

US EPA ARCHIVE DOCUMENT

Test and Quality Assurance Plan

Electric Power and Heat Generation Using
the UTC PC25 Fuel Cell Power Plant and
Anaerobic Digester Gas

Prepared by:



**Greenhouse Gas Technology Center
Southern Research Institute**



Under a Cooperative Agreement With
U.S. Environmental Protection Agency

and



Under Agreement With
New York State Energy Research and Development Authority



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Greenhouse Gas Technology Center

A U.S. EPA Sponsored Environmental Technology Verification (ETV) Organization



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This Test and Quality Assurance Plan has been reviewed and approved by the Greenhouse Gas Technology Center Project Manager and Director, the U.S. EPA APPCD Project Officer, and the U.S. EPA APPCD Quality Assurance Manager.

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TABLE OF CONTENTS

	<u>Page</u>
Appendices	iii
List of Figures	iii
List of Tables	iii
Distribution List.....	vii
Acronyms/Abbreviations	iv
1.0 INTRODUCTION	1-1
1.1 BACKGROUND	1-1
1.2 PC25 FUEL CELL TECHNOLOGY DESCRIPTION.....	1-2
1.3 RED HOOK WPCP DESCRIPTION AND SYSTEM INTEGRATION.....	1-5
1.4 PERFORMANCE VERIFICATION PARAMETERS.....	1-6
1.4.1 Heat and Power Production Performance	1-8
1.4.2 Power Quality Performance	1-8
1.4.3 Air Pollutant Emission Performance.....	1-9
1.4.4 Emission Reductions.....	1-9
1.4.5 GPU Gas Conditioning Performance.....	1-10
1.5 ORGANIZATION	1-10
1.6 SCHEDULE.....	1-12
2.0 VERIFICATION APPROACH.....	2-1
2.1 OVERVIEW	2-1
2.2 HEAT AND POWER PRODUCTION PERFORMANCE	2-4
2.2.1 Electrical Power Output and Efficiency.....	2-4
2.2.2 Heat Recovery Rate and Thermal Efficiency Determination.....	2-6
2.2.3 Measurement Instruments.....	2-7
2.2.3.1 Power Output Measurements	2-7
2.2.3.2 Heat Recovery Rate Measurements.....	2-8
2.2.3.3 Fuel Gas Meter.....	2-9
2.2.3.4 Gas Temperature and Pressure Measurements.....	2-9
2.2.3.5 Gas Composition and Heating Value Analysis	2-10
2.2.3.6 Ambient Conditions Measurements	2-10
2.3 POWER QUALITY PERFORMANCE	2-11
2.3.1 Electrical Frequency	2-12
2.3.2 Generator Line Voltage.....	2-12
2.3.3 Voltage Total Harmonic Distortion	2-12
2.3.4 Current Total Harmonic Distortion.....	2-13
2.3.5 Power Factor	2-14
2.3.6 Power Quality Measurement Instruments.....	2-14
2.4 PC25 EMISSIONS.....	2-14
2.4.1 Reference Method Modifications.....	2-16
2.4.2 Gaseous Sample Conditioning and Handling	2-18
2.4.3 Gaseous Pollutant Analytical Procedures	2-18
2.4.4 Determination of Emission Rates.....	2-19
2.5 ELECTRICITY OFFSETS AND ESTIMATION OF ANNUAL EMISSION REDUCTIONS	2-21
2.6 GPU PERFORMANCE	2-25
2.6.1 Determination of Raw and Processed ADG Composition.....	2-25
2.6.3 Determination of Raw and Processed ADG Moisture Content.....	2-26

3.0 DATA QUALITY 3-1

3.1 BACKGROUND 3-1

3.2 ELECTRICAL POWER OUTPUT AND POWER QUALITY 3-2

3.3 HEAT RECOVERY RATE 3-6

3.4 ELECTRICAL, THERMAL, AND CHP EFFICIENCY 3-6

3.4.1 ADG and Fuel Flow Rate Quality Assurance 3-7

3.4.2 Gas Pressure and Barometric Pressure Quality Assurance 3-8

3.4.3 Gas Temperature and Ambient Temperature Quality Assurance 3-8

3.4.4 ADG Analyses Quality Assurance 3-8

3.5 EMISSIONS TESTING QA/QC PROCEDURES 3-8

3.5.1 Analyzer and Sampling System QA/QC Procedures 3-11

3.6 GPU PERFORMANCE GAS ANALYSES 3-14

3.6.1 ADG VOCs (Method TO-15) 3-14

3.6.2 ADG Sulfur Compounds (ASTM 5504) 3-14

3.6.3 ADG Moisture Content 3-15

3.7 INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE 3-15

3.8 INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES 3-15

4.0 DATA ACQUISITION, VALIDATION, AND REPORTING 4-1

4.1 DATA ACQUISITION AND STORAGE 4-1

4.1.1 Continuous Measurements Data Acquisition 4-1

4.1.2 Emission Measurements 4-4

4.1.3 ADG Sampling 4-4

4.2 DATA REVIEW, VALIDATION, AND VERIFICATION 4-4

4.3 RECONCILIATION OF DATA QUALITY OBJECTIVES 4-5

4.4 ASSESSMENTS AND RESPONSE ACTIONS 4-5

4.4.1 Project Reviews 4-6

4.4.2 Performance Evaluation Audit 4-6

4.4.3 Technical Systems Audit 4-6

4.4.4 Audit of Data Quality 4-7

4.5 DOCUMENTATION AND REPORTS 4-7

4.5.1 Field Test Documentation 4-7

4.5.2 QC Documentation 4-7

4.5.3 Corrective Action and Assessment Reports 4-8

4.5.4 Verification Report and Verification Statement 4-8

4.6 TRAINING AND QUALIFICATIONS 4-9

4.7 HEALTH AND SAFETY REQUIREMENTS 4-9

5.0 REFERENCES 5-1

APPENDICES

	<u>Page</u>
APPENDIX A	Test Procedures and Field Log Forms A-1
APPENDIX B	Quality Assurance/Quality Control Checks and Log Forms..... B-1
APPENDIX C	Emissions Estimates for the Utility Grid C-1
APPENDIX D	ADG Target Analytes D-1

LIST OF FIGURES

	<u>Page</u>
Figure 1-1	PC25 System Schematic 1-3
Figure 1-2	PC25 Integration For Red Hook WPCP..... 1-6
Figure 1-3	Project Organization 1-10
Figure 2-1	Fuel Cell System Sampling and Measurement Schematic..... 2-3
Figure 2-2	Exhaust Gas Sampling and Analysis System 2-17
Figure 4-1	DAS Schematic..... 4-2

LIST OF TABLES

	<u>Page</u>
Table 1-1	Verification Test Matrix..... 1-7
Table 2-1	PTC-50 Maximum Permissible Variations in Test Operating Conditions..... 2-4
Table 2-2	Summary of Emission Testing Methods 2-15
Table 2-3	Modifications to Reference Method Specifications 2-17
Table 2-4	Electrical Demand of the Red Hook WPCP 2-22
Table 2-5	Displaced Emission Rates for the NY ISO 2-23
Table 3-1	Verification Parameter DQOs 3-1
Table 3-2	Measurement Instrument Specifications and DQI Goals For Heat and Power Production..... 3-3
Table 3-3	Summary of QA/QC Checks For Heat and Power Production 3-5
Table 3-4	Electrical Efficiency Error Propagation and DQO..... 3-7
Table 3-5	Instrument Specifications and DQI Goals for Emissions Testing..... 3-10
Table 3-6	Summary of Emissions Testing Calibrations and QC Checks 3-11
Table 3-7	Summary of ADG VOCs QA/QC Checks 3-14
Table 3-8	Summary of Sulfur Compounds QA/QC Checks 3-15
Table 4-1	Continuous Data to be Collected for Microturbine Evaluation..... 4-3

ACRONYMS/ABBREVIATIONS

Abs. Diff.	absolute difference
AC	alternating current
ADG	anaerobic digester gas
ADQ	Audit of Data Quality
amps	amperes
ANSI	American National Standards Institute
APPCD	Air Pollution Prevention and Control Division
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
Btu	British thermal units
Btu/hr	British thermal units per hour
Btu/lb	British thermal units per pound
Btu/min	British thermal units per minute
Btu/scf	British thermal units per standard cubic foot
C ₁	methane
C ₆₊	hexanes plus
CAR	Correction Action Report
CH ₄	methane
CHP	combined heat and power
CO	carbon monoxide
CO ₂	carbon dioxide
CT	current transformer
DAS	data acquisition system
°C	degrees Celsius
°F	degrees Fahrenheit
°R	degrees Rankine
DG	distributed generation
DMM	digital multimeter
DOE	U.S. Department of Energy
DP	differential pressure
DQI	data quality indicator
DQO	data quality objective
dscf/MMBtu	dry standard cubic feet per million British thermal units
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ETV	Environmental Technology Verification
FERC	Federal Energy Regulatory Commission
FID	flame ionization detector
fps	feet per second
ft ³	cubic feet
gal	U.S. Imperial gallons
GC	gas chromatograph
GHG Center	Greenhouse Gas Technology Center
gal/min	gallons per minute
GPU	gas processing unit
GU	generating unit

ACRONYMS/ABBREVIATIONS

(continued)

Hp	Horsepower
hr	hour
HRSG	heat recovery steam generator
Hz	hertz
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organization, or Independent System Operator
kVA	kilovolt-ampere
kVAr	kilovolt reactive
kW	kilowatt
kWh	kilowatt hour
kWh/yr	kilowatt hour per year
lb	pound
lb/Btu	pounds per British thermal unit
lb/dscf	pounds per dry standard cubic foot
lb/ft ³	pounds per cubic foot
lb/hr	pounds per hour
lb/kWh	pounds per kilowatt-hour
lb/yr	pounds per year
LHV	lower heating value
liters per minute	lpm
Mlb/yr	thousand pounds per year
MMBtu/hr	million British thermal units per hour
MMcf	million cubic feet
mol	molecular
N ₂	nitrogen
NDIR	nondispersive infrared
NIST	National Institute of Standards and Technology
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
O ₂	oxygen
ODBC	open database connectivity
ORD	Office of Research and Development
PAFC	phosphoric acid fuel cells
PEA	Performance Evaluation Audit
PEM	Proton Exchange Membrane
ppbv	parts per billion volume
ppmv	parts per million volume
ppmvd	parts per million volume dry
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PT	potential transformer
PTC	performance test code
QA/QC	Quality Assurance/Quality Control

ACRONYMS/ABBREVIATIONS
(continued)

QMP	Quality Management Plan
Rel. Diff. Report	relative difference Environmental Technology Verification Report
RH	relative humidity
rms	root mean square
RTD	resistance temperature detector
scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
T&D	transmission and distribution
Test Plan	Test and Quality Assurance Plan
THCs	total hydrocarbons
THD	total harmonic distortion
TSA	technical systems audit
U.S.	United States
UTC	United Technologies Corporation
VAC	volts alternating current
WRI	World Resources Institute
WPCP	Water Pollution Control Plant

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1.0 INTRODUCTION

1.1 BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of the ETV program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. Congress funds ETV in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permittees in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The Greenhouse Gas Technology Center (GHG Center) is one of six verification organizations operating under the ETV program. The GHG Center is managed by EPA's partner verification organization, Southern Research Institute (Southern), which conducts verification testing of promising GHG mitigation and monitoring technologies. The GHG Center's verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, obtaining independent peer-review input, and reporting findings. Performance evaluations are conducted according to externally reviewed verification Test and Quality Assurance Plans (Test Plans) and established protocols for quality assurance (QA).

The GHG Center is guided by volunteer groups of stakeholders. These stakeholders offer advice on specific technologies most appropriate for testing, help disseminate results, and review Test Plans and Technology Verification Reports. The GHG Center's Executive Stakeholder Group consists of national and international experts in the areas of climate science and environmental policy, technology, and regulation. It also includes industry trade organizations, environmental technology finance groups, governmental organizations, and other interested groups. The GHG Center's activities are also guided by industry-specific stakeholders who provide guidance on the verification testing strategy related to their area of expertise and who peer-review key documents prepared by the GHG Center.

A technology area of interest to some GHG Center stakeholders is distributed electrical power generation (DG), particularly with combined heat and power (CHP) capability. DG refers to electricity generation equipment, typically ranging in size from 5 to 1,000 kilowatts (kW), that provides electric power at a customer's site (as opposed to central station generation). A DG unit can be connected directly to the customer and/or to a utility's transmission and distribution (T&D) system. Examples of technologies available for DG include gas turbine generators, internal combustion engine generators (gas, diesel, other), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: standby generation (i.e., emergency backup power), peak shaving generation (during high-demand periods), base-load generation (constant generation), and CHP generation. An added environmental benefit of some DG technologies is the ability to fuel these systems with renewable energy sources such as anaerobic digester gas (ADG) or landfill gas. These gases, when released to atmosphere, contribute millions of tons of methane emissions annually in the U.S. Cost-effective technologies are available that can stem this emission growth by recovering methane and using it as an energy source.

The GHG Center and the New York State Energy Research and Development Authority (NYSERDA) have agreed to collaborate and share the cost of verifying several new DG technologies located throughout the State of New York. One such technology is the PC25 Fuel Cell Power Plant (PC25) offered by United Technologies Corporation (UTC) Fuel Cells. The PC25 is a phosphoric acid fuel cell capable of producing nominal 200 kW of electrical power with the potential to produce an additional 205 kW of heat. The PC25 selected for this verification is fueled by ADG produced at a water pollution control plant (WPCP). The PC25 verified here includes a gas processing unit (GPU) that treats the ADG prior to use as a fuel. Under a partnership between NYSERDA, New York Power Authority (NYPA), and others, a total of eight fully interconnected PC25 systems will be installed at four WPCPs in Brooklyn, New York. Each system will be fueled with ADG generated from anaerobic digestion of sewage sludge. The PC25 system selected for this verification is located at the Red Hook WPCP operated by the New York City Department of Environmental Protection.

Field tests will be performed on the PC25 to independently verify the electricity generation rate, heat recovery rate, energy efficiency, electrical power quality, conventional and criteria air pollutant emissions, and GHG emission reductions from offsetting CHP generation and the practice of venting or flaring ADG. Performance of the associated GPU will also be evaluated. This document is the Test Plan for performance verification of the PC25 and the GPU. It contains the rationale for the selection of verification parameters, the verification approach, data quality objectives (DQOs), and Quality Assurance/Quality Control procedures (QA/QC). The Plan will guide implementation of the test, creation of the Verification Report and other documentation, and data analysis.

This Test Plan has been reviewed by NYSERDA, NYPA, UTC Fuel Cells, the EPA QA team, and selected members of the Center's Advanced Energy Stakeholder group. Once approved, as evidenced by the signature sheet at the front of this document, it will meet the requirements of the GHG Center's Quality Management Plan (QMP) and thereby satisfy the ETV QMP requirements. The final Test Plan will be posted on the Web sites maintained by the GHG Center (www.sri-rtp.com) and the ETV program (www.epa.gov/etv).

Upon field-test completion, the GHG Center will prepare separate Verification Reports and Verification Statements for the PC25 and the GPU. The Verification Reports and Statements will be reviewed by the same organizations listed above, followed by EPA-ORD technical review. The GHG Center Director and EPA-ORD Laboratory Director will sign the Verification Statements when this review is complete, and the final documents will be posted on the GHG Center and ETV program Web sites.

The following section provides a description of the PC25 and the Red Hook WPCP test site. This is followed by a list of performance verification parameters that will be quantified through independent testing at the site. The section concludes with a discussion of key organizations participating in this verification, their roles, and the verification test schedule. Section 2.0 describes the technical approach for verifying each parameter, including sampling and analytical procedures. Section 3.0 identifies the data quality assessment criteria for critical measurements and states the accuracy, precision, and completeness goals for each measurement. Section 4.0 discusses data acquisition, validation, reporting, and auditing procedures.

1.2 PC25 FUEL CELL TECHNOLOGY DESCRIPTION

The PC25 fuel cell generates electricity through an electrochemical process in which the energy stored in a fuel is converted into direct current (DC) electricity. The unit has a rated generating capacity of nominal 200 kW at 480 volts. Electrical efficiency of the PC25 averages 35 to 40 percent, but total system efficiency can rise to about 80 percent if the waste heat is reused in a cogeneration system. Figure

1-1 provides a simple schematic of the PC25 system and its three major components including: (1) the GPU, (2) the power module, and (3) the cooling module.

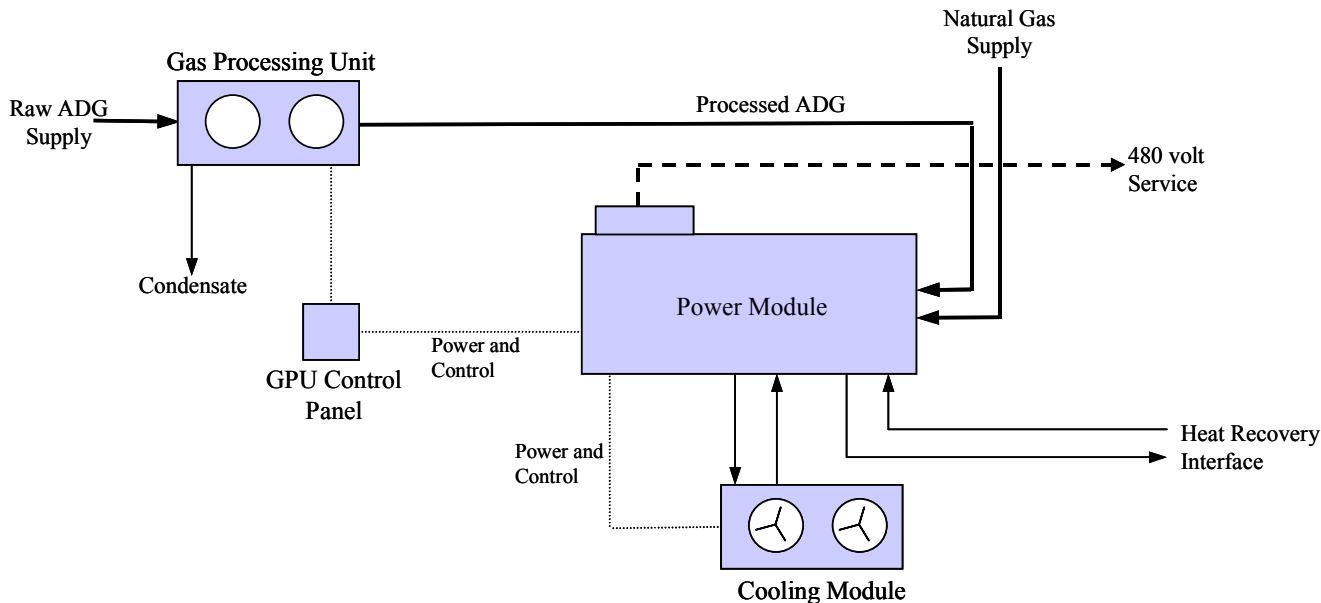


Figure 1-1. PC25 System Schematic

Gas Processing Unit

Prior to use as a fuel, the raw ADG is processed using an integrated GPU. The GPU used here is manufactured by US Filters and specifically designed for integration with the PC25. The GPU is electrically integrated with the PC25 such that the fuel cell provides power and startup/shutdown control to the GPU. The GPU includes a variable speed gas blower that is used to pressurize low pressure ADG fuel supply as needed to overcome GPU pressure drop. PC25 fuel pressure sensors and electronics are used to control GPU blower speed. The GPU is designed primarily to remove water and hydrogen sulfide (H₂S) from the ADG as the presence of either is damaging to the PC25. The GPU will also remove other potentially harmful ADG components such as other sulfur species and hydrocarbons.

The GPU consists of three major components including a coalescing filter, activated carbon beds, and the blower. The coalescing filter removes water vapor and entrained particulates from the raw gas. The GPU is equipped with liquid traps to remove condensed water from the fuel supply line. Collected and condensed water is piped back into the waste water treatment system at the plant.

The dry ADG is then directed to two 1,200 lb carbon beds in series to capture H₂S and other harmful contaminants. Each bed is designed to operate for approximately six months with ADG containing up to 200 ppm H₂S. The system is configured with the capability to operate using a single bed when a bed needs to be changed out. Periodic monitoring of the H₂S levels in the raw and processed ADG is conducted manually by system operators. Additionally, periodic sampling of the carbon beds is conducted to evaluate the condition of the carbon.

