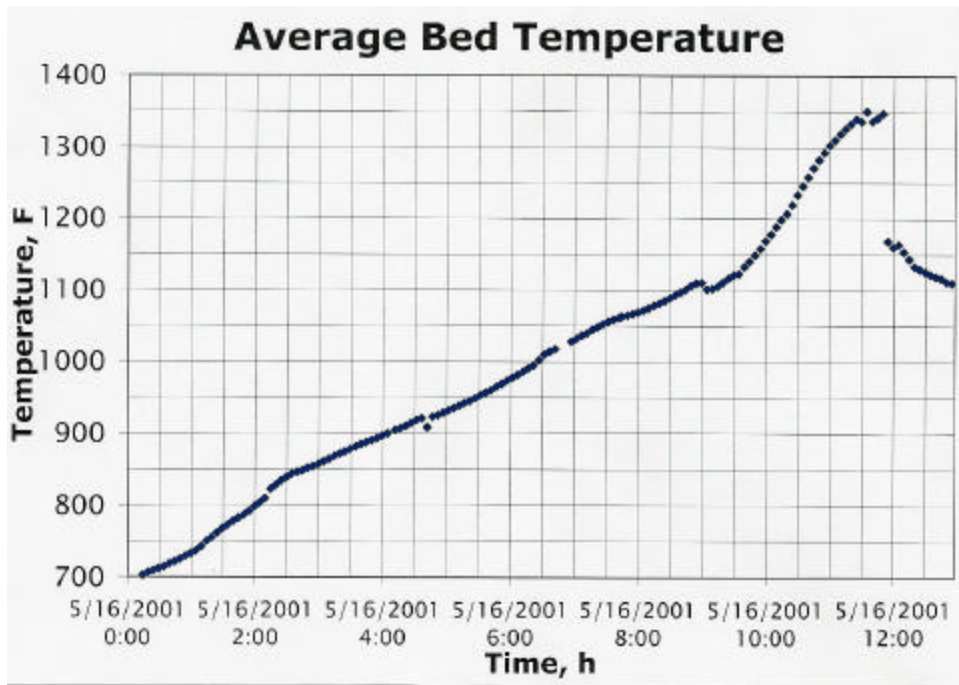
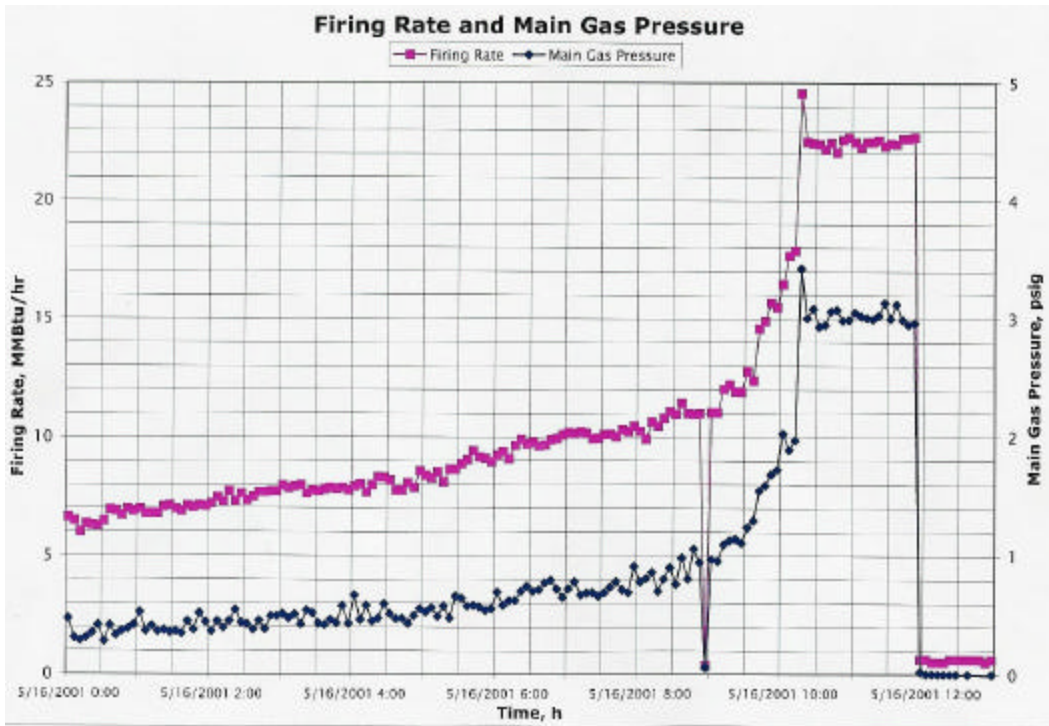