Power Module

The PC25 Power Module consists of three components system including: (1) the fuel processor, (2) the fuel cell stack, and (3) the power conditioner. A reformed fuel (reformate) rich in H₂ is derived from the processed ADG in the reformer. The PC25 uses catalytic steam reforming (CSR). The CSR reforming process yields the highest H₂ per unit of fuel, boosting fuel quality and fuel cell efficiency. This occurs because all of the O₂ needed to oxidize the carbon compounds is provided by steam, which also contributes to the H₂ content of the reformate. The reformed fuel is then directed to the fuel cell stack.

The fuel cell stack uses an electrolyte (phosphoric acid (H₃PO₄)) which can approach 100% concentration. The electrodes are made of carbon paper coated with a finely dispersed platinum catalyst. The catalyst strips electrons off the hydrogen-rich fuel at the anode. Positively charged hydrogen ions then migrate through the electrolyte from the anode to the cathode. Electrons generated at the anode cannot pass through this electrolyte and they travel through an external circuit, providing DC power, and return to the cathode. The electrons, hydrogen ions, and oxygen form water, which is discharged from the cell. A platinum catalyst at the electrodes speeds the reactions. Individual fuel cells can be combined into a fuel cell "stack". The number of fuel cells in the stack determines the total voltage. This set of reactions in the fuel cell produces electricity and by-product heat. The reactions are:



The ionic conductivity of phosphoric acid is low at low temperatures, so phosphoric acid fuel cells (PAFCs) are operated at the upper end of the range 150 °C–220 °C (about 300 to 400 °F). This is above the boiling point of water. (This is one reason why phosphoric acid is preferred although it is a less-efficient conductor of electricity than other acidic electrolytes. Acid electrolytes that require water for conductivity do not have this capability.)

The formation of carbon monoxide (CO) around electrodes can "poison" a fuel cell. One advantage of PAFC cells is that at 200°C they tolerate a CO concentration of about 1.5 percent. Another advantage is that concentrated phosphoric acid electrolyte can operate above the boiling point of water, a limitation on other acid electrolytes that require water for conductivity. The acid requires, however, that other components in the cell resist corrosion.

The cell can use ordinary air directly as an oxidizing agent and can operate with impure hydrogen produced by reforming other fuels. The CO₂ formed as a byproduct of the reform process passes through the cell without affecting its performance. The reducing reactions of oxygen and oxidation of hydrogen operate most efficiently when platinum is used as a catalyst, dispersed in carbon powder containing added polytetrafluoroethylene (PTFE). After the fuel cell stack, the spent reformed fuel and water are emitted to atmosphere.

In the power conditioner, the DC electricity produced by the fuel cell stack is converted to AC power using an inverter. Finally, the system is equipped with a cooling module to reject heat generated by the PC25 that is not used for cogeneration. The cooled water (cooled either by the cooling module or a heat recovery interface) is circulated through the power module.

1.3 RED HOOK WPCP DESCRIPTION AND SYSTEM INTEGRATION

The Red Hook WPCP is a 60-million gallons per day (MGD) secondary wastewater treatment facility located at 63 Flushing Avenue in Brooklyn, New York. Two PC25 fuel cell systems were installed at the Red Hook WPCP in May of 2003 to provide on-site generation of power and hot water. One of the PC25 systems will be selected for this verification test.

The Red Hook facility currently purchases power from the local utility (Consolidated Edison (ConEd)) to meet its entire electrical demand. Facility heat demand for process heat, space heating, and hot water production varies by season, but averages around 11.0 MMBtu/hr in winter months and 7.20 MMBtu/hr in summer months. Heat demand is met under normal site operations using low-pressure steam supplied by an adjacent cogeneration facility. The cogeneration facility (owned and operated by Cogeneration Technologies, Inc.) is a 286 MW combined-cycle gas-fired turbine and steam turbine equipped with a heat recovery steam generator (HRSG) capable of producing 800,000 lb/hr steam. A small fraction of the steam produced at the facility is directed to the Red Hook WPCP to meet the process heat, space heating, and hot water production demands. Total annual steam flow to the Red Hook site has averaged approximately 54,400 Mlb/yr during the past three years, representing less than one percent of the cogeneration facility's steam generation capacity.

The Red Hook WPCP also has three gas- or oil-fired boilers that can meet the plant's heat demand should the cogeneration facility not provide steam to the site. The boilers are identical York-Shipley Series 576 Steam Pak Boilers. Each 350 horsepower (Hp) unit has a rated heat input of 14.7 MMBtu/hr and a heat output rate of 11.7 MMBtu/hr. Steam output is rated at 12,075 lb/hr. The boilers are rarely needed at the facility because steam availability from the cogeneration facility is greater than 98 percent.

Figure 1-2 provides a simplified schematic of fuel cell integration at the Red Hook site. The two PC25 systems will provide a total of 400 kW of power to offset power purchased from ConEd. The PC25 systems will also offset a small portion of the heat provided by the cogeneration facility (approximately 1.6 MMBtu/hr, or about 14 percent of the average cold weather demand).

Both fuel cells will be configured to use either natural gas or ADG produced at the site as fuel. ADG will be the primary fuel under normal site operations with natural gas used only during fuel cell startup or as a backup fuel during digester upset conditions.

The ADG is produced at the Red Hook facility using a series of anaerobic sludge digesters. The ADG is typically composed of 60 to 65 percent methane with a lower heating value (LHV) of 600 to 650 Btu/cf. Preliminary ADG composition data collected at the site indicate that methane concentrations as low as 40 percent are rare, but possible. The system is designed to switch to natural gas fuel whenever methane concentrations are less than around 50 percent. Gas production rates at the facility will also vary depending on daily plant wastewater flow rates and ambient temperatures. Peak production rates during the summer months can approach 750 cubic feet per minute. All ADG is combusted in a single enclosed flare during current and normal site operations. The flare is a Whessoe-Varic Model WV 249-15-4-24-6 biogas ground flare which was installed in 1988. The flare is rated for a maximum biogas flow rate of 15,000 scfh and operating temperatures ranging between 1,400 and 1,600 °F. Approximately 7,000 cfh of the ADG will be diverted from the flare and used as fuel with the two PC25 fuel cells in operation. Site operators report that ADG production rates at the plant will exceed the 7,000 cfh needed to operate both fuel cells at full load at all times of normal site operations. ADG produced in excess of 7,000 cfh will be combusted in the flare.

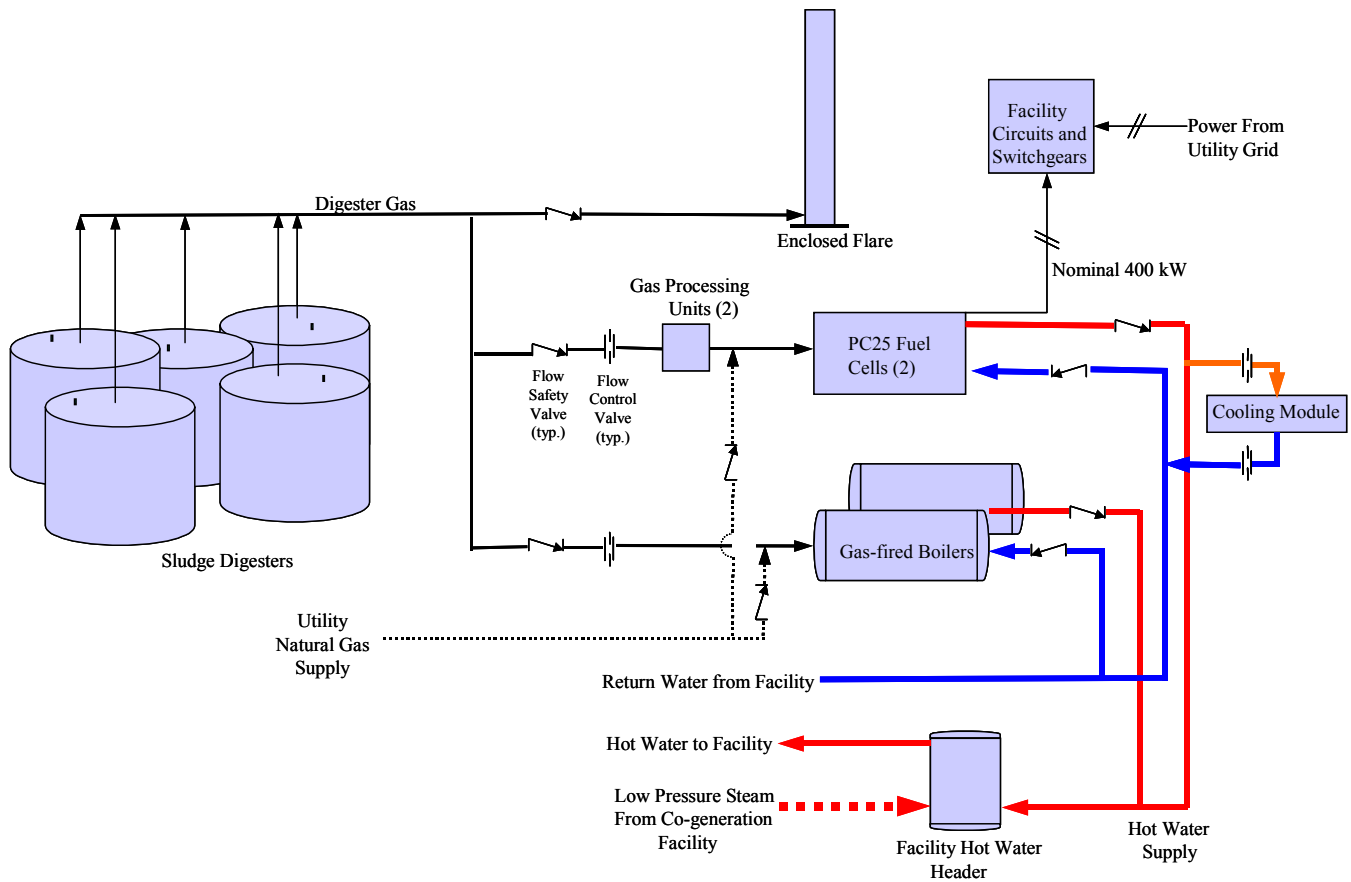


Figure 1-2. PC25 Integration Schematic for Red Hook WPCP

1.4 PERFORMANCE VERIFICATION PARAMETERS

The GHG Center’s stakeholder groups and other organizations interested in DG applications have an interest in obtaining verified field data on the emissions, technical, and operational performance of DG systems. This includes fuel cells, microturbines, engines, and CHP variants of these energy generation technologies.

Performance parameters of greatest interest include electrical power output and quality, heat recovery and production performance, thermal-to-electrical energy conversion efficiency, total energy efficiency, exhaust emissions of conventional air pollutants and GHGs, GHG emission reductions, operational availability, maintenance requirements, and economic performance. The test approach described here focuses on assessing those technical performance parameters of high interest to potential fuel cell technology customers. Long-term evaluations cannot be performed with available resources, so economic performance and maintenance requirements will not be evaluated. This verification will evaluate the technical performance of the PC25 system at the site conditions encountered during testing.

The primary objectives of this verification are to test the following PC25 performance features: (1) power and heat production performance (includes energy efficiency), (2) electrical power output quality, (3) emissions performance, and (4) GPU performance. Evaluations of emissions, power production

performance, and GPU performance will be conducted as a series of controlled test periods (load tests) at PC25 power output settings or load levels including 100, 150, and 200 kW. All testing will be conducted while using ADG as fuel. Field personnel will simultaneously monitor power output, heat recovery rate, fuel consumption, ambient meteorological conditions, ADG composition, and exhaust stack emission rates of CO₂, CH₄, NO_x, CO, and THC during each load test. Average electrical power output, heat recovery rate, electrical and thermal energy conversion efficiency, and exhaust stack concentrations and emission rates will be reported for each load condition. Test results will represent the net CHP system power output and efficiency because power output measurements will represent the net power delivered to the facility (the PC25 has internal parasitic loads such as power to operate the gas conditioning system and the water circulation pump). Table 1-1 summarizes the verification test matrix.

Table 1-1. Verification Test Matrix			
Load Testing			
Test Condition (Percent of Rated Power Output)	Fuel Cell Power Setting (kW)	No. of Replicate Test Runs Executed	Duration of Each Test Run (minutes)
100	200	3	60
75	150	3	60
50	100	3	60
Extended Monitoring at Normal Site-Operating Conditions			
Fuel Cell Power Setting (kW)	Duration of Testing		
	Total Energy Generated, Power Quality Performance Evaluation, and CHP Efficiency		
200	2 - 4 weeks		

The GHG Center will also conduct extended monitoring to evaluate electrical power quality performance and changes in electrical and thermal efficiency during normal site system operations. The PC25 will be operated 24 hours per day, fueled by ADG, at an electrical power output setting of 200 kW under normal site operating conditions. Instruments will monitor power output, heat recovery rate, heat input, and power quality parameters such as electrical frequency, voltage output, power factor, and total harmonic distortion (THD) in one-minute intervals during this extended period. Continuous logging of ambient meteorological conditions will also be performed to examine trends in power and heat production and energy efficiency as a function of ambient conditions.

The parameters to be verified are listed below, followed by a brief description of each. Section 2.0 presents detailed descriptions of measurement and analysis methods and Section 3.0 discusses data quality assessment procedures for each verification parameter.

Verification Parameters

Heat and Power Production Performance

- Electrical power output at selected loads, kW
- Heat recovery rate at selected loads, Btu/hr, kW
- Electrical efficiency at selected loads, %
- Thermal energy efficiency at selected loads, %
- Combined heat and power production efficiency at selected loads, %

Electrical Power Quality Performance

- Electrical frequency, Hz
- Voltage Output, VAC
- Power factor, %
- Voltage THD, %
- Current THD, %

Emissions Performance

- CO, NO_x, THC_s, CO₂, and CH₄ concentrations at selected loads, (ppmv), %
- CO, NO_x, THC_s, CO₂, and CH₄ emission rates at selected loads, lb/hr, lb/MMBtu, lb/kWh

Emission Reductions

- Estimated annual NO_x emission reductions, (lb NO_x), %
- Estimated annual CO₂ emission reductions, (lb CO₂), %

GPU Performance

- Composition and heating value of raw and processed ADG
- H₂S, VOC, halides, and moisture-removal efficiency, %

1.4.1 Heat and Power Production Performance

The GHG Center will evaluate CHP performance during both the load testing and the extended test periods. The GHG Center will install an electrical meter to measure the power generated. Heat input will be determined using a flow meter to measure ADG flow rates to the PC25 and by having ADG samples collected periodically to quantify ADG energy content and LHV. Fuel energy-to-electricity conversion efficiency will be determined by dividing the average electrical power output by the average heat input for each load condition.

Heat recovery rates will be verified simultaneously with power output measurements by metering the water flow rate and hot (supply) and cold (return) temperatures. Thermal energy conversion efficiency at each load will be determined by dividing the average heat recovered by the heat input. CHP production efficiency will be reported as the sum of electrical and thermal efficiencies at each operating load.

The sum of the one-minute average power output and heat recovery measurements collected over the extended testing period will represent total electrical and thermal energy generated over the period. The total energy generated over the extended period will be divided by the total heat input over the period to produce an overall average CHP energy conversion efficiency for the extended monitoring period.

Ambient temperature, relative humidity (RH), and barometric pressure will be measured throughout the verification period to document weather conditions during the test periods and to evaluate the effect of ambient temperature on CHP system performance. A detailed discussion of sampling procedures, analytical procedures, and measurement instruments related to power production performance parameters is provided in Section 2.3.

1.4.2 Power Quality Performance

Monitoring and determination of the power quality performance parameters listed earlier are required to insure compatibility with the electrical grid and to demonstrate that electricity produced by the PC25 will not interfere with or harm microelectronics and other sensitive electronic equipment within the facility.

The Institute of Electrical and Electronics Engineers (IEEE) *Master Test Guide for Electrical Measurements in Power Circuits (I)* contains standards for power quality measurements that will be followed. Power quality parameters will be determined over the extended monitoring period and under representative and normal operating conditions for the PC25. The same wattmeter used to measure electric power output will be used to measure all power quality parameters. Section 2.4 describes the sampling procedures, analytical procedures, and measurement instruments used to verify power quality parameters.

1.4.3 Air Pollutant Emission Performance

Emissions testing for CO, NO_x, THC_s, CO₂, and CH₄ will be conducted simultaneously with the efficiency determinations at each load condition. The GPU is designed to remove moisture, particulate matter, and H₂S from the ADG, so emissions of particulate matter and sulfur compounds are not quantified here. Three test runs, each lasting about 60 minutes in duration, will be replicated at each load condition. This triplicate measurement design is based on the U.S. EPA New Source Performance Standards (NSPS) guidelines for measuring emissions from stationary sources (13).

Exhaust stack emission testing procedures described in EPA's NSPS will be followed to verify pollutant concentrations and mass flow rates. Concentration measurements will be reported in units of parts per million volume, dry basis (ppmvd) and corrected to 15-percent O₂. Emission rates will be reported in units of pound per hour (lb/hour), pound per British thermal unit of heat input (lb/Btu), and pound per kilowatt-hour of energy output (lb/kWh). Section 2.5 provides a detailed discussion of sampling procedures, analytical procedures, and measurement instruments.

1.4.4 Emission Reductions

Emission reductions for CO₂ and NO_x will be estimated by subtracting emissions from the on-site PC25 fuel cell CHP system from emissions associated with baseline power and heat generation technology for the facility. It will be assumed that the on-site electrical power will reduce the need for the same amount of electricity from the local grid. Subtraction of the estimated emissions from the on-site unit from the estimated emissions associated with the mix of power stations serving the local grid will yield an estimate of the CO₂ and NO_x emission reductions. Annual estimates of emissions will be determined based on measured emission rates at full load and on-site energy demand profiles from the calendar year preceding the verification.

Additional emission reductions may occur due to the use of the ADG as fuel and elimination of the need to burn the gas in an open flare. These offsets will be based on the difference between measured emission rates from the PC25 and measured flare emissions (obtained from the most recent NO_x and CO₂ emissions testing data available for the flare at this site). Total emission reductions for the Red Hook facility will then be calculated as the emissions offsets realized through generation of on-site power and reduction in flare emissions.

Computation of estimated annual emission reductions by a CHP technology would normally also account for reduction in the natural gas consumption of boilers to on-site generation of heat. The heat supplied to the Red Hook facility in this case however, is already a product of cogeneration, so additional emissions offsets are not realized by heat production. Section 2.5 presents the procedures for estimating emission reductions.

1.4.5 GPU Gas Conditioning Performance

Testing will be conducted to evaluate GPU performance by comparing the composition and heating value of raw ADG to that of processed gas. The following gas compositional and quality criteria will be evaluated on raw and processed ADG samples:

- Gas properties (gross and net heating value, density, and compressibility)
- Gas composition (N₂, O₂, CO₂, and C₁ through C₆)
- Sulfur compounds
- Volatile Organic Compounds (VOCs) and total halides
- Moisture content

A minimum of six ADG samples will be collected on both the upstream and downstream sides of the GPU and submitted for analysis during the controlled testing periods for efficiency and emissions. Results of the analyses will be used to evaluate GPU removal efficiency for moisture, H₂S and sulfur compounds, VOCs, and halides. The results will also allow the Center to evaluate the effects, if any, on ADG composition and heating value.

1.5 ORGANIZATION

Figure 1-3 presents the project organization chart. The following section discusses functions, responsibilities, and lines of communications for the verification test participants.

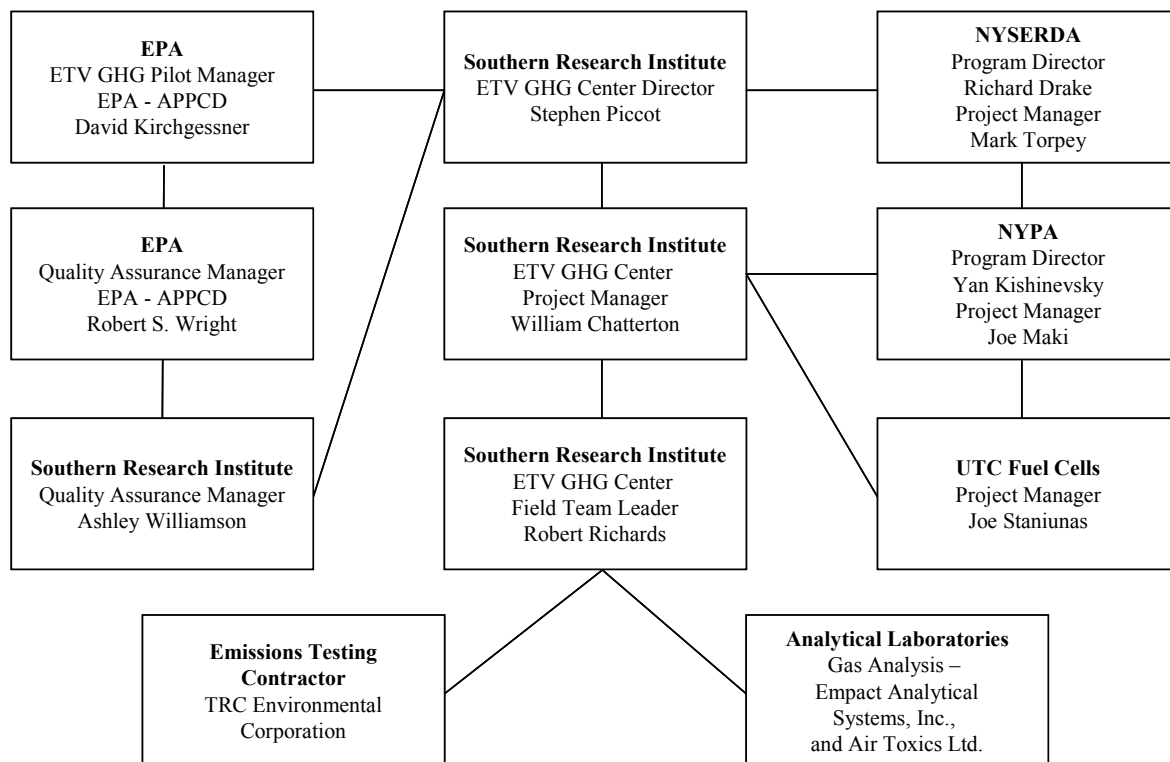


Figure 1-3. Project Organization

Southern's GHG Center has overall responsibility for planning and ensuring the successful implementation of this verification test. The GHG Center will ensure that effective coordination occurs, schedules are developed and adhered to, effective planning occurs, and high-quality independent testing and reporting occurs.

Mr. Stephen Piccot is the GHG Center Director. He will ensure that the staff and resources are available to complete this verification as defined in this Test Plan. He will ensure effective review of the Test Plan and Reports occur to ensure they are of high quality and consistent with ETV operating principles. He will oversee the activities of the GHG Center staff and provide management support where needed. Mr. Piccot will sign the Verification Statement along with the EPA-NRML Laboratory Director.

Mr. William Chatterton will serve as the Project Manager. He will be responsible for developing the Test Plan and overseeing field data collection activities of the GHG Center's Field Team Leader, including assessment of the Team Leader's accomplishment of DQOs. Mr. Chatterton will ensure the procedures outlined in Sections 2.0 and 3.0 of this Test Plan are adhered to during testing unless modification is required. He is also ultimately responsible for conformation that quality control procedures specified in this Test Plan are conducted and criteria met by field personnel and subcontractors. Modifications will be completed, explained, and justified in the Verification Report. Mr. Chatterton will have authority to suspend testing should a situation arise during testing that could affect the health or safety of any personnel. He will also have the authority to suspend testing if quality problems occur or host site or vendor problems arise. He will also be responsible for maintaining effective communications with NYSERDA, NYPA, UTC, EPA-ORD participants, Southern QA team members, and ETV document reviewers.

Mr. Robert Richards will serve as the Field Team Leader. Mr. Richards will be responsible for the effective planning, mobilization, and execution of all field-testing activities. He will install and operate measurement instruments, supervise and document testing and quality control activities conducted by the emissions testing contractor, collect gas samples and coordinate sample analysis with the laboratory, and ensure that all QA/QC procedures outlined in Section 2.0 are adhered to. He will also support Mr. Chatterton's data quality determination and report preparation activities and will submit all results to Mr. Piccot documenting the final reconciliation of DQOs. He will be responsible for ensuring that performance data collected by continuously monitored instruments and manual sampling techniques are based on procedures described in Section 4.0.

Southern's Quality Assurance Manager, Dr. Ashley Williamson, will review this Test Plan. He will also review the results from the verification test and conduct an Audit of Data Quality (ADQ), described in Section 4.4. Dr. Williamson will prepare a written report of his findings from internal audits and document reviews. These findings will be used to prepare the Verification Report.

Mr. Mark Torpey, Senior Project Manager, will serve as the primary contact person for NYSERDA. Mr. Torpey will provide technical assistance and help coordinate this test with the host site and UTC as necessary. NYSERDA's Program Manager for Transportation and Power Systems Research, Mr. Richard Drake, will direct his activities.

Mr. Joe Maki of NYPA will coordinate with Southern throughout this verification and will ensure the PC25 fuel cell is operating properly and representatively prior to the start of scheduled testing and throughout the entire testing period. He will also provide technical input and guidance on the design and operation of the fuel cell system as needed to effectively plan and complete this verification. Mr. Maki will coordinate and conduct NYPA's review of the Test Plan and Verification Report and will provide written comments on both documents to Southern.

EPA-ORD will provide oversight and QA support for this verification. The APPCD Project Officer, Dr. David Kirchgessner, is responsible for obtaining final approval of the Test Plan, Verification Report, and Verification Statement. Mr. Robert S. Wright of the APPCD QA Team will ensure review of the Test Plan and Reports occur and that approval is granted once any issues have been resolved satisfactorily.

1.6 SCHEDULE

Installation and shakedown of the PC25 system at the Red Hook WPCP is scheduled to be completed by May of 2003. Based on this, the tentative schedule of activities for this verification are outlined below.

<u>Verification Milestone</u>	<u>Scheduled Completion</u>
Verification Test Plan Development	
GHG Center Internal Draft Completed	Completed
NYSERDA, NYPA, and UTC Fuel Cells Review & Revision	Completed
EPA and Peer-Review & Revision	January 9, 2004
Final Test Plan Posted	January 23, 2004
Verification Testing and Analysis	
Measurement Instrument Installation/Shakedown	TBD
Field Testing	TBD (est. March 2004)
Data Validation and Analysis	TBD
Verification Report Development	
GHG Center Internal Draft Development	TBD
NYSERDA, Vendor, and Host Site Review/Revision	TBD
EPA and Industry Peer-Review/Revision	TBD
Final Report Posted	TBD (est. May 2004)

2.0 VERIFICATION APPROACH

2.1 OVERVIEW

Phosphoric acid fuel cell systems are the most widely used fuel cells in use today for DG purposes. The GHG Center's stakeholder groups and other organizations concerned with DG have a specific interest in verified field data on fuel cell emissions, technical performance, and operational performance. Systems with CHP capability provide additional economic and environmental benefit, and for systems with the capability to use biogas for fuel, these advantages can be profound. Fuel cell emission rates are expected to be extremely low and stakeholders are also interested in verifiable emissions test techniques.

Performance parameters of greatest interest include: electrical power output and quality; CHP performance; electrical, thermal, and total energy conversion efficiency at various loads; conventional air pollutant and GHG emissions; GPU gas conditioning performance; and potential GHG emission reductions. The test approach described here will assess these performance parameters for potential purchasers and users of the UTC PC25 fuel cell fueled with ADG.

Development of the verification strategy for this fuel cell system was based on the GHG Center adopting: (a) existing standards for fuel cell power systems; (b) previous peer-reviewed DG/CHP system evaluations; (c) U.S. EPA methods; (d) professional engineering judgment; and (e) technical input from the verification team. In considering electrical power generation, power quality, and heat production, the GHG Center acquired some concepts described directly from documents such as:

- The American Society of Mechanical Engineers (ASME) Performance Test Code for Fuel Cell Power Systems, PTC-50 (4);
- The American National Standards Institute / Institute of Electrical and Electronics Engineers IEEE Master Test Guide for Electrical Measurements in Power Circuits (1);
- The IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems (2); and
- The American National Standards Institute/American Society of Heating, Refrigeration and Air-Conditioning Engineers (ANSI/ASHRAE) Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems (3).

This verification will adopt EPA reference methods described in 40 CFR 60, Appendix A (13) for criteria pollutant and GHG emissions determinations. These generalized methods do not directly address the expected low NO_x concentrations, high moisture content, and relatively high CO₂ concentrations in the exhaust and their interactions. The GHG Center will, therefore, use specialized test methods and modifications to the reference methods where needed as described in Section 2.4. The GHG Center will conduct short-term emissions and performance testing at three operating loads and extended monitoring at normal site conditions to address the following verification parameters:

Heat and Power Production Performance (Section 2.2)

- Electrical power output at selected loads, kW
- Heat recovery rate at selected loads, Btu/hr, kW
- Electrical efficiency at selected loads, %
- Thermal efficiency at selected loads, %
- Combined heat and power production efficiency at selected loads, %

Electrical Power Quality Performance (Section 2.3)

Electrical frequency, Hz

Power factor, %

Voltage THD, %

Current THD, %

Air Pollutant Emission Performance (Section 2.4)

CH₄, CO, CO₂, NO_x, and THC concentrations at selected loads, ppmv, %

CH₄, CO, CO₂, NO_x, and THC emission rates at selected loads, lb/hr, lb/Btu, lb/kWh

Emission Reductions (Section 2.5)

Estimated annual NO_x emission reductions, lb NO_x/yr

Estimated annual GHG emission reductions, lb CO₂/yr

GPU Performance (Section 2.6)

Composition and heating value of raw and processed ADG

Removal efficiency for sulfur species, VOCs, and moisture, %

Figure 2-1 illustrates the measurement system to be used. Sections 2.2 through 2.5 provide detailed testing and analytical method descriptions.

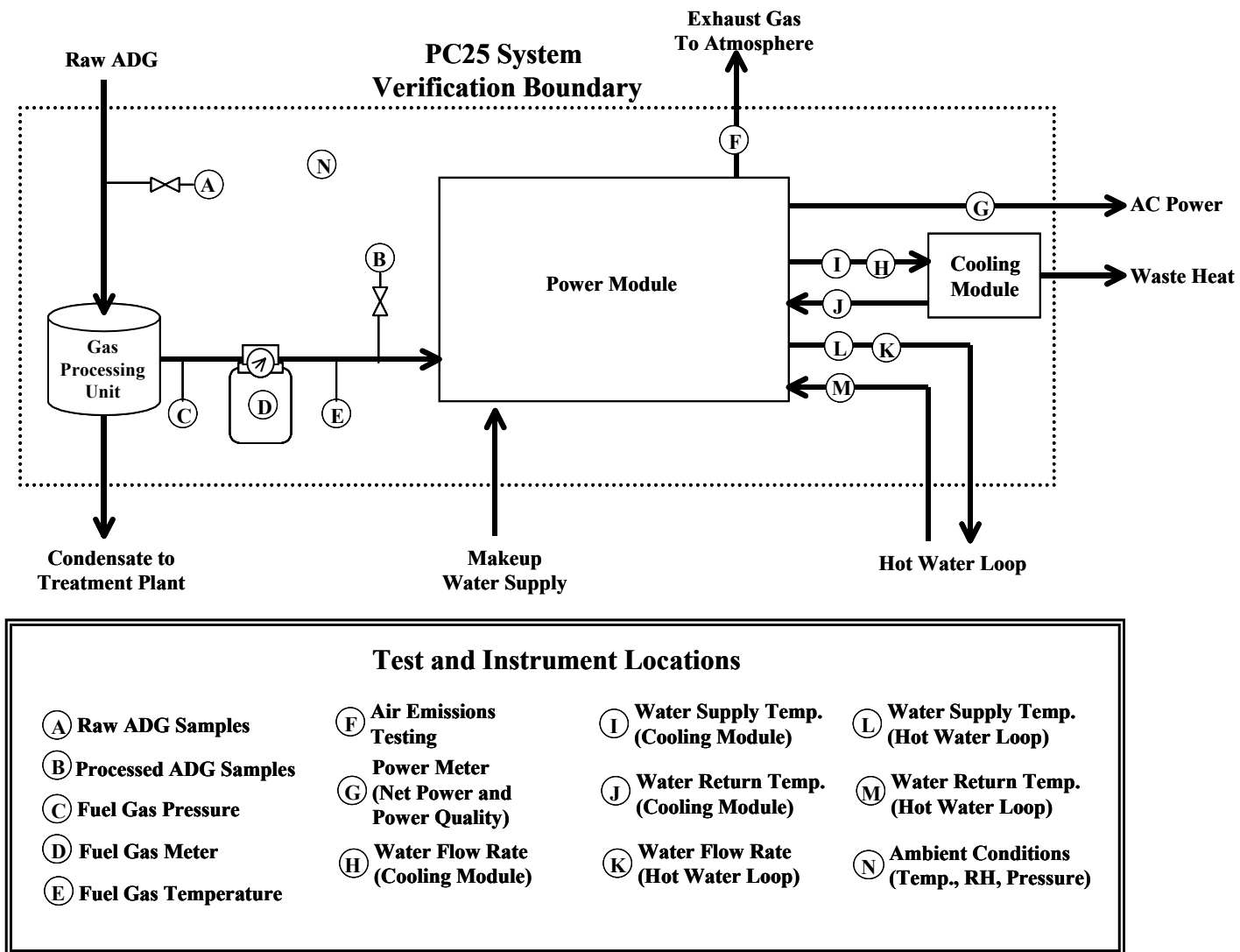


Figure 2-1. Fuel Cell System Sampling and Measurement Schematic

2.2 HEAT AND POWER PRODUCTION PERFORMANCE

The GHG Center will conduct short-term controlled tests and extended monitoring on the PC25. Short-term controlled tests will evaluate power and heat production and emissions performance at the operating loads specified earlier in Table 1-1 (power commands of 200, 150, and 100 kW). Each test at each operating load will consist of three individual one-hour runs conducted concurrently with the emissions tests described in Section 2.4. Appendix A-1 contains detailed procedures; Appendix A-2 provides a log form. Extended monitoring of power production performance and power quality will commence after completion of the controlled tests.

Simultaneous measurements of electric power output, heat recovery rate, heat input, ambient meteorological conditions, and exhaust emissions will be performed during testing at each load to determine electrical and thermal power output and efficiency. These determinations will reflect the net power and efficiency after parasitic losses associated with the GPU blower, the water circulation pump, the cooling module fans, and other internal electronic loads. The time-synchronized measurements data will be used to compute electrical efficiency as specified in PTC-50. PTC-50 mandates using electric power data collected over time intervals of not less than 60 minutes. This restriction minimizes electrical efficiency determination uncertainty due to changes in operating conditions. PTC-50 specifies the maximum permissible variations in test operating conditions within this time period to be less than the values shown in Table 2-1. The GHG Center will use only those time periods that meet these requirements to compute performance parameters. The load test will be considered invalid and the test will be repeated if the variation in power output, power factor, fuel flow, or ambient conditions exceed the limits.

Measured Parameter	Maximum Permissible Variation
Real power output, kW _e	± 2.0 %
Total power output, kVA	± 2.0 %
Barometric pressure, psia	± 0.5%
Inlet air temperature, °F	± 5.0 °F
Gas fuel pressure, psig	±1.0 %
Gas fuel flow, scfm	± 2.0 %

2.2.1 Electrical Power Output and Efficiency

Electrical efficiency will be calculated at each of the selected loads with the following equation:

$$\eta = \frac{3412.14(kW)}{HI} \tag{Eqn. 1}$$

where:

η = efficiency, as proportion, %

kW = average electrical power output, kW (Eqn. 2)

HI = average lower heating value (LHV) based heat input, Btu/hr (Eqn. 3)

3412.14 = converts kW to Btu/hr

Average electrical power output is the mean of the one-minute instantaneous readings gathered over the one-hour sampling period as shown in Equation 2.

$$kW = \frac{\sum_{i=1}^n kW_i}{n} \quad (\text{Eqn. 2})$$

where:

- kW = average electrical power output, kW
- kW_i = instantaneous kW sensor reading during minute i, kW
- n = number of 1-minute readings logged by the kW sensor

A field-mounted flow meter system will continuously monitor fuel gas consumption corrected to standard cubic feet per minute (scfm); the GHG Center's data acquisition system (DAS) will record one-minute averages throughout each test period. These data, combined with laboratory analyses of the fuel LHV, allow determination of the PC25's heat input according to Equation 3.

$$HI = 60(V_g)LHV \quad (\text{Eqn. 3})$$

where:

- HI = average heat input, Btu/hr
- 60 = minutes per hour
- V_g = fuel flow rate during tests, scfm, (Eqn. 4)
- LHV = fuel gas LHV during tests (average of two samples), Btu/scf

The flow meter system will include a gas meter whose output units are actual cubic feet per minute (acfm). Equation 3 requires corrected flow rate at standard conditions (60 °F, 14.73 psia). The corrected fuel flow rate is derived from the Ideal Gas law according to the following:

$$V_g = V_m \left(\frac{P_g}{14.73} \right) \left(\frac{520}{T_g} \right) \left(\frac{Z_{std}}{Z_g} \right) \quad (\text{Eqn. 4})$$

where:

- V_g = fuel flow rate, compensated for pressure, temperature, and compressibility, scfm
- V_m = average volumetric flow rate of fuel gas recorded during the test run, acfm
- P_g = fuel gas pressure, psia
- 14.73 = standard pressure, psia
- 520 = standard temperature, °R
- T_g = fuel gas absolute temperature, °R
- Z_{std} = compressibility factor at standard pressure and temperature, based on gas analysis performed per ASTM D3588 (6)
- Z_g = compressibility factor at fuel gas pressure and temperature, based on gas analysis performed per ASTM D3588 (6)

The GHG Center will install sensors in the fuel gas line and continuously monitor the fuel gas temperature and pressure during testing to acquire the gas temperature and pressure data. Laboratory analysis of fuel gas samples will supply the required compressibility data.

The operator will restore the system to normal function at 200 kW nominal output at the conclusion of the controlled load test runs. Facility electrical and thermal demand exceeds the PC25's power and heat production at all times as described in Section 1.3 so significant changes in PC25 operation (power output and heat recovery) are not anticipated. However, certain site operational variables such as ambient temperature, gas composition, and boiler water return temperatures may impact the performance of the PC25 system. The Center will, therefore, conduct an extended monitoring period for at least 2 weeks. Simultaneous measurements of electric power output, heat recovery rate, heat input, and ambient meteorological conditions will be performed during the extended testing to determine performance trends.

2.2.2 Heat Recovery Rate and Thermal Efficiency Determination

The PC25 CHP system produces heat as a byproduct of electricity generation. The CHP heat recovery performance is a function of the amount of heat used by other processes (primarily to pre-heat return boiler water for this facility). This verification will, therefore, attempt to quantify maximum heat recovery potential during full-load testing. Assuming the return water temperature is 100 °F, the hot water supply temperature for the heat recovery unit will be manually set to 125 °F. Facility heat demand is expected to exceed the heat recovery potential of the PC25. Site operators will maintain plant operations during the controlled test periods to maximize heat demand on the PC25. During the test periods, it is likely that some heat generated by the power module will be dissipated through the cooling module. During each of the test periods then, the Center will also monitor the amount of heat rejected by the cooling module. This will allow the Center to verify the total heat generated, the amount of heat used by the facility, and maximum heat recovery performance for this site.

The following equation provides a standard method to determine heat recovery rates according to ANSI/ASHRAE Standard 125 (3):

$$Q = 0.13368 V_1 \rho C_p (T_1 - T_2) 60 \quad (\text{Eqn. 5})$$

where:

- Q = heat recovery rate, Btu/hr
- 0.13368 = conversion of ft³ to gal
- 60 = minutes per hour
- V₁ = total volume of liquid passing through the system during a minute, gal/min
- ρ = density of liquid evaluated at the average fluid temperature, [(T₂+T₁)/2], lb/ft³
- C_p = specific heat of liquid evaluated at the average fluid temperature, [(T₂ + T₁)/2], Btu/lb, °F
- T₁ = temperature of heated liquid exiting the heat exchanger (“supply”), °F
- T₂ = temperature of cooled liquid entering the heat exchanger (“return”), °F

The heat recovery rate determination shown in Equation 5 requires the definition of the density and specific heat of the circulation fluid at actual operating temperatures. The system being tested uses water as the working fluid (no glycol is added). The GHG Center will specify the properties of water for this equation.