SERIES 3



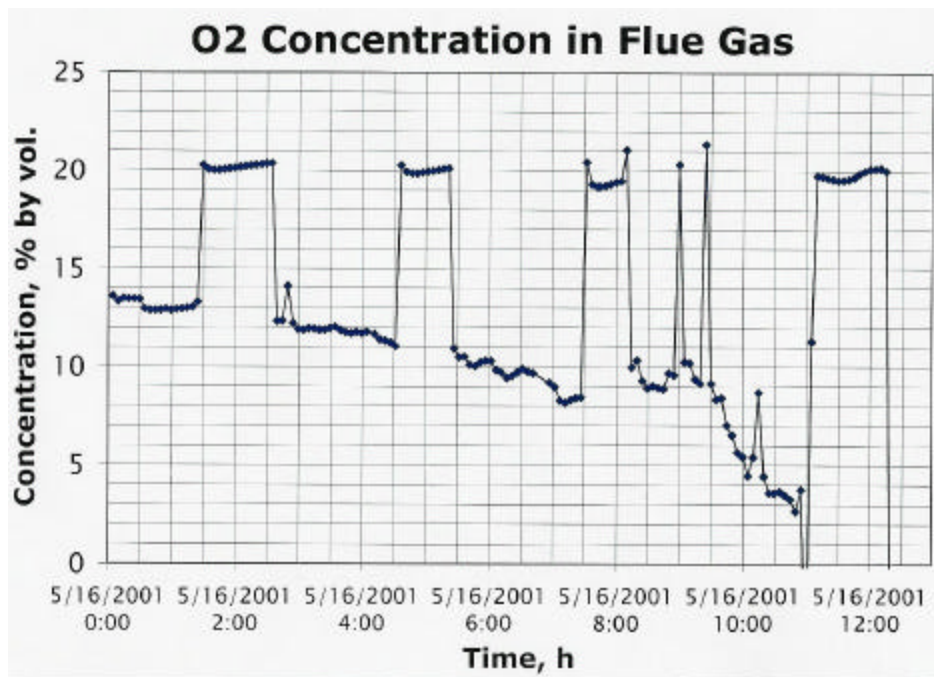
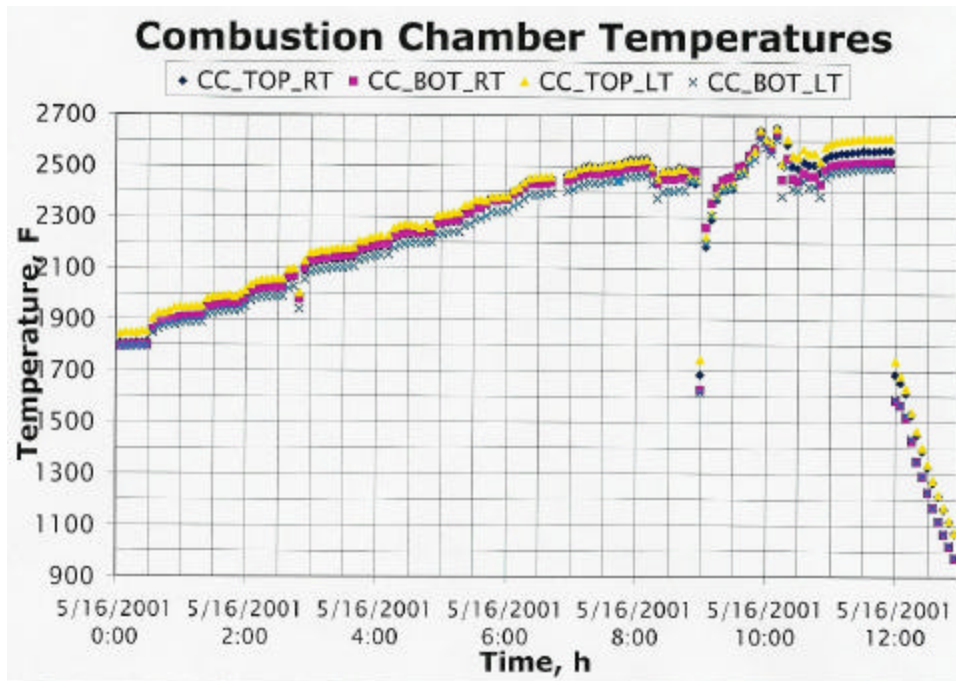