The GHG Center will use portable Controlotron (Model 1010EP) heat meters to quantify the recovered heat (one on the hot water loop and another on the cooling module). The heat meters contain ultrasonic transmitters to measure fluid velocity and resistive temperature detectors (RTDs) to measure the supply and return water temperatures. Algorithms within the heat meter software use physical properties of the

working fluid to calculate fluid flow rate and heat recovery rate. The heat meter provides four analog outputs as follows:

<u>Measurement</u>	<u>Units</u>
Fluid flow rate	gal/min
Heat recovery rate	Btu/min
Return temperature	°F
Supply temperature	°F

The GHG Center’s DAS will log the heat meters outputs as one-minute averages during all test periods. A description of the ultrasonic flow meter is provided in Section 2.2.3.2. The one -minute average heat recovery values will be averaged over the time intervals corresponding to each load test and normalized to Btu/hr. The following equation will be used to compute thermal efficiency:

$$\eta_{Th,j} = Q_j / HI_j \tag{Eqn. 6}$$

where:

- $\eta_{Th,j}$ = thermal efficiency at load condition j, %
- Q_j = average heat recovered for load condition j, Btu/hr
- HI_j = average heat input using LHV for load condition j, Btu/hr, (Eqn. 3)

The Verification Report will state CHP production efficiency as the sum of η_e and η_{th} for each valid test run. The Report will also summarize average CHP production efficiency at each load level during controlled-load testing, during normal site operating conditions, and for the extended testing period.

Figure 2-1 shows the location of the ultrasonic transmitters and temperature sensors. The sensors will be located as close as practicable to the inlet and outlet of the supply and return lines during load testing. The ultrasonic transmitters must be surface-mounted while the RTDs can be surface-mounted or inserted into thermowells (depending on pipe size and configuration). The GHG Center will use the surface-mounted RTDs on both sets of piping associated with the PC25. Testing personnel will follow manufacturer's recommendations and wrap insulation around the surface-mounted RTDs to minimize temperature- reading variations caused by ambient conditions.

The following subsections describe the electric power, heat recovery rate, and heat input metering systems. This section concludes with a discussion of the fuel sampling protocol and the laboratory analyses which will provide the heating value and compressibility data required by Equations 3 and 4. Section 3.0 presents the associated data quality objectives, data quality indicators, quality assurance/quality control checks, calibrations, and sensor function checks.

2.2.3 Measurement Instruments

2.2.3.1 Power Output Measurements

The GHG Center will measure total electric power output from the PC25 with a digital power meter manufactured by Power Measurements Ltd. (Model 7600 ION, 7500 ION, or equivalent). The meter scans all power parameters once per second and sends the data to the DAS. The DAS then computes and

records one-minute averages. Section 4.0 provides further discussion of the DAS. Analysts will enter the one-minute average power output readings into Equations 1 and 2 to compute electrical efficiency at each load.

Test personnel will install the power meter on the PC25's distribution panel. The meter will operate continuously, unattended, and will not require further adjustments after installation. The rated accuracy of the power meter is ± 0.1 percent, and the rated accuracy of the current transformers (CTs) needed to employ the meter at this site is ± 1.0 percent. Overall power measurement error is then ± 1.0 percent.

2.2.3.2 Heat Recovery Rate Measurements

The Controlotron (Model 1010EP in Table 3-2) energy meter is a digitally integrated system that includes a portable computer, ultrasonic fluid-flow transmitters, and 1,000-ohm platinum RTDs. The system has an overall rated accuracy of ± 1 to 2 percent of reading depending on location of the RTDs and accuracy of computer programming parameters (e.g., pipe diameter, wall thickness, working fluid composition). The system can be used on pipe or tubing sizes ranging from 0.25 to 360 inches in diameter with fluid velocities ranging from 0 to 60 feet per second.

The meter determines fluid velocity by measuring pulse transit times between two ultrasonic transducers. A precision-mounting jig secures the transducers to the pipe at a known distance apart. The operator enters the fluid composition, pipe diameter, material, wall thickness, and expected sonic velocity into the heat meter's computer. The heat meter determines the exact sonic-velocity based on the known distance between the transducers under zero-flow conditions with the pipe full of fluid. It multiplies the fluid velocity by the internal area of the pipe to yield volumetric flow rate during operation. The test operator mounts the ultrasonic transducers on the pipe at least ten diameters from upstream and five diameters from the downstream disturbances (e.g., elbows, valves) adjacent to one of the RTDs. The operator enters that RTD's identifier (i.e., supply or return) into the meter software so it can properly calculate heat flow limitation. The RTDs are mounted as close to the heat recovery unit as configuration allows. They provide continuous supply and return fluid line temperatures to the computer, which calculates the temperature difference.

The Field Team Leader will program the following critical parameters into the heat meter's computer prior to verification:

- pipe diameter or tubing,
- wall material and thickness,
- distances between ultrasonic transducers, and
- working fluid composition

The accuracy of these parameters will directly impact the overall accuracy of the meter. The Field Team Leader will obtain pipe or tubing material, exact diameter, and wall thickness from manufacturer specifications. The heat meter includes an alignment bracket which ensures precise measurement of the distance between transducers. The energy meter software contains lookup tables that provide ASHRAE and ASME working fluid density and specific heat values corrected to the average fluid temperature measured by the RTDs. The fluid composition must be known or determined and programmed into the computer in order for these values to be correct. The system will be programmed for water as the fluid for this verification. The DAS will record one-minute average fluid flow rate, heat recovery rate, supply temperature, and return temperature.

Several QA/QC procedures will be conducted prior to and during the verification testing to evaluate the accuracy of the meter. These procedures, which include factory calibration of sensors and performance checks in the field, are detailed in Section 3.3.

2.2.3.3 Fuel Gas Meter

A gas meter (location D on Figure 2-1.) will be installed to measure fuel flow rates to the PC25 system. The average fuel flow rate, multiplied by the average LHV, yields average heat input to the system (Equation 3). The flow rate measurements are also used to determine operational stability during load testing.

A Roots (Model 5M175 SSM, Series B3) rotary positive-displacement meter manufactured by DMD-Dresser will be used. The meter's rated capacity is 5,000 actual cubic feet per hour (acfh), or approximately 83 actual cubic feet per minute (acfm). This capacity is appropriate for the PC25's expected demand of 50 to 60 acfm. Rated accuracy of the meter is ± 1.0 percent of reading. Actual meter accuracy will be certified by the manufacturer.

The meter will be equipped with a frequency transmitter manufactured by Love Controls (Model SC 478). This transmitter is mounted on the meter's index and will provide a scaled 4 - 20 mA signal to the DAS. The pulse transmitter system has a resolution of 108 pulses per every actual cubic foot. The DAS will record actual gas flow as one-minute averages. Analysts will use computer spreadsheets to calculate corrected standard flow according to Equation 4.

2.2.3.4 Gas Temperature and Pressure Measurements

Fuel gas temperature and pressure data are used to convert measured fuel flow rate to standard conditions and verify PTC-50 stability requirements. The following paragraphs describe the instruments to be used.

The DAS will record one-minute average fuel temperatures as monitored by an Omega Model 93-K2 type K thermocouple and transmitter. The sensor's location will be in a thermowell in the pipeline adjacent to the pressure transducer (location C in Figure 2-1). The thermocouple's range is from 0 to 200 °F, with accuracy rated at ± 1.5 percent of full-scale. The GHG Center will obtain and review the NIST-traceable factory calibration documents to ensure achievement of the accuracy goal. GHG Center analysts will compute the average fuel gas temperature for each test run and the resulting value ($^{\circ}\text{F} + 460$) will be used as the " T_g " term in Equation 4.

The GHG Center expects the fuel pressure to be reasonably stable during each test run. Pressures expected are approximately 4 inches water gauge (or 0.14 psig) above local ambient (or "station") barometric pressure. A Rosemount (Model 3051) "smart" pressure transducer will monitor fuel gas pressure in the ADG gas delivery pipe upstream of the gas meter (location C in Figure 2-1). Rosemount will set the full-scale range at -100 to 100 inches of H_2O , and perform a factory calibration prior to the verification. The sensor's accuracy is ± 0.1 percent of full-scale. The DAS will record one-minute averages. The Field Team Leader will enter the average fuel gas pressure for each test run as " P_g " into Equation. 4.

2.2.3.5 Gas Composition and Heating Value Analysis

The Field Team Leader will collect ADG samples and submit them to Empact Analytical Systems, Inc. of Brighton, Colorado (Empact) to obtain the LHV data required by Equation 3 and the compressibility data required by Equation 4. Test personnel will collect at least two samples spaced throughout each short-term load testing condition. At least two additional samples will be collected at both the beginning and end of the extended monitoring period. Samples will be collected downstream of the GPU (location B in Figure 2-1) to ensure that gas composition is representative of the PC25 fuel (i.e., moisture and H₂S removed from raw ADG) for the efficiency determinations.

A tee fitting and ball valve located in the fuel pipeline between the gas metering equipment and the PC25 will provide access for the 600-ml stainless-steel gas sampling canisters. The laboratory evacuates the canisters to prepare them for sampling. Test personnel will check the canisters with a vacuum gauge to ensure that they remain under vacuum and are leak-free prior to sample collection. Canisters that are not fully evacuated will not be used or will be evacuated on site and checked again before use. Appendices A-3, A-4, and A-5 contain detailed sampling procedures, log, and chain-of-custody forms.

The Field Team Leader will submit the collected samples to Empact for compositional analysis. All samples shipped to the laboratory will be accompanied by appropriate chain-of-custody forms and documentation of sample identification, matrix, date and time of collection, analyses required, methods and release signature. Analyses will be in accordance with ASTM Specification D1945 (5) for quantification of speciated hydrocarbons including methane through pentane (C₁ through pentane C₅), heavier hydrocarbons (grouped as hexanes plus C₆₊), N₂, O₂, and CO₂. The lab procedure specifies sample gas is injected into a Hewlett Packard 589011 gas chromatograph equipped with a molecular sieve column and a thermal conductivity detector (TCD). The column physically separates gas components, the TCD detects them, and the instrument plots the chart traces and calculates the resultant areas for each compound. The instrument then compares these areas to the areas of the same compounds contained in a calibration reference standard analyzed under identical conditions. The reference standard areas are used to determine instrument response factors for each compound and these factors are used to calculate the component concentrations in the sample.

The laboratory calibrates the instruments weekly with the reference standards. The instrument operator programs the analytical response factors generated for each compound analyzed into the instrument during calibrations. Allowable method error during calibration is ± 1 percent of the reference value of each gas component. The laboratory re-calibrates the instrument whenever its performance is outside the acceptable calibration limit of ± 1 percent for each component. The GHG Center will obtain and review the calibration records.

The laboratory will use the compositional data to calculate the gross (HHV) and net (LHV) heating values (dry, standard conditions), compressibility factor, and the specific gravity of the gas per ASTM Specification D3588 (6). The data quality of the heating value determinations is related to the repeatability of the ASTM D1945 analysis discussed above. ASTM D3588 specifies that LHV repeatability is approximately 1.2 Btu/1,000 ft³ or about 0.1 percent provided the analytical repeatability criteria are met. Accuracy is twice this value, or 0.2 percent.

2.2.3.6 Ambient Conditions Measurements

The GHG Center will collect meteorological data to determine if the Table 2-1 maximum permissible limits for electrical efficiency determination are satisfied. The Field Team Leader will install a Vaisala

Model HMD60Y integrated temperature/relative humidity sensor and a Setra Model 280E ambient pressure sensor near the SU1 air inlet plenum for this purpose.

The integrated temperature/humidity unit uses a platinum RTD for temperature measurement. As the temperature changes, the resistance of the RTD changes. This resistance change is detected and converted by associated electronic circuitry that provides a linear (DC 4-20 mA) output signal. The temperature accuracy is ± 1 °F. A thin-film capacitive sensor measures humidity. The dielectric polymer's capacitance varies with relative humidity. Internal electronics convert the capacitance change into a linear output signal (DC 4-20 mA). Relative humidity accuracy is ± 2.0 percent, absolute. The barometric pressure sensor (ambient psia) also employs a variable capacitance sensor. The capacitance decreases as pressure increases; full-scale span is 25.0 psia. Accuracy is ± 1.0 percent of full scale, or 0.25 psia.

The GHG Center's DAS will convert the 4-20 mA analog signals to digital format and then store the data as 1-minute averages. After each emission test run, the Field Team Leader will review the data for compliance with the permissible variation limits in Table 2-1.

2.3 POWER QUALITY PERFORMANCE

Electric power users, utilities, and distributors are concerned with a number of power quality issues which power generator operators must address. For example, a generating unit in grid parallel mode must detect and synchronize with grid voltage and frequency before actual grid connection occurs. The PC25 must automatically disconnect from the grid under out-of-tolerance operating conditions such as overvoltages, undervoltages, and over/under frequency. The control circuitry also must disconnect and shut the unit down during grid outages to prevent islanding. The system's delivered power factor should also be close to unity (100 percent) to avoid billing surcharges. The unit's voltage and current harmonic distortion must also be minimized to reduce damage or disruption to electrical equipment (e.g., lights, motors, office equipment).

The generator's effects on electrical frequency, power factor, and THD cannot be completely isolated from the grid. The quality of power delivered actually represents an aggregate of disturbances already present in the utility grid. For example, locally generated power with low THD will tend to dampen grid power with high THD in the test facility's wiring network. This effect will drop off with increased distance from the generator. The generator's effects on power factor will also change with increasing distance as the aggregate grid power factor begins to predominate.

The GHG Center and its stakeholders developed the following power quality evaluation approach to address these issues. Two ANSI/IEEE documents (1, 2) form the basis for selecting the power quality parameters of interest and required measurement methods. The GHG Center will measure and record the following power quality parameters during the short-term testing and extended monitoring periods:

- Electrical frequency
- Voltage
- Voltage THD
- Current THD
- Power factor

The ION power meter (7600 ION or 7500 ION) used for power output determinations will perform these measurements as described in the following subsections.

2.3.1 Electrical Frequency

The ION power meter will continuously measure electrical frequency at the PC25's distribution panel. The DAS will record one-minute averages throughout all test periods and the GHG Center will report mean frequency as compared to the U.S. standard 60 ± 0.6 Hz (± 1.0 percent). The mean frequency is the average of all the recorded one-minute data over the test period; sample standard deviation is a measure of dispersion about the mean as follows:

$$F = \frac{\sum_1^n F_i}{n} \quad (\text{Eqn. 7})$$

$$\sigma_F = \sqrt{\frac{\sum_1^n (F - F_i)^2}{n - 1}} \quad (\text{Eqn. 8})$$

where:

- F = mean frequency for operating period, Hz
- F_i = average frequency for the i th minute, Hz
- n = number of one-minute readings logged
- σ_F = sample standard deviation in frequency for operating period

2.3.2 Generator Line Voltage

The fuel cell generates power at 480 VAC. The electric power industry accepts that voltage output can vary within ± 10 percent of the standard voltage without causing significant disturbances to the operation of most end-use equipment. Deviations from this range are often used to quantify voltage sags and surges.

The ION power meter will continuously measure true root-mean square (rms) line-to-line voltage at the PC25's distribution panel. True rms voltage readings provide the most accurate AC voltage representation. The DAS will record one-minute averages throughout all test periods. The GHG Center will report voltage data for each test period as follows:

- Total number of voltage disturbances exceeding ± 10 percent
- Maximum, minimum, mean, and standard deviation of voltage exceeding ± 10 percent
- Maximum and minimum duration of incidents exceeding ± 10 percent

Analysts will use Equations 7 and 8 to compute the mean and standard deviation of the voltage output by substituting the voltage data for the frequency data.

2.3.3 Voltage Total Harmonic Distortion

Harmonic distortion results from the operation of non-linear loads. Harmonic distortion can damage or disrupt many kinds of industrial and commercial equipment. Voltage harmonic distortion is any deviation from the pure AC voltage sine wave form.

The ION power meter applies Fourier analysis algorithms to quantify total harmonic distortion (THD). Fourier showed that one sum of pure sine waves with different frequencies can represent any wave form. He also showed that each contributing sine wave is an integer multiple (or harmonic) or the lowest (or fundamental) frequency. For 60 Hz electrical power in the US, the 2nd harmonic is 120 Hz, the 3rd is 180

Hz, and so on. The types of devices (i.e. capacitors, motor control thyristors, inverters) connected to the distribution can strongly affect certain harmonics, such as the 5th or 12th.

The magnitude of the distortion can vary for each harmonic. Typically, each harmonic's magnitude is represented as a percentage of the rms voltage of the fundamental. The aggregate effect of all harmonics is called THD. THD is the sum of the rms voltage of all harmonics divided by the rms voltage of the fundamental, converted to a percentage. THD gives a useful summary view of the generator's overall voltage waveform quality.

The ION meter will continuously measure voltage THD up to the 63rd harmonic. The meter's output value is the result of the following calculation:

$$THD_{volt} = \left[\frac{\sum^{63} volt_i}{volt_1} \right]^2 * 100 \quad (\text{Eqn. 9})$$

where:

- THD_{volt} = voltage THD, %
- volt_i = rms voltage reading for the ith harmonic, volts
- volt₁ = rms voltage reading for the fundamental, volts (220, 480, etc.)

The "recommended practices for individual customers" in the IEEE 519 standard specifies a 5.0% maximum voltage THD. The GHG Center will adopt this specification for this verification. The DAS will record one-minute voltage THD averages throughout all test periods. The GHG Center will report periods for which overall voltage THD exceeded 5.0%, mean, and standard deviation per the methods outlined in Equations 7 and 8 above.

2.3.4 Current Total Harmonic Distortion

Current THD is any distortion of the pure current AC sine waveform and similar to voltage THD can be quantified by Fourier analysis. The current THD limits recommended in the IEEE 519 standard range from 5.0% to 20.0%, depending on the size of the generator, the test facility's demand, and its distribution network design as compared to the capacity of the local utility grid. The standard's recommendations for a small generating unit connected to a large capacity grid, for example, are more forgiving than those for a large generating unit connected to a small capacity grid.

Detailed analysis of the facility's distribution network and the local grid are beyond the scope of this verification. The GHG Center will, therefore, report current THD data without reference to a particular recommendation. The ION power meter will continuously measure current THD as with voltage THD. The DAS will record one-minute current THD averages throughout all test periods. The GHG Center will report mean and standard deviation of current THD per the methods outlined in Equations 7 and 8 above.

2.3.5 Power Factor

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. Current and voltage are in phase, under ideal conditions which results in a unity (100 percent) power factor. Power factors are less than this optimum value if reactive loads are present. The actual power factor of the electricity supplied by the utility may be much lower because of load demands of different end users although it is desirable to maintain unity power factor. Typical values ranging between 70 and 90 percent are common. Low power factor causes heavier current to flow in power distribution lines for a given number of real kilowatts delivered to an electrical load.

Mathematically, electricity consists of three components, which can be mapped as vectors to form a power triangle: real power (kW), reactive power (kVAr), and apparent power (kVA). Real power is the part of the triangle that results in actual work being performed in the form of heat and energy. Reactive power, which accounts for electric and magnetic fields produced by equipment, always acts at right angles or 90 degrees to real power.

Real power and reactive power create a right triangle whose hypotenuse is the apparent power, measured in kilovolt-amperes (kVA). The phase angle between real power and apparent power in the power triangle determines the size of the reactive power leg of the triangle. The cosine of the phase angle is called the power factor and is inversely proportional to the amount of reactive power that is being generated. The larger the amount of reactive power, the lower the power factor will be. Reactive power does not contribute to the system's mechanical or resistive (heat) work, but the conductors still must carry the reactive current. Low power factors require larger capacity equipment and conductors. Low power factors can also exacerbate problems with THD, resonance, and other power quality parameters.

The ION power meter will continuously measure average power factor. The DAS will record one-minute averages during all test periods. The GHG Center will report maximum, minimum, mean, and standard deviation per the methods outlined in Equations 7 and 8 above.

2.3.6 Power Quality Measurement Instruments

The 7600 ION power meter is capable of measuring all power quality parameters. The DAS will record one-minute average measurements. Section 3.0 provides details regarding the instrument, its calibration, and additional QA/QC checks (instrument setup, calibration, sensor function checks).

2.4 PC25 EMISSIONS

Field personnel will conduct PC25 exhaust stack emissions tests for the following air pollutants: NO_x, CO, THC_s, and greenhouse gases (CO₂ and CH₄). The GHG Center has developed a modified approach for evaluating emissions from the PC25 fuel cell. This approach addresses several sampling complications specific to fuel cell exhaust gas streams that are not typically considered when measuring emissions from combustion sources. Fuel cell exhaust gas characteristics that complicate emissions measurements include the following:

- Extremely low pollutant concentration levels: NO_x and CO concentrations are expected to be in the range of 1 ppm or less. This will require highly sensitive analytical detectors for accurate quantification of these parameters.
- Potential interferences: Relatively high moisture (10 to 20 percent) and CO₂ (12 to 15 percent) concentrations in the exhaust gas have the potential to interfere with small pollutant concentrations.

The GHG Center designed this protocol to address these complications. The sampling system and analytical approach minimizes analytical bias introduced by the issues outlined above, and the protocol specifies well-defined procedures that will allow quantification of low level NO_x and CO emissions. The following subsections describe the emissions testing protocol, sampling and analytical procedures, and the rationale for reference method modifications.

The GHG Center will conduct three test runs at each of the power output set points that coincide with the power production load tests described earlier to verify PC25 emissions. The system will operate under normal and steady conditions during each test run as specified in Table 2-1. The verification report will present individual test run results and the average result of three valid test runs at each load. The report will state average concentrations measured during each test run in units of parts per million volume, dry (ppmvd) or parts per billion volume, dry (ppbvd) where appropriate for NO_x, CO, CH₄, and THC, and percent for CO₂. The report will also present average emission rates for each pollutant in units of pounds per hour (lb/hr), and normalize emissions to power output (lb/kWh).

A qualified testing contractor (TRC Environmental Corporation) will perform all emissions testing. The testing contractor will provide all equipment, sampling media, and labor needed to complete the testing and will operate under the supervision of the GHG Center Field Team Leader following this protocol for quantifying PC25 emissions. Table 2-2 summarizes the standard U.S. EPA Federal Reference Methods that will be followed. These reference methods are well documented in the Code of Federal Regulations (13) they are used to determine pollutant levels from a wide variety of sources. They include measurement system performance specifications, test procedures, quality control procedures, and emission calculations.

Table 2-2. Summary of Emission Testing Methods

Parameter	U.S. EPA Reference Method	Principle of Detection	Proposed Analytical Range	Instrument Limit of Detection
O ₂	3A	Electrochemical cell	0 to 25 %	0.1 %
CO ₂	3A	NDIR	0 to 20 %	0.1 %
NO _x	7E	Chemiluminescence	0 to 2 ppm	20 ppb
CO	10	NDIR-gas filter correlation	0 to 10 ppm	40 ppb
THC	25A	FID	0 to 20 ppm	0.5 ppm
CH ₄	18	GC/FID	0 to 20 ppm	0.5 ppm
Moisture Content	4	Gravimetric	not specified	not specified
Exhaust gas velocity	2	Differential pressure	0.020 to 0.150 “ H ₂ O; ≈ 15 to 25 ft/sec	0.005 “ H ₂ O; ≈ 5.0 ft/sec

Each of the instrumental analyzer methods includes performance-based specifications for the gas analyzer used. These performance criteria cover span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements. The following subsections discuss each test method in more detail. The reference method descriptions will not be repeated here, but will be available to site personnel during testing.

2.4.1 Reference Method Modifications

Certain procedural modifications and additions will be made to the reference methods listed above to more accurately detect and quantify the low level emissions expected from the PC25. The GHG Center anticipates that PC25 NO_x emissions will be very low which implies that the analyzer span must also be low. Data quality may also be affected by method, calibration, CO₂/H₂O interferences, or quality assurance / quality control (QA/QC) problems.

The presence of CO₂ can quench the chemiluminescence effect for certain analyzers, biasing the NO_x result low (11). The proportion of NO₂ to total NO_x can be quite high for low emission sources and the effects of sample train construction materials on that higher proportion of NO₂ can be significant (10). Some researchers have found that moisture removal systems can bias NO₂ (and the resulting total NO_x) results because NO₂ readily dissolves in water (9). However, others have not documented such effects (10), possibly because of different residence times in different sample conditioning systems.

Measurement of the expected extremely low NO_x emissions will be difficult, and field verification of the measurements will be essential. The GHG Center proposes inclusion of an additional NO₂ to NO converter, on-site generation of low-level calibration gases, and recommendation of a certain moisture removal system. The Center does not endorse the use of any single instrument type, but in certain cases pre-existing data warrant the use of specific instruments.

Figure 2-2 presents a sampling system schematic. The figure illustrates analyzer sampling system modifications. Table 2-3 provides method modification summaries. The following subsections provide details regarding sampling modifications or additions to the standard methods and analytical procedures. Section 3.0 discusses quality assurance / quality control (QA/AC) checks, and analyzer and system calibration procedures.

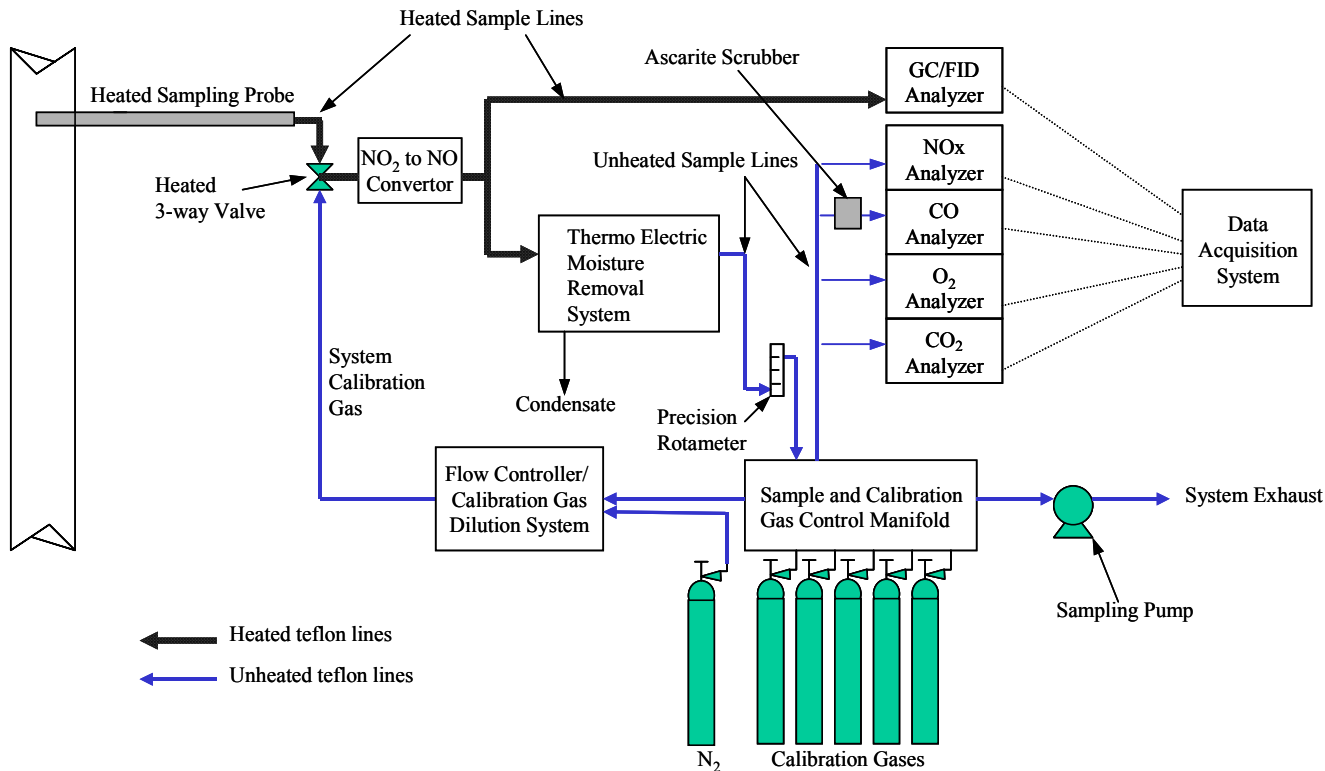


Figure 2-2. Exhaust Gas Sampling and Analysis System

Table 2-3. Modifications to Reference Method Specifications

System Component		Method Modification or Additional Requirement	Reason/Purpose for Modification
Gas Extraction System	Heated Teflon sample lines	Precleaned with Alcanox (or equivalent) laboratory-grade detergent and purged with nitrogen	Minimize bias introduced by contaminated surfaces
	Unheated Teflon sample lines	New or "virgin" Teflon to be used	
	NO ₂ to NO converter	Additional NO ₂ to NO converter installed near stack	Conversion of NO ₂ in exhaust gas to NO prior to moisture removal system
	Gas conditioning system	Baldwin Environmental Model M5210 moisture removal system is specified	Minimize NO ₂ losses caused by scrubbing during moisture removal process
Low-level pollutant analyzers	NO _x and CO analyzers	Ambient level analytical ranges for both analyzers required	Lower analytical detection limits
	Calibration gas delivery system	Low-level calibration gases generated on-site using gas dilution system (EPA Method 205)	Conduct analyzer and sampling system calibrations at ambient levels

2.4.2 Gaseous Sample Conditioning and Handling

All gas conditioning and handling system interior surfaces will be made of stainless steel, Teflon™, or glass to minimize any reactions with the sample gas components. The extremely low levels of NO_x and CO expected require that added precautions be taken to minimize potential bias introduced by dirty or contaminated sampling system surfaces. All unheated Teflon tubing will be new or "virgin" Teflon. All heated Teflon lines indicated in Figure 2-2 will be cleaned immediately prior to the test using Alconox or equivalent laboratory grade cleaner and then purged with laboratory-grade pure nitrogen for at least one hour. Heated gas transport lines will maintain a gas temperature of no less than 250 °F during all testing.

A vacuum ("sampling pump") on the system's downstream side will extract exhaust gas from a single point near the center of the 10-inch inside diameter test duct (Figure 2-2). A precision rotameter with a needle valve will control the sampling rate throughout the entire system at approximately 3 liters per minute (lpm). Limiting the sampling rate to this level provides several benefits. This rate also optimizes the NO₂ to NO conversion efficiency and the low rate minimizes the amount of moisture introduced to the system (exhaust gas moisture content is expected to be 10 to 15 percent). Also, this rate limits the potential bias from NO₂ losses within the sampling system because NO₂ can adhere to sampling system surfaces. The 3 lpm sampling rate will provide sufficient gas for the analyzers.

Extracted gas first passes through a heated 3-way valve where calibration gases are introduced and then through a near stack NO₂ to NO converter (Baldwin development model or equivalent). This converter's function is to convert the majority of the NO₂ fraction of NO_x to NO prior to removing moisture from the gas. This precaution will help minimize NO₂ losses during the moisture removal process because NO is much less soluble in water than NO₂. The converter is constructed of molybdate carbon material, has a rated conversion efficiency of 98 percent, and will be maintained at a temperature of 650°F during testing.

A heated Teflon™ sample line conveys the gas stream to a moisture removal system specifically designed for low NO_x measurement (Baldwin Model M325A/B, or equivalent). The Baldwin system to be used here is a portable unit that incorporates a thermo-electronic chiller that cools gases passing through a glass-coated stainless-steel impinger. This instrument is specifically designed for the sampling rates desired here (approximately 3 lpm), and tests have shown that NO₂ losses due to high moisture content in the gas stream are minimal (11).

The clean, dry sample is then transported to a flow distribution manifold where the operator controls sample flow to each analyzer. Calibration gases are routed through this manifold and a Teflon line to the heated 3-way valve near the sample probe. This allows calibration and bias checks to include all components of the sampling system. The distribution manifold also routes calibration gases directly to the analyzers where linearity checks are performed.

Testers will use an on-site flame ionization detector (FID) to quantify THC concentrations. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second heated sample line will deliver the unconditioned exhaust gases from the stack to the FID.

2.4.3 Gaseous Pollutant Analytical Procedures

A chemiluminescence analyzer (Thermo Environmental Instruments (TEI) Model 42C or equivalent) will continuously determine NO_x concentrations. An efficiency check of the catalytic converter that changes

NO₂ to NO is a part of instrument set-up and checkout. The NO_x analyzer will be operated on a range of 0 to 2 ppm based on preliminary test results from UTC. The Field Team Leader will implement analyzer

range adjustments in the field to ensure that measured NO_x concentrations are within 20 and 100 percent of the analyzer's full scale.

A gas filter correlation non-dispersive infrared (NDIR) analyzer (TEI Model 48C or equivalent) will be used for CO determinations. The analyzer will be equipped with an ascarite scrubber to minimize CO₂ interference. Field personnel will set the CO analyzer range at or near 0 to 10 ppm based on the PC25 manufacturer's preliminary measurements. The Field Team Leader will implement modified analyzer ranges during testing if proposed ranges are inadequate. A second NDIR analyzer (Servomex Model 1415B or equivalent) will measure CO₂ concentrations. Test personnel will set the CO₂ analyzer range at 0 to 20 percent based on UTC's preliminary measurements.

A paramagnetic or electrochemical cell analyzer (Servomex Model 1420B or equivalent) will measure exhaust gas oxygen. Exhaust gas O₂ concentrations are expected to be around 8 percent, so testers will set the O₂ analyzer range at or near 0 to 20 percent.

Total hydrocarbons in the exhaust gas will be measured using a FID which passes the sample through a hydrogen flame (California Analytical Model 300 AD or equivalent). Because many types of hydrocarbons are being analyzed, THC results will be normalized and reported as CH₄ equivalent. The calibration gas for THC will be propane. Concentrations of CH₄ will be determined by collecting integrated gas samples in Tedlar bags and shipping samples to a qualified laboratory for analysis. In the laboratory, samples will be directed to a Hewlett Packard 5890 GC/FID. Similar to the fuel sampling, the GC/FID will be calibrated with appropriate certified calibration gases. Sample collection bags will be leak checked prior to testing. In addition, one replicate sample will be collected and one duplicate analysis will be conducted for each turbine load tested.

The Method 25A and 18 tests provide concentrations on a wet basis (ppmvw). Stack gas moisture content will be determined in conjunction with each test run using EPA Method 4 by converting measured concentrations to a dry basis. Each Method 4 test run will be approximately 60 minutes in duration and will coincide with the emissions test runs.

2.4.4 Determination of Emission Rates

The instrumental testing for CO₂, O₂, NO_x, CO, THC, and CH₄ provides exhaust gas concentrations in units of percent for CO₂ and O₂, and ppmvd for NO_x, CO, THC, and CH₄. Exhaust gas flow rate determinations via Method 2 are required to convert the measured pollutant concentrations to mass emissions in terms of pounds per hour (lb/hr). Test personnel will conduct one stack gas velocity and temperature traverse per emission test run with a calibrated thermocouple, a standard-type pitot tube, and a digital micromanometer. Testers will select the traverse point number and locations in accordance with EPA Method 1.

Stack gas velocity depends on the average pitot differential pressures, gas molecular weight, temperature, and pressure as follows:

$$V_s = 85.49(C_p)(Avg[\sqrt{\Delta p}])\sqrt{\frac{T_s}{P_s M_s}} \quad \text{Eqn. 10)}$$

where:

- V_s = stack gas velocity, ft/sec
- C_p = pitot coefficient, dimensionless
- Δp = change in velocity head, inches H_2O
- T_s = average stack temperature, °R
- P_s = absolute pressure in stack, in. Hg
- M_s = molecular weight of stack gas, lb/lb-mole

Volumetric flow rate under standard conditions is:

$$Q_{std} = V_s A (1 - B_{ws}) \frac{P_s}{P_{std}} \frac{T_s}{T_{std}} 60 \quad (\text{Eqn. 11})$$

where:

- Q_{std} = volumetric flow rate, dscf/min
- V_s = stack gas velocity, ft/sec
- A = stack cross-sectional area, ft^2
- B_{ws} = stack gas moisture content, %
- P_s = absolute pressure in stack, in. Hg
- P_{std} = standard pressure, 29.92 in. Hg
- T_s = average stack absolute temperature, °R
- T_{std} = standard temperature, 532 °R
- 60 = seconds per minute

EPA Method 4 test runs conducted in conjunction with each emission test will supply stack gas moisture content (B_{ws}). These data, combined with the direct CO_2 and O_2 determinations (Method 3A) and the assumption that the balance of the stack gas is N_2 , allow calculation of the stack gas molecular weight (M_s) required in Equation 10.

Analysts will convert measured pollutant concentrations as ppmvd (or ppbvd) to pounds per dry standard cubic foot (lb/dscf) using the following unit conversion factors:

- CH_4 : 1 ppmvd = $4.150E-08$ lb/dscf
- CO : 1 ppmvd = $7.263E-08$ lb/dscf
- CO_2 : 1 ppmvd = $1.141E-07$ lb/dscf
- NO_x : 1 ppmvd = $1.194E-07$ lb/dscf NO_x (emissions are quantified as NO_2)
- THC: 1 ppmvd = $4.150E-08$ lb/dscf THC (emissions are quantified as CH_4)

After conversion of measured pollutant concentrations to mass units (lb/dscf), emission rate values are:

$$E_{poll} = C_{poll} K_{poll} Q_{std} 60 \quad (\text{Eqn. 12})$$

where:

- E_{poll} = pollutant emission rate, lb/hr
- C_{poll} = average pollutant concentration during the test run, ppmv
- K_{poll} = pollutant ppmvd to lb/dscf (conversion factor, see above)
- Q_{std} = standard dry volumetric flow rate, dscf/min, (Eqn. 9)
- 60 = minutes per hour

The verification report will present the mean of the three test results at each load factor as the average emission rate for that load factor. The GHG Center will then normalize emission rates for each pollutant to system power output in terms of lb/kWh as follows:

$$E_{norm} = \frac{E_j}{kWh_j} \tag{Eqn. 13}$$

where:

- E_{norm} = normalized emission rate, lb/kWh
- E_j = mean emission rate at load condition j, lb/hr
- kWh_j = mean power production rate at load condition j

The mean of the three normalized emission rates will be reported as the average emission rate in lb/kWh.

All of the sampling and analytical procedures and reference methods cited here contain QA/QC procedures that will be followed to evaluate data quality. Section 3.0 contains the procedures and associated DQOs.

2.5 ELECTRICITY OFFSETS AND ESTIMATION OF ANNUAL EMISSION REDUCTIONS

Typical site operations for the Red Hook WPCP are described in Section 1.3. Normal site operations in the absence of the PC25 fuel cells include destruction of the ADG in the enclosed flare, purchase of electricity from ConEd, and procurement of steam for process heat, space heating, and domestic hot water from the neighboring cogeneration facility. These operations represent the baseline power and heat scenario for this facility. Emissions of CO₂ and NO_x generated by the baseline power and heat scenario represent the baseline emissions scenario for this site.

A portion of the ADG generated is used to meet some of the power and heat demand of the facility through on-site generation when the PC25 is operating. Less power is purchased from the grid, less heat from the cogeneration facility is used, and less ADG is combusted in the flare under this scenario. This represents the PC25 system power and heat scenario for this facility and, consequently, the PC25 system emissions scenario. A reduction in emissions will be realized under the PC25 system scenario if emissions of CO₂ and NO_x from the PC25 are lower than the emissions associated with the utility grid. An on-site CHP system used to provide heat as well as power will also typically create an emissions reduction for the baseline heat source. That is not the case at this facility, however, because the heat is generated by a large co-generating facility that can use the offset heat for other customers. Production of heat by the PC25 at Red Hook will not change operations at the cogeneration facility and, therefore, no emission reductions are realized.

Use of the PC25 at this facility presents an added environmental benefit by offsetting emissions from the enclosed flare. ADG used to fuel the PC25 would otherwise be combusted by the flare. An additional reduction in emissions will be realized under the PC25 system scenario if emissions of CO₂ and NO_x from the PC25 are lower than the emissions associated with the flare.

Emissions from the PC25 will be compared with the baseline scenario to estimate annual NO_x and CO₂ emission levels and reductions (lb/yr). These pollutants were considered because CO₂ is the primary greenhouse gas emitted from combustion processes and NO_x is a primary pollutant of regulatory interest. Emission factors for the electric utility grid are available for both gases as are flare emission rates. Emission reductions are computed as follows:

$$\text{Annual Emission Reductions (lb/yr)} = [\text{Baseline Scenario Emissions (lb/yr)}] - [\text{PC25 System Scenario Emissions (lb/yr)}]$$

$$\text{Annual Emission Reductions (\%)} = \text{Annual Emission Reductions (lb/yr)} / [\text{Baseline Scenario Emissions (lb/yr)}] * 100$$

The following 4 steps describe the methodology used.