SERIES 3



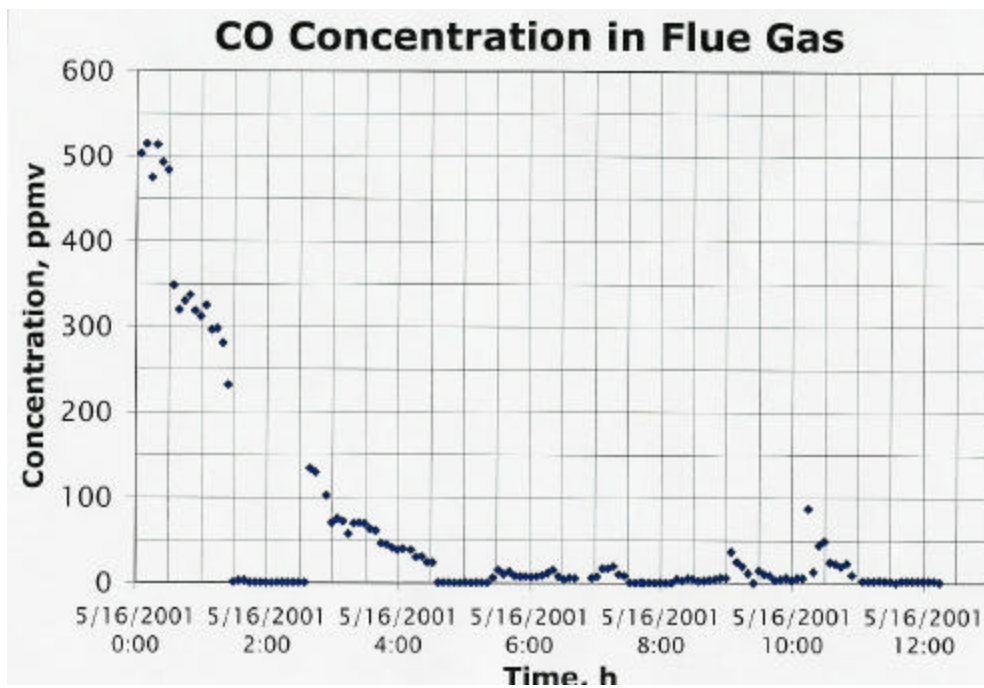
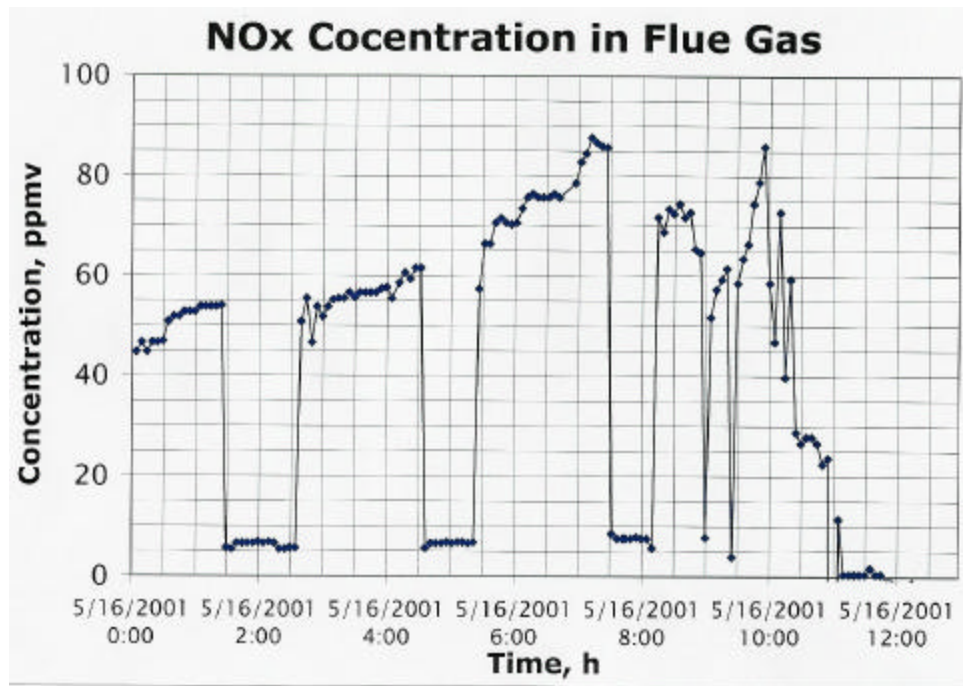