Step 1 - Determination of the Annual Electrical Energy Profile of the Red Hook WPCP

The first step in estimating emission reductions is to determine the annual electrical energy demand of the facility on a monthly basis. This will be done by obtaining the monthly power bills from the facility and compiling the demand for the calendar year preceding the verification testing. These data will be compiled as shown in the example data in Table 2-4. These monthly demand values, along with estimated annual flare emissions, will represent the baseline emissions scenario for Red Hook.

Table 2-4 will be completed after verification testing to estimate the distribution of energy demand as supplied by the systems in the baseline and PC25 scenarios. The power values reported for the PC25 will be determined based on the average power output measured during full-load tests and the number of operating days in each month.

Table 2-4 Electrical Demand of the Red Hook WPCP				
	Monthly Electrical Demand* (kWh)	Baseline Scenario	PC25 System Scenario	
		Power Supplied By Utility Grid* (kWh _{Grid})	Power Supplied by PC25 (kWh _{SU1})	Power Supplied by Grid (kWh _{Grid})
Jan	114,710	114,710	Estimated for each month using power output verified during testing	Calculated as monthly demand minus power supplied by PC25
Feb	90,833	90,833		
Mar	94,007	94,007		
Apr	86,251	86,251		
May	86,066	86,066		
June	99,260	99,260		
July	112,824	112,824		
Aug	112,770	112,770		
Sept	95,335	95,335		
Oct	86,451	86,451		
Nov	88,677	88,677		
Dec	104,540	104,540		
Annual Total	1,171,724	1,171,724		

* Data are not actual facility demand data, they are presented for demonstration only.

Step 2 - Emissions Estimate For the Utility Grid

Emissions associated with electricity generation at central power stations is defined by the following equation:

$$E_{Grid} = kWh_{Grid} * 1.078 * ER_{Grid} \quad (\text{Eqn. 14})$$

where:

E_{Grid}	=	grid emissions (lb/yr)
kWh_{Grid}	=	electricity supplied by the grid, Table 2-4 (kWh)
1.078	=	transmission and distribution system line losses (dimensionless)
ER_{Grid}	=	NY ISO-displaced emission rate (lb/kWh)

The kWh_{Grid} variable shown above represents the estimated electricity supplied by the utility grid under the baseline scenario and the PC25 scenario (Table 2-4). These values are increased by a factor of 1.078 to account for line losses between central power stations and the end user.

The grid emission rate (ER_{Grid}) is a complex subject, and the methodology for estimating it is continuously evolving. The discussion presented in Appendix C-1 provides a background on the concept of displaced emissions and details the strategy employed by the GHG Center to assign ER_{Grid} for this verification.

The GHG Center will use the emission factors developed by the Ozone Transport Commission (OTC) as discussed in Appendix C-1. The OTC emission factors for this region are separated into ozone and non-ozone seasons as well as weekdays and night/weekend time periods as summarized in Table 2-5.

	NO_x (lb/kWh_e)	CO₂ (lb/kWh_e)
Ozone season weekday ^a	0.0021	1.37
Ozone season night/weekend ^b	0.0028	1.67
Non-ozone season weekday ^c	0.0021	1.46
Non-ozone season night/weekend ^d	0.0028	1.61
^a Average of all hourly marginal emission rates during weekdays, May through September, 7:00 am through 10:59 pm ^b Average of all hourly marginal emission rates during all nights, May through September, 11:00 pm through 6:59 am, and all weekend days during this period ^c Average of all hourly marginal emission rates during weekdays, October through April, 7:00 am through 10:59 pm ^d Average of all hourly marginal emission rates during all nights, October through April, 11:00 pm through 6:59 am, and all weekend days during this period		

The Center will use the monthly demand profiles shown in the example in Table 2-4 along with the seasonal emission factors above to estimate total annual grid emissions associated with the Red Hook facility.

Step 3 – Estimate Annual Flare Emissions

The Red Hook facility monitors ADG flow to the flare throughout the year. The Center will use these records to estimate the total ADG combusted during the year calendar year preceding the verification. These data will be used in conjunction with the most reliable CO₂ and NO_x emission factors available for this flare. Published EPA flare emission factors (AP-42) will be used if reliable emissions-data specific to this flare are not made available by the owner. These data, in units of pounds of pollutant per standard cubic foot of ADG (lb/scf), will yield the estimated flare emissions as lb/yr. The flare emissions will be added to the estimated annual grid emissions to establish the total facility baseline emission estimate.

The same approach will be used to estimate flare emissions for the PC25 scenario except the estimated annual ADG combusted in the flare will be reduced by the amount of ADG used to fuel the PC25. The average PC25 gas consumption rate measured during the verification testing at full load will be used to estimate the amount of gas used during a typical year of PC25 operation as shown in the following equation:

$$Q_{annual} = Q_{full\ load} * 8,760 * 0.95 \tag{Eqn. 15}$$

where:

- Q_{annual} = annual PC25 ADG consumption, scfy
- $Q_{full\ load}$ = PC25 ADG consumption rate at full load, scfh
- $8,760$ = hours per year hr/yr
- 0.95 = projected PC25 availability %

Step 4 – Emissions Estimate For the PC25

Annual PC25 emissions will be estimated using the system power output (kW) and NO_x and CO₂ emission rates (lb/kWh) measured during the verification testing. Total PC25 power produced during each month will be projected and used in Table 2-4 to establish the PC25 emissions scenario. Fuel cell power output and emission rates are not expected to change seasonally as a function of ambient conditions. The monthly power output and associated emissions will be calculated as follows:

$$P_{PC25} = (GR * hr_i * 0.95) \tag{Eqn. 16}$$

where:

- P_{PC25} = monthly power generated, kWh
- GR = average measured power output, kW
- hr_i = hours in each month
- 0.95 = reported system availability

$$ER_{PC25} = ER_{full\ load} * P_{PC25} \tag{Eqn. 17}$$

where:

- ER_{PC25} = monthly PC25 emissions, lb/mo
- $ER_{full\ load}$ = average measured PC25 emission rate lb/kWh
- P_{PC25} = monthly power generated from Equation 16 kWh/mo

2.6 GPU PERFORMANCE

Testing will be conducted to evaluate the GPU performance by comparing the composition, heating value, and contaminant concentrations of raw ADG to that of processed gas. The following gas compositional and quality criteria will be evaluated on raw and processed ADG samples:

- Gas properties (gross and net heating value, density, and compressibility)
- Gas composition (N₂, O₂, CO₂, and C₁ through C₆)
- Sulfur compounds
- Volatile organic compounds (VOCs) and total halides
- Moisture content

A minimum of six ADG samples will be collected on both the upstream and downstream sides of the GPU during the controlled testing periods for efficiency and emissions. Results of the analyses will be used to evaluate GPU removal efficiency for moisture, H₂S and sulfur compounds, and VOCs. The results will also allow the Center to evaluate the effects, if any, on ADG composition and heating value.

2.6.1 Determination of Raw and Processed ADG Composition

Section 2.2.3.5 of this Test Plan detailed the sampling and analytical procedures that will be used to determine gas composition and heating value for processed gas (fuel gas to PC25). The same sampling and analytical procedures will be used for the ADG prior to GPU treatment. Two processed ADG samples are specified for each load condition tested during the controlled test periods (total of six anticipated). During these tests, at least six corresponding raw ADG samples will be collected for comparison of basic compositions and LHV. Like the processed ADG samples previously specified, the raw gas samples will be collected in stainless steel canisters and shipped to Empact. Associated QA/QC procedures for these samples are detailed in Section 3.4.4.

In addition to the raw and processed ADG samples collected in the stainless steel canisters, a corresponding set of at least three raw and three processed ADG samples will also be collected in Tedlar bags. These samples will be submitted to Air Toxics, Ltd. of Folsom, California (ATL) for VOC and sulfur compounds analysis. The samples will be analyzed within 24 hours of collection. All samples shipped to the laboratory will be accompanied by appropriate chain-of-custody forms and documentation. The VOC analyses will be conducted in accordance with EPA Method TO-15 (15), and the sulfur compounds analyses will be conducted using ASTM Method 5504 (8). VOC and sulfur species to be quantified are listed in Appendix D.

For VOC analysis by Method TO-15, a known volume of sample is extracted from the bag through a mass flow controller and is concentrated on a multisorbent bed where VOC species are trapped and water vapor is released. The VOCs are then thermally desorbed from the concentrator, entrained in a carrier gas, and carried onto a gas chromatographic (GC) column for separation. The GC is coupled with a mass spectrometer (MS) in the Selective Ion Monitoring (SIM) mode for VOC species detection. A total of 60 VOCs are included in the analysis with individual compound reporting limits ranging from 0.5 to 2.0 ppb. ATL maintains a rigorous QA/QC protocol for this analysis including instrument calibrations, laboratory control samples, calibration verification, laboratory blanks, and duplicate analyses. Details regarding the QA/QC procedures are presented in Section 3.6.2. Results of the TO-15 analyses are used to compute halide concentrations. This is done by summing the products of the concentration of each halide species detected and the number of halide atoms per mole of each species (e.g., 10 ppbv of carbon tetrachloride will contribute 40 ppbv to the total halide concentration reported).

For analysis of sulfur species, a known volume of sample is injected into a GC equipped with a molecular sieve column. As the sulfur components elute from the GC, they are transferred to a sulfur chemiluminescence detector (SCD) for quantitation. Resultant peaks in the chart trace are determined for each compound. These areas are compared to the areas of the same compounds contained in a calibration reference standard that is analyzed under identical conditions. A total of 20 sulfur compounds are included in the analysis with individual compound reporting limits of 4.0 ppb. QA/QC procedures for this analysis including instrument calibrations, laboratory control samples, internal standards, laboratory blanks, and duplicate analyses. Details regarding the QA/QC procedures are presented in Section 3.6.3.

2.6.3 Determination of Raw and Processed ADG Moisture Content

GHG Center personnel will determine ADG moisture content in the field by ASTM D4888-88 (7). The Center will acquire at least one moisture sample in conjunction with each ADG sample collected at the GPU inlet and outlet. A Drager CMS Chip Measurement System will be utilized for on site analysis of gas samples. The chip measurement system utilizes the same technology as the traditional hand pumped Drager detector tubes, using a gas specific chemical reaction to produce a color change in a detector tube loaded with reactant. Any water vapor present in the sample reacts with the chemical to produce a color change or stain. The length of the stain, when exposed to a measured volume of gas, is directly proportional to the amount of water vapor in the gas. The Drager CMS uses a metered automatic pump to consistently extract the required sample volume, and uses a photo-optical controller to monitor the rate and amount of color change in the detector tube. Based on calibration data included for the individual gas chip, the CMS outputs a water vapor content reading in milligrams per liter (mg/L). Each chip is calibrated at the factory and calibration data included in a bar code on the chip for input to the CMS reader.

The analytical range of the CMS with water vapor chip (Drager 6406450) is 0.40 to 10 mg/l of H₂O. Accuracy of the Drager CMS is approximately ± 8 percent of reading, with a reproducibility of ± 10 percent of reading.

The Drager CMS unit performs an electronic system self-test when powered on and a sampling system self-test prior to each sample collection. This ensures that the sampling unit and analyzer are functioning properly. The CMS also uses a mass flow controller that also compensates for atmospheric pressure changes to ensure that the same mass of air is sampled during each analysis.

3.0 DATA QUALITY

3.1 BACKGROUND

The GHG Center selects methodologies and instruments for all verifications to ensure a stated level of data quality in the final results. The GHG Center specifies DQOs for each verification parameter before testing commences as a statement of data quality. For DG/CHP technologies such as the PC25 being verified here, these DQOs have been established based on the level of accuracy desired by the GHG Center's stakeholders, and the measurement accuracies achieved in similar verifications conducted in the past. Each test measurement that contributes to the determination of a verification parameter has stated data quality indicators (DQIs) which, if met, ensure achievement of that parameter's DQO.

The establishment of DQOs begins with the determination of the desired level of confidence in the verification parameters. Table 3-1 summarizes the DQOs for each verification parameter. The next step is to identify all measured values which affect the verification parameter and to determine the levels of error which can be tolerated. The DQI goals, most often stated in terms of measurement accuracy, precision, and completeness, are used to determine if the stated DQOs are satisfied.

Table 3-1. Verification Parameter DQOs		
Parameter	Total Measurement Error ^a (±)	
	Absolute	Relative
Heat and Power Production Performance		
Electrical power output at selected loads (kW)	2.0 ^b kW	1.0^c %
Electrical efficiency at selected loads (%)	0.56 %	1.6^d %
Heat recovery rate at selected loads (MMBtu/hr)	13,700 ^b Btu/hr	1.7^d %
Thermal energy efficiency at selected loads (%)	0.70 %	1.7^d %
CHP production efficiency (%)	1.7 %	2.3^d %
Power Quality Performance		
Electrical frequency (Hz)	0.006 Hz	0.01 %
Voltage (VAC)	4.85 V	1.0^c %
Power factor (%)	TBD	0.50 %
Voltage and current THD (%)	TBD	1.00 %
Emissions Performance		
CO, NO _x , CO ₂ concentration (ppmv, %)	TBD	2.0 % FS
CH ₄ , THC concentration (ppmv)	TBD	5.0 % FS
CO, NO _x , CO ₂ emission rates (lb/kWh)	TBD	5.6 %
CH ₄ , THC emission rates (lb/kWh)	TBD	7.2 %
GPU Performance		
ADG Sulfur and VOCs content (ppm or ppb)	TBD	30.0 %
ADG Moisture Content (%)	TBD	10.0 %
^a Bold column entries are DQOs; non-bold column entries are for information purposes ^b Assumes full load operation 200 kW: 480 VAC, 282 A ^c Includes 0.1 percent instrument error and 1.0 percent current transformer (CT) ^d Calculated composite error described in text TBD = to be determined		

3.2 ELECTRICAL POWER OUTPUT AND POWER QUALITY

The ION power meter will measure electrical power output and power quality. The inherent instrument error constitutes the DQO for power output, frequency, voltage, power factor, and THD as listed in Table 3-1. Table 3-2 summarizes the instrument specifications, DQI goals, and the primary method of evaluating the DQI goals achieved for each measurement. Factory calibrations, sensor function checks, and reasonableness checks in the field (listed in Tables 3-2 and 3-3) will document achievement of the DQI goals. Some of the QA/QC procedures to be performed are described below.

The power meter manufacturer will issue a calibration certificate which shows compliance with IEC 687 S0.2 and ANSI C12.20 CA0.2. Consistent with ISO 9002-1994 requirements, the manufacturer will supply calibration documents, which certify NIST traceability. The GHG Center will review the certificate and traceability records to ensure that the instrument meets or exceeds the accuracy specifications listed in Table 3-2. Note that the accuracy standard for power kW, compounded with the ± 1.0 percent accuracy specification for the current transformers, yields the ± 1.0 percent DQO specified in Table 3-1.

The power meter is designed and marketed for electric utility custody transfer applications. Its calibration records are reported to be valid for a minimum of one year of use, provided the manufacturer-specified installation and setup procedures are followed. GHG Center personnel will follow installation, setup, and QC procedures detailed in Appendices B-1 and B-2.

GHG Center personnel will perform checks in the field for two key measurements – voltage and current output – which are directly related to the power output measurement. These checks are intended to verify proper field wiring and function of the meter. The Field Team Leader will measure distribution panel voltage and current at the beginning of the verification period. He will use a digital multimeter (DMM) and compare voltage and current readings to the power meter readings as recorded by the DAS. The Field Team Leader will obtain a minimum of five individual voltage and current readings for the given load. The power meter voltage and current accuracies are ± 1.0 percent while the DMM is ± 1 percent. The percent difference between the DMM reading and the power meter reading should be within ± 1.4 percent for voltage and current (± 1.4 percent is the propagated error of the two measurements). In these cases, the power meter will be deemed to be functioning properly.

Comparisons of the power meter readings as recorded by the GHG Center's DAS with the power output recorded by the PC25 control panel will constitute the reasonableness check. The power meter and control panel readout should indicate between 180 and 200 kW at full load.

Table 3-2. Measurement Instrument Specifications and DQI Goals For Heat and Power Production

						Data Quality Indicator Goals			
Measurement Variable		Operating Range Expected in Field	Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Accuracy ^a	Completeness	How Verified / Determined
Electrical Power Output and Quality	Power	0 to 200 kW	Electric Meter/ Power Measurements 7600 ION or equivalent	0 to 260 kW	± 1.0% reading	Once per sec.; DAS records 1 - min averages	± 1.0% reading ^c	100% for load test periods, 90% for extended monitoring at normal site conditions.	Review manufacturer calibration certificates; perform sensor function checks in field
	Voltage	480 V 3 -phase ± 10%		0 to 600 V	± 1.0% reading		± 1.0% reading		
	Frequency	60 Hz		57 to 63 Hz	± 0.01% reading		± 0.01% reading		
	Current	0 to 282 amps		0 to 400 amps	± 1.0% reading		± 1.0% reading		
	Voltage THD	0 to 100%		0 to 100 %	± 1.0% FS		± 1.0% FS		
	Current THD	0 to 100%		0 to 100 %	± 1.0% FS		± 1.0% FS		
	Power Factor	0 to 100%		0 to 1.0	± 0.5% reading		± 0.5% reading		
Heat Recovery	Fluid Flow Rate	0 to 40 gpm	Controlotron Model 1010WP	Approx. 0 to 100 gpm	± 1.5% reading		± 1.5% reading		
	Supply and Return Fluid Temperatures ^b	100-150 °F		-40 to 250 °F	± 0.02 °F		± 1.5 °F @ 150 °F		
Ambient Meteorological Conditions	Ambient Temperature ^b	30 to 90 °F	Vaisala HMD 60YO	-40 to 140 °F	± 1 °F	1 - min averages	± 1 °F		Review manufacturer calibration certificates
	Relative Humidity ^b	20 to 90%		0 to 100%	± 2% 0 to 90% (RH.) ± 3% 90 to 100% (RH)		± 3%		
	Ambient Pressure ^b	14 to 15 psia	SETRA Model 280E or equiv.	0 to 25 psia	± 0.1% FS		± 0.1% FS		

Table 3-2. Measurement Instrument Specifications and DQI Goals For Heat and Power Production (continued)

						Data Quality Indicator Goals			
Measurement Variable	Operating Range Expected in Field		Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Accuracy ^a	Completeness	How Verified / Determined (see Table 3-3)
ADG Input	Volumetric Flow Rate	29.2 to 58.3 acfm	Dresser-Roots Series B3; Model 5M175CEX rotary meter	0 to 83.3 acfm	± 1.0% reading	DAS records 1-min averages	± 1.0% reading	95% valid 1-min averages for short-term tests; 80% valid 1-min averages for extended monitoring period	Review manufacturer's NIST-traceable calibration records; perform reasonableness checks
	Gas Pressure	0 to 10 in. H ₂ O	Pressure Transmitter / Rosemount 3051	-100 to 100 in. H ₂ O	± 0.1% FS		± 0.1% FS		
	Gas Temperature	50 to 90 °F	Omega Model 93-K2 Type K transmitter	0 to 200 °F	± 1.5% reading		± 1.5 % reading		
	Fuel Gas Composition and LHV	60 to 65% CH ₄ (600 to 700 Btu/scf)	Gas Chromatograph / HP 589011	0 to 100% CH ₄	± 3.0% accuracy and ± 0.2% repeatability for CH ₄ ; ± 0.1% repeatability for LHV	Min. 2 samples per day during controlled test periods	± 0.2% for LHV	100% for short-term load tests	Repeatability check: Duplicate analyses on each sample

FS: full-scale

^a Accuracy goal represents the maximum error expected at the operating range. It is defined as the sum of instrument and sampling errors.

^b These variables are not directly used to assess DQOs, but are used to determine if DQIs for key measurements are met. They are also used to form conclusions about the system performance.

^c Includes instrument and current transformer (CT) errors.