SERIES 4



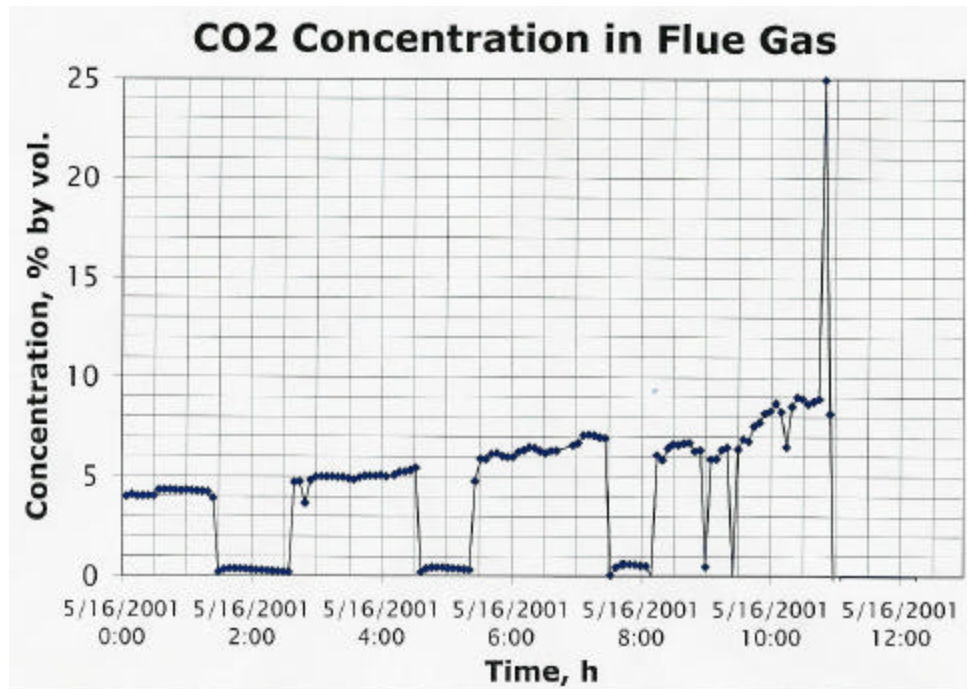
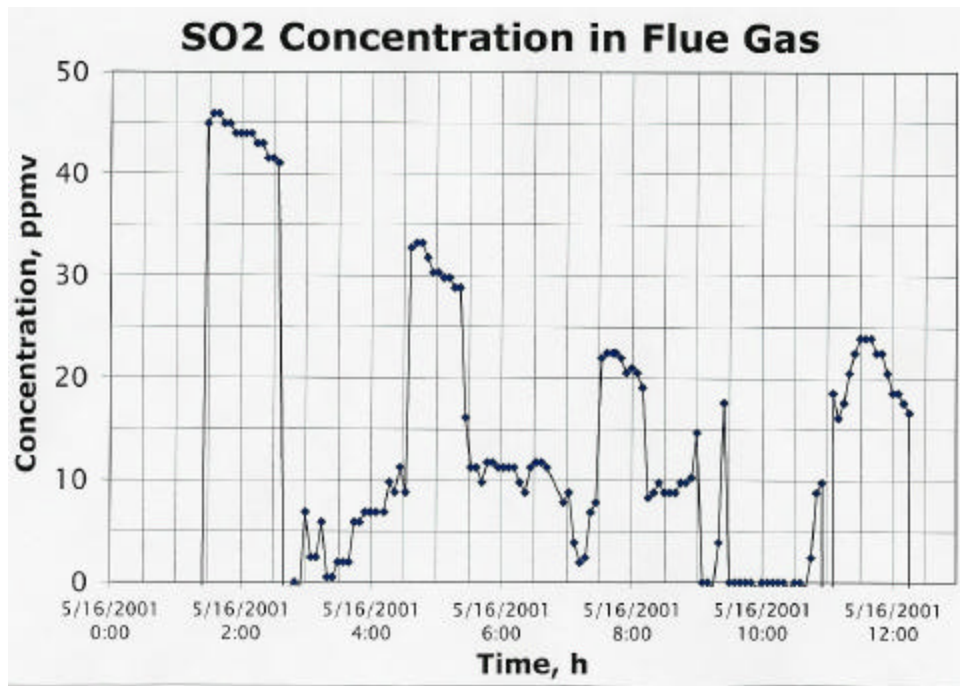
SERIES 4



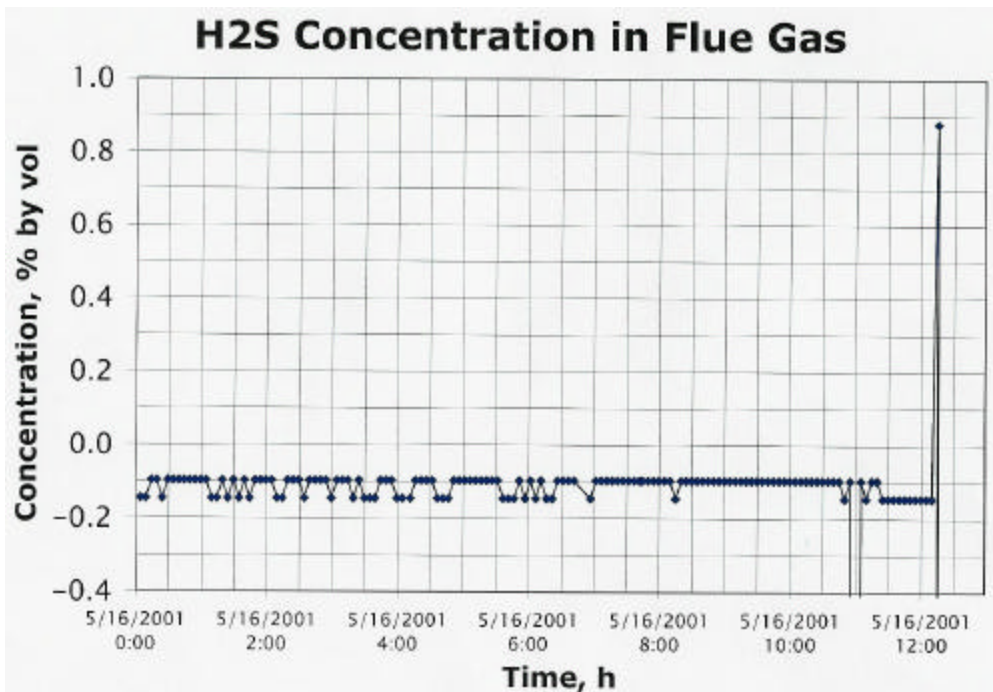
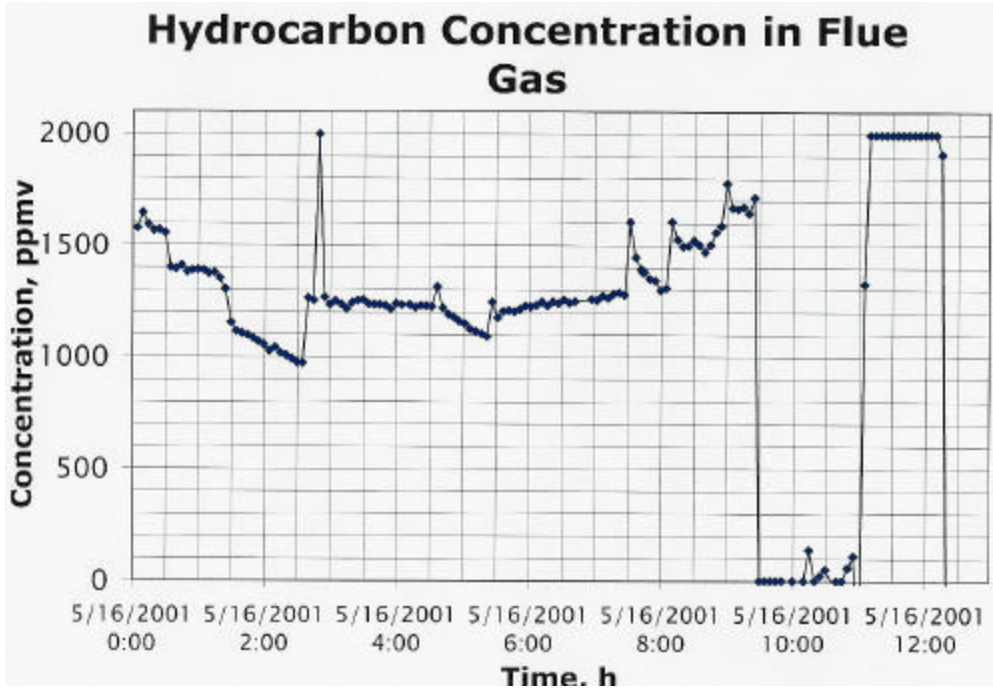