Table 3-3. Summary of Heat and Power Production QA/QC Checks

<i>Measurement Variable</i>	<i>QA/QC Check</i>	<i>When Performed/Frequency</i>	<i>Expected or Allowable Result</i>	<i>Response to Check Failure or Out of Control Condition</i>
Power Output	Instrument calibration by manufacturer ^a	Annually	± 0.1% reading	Identify cause of any problem and correct, or replace meter
	Sensor diagnostics in field	Beginning of test	Voltage and current checks within ± 1.4% reading	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	180 to 200 kW at full load	Identify cause of any problem and correct or replace meter
Fuel Flow Rate	Instrument calibration by manufacturer ^a	Prior to meter installation	± 1.0% reading	Identify cause of any problem and correct, or replace meter
	Differential rate test	Beginning of test	± 10 percent of anticipated value	
	DAS calibration	Beginning of test	Not applicable	Develop calibration curve and apply to DAS log
Fuel Gas Pressure	Instrument calibration by manufacturer ^a	Annually	± 0.1% FS	Identify cause of any problem and correct, or replace sensor
Fuel Gas Temperature	Instrument calibration with NIST traceable reference standard ^a	Annually	± 1.5% reading	Identify cause of any problem and correct, or replace sensor
ADG Composition and Heating Value Analysis	Duplicate analyses performed by laboratory	At least once for load tests and on three of the GPU performance tests	Refer to ASTM D1945	Repeat analysis
	Calibration with gas standards by laboratory	Prior to analysis of each lot of samples submitted	± 1.0% for CH ₄	Repeat analysis
Heat Recovery Rate	Calibrate ultrasonic fluid flow meter with NIST traceable standard ^a	Prior to testing	Fluid flow rate: ± 1.5% of reading	Recalibrate flow meter
	Meter zero check	Prior to testing	Reported heat recovery < 0.5 Btu/min	Recalibrate heat meter
	Independent performance check of temperature readings ^a	Beginning of test period	Difference between RTD readings < 0.4 °F. Difference between RTD and thermocouple readings < 1.5 °F.	Identify cause of discrepancy and recalibrate heat meter
	Reasonableness Check	At least once during test	Difference between DAS and manual calculation < 5%	Identify discrepancies / recalibrate heat meter
Ambient Meteorological Conditions	Instrument calibration by manufacturer or certified laboratory ^a	Annually	Temp: ± 1 °F Pressure: ± 0.1% FS RH: ± 3%	Identify cause of any problem and correct, or replace sensor

^a Results of these QA checks will be used to reconcile DQIs.

3.3 HEAT RECOVERY RATE

Tables 3-2 and 3-3 summarize the DQIs and QA/QC checks associated with this verification parameter. The following paragraphs discuss these checks. The GHG Center will obtain factory calibrations for the flow transducers and RTDs to ensure the energy meters' accuracy requirements are met. The flow transducer is calibrated by Controlotron at the factory following their CS2 Flow Through Calibration Procedure. In general, the meter is mounted on a specific type and size of pipe as requested by the Center following standard installation procedures. A series of tests are then conducted by passing known amounts of water through the pipe and comparing the meter response with the reference standard. The reference standard consists of a NIST traceable temperature sensor, timer, balance, and reference weights. This meter was calibrated on 2-inch carbon steel pipe and 1.5-inch copper pipe in October 2002.

The meter zero check verifies a zero reading by the meter when the CHP system is not in operation. The energy meter's fluid index check uses the ultrasonic signal transit time to verify the meter installation integrity. The meter's software uses a series of look-up tables to assign a reference transit time signal based on input parameters which includes tubing specifications and fluid composition. The Field Team Leader will compare the actual transit-time signal to the reference value. After installation of the meter components, differences between the actual and reference values in excess of 5.0 percent indicate an installation or programming error and a need for corrective action.

The Field Team Leader will independently verify RTD accuracy in the field. He will remove the RTDs from the fluid tubing and place them in an ice water bath along with thermocouples of known accuracy. Temperature readings from both sensors will be recorded for comparison. He will then repeat the procedure in a hot water bath. If the average differences in temperature readings are greater than 1.5 °F, the meter RTDs will be sent for re-calibration. Appendix B-6 contains the field data form.

3.4 ELECTRICAL, THERMAL, AND CHP EFFICIENCY

Electrical efficiency requires determination of electrical power output and fuel heat input. Fuel heat input requires determination of standard flow rate and fuel LHV. Standard flow rate requires determination of actual flow rate, fuel gas pressure, temperature, and compressibility ratios. Determination of total measurement error requires propagation of the individual contributing measurement errors, each with their own characteristic absolute and relative errors. Appendix B-5 presents the error propagation methods to be used in this verification.

Table 3-4 applies the concepts to estimate the electrical efficiency compounded errors. The table includes the referenced equations, contributing measurements, expected measured values, and instrument or compounded errors. The equations presented in Section 2.2 were used to calculate values in this table.

The electrical efficiency DQO will be 1.90 percent, as shown above and in Table 3-1. The DQI goals listed in Table 3-2 are directly linked to the DQO achievement because if DQIs are met, the instruments and measurements will achieve the listed accuracies. Analysts can reasonably conclude that the DQO is achieved in turn if the test campaign achieves each of the listed accuracies. Section 3.2 discussed the QA/QC procedures to be performed to assess achievement of DQI goals for the power meter. The following subsections describe the QA/QC procedures for the remaining measurements.

Table 3-4. Electrical Efficiency Error Propagation and DQO

Contributing Measurements		Expected Value	Absolute Error	Relative Error (%)
Fuel flow rate at standard conditions, V_g , requires Equation 4 and these measurements	Actual fuel flow rate, V_g	58.30 acfm	0.583 acfm	1.0
	Fuel gas pressure, P_g	14.87 psia	0.05 psia	0.3
	Fuel gas temperature, T_g	560 °R	1.74 °R	0.3
	Fuel gas compressibility factor @ standard conditions, Z_{std}	0.9980	0.00200	0.2
	Fuel gas compressibility factor @ actual conditions, Z_g	0.9979	0.00200	0.2
	Eqn. 4 result:	54.65 scfm	0.623 scfm ^a (54.65*0.0114)	1.1 ^a
Heat input, HI, requires Equation 3, this measurement, and the Equation 4 result	LHV, Btu/scf	600 Btu/scf	1.2 Btu/scf	0.20
	Eqn. 3 result:	1,967 MBtu/hr	22.8 MBtu/hr ^a (1,967*0.0116)	1.2 ^a
Electrical Efficiency, η_e , requires Equation 1, this measurement, and the Equation 3 result	Power Output, kW	200.0 kW	2.0 kW	1.0
	Eqn. 1 result:	34.7 %	0.56% ^a (34.7*0.016)	1.6^{a,b}
^a Errors compound per Appendix B-5				
^b DQO for electrical efficiency				

3.4.1 ADG and Fuel Flow Rate Quality Assurance

The new Roots rotary-type gas meter will be delivered from the factory with a NIST-traceable calibration at a minimum of 2 points within the specified meter range. The calibration certificate will indicate measured readings, reference readings, and the percent difference between the diaphragm gas meter and the reference standard. The average percent difference will represent the overall accuracy of the meter. GHG Center personnel will review the calibration to ensure satisfaction of ± 1.0 percent accuracy specification. A differential rate test will be conducted on the meter in the field to confirm the meters functionality after installation. This check will be conducted following manufacturer guidelines. The differential pressure across the meter across will be measured in units of inches of water using a manometer. The differential pressure measured in the field will be compared to the factory curve for this particular meter. With the fuel cell operating at full load, the meter's pressure differential should be around 0.52 inches of water.

The meter is equipped with a pulse counter and transmitter to allow the Center to log gas flow rates electronically on the DAS. A calibration curve will be developed to eliminate any possible bias between the electronically logged data and the meter index. The calibration will be conducted at four gas flow rates including zero flow and the gas flow rate at the three controlled test load settings (100, 75, and 50 percent of fuel cell generating capacity). Manual index readings will be compared to data logged on the DAS at each gas flow set point using the procedures described in Appendix B-3. The four calibration points will be used to develop the calibration curve, which will then be applied to the gas flow data stored on the DAS.

3.4.2 Gas Pressure and Barometric Pressure Quality Assurance

The manufacturers will calibrate the Setra ambient pressure and Rosemount 3051 fuel gas pressure transducers prior to testing. The resulting calibration certificates will be NIST-traceable; GHG Center personnel will review the calibration to ensure satisfaction of the accuracy specifications for each unit.

3.4.3 Gas Temperature and Ambient Temperature Quality Assurance

The Omega gas temperature sensor and the Vaisala ambient temperature/RH sensor will be calibrated prior to testing. The resulting calibration certificates will be NIST-traceable. GHG Center personnel will review the calibration to ensure satisfaction of the ± 1.4 °F at 90 °F specification for the gas temperature sensor, and the ± 1 °F specification for ambient temperature.

A reasonableness check prior to testing will have the GHG Center comparing the sensors' DAS readings with a hand-held digital thermometer while all three temperature gauges are exposed to ambient air. Agreement within ± 4 °F will show that the sensors are operating properly. Appendix B-4 contains the procedure and log form.

3.4.4 ADG Analyses Quality Assurance

PTC-50 specifies that the fuel heating value be accurate to ± 1.0 percent or better. This will be the DQI for the fuel analysis. Field personnel will collect fuel gas samples as described in Section 2.2.3.5 and submit them for laboratory analysis. The laboratory will perform compositional analysis by ASTM D1945 and calculate LHV and HHV by ASTM D3588.

ASTM D1945 repeatability directly affects the ASTM D3588 LHV and HHV data quality. Provided the D1945 repeatability criteria are met, the LHV and HHV repeatability is approximately 1.2 Btu per 1000 ft³, or about 0.1 percent. The ASTM D1945 allowable method error during calibration is ± 1.0 percent of the reference value for each gas component. The reference standard will be a NIST-traceable natural gas reference standard of known concentration.

The compounded accuracy of the two methods, including repeatability, allowable instrument error, and the maximum permitted calibration error, is therefore 1.0 percent. Achievement of proper calibrations and repeatability imply that use of these two ASTM methods will ensure that LHV and HHV data are accurate to ± 1.0 percent or better.

At the laboratory, analysts will challenge the instrumentation at least weekly with a gas reference standard. The result for each gas component must be within ± 1.0 percent. The laboratory will also analyze each fuel gas sample in duplicate. The duplicate analyses must conform to the ASTM D1945 repeatability guidelines for each gas component.

3.5 EMISSIONS TESTING QA/QC PROCEDURES

This verification will use the EPA reference methods listed Table 2-2 to quantify criteria pollutant and GHG emission rates. The reference methods clearly specify sampling methods, calibration methods, and data quality checks which assure that the acquired data meets required quality goals. These methods ensure that run-specific quantification of instrument and sampling system drift and accuracy occurs and that testers repeat runs if specific performance goals are not met. The DQOs for concentration

measurements, based on reference method requirements, are ± 2 percent for NO_x , CO, and CO_2 , and ± 5 percent for THC and CH_4 . The data quality indicator goals (DQIs) required to meet these DQOs will consist of assessing the sampling system accuracy, precision, and drift as outlined in Table 3-5.

The GHG Center will assess emissions data quality, integrity, and accuracy with a series of measurement system calibrations and quality control checks. The reference method QC checks vary between methods and are pollutant-specific. Table 3-6 lists the QC checks required for each parameter, how often testers will perform them, the maximum allowable result, and the corrective measures for failed checks. The DQI goals and QC checks listed in Tables 3-5 and 3-6 are similar to the electric power performance parameters directly linked to the achievement of the emission testing DQOs listed in Table 3-1 because, if they are met, the instruments and measurements will achieve the listed accuracies. The DQOs will be achieved in turn if each of the listed accuracies are achieved.

Table 3-5. Instrument Specifications and DQI Goals for Emissions Testing

Measurement Variable		Instrument Specifications			Data Quality Indicators		
		Instrument Type or Method	Instrument Accuracy ^a	Frequency of Measurements	Overall Sampling System Accuracy	Completeness	How Verified / Determined ^b
PC25 Emissions	NO _x Concentrations	Chemiluminescence analyzer	± 1% FS	1-minute averages (DAS polls analyzer outputs at 5-second intervals)	± 2 % FS includes sampling system bias corrections)	100%; 3 valid runs at each specified load)	Follow EPA Method calibration and system performance check criteria
	CO Concentrations	NDIR analyzer	± 1% FS				
	CO ₂ / O ₂ Levels; Stack Gas Molecular Weight	NDIR (CO ₂) / paramagnetic or equivalent (O ₂)	± 1% FS				
	THC Concentrations	FID	± 1% FS		± 5% FS		
	CH ₄ Concentrations	GC / FID	± 0.1% FS	Once per test run	± 5% FS		
	Water Content	Gravimetric	± 0.2% FS (FS = 100%)	Once per load condition	±5% FS		
	Stack Gas Flow Rate	Pitot and Thermocouple	Pitot Δp: ± 1.0% Thermocouple: ± 1.5 % of average stack temperature	Once per test run	± 5% FS		

^a Instrument accuracy is a function of the selected range or full-scale (FS). See Table 2-2 for a complete list of anticipated instrument ranges.
^b For a full description, see Table 3-8.

Table 3-6. Summary of Emissions Testing QC Checks

Measurement Variable	Calibration/QC Check	When Performed/ Frequency	Expected or Allowable Result	Response to Check Failure or Out of Control Condition
NO _x	NO ₂ to NO converter efficiency test	Once before testing	Efficiency > 90 percent required	Repair or replace analyzer
	Analysis of a blind audit gas		± 5% of reading	
NO _x , CO, THC, CO ₂ , O ₂	Analyzer calibration error test	Daily before testing	± 2% of analyzer span	Repair or replace analyzer
	System bias checks*	Before each test run	± 5% of analyzer span	Correct or repair sampling system
	Calibration drift test	After each test run	± 3% of analyzer span	Repeat test
CH ₄	Duplicate analysis*	At least 3 samples	± 5% difference	Repeat analysis of same sample
	Calibration of GC/FID with gas standards	Prior to analysis of the samples submitted for this test	± 5% for each compound	Repeat calibration
Sample Gas Transfer Lines	Material and condition inspection	Immediately prior to testing	Unheated lines are virgin Teflon; heated lines have been cleaned	Clean and/or replace tubing as needed
NO _x , CO calibration gases	Method 205 field evaluation test	Once before testing	Average analyzer response within ± 2 % of predicted value	Correct or repair gas dilution system
Stack Gas Flow	Pitot tube inspection and leak check	Once before and once after testing	See 40CFR60 Method 2	Select different pitot tube
	Thermocouple Calibration	Once after testing	± 1.5% at average stack temperature recorded during final test run	Adjust average stack temperatures for all test runs; recalculate stack flow rates
* Results of these checks will be used to reconcile data quality indicators				

3.5.1 Analyzer and Sampling System QA/QC Procedures

The corresponding reference methods detail the standard procedures listed in Table 3-6; they will not be repeated here in their entirety. The following paragraphs provide modifications to these procedures and specific procedure descriptions where needed for this verification.

NO₂ Sampling System and Zero Gas

GHG Center personnel will verify that the sampling system umbilicals, tubing, and manifolds have been cleaned or are constructed of “virgin” TeflonTM. The calibration gas manifold and/or regulators must incorporate check valves to prevent atmospheric O₂ from contaminating the NO₂ calibration gas. Testers must also follow proper calibration gas line and pigtail purging procedures to prevent cross-contamination. The zero gas for the NO_x sampling system must be analyzed and certified to contain less than 10 ppbv NO_x or CO. The Field Team Leader will inspect the zero gas calibration certificate prior to testing.

NO₂ Converter Efficiency Test

The NO_x analyzer converts any NO₂ present in the gas stream to NO prior to gas analysis. Testers will install an additional converter near the stack which will convert most NO₂ to NO prior to gas conditioning. It is important during low NO_x measurements to minimize NO₂ loss in the sampling system umbilical and moisture removal system. Testers will conduct a converter efficiency test prior to testing. They will determine converter efficiency for the overall sampling system according to the EPA approved alternative procedure (14). The converters will not be evaluated separately. The procedure specifies introduction of an appropriate EPA Protocol 1 NO₂ calibration gas to the system (approximately 1 to 2 ppm NO₂ in N₂ for this test series). Testers will record analyzer response every minute until the response stabilizes. The converters will be accepted if the recorded response is within 90 percent of the certified gas value. Testers will repair or replace one or both of the converters prior to testing of the NO_x measurement system fails the efficiency test.

NO_x Audit Gas

It is expected that NO_x emissions will be very low (2 ppm or less). To evaluate the NO_x sampling system accuracy at low concentrations, the GHG Center will provide an EPA Protocol 1 audit sample with a certified concentration around 1 ppm. The audit gas will be introduced as a blind audit to the sampling system at the probe tip and a stable system response will be recorded. System error will be calculated as follows:

$$[(\text{system error percent span}) = \{(\text{system response ppm}) / \text{audit gas ppm}\} / \text{span}] \times 100$$

The audit gas mixture will also contain a known concentration of CO₂ similar to that expected in the stack gas (approximately 12 percent). This will allow testers to evaluate whether the CO₂ levels cause an interference with the NO_x measurements.

Calibration Error, System Bias, and Calibration Drift Tests

Calibration error, drift, and system bias tests verify CO, CO₂, NO_x, THC, and O₂ measurement accuracy and will occur at the beginning of each day of testing. All calibration gas mixtures will conform to EPA Protocol 1 requirements. Testers introduce a suite of calibration gases directly to each analyzer and record the analyzer responses. Gas concentrations for CO₂, NO_x, and O₂ include zero, 40 to 60 percent of span, and 80 to 100 percent of span. CO and THC concentrations include zero and approximately 30, 60, and 90 percent of span. Analyzer response to any calibration gas must be within percent of span, according to ± 2 .

Testers will introduce zero-and mid-level calibration gases to the sampling system at the probe and record the response before and after each test. System bias is the comparison between these responses and the calibration error responses recorded earlier. The sampling system is acceptable if system bias is less than ± 5 percent of span for each parameter. Comparison of the pre- and post-test system bias calibrations quantifies each analyzer's drift. Drifts in excess of ± 3 percent are unacceptable and the test run will be repeated.

The low expected levels and analyzer spans for CO and NO_x require low calibration gas concentrations. Testers will therefore use a dynamic gas dilution system to generate specific calibration gas concentrations on site. They will follow EPA Method 205 field evaluation procedures which specify that gas concentrations will be within ± 2.0 percent of the predicted value after dilution. The Method 205 procedure is not repeated here but test personnel will perform all of the required QA/QC checks (including field evaluation of the dilution system). Method 205 generally specifies certified Protocol 1

calibration gases (one for each parameter), pure N₂, and a mass flow controller for accurate gas dilution (EnviroNics Series 6100 computerized multi-gas calibration system, or equivalent) to generate the low level calibration gases.

GC/FID Calibration

GC/FID procedures performed according to EPA Method 18 will determine concentrations of CH₄. Test personnel will calibrate the GC/FID prior to sample analysis with certified CH₄ standards. Analytical results must be within ± 5 percent. Each analysis includes the following quality assurance procedures outlined in 40 CFR Part 60, Appendix A, Method 18, Section 7.4.4 - Quality Assurance:

- Duplicate injections for at least three samples, with agreement to within 5 percent;
- Three-point calibration curves based on least-squares regression analysis;
- Calibration curves developed prior to analysis; and
- Agreement of all calibration points with the theoretical value to within 5 percent.

Testers will perform a triplicate mid-point calibration after all samples have been analyzed. Testers will generate a full post-test calibration curve if the as-analyzed value for any compound detected in the test program does not agree within ± 5 percent of its pretest value. Analysts will then base all reported concentrations on the average of the pre- and post-test calibration points.

Exhaust Gas Flow Rate

Exhaust gas flow rate determination includes exhaust CO₂, H₂O, and O₂ concentrations, velocity (differential pressure across a pitot tube), and gas temperature measurements. The GHG Field Team Leader will review O₂ and CO₂ instrumental analyzer data and calibrations at the end of each test day. Review criteria will be as described previously for the instrumental analyzers. He will also review exhaust gas moisture field data for conformance with EPA Method 4 practices.

Emissions test operators will certify that the pitot tubes meet applicable requirements for dimensional accuracy using the design criteria detailed in Method 2. They will also perform pre- and post-test thermocouple calibrations by subjecting the thermocouples used during testing to the average temperature found during testing and comparing the readings to a NIST-traceable reference thermometer. For acceptable results, the thermocouple reading must be within 1.5 percent of the reference thermometer. 40CFR60 Method 2, Section 10.3.1 presents specific thermocouple calibration details.