SERIES 4



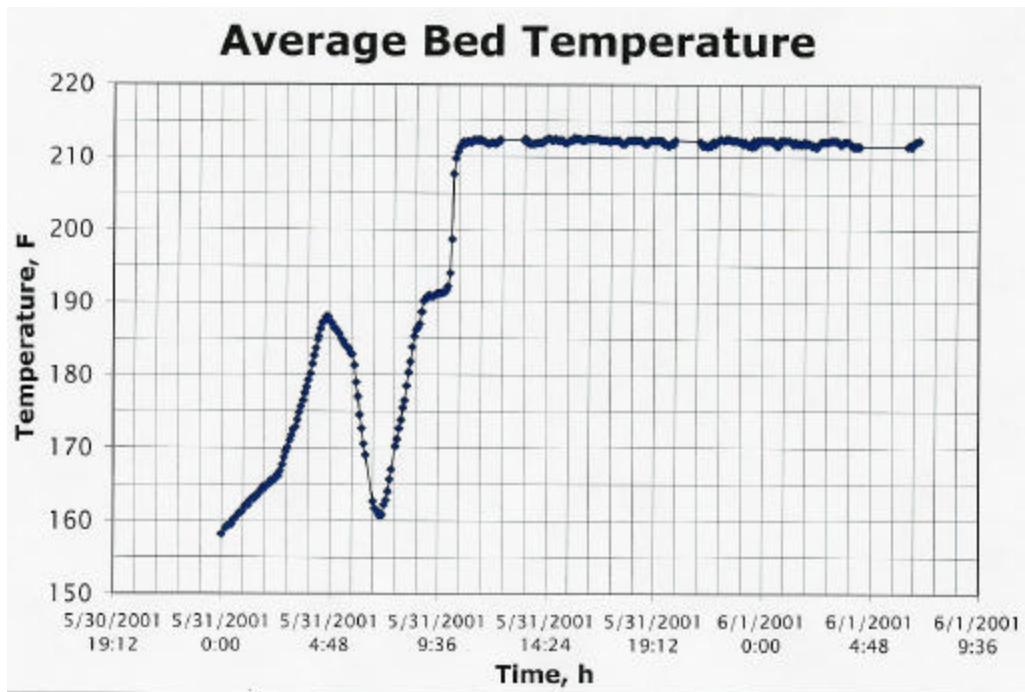
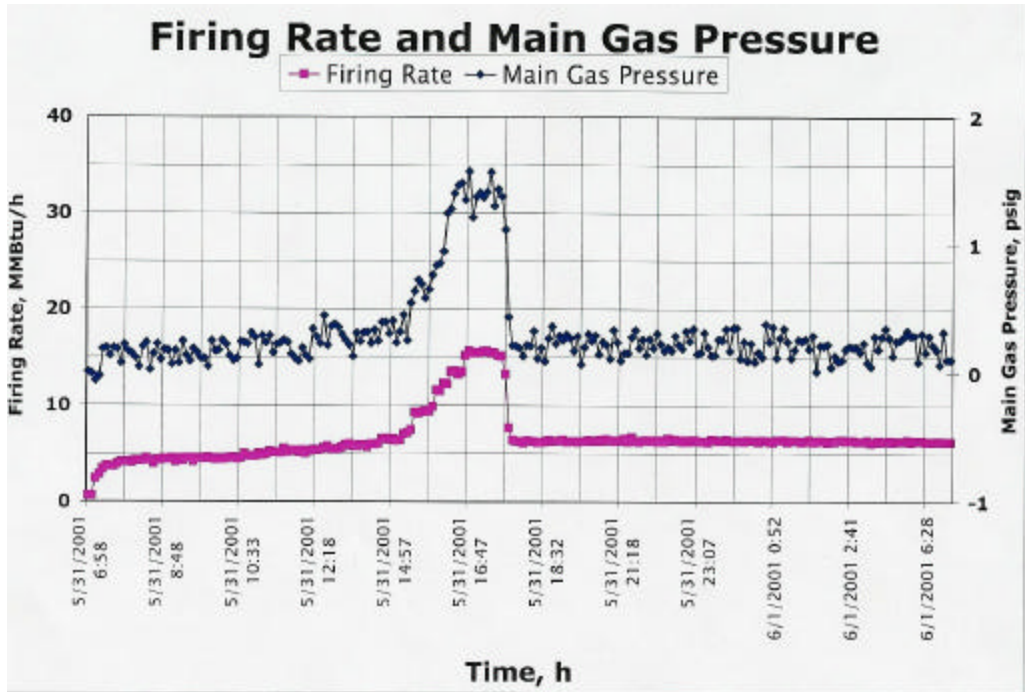
SERIES 4



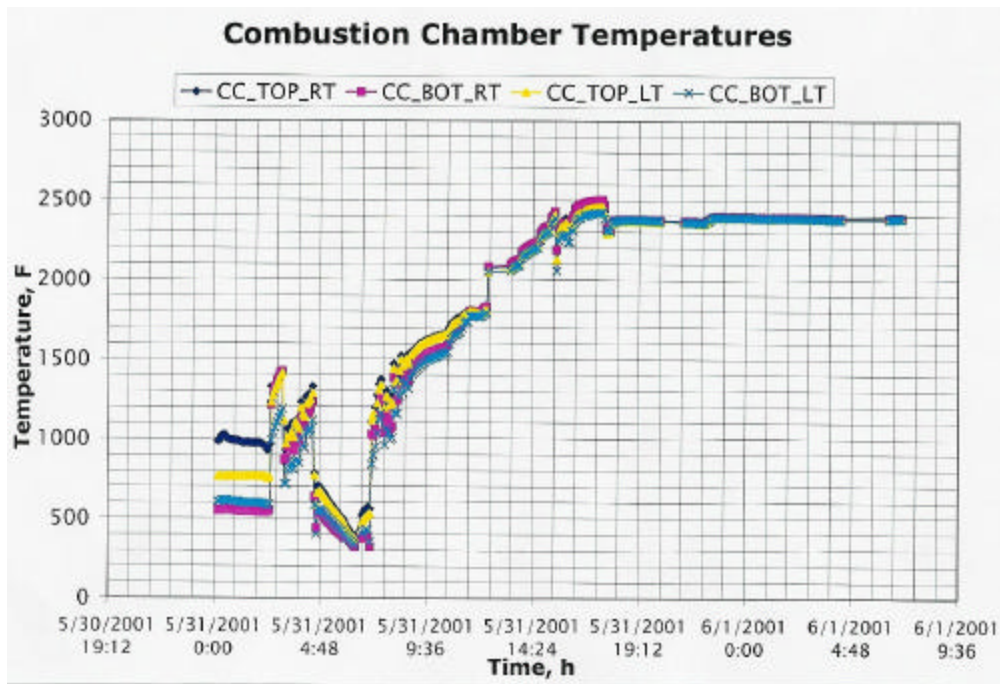
SERIES 4



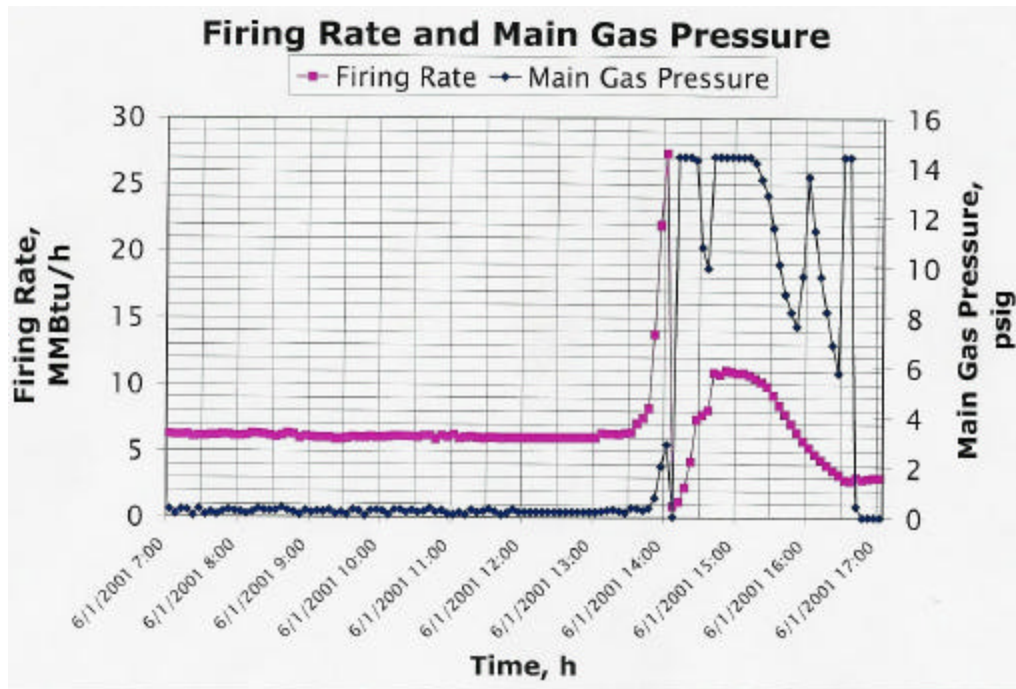
SERIES 5



SERIES 5



SERIES 6



SERIES 6