Composite Error in Emission Rate Determinations

Air pollutant emissions are measured in terms of concentration and production rate (in pounds per hour). These results are divided by the electrical power production rate in kWh to yield the air pollutant emission rate in pounds per kilowatt-hour. To determine overall emission rate error, the contributing measurement errors must be propagated as shown in Table 3-4. For example, the contributing measurements for the NO_x emission rate are stack gas concentration (ppmv converted to lb/dscf), exhaust gas flow rate (dscf/hr), and the total CHP power output (kW). The accumulated errors (i.e., DQIs) are ± 2.0 , ± 5.0 , and ± 1.5 percent, respectively. Compounding of errors in each of these measurements is multiplicative, similar to the discussion above. The result is an overall ± 5.59 percent relative error in the NO_x pound per kilowatt-hour emission rate. The calculations for CO and CO₂ are identical; For CH₄ and THC the higher concentration error yields a composite error of 7.22 percent. Table 3-1 summarizes these DQOs for all emission measurements.

3.6 GPU PERFORMANCE GAS ANALYSES

Analyses of raw and treated ADG includes quantification of VOCs and sulfur species by Air Toxics, Ltd. (ATL) and on-site determination of gas moisture content. QA/QC procedures for each of these analyses are summarized below.

3.6.1 ADG VOCs (Method TO-15)

Raw and treated ADG samples will be analyzed for the VOCs summarized in Appendix D-1. Following reference method guidelines, ATL maintains a rigorous quality assurance protocol to verify the accuracy of each analyte to ± 30 percent relative. Table 3-7 summarizes the QC checks and the corresponding performance criteria. Documentation from ATL that each of these QC checks were conducted and achieved will indicate that the DQO of ± 30 percent specified in Table 3-1 has been achieved.

Table 3-7. Summary of ADG VOCs QA/QC Checks		
QC Check^a	Minimum Frequency	Acceptance Criteria
Five point instrument calibration (ICAL)	Prior to sample analysis	Relative standard deviation ≤ 30%
Laboratory control sample (LCS)	After each ICAL	90% of VOCs listed in Appendix D-1 must be within 70 - 130% of expected values
Continuing calibration verification (CCV)	Beginning of each day of analyses	% difference ± 30% for each compound
Laboratory blank	After the CCV	Results lower than reporting limit
Surrogates	As each standard, blank, and sample is analyzed	70 to 130% surrogate recovery required
Duplicate analyses	10% of the samples	Relative percent difference of ≤ 25% for compounds detected 5 times higher than reporting limits

^a Appendix D-3 provides a brief description of each QC Check.

3.6.2 ADG Sulfur Compounds (ASTM 5504)

Raw and treated ADG samples will be analyzed for the 20 sulfur species summarized in Appendix D-2. Following reference method guidelines, ATL maintains a quality assurance protocol to verify the accuracy of each analyte to ± 30 percent relative. Table 3-8 summarizes the QC checks and the corresponding performance criteria.

The GHG Center will obtain, review, and archive documentation from ATL that each of these QC checks were conducted and criteria were achieved. This documentation will indicate that the DQO of ± 30 percent specified in Table 3-1 has been achieved.

Table 3-8. Summary of ADG Sulfur Compounds QA/QC Checks

QC Check ^a	Minimum Frequency	Acceptance Criteria
Five point instrument calibration (ICAL)	Prior to sample analysis	Relative standard deviation $\leq 30\%$
Laboratory control sample (LCS)	After each ICAL	90 percent of the compounds listed in Appendix D-2 must be within 70 - 130% of expected values
Continuing calibration verification (CCV)	Beginning of each day of analyses	90 percent of the compounds listed in Appendix D-2 must be within 70 - 130% of expected values
Laboratory blank	After the CCV	Results lower than reporting limit
Duplicate analyses	10% of the samples	Relative percent difference of $\leq 25\%$ for compounds detected 5 times higher than reporting limits

^a Appendix D-3 provides a brief description of each QC Check.

3.6.3 ADG Moisture Content

The DQO for ADG moisture determinations using the Drager chips will be evaluated by analyzing replicate samples. Back-to-back moisture samples will be collected at least three times during the verification period as a check for the method's repeatability. Each back-to-back sample will be collected immediately after the preceding moisture sample. Logged values should agree with each other within ± 10 percent or additional analyses will be run. Appendix A-8 provides the log form.

3.7 INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE

GHG Center personnel, the Field Team Leader, laboratories, and/or contracted test organizations will subject all test equipment to the pre- and post-test QC checks discussed earlier. Operators will assemble and test it as anticipated to be used in the field before the equipment leaves the GHG Center or analytical laboratories. They will operate and calibrate all controllers, flow meters, computers, instruments, and other sub-components of the measurements system as required by the manufacturer and/or this Test Plan. Any faulty sub-components will be repaired or replaced before being transported to the test site. Test personnel will maintain a small amount of consumables and frequently needed spare parts will be maintained at the test site. The Field Team Leader and Project Manager will handle major sub-component failures on a case-by-case basis (e.g., by renting replacement equipment or buying replacement parts).

3.8 INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES

Field personnel will use Natural Gas Reference Standard gases to calibrate the GC used for fuel analyses and EPA Protocol 1 NO_x calibration gases for the blind NO_x audit sample. The suppliers certify reference standard and audit gas concentrations to within ± 2 percent of the tag value. Copies of the audit gas certifications will be available on-site during testing and archived at the GHG Center.

Calibrations will use EPA Protocol 1 gases supplied either by the dilution system described above or directly from cylinders. The actual concentration must be within ± 2 percent of the certified tag value per EPA Protocol gas specifications. Copies of the EPA Protocol gas certifications will be available on-site.

4.0 DATA ACQUISITION, VALIDATION, AND REPORTING

4.1 DATA ACQUISITION AND STORAGE

Test personnel will acquire the following types of data during the verification:

- Continuous measurements (i.e., gas flow, pressure, and temperature; power output and quality; heat recovery rate; and ambient conditions) will be collected by the GHG Center's DAS.
- Fuel gas composition; heating value; compressibility factor; and sulfur, VOCs, and moisture content from canister samples will be collected by the Field Team Leader and submitted to the laboratory for analysis.
- Volumetric gas flow measurements will be collected by the Field Team Leader.
- Emission measurements data will be collected by the contractor and supervised by the Field Team Leader.

The Field Team Leader will also take site photographs and maintain a Daily Test Log which includes the dates and times of setup, testing, teardown, and other activities.

The Field Team Leader will submit digital data files, gas analyses, chain-of-custody forms, and the Daily Test Log to the Project Manager. The Project Manager will initiate the data review, validation, and calculation process. These submittals will form the basis of the Verification Report which will present data analyses and results in table, chart, or text format as suited to the data type. The Verification Report's conclusions will be based on the data and the resulting calculations. The GHG Center will archive and store all data in accordance with the GHG Center QMP.

4.1.1 Continuous Measurements Data Acquisition

An electronic DAS will collect and store continuous process and ambient meteorological data. Core components of the DAS are an Allen-Bradley (AB) Model SLC 5/05 programmable logic controller (PLC) and a Gladiator Unix-based data acquisition computer data server (TOGA). Figure 4-1 is a schematic of the DAS.

The PLC brings all analog and digital signals from the measurement sensors together into a single real-time data source. The DAS can accommodate any combination of up to 16 analog signal channels with 4 to 20 mA current or ± 10 VDC voltage inputs. Sensors can also provide digital signals *via* the ModBus network to the DF1 interface unit. This converts the ModBus data to the AB "DF1" protocol which is compatible with the PLC. The PLC nominally polls each sensor once per second and converts the signals to engineering units. It then computes 1-minute averages for export to the TOGA and applies a common time stamp to facilitate data synchronization of all measurements.

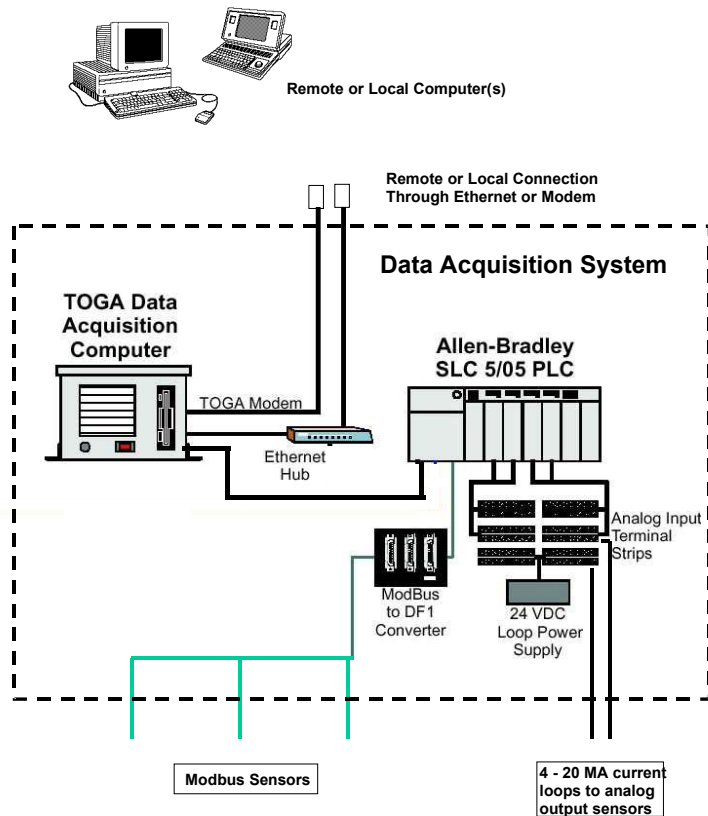


Figure 4-1. DAS Schematic

The TOGA data server records information from the PLC and contains the software for programming the PLC (i.e., data sampling rates, engineering unit conversions, calibration constants). Its UNIX operating system writes all PLC data to a My-SQL relational database for export to spreadsheet, graphics, and other programs. This database is open database connectivity (ODBC)-compliant, which means that almost any MS Windows program can use the data. The data server includes an external modem and Ethernet card for remote and local communications. The user accesses the data server with a portable laptop or remote computer (PC) *via* its communications port, Ethernet link, or telephone connection. During normal operations, spreadsheets allow the user to download the entire database or only that portion which has been added since the last download. The user then conducts data queries (i.e., for certain times, dates, and selected data columns on the downloaded data) as needed.

GHG Center personnel will configure the DAS to acquire the process variables listed in Table 4-1 during the verification testing. Note that the Field Team Leader will acquire the PC25 power command and date/time data manually at the start of each test run. Configuration and calibration of the DAS channels are recorded on log forms (Appendices A-7 and B-9, respectively).

Table 4-1 Continuous Data to be Collected for PC25 Evaluation

Sensor / Source	Measurement Parameter	Purpose ^a	Significance
Dresser-Roots gas meter	ADG flow (acfm)	P	System performance parameter
Rosemount pressure transducer	ADG pressure (psia)	P	System performance parameter
Omega Type K Thermocouple	ADG temperature (°F)	P	System performance parameter
Vaisala Model HMP60YO	Ambient temperature (°F)	P	System performance parameter
	Ambient relative humidity (% RH)	P	System performance parameter
Setra Model 280E	Ambient pressure in (Hg)	P	System performance parameter
Electric Meter 7600 ION	Voltage Output (volts)	P	System performance parameter
	Current (amps)	P	System performance parameter
	Power factor	P	System performance parameter
	Power Output (kW)	P	System performance parameter
	Kilovolt-amps reactive	S	System operational parameter
	Frequency (Hz)	P	System performance parameter
	Voltage THD (%)	P	System performance parameter
	Current THD (%)	P	System performance parameter
PC25 Communication System (logged by facility)	Power Command (kW)	P	User input parameter
	Date, time	D/S	System operational parameter
Controlotron Model 1010EP (2)	Temperature of heated liquid exiting heat exchanger (°F)	S	System operational parameter
	Temperature of cooled liquid entering heat exchanger(°F)	S	System operational parameter
	Liquid flow rate (ft ³ /min)	S	System operational parameter
	Heat recovery rate (Btu/min)	P	System performance parameter

^a D = Documentation/diagnostic
P = Primary value; data used in verification
S = Secondary value; used as needed to perform comparisons and assess apparent abnormalities

The Field Team Leader will retrieve, review, and validate the electronically collected data at the end of each load test run during field testing. He will analyze time series power output, power factor, gas flow rate, ambient temperature, and ambient pressure with Microsoft Excel® spreadsheet statistical tools to determine if the criteria for electrical efficiency determinations are met. If he determines that maximum permissible limits for each variable meet the variability criteria in Table 2-1, the electrical efficiency measurement goal will be met. Conversely, he will repeat the load testing until maximum permissible limits are attained. The GHG Center maintains the required data by computer and with handwritten entries. The Field Team Leader will record manually acquired data (i.e., test run information and observations) in the Daily Test Log and on the log forms in Appendix A. Disk copies of the Excel spreadsheet results will be made at the end of each day. The Field Team Leader will report the following results to the Project Manager:

- Electrical power generated at selected loads,
- ADG consumption, pressure, and temperature at selected loads,
- Electrical efficiency at selected loads (estimated until gas analyses results are submitted),
- Heat recovery rate at selected loads,
- Thermal efficiency at selected loads, and
- CHP production efficiency

Section 3.0 discussed the data quality assurance checks for the instruments illustrated in Figure 2-1. The Field Team Leader will maintain manual and electronic records (as required) resulting from these checks.

The GHG Center will store original field data forms, the Daily Test Log, and electronic copies of data output and statistical analyses at the GHG Center's RTP office per guidelines described in the GHG Center's QMP after the completion of all test runs.

4.1.2 Emission Measurements

The emissions testing contractor will be responsible for all emissions data, QA log forms, and electronic files until they are accepted by the Field Team Leader. The emissions contractor will use software to record the concentration signals from the individual monitors for pollutant quantified on-site with analyzers. The typical DAS records instrument output at one-second intervals, calculates, and records 1-minute averages. The contractor will transfer the data into an Excel spreadsheet for analysis at the conclusion of a test run.

The emissions contractor will report emission measurements results to the Field Team Leader as parts per million by volume (ppmv) and pounds per hour (lb/hr). The emissions contractor will provide copies of calibrations, pre-test checks, system response time, NO₂ converter efficiency, and field test data to the Field Team Leader prior to leaving the site upon completion of the field test activities.

The contractor will prepare and submit a formal report in printed and electronic (Microsoft Word format) to the GHG Center Field Team Leader within three weeks of completion of the field activities. The report will describe the test conditions, document all QA/QC procedures, include copies of calibrations, calibration gas, and the certification test results. The report will include field data as an appendix. The GHG Center will archive the submitted information at the GHG Center's RTP office per guidelines defined in the QMP.

4.1.3 ADG Sampling

Sections 2.0 and 3.0 discussed gas sampling and QA/QC. The Field Team Leader will maintain sampling logs and chain-of-custody records. The laboratory will submit results for each sample, calibration records, and repeatability test results to the Field Team Leader after the field test. The GHG Center will store original lab reports, electronic data copies, and statistical analyses at the GHG Center's RTP office per guidelines described in the GHG Center's QMP. The Field Team Leader will compute the actual electrical efficiency at each load tested and report the results to the Project Manager after receipt of the laboratory analyses.

4.2 DATA REVIEW, VALIDATION, AND VERIFICATION

Data review and validation will primarily occur at the following stages:

- On-site -- by the Field Team Leader
- Before writing the draft Verification Report -- by the Project Manager
- During QA review of the draft Verification Report and audit of the data -- by the GHG Center QA Manager

Section 1.0 identifies the individuals who are responsible for data validation and verification.

The Field Team Leader will be able to review, verify, and validate some data (i.e., DAS file data, reasonableness checks) while on-site. Other data, such as fuel LHV and fuel gas properties, must be

reviewed, verified, and validated after testing has ended. The Project Manager has overall responsibility for these tasks.

All collected data will be classed as valid, suspect, or invalid after review. The GHG Center will use the QA/QC criteria discussed in Section 3.0 and specified in the associated tables. Source material for data classification include factory and on-site calibrations, maximum calibration and other errors, and lab repeatability results.

Valid results are based on measurements which meet the specified DQIs and QC checks. They were collected when an instrument was verified as being properly calibrated and they are consistent with reasonable expectations (e.g., manufacturers' specifications, professional judgement).

The data review process often identifies anomalous data. Test personnel will investigate all outlying or unusual values in the field as is possible. Anomalous data may be considered suspect if no specific operational cause to invalidate the data is found.

The Verification Report will incorporate all data-valid, invalid, and suspect. However, report conclusions will be based on valid data only and the report will justify the reasons for excluding any data. Suspect data may be included in the analyses, but may be given special treatment as specifically indicated. The Project Manager will decide to either continue the test, collect additional data, or terminate the test and report the data obtained if the DQI goals cannot be met due to excessive data variability.

The QA Manager will review and validate the data and the draft Verification Report using the Test Plan and test method procedures as source material. The data review and data audit will be conducted in accordance with the GHG Center's QMP. For example, the QA Manager will randomly select raw data and independently calculate the Performance Verification Parameters dependent on that data. The comparison of these calculations with the results presented in the draft Verification Report will yield an assessment of the QA/QC procedures used by the GHG Center.

4.3 RECONCILIATION OF DATA QUALITY OBJECTIVES

A fundamental component of all verifications is the reconciliation of the data and its quality as collected from the field with the DQOs.

The Field Team Leader and Project Manager will typically review the collected data to ensure that they are valid and are consistent with expectations. They will assess the quality of the data in terms of accuracy and completeness as they relate to the stated DQI goals. Section 3.0 discusses each of the verification parameters and their contributing measurements in detail. It also specifies the procedures that field personnel will use to ensure that DQIs are achieved. If the test data show that DQI goals were met, then analysts will conclude that DQOs were achieved. DQIs and DQOs will therefore be reconciled. The GHG Center will assess achievement of certain DQI goals during field testing because QC checks and calibrations will be performed on-site or prior to testing. Other DQIs, such as gas analysis repeatability, will be reconciled after field tests have concluded.

4.4 ASSESSMENTS AND RESPONSE ACTIONS

The Field Team Leader, Project Manager, QA Manager, GHG Center Director, and technical peer-reviewers will assess the quality of the project and associated data. The Project Manager and QA Manager independently oversee the project and assess its quality through project reviews, inspections (if

needed), a technical systems audit (TSA), performance evaluation audit (PEA), and an audit of data quality (ADQ).

4.4.1 Project Reviews

The Project Manager is responsible for project data review and writing project reports. He is also responsible for conducting the first complete project assessment. Although project personnel are involved with ongoing data review, it is the Project Manager who must ensure that project activities meet the measurement and DQO requirements.

The GHG Center Director performs the second project review. The Director is responsible for ensuring that the project's activities adhere to the ETV program requirements and stakeholder expectations. The GHG Center Director's review will also include an overall project assessment to ensure that the Field Team Leader has the equipment, personnel, and resources to complete the project as required and to deliver data of known and defensible quality.

The third review is that of the QA Manager, who is responsible for ensuring that the project management systems function as required by the QMP and corporate policy. The QA Manager is the final reviewer within the Southern organization, and is responsible for assuring the achievement of all QA requirements.

The NYSERDA team, the vendor (UTC), and selected members of the DG Technical Panel will then review the report. Technically competent persons who are familiar with the technical aspects of the project, but not involved with the conduct of project activities, will perform the peer-reviews. The peer-reviewers will provide written comments to the Project Manager. Further details on project review requirements can be found in the GHG Center's QMP.

The draft report will then be submitted to EPA QA personnel, and the Project Manager will address their comments as needed. The Verification Report and Statement will undergo EPA management reviews, including the GHG Center Program Manager, EPA ORD Laboratory Director, and EPA Technical Editor following this review.

4.4.2 Performance Evaluation Audit

Submittal of the blind audit NO_x calibration gas described in Section 3.5.1 will serve as a performance evaluation audit (PEA) for NO_x emissions determinations. The Field Team Leader will evaluate the performance data for compliance with the project requirements and report the findings to the QA Manager upon receiving the analytical data from the analyst.

4.4.3 Technical Systems Audit

A Technical Systems Audit (TSA) assesses implementation of Test/QA Plans. Regarding internal TSAs, the Center's QMP specifies that:

The Test/QA Plan for each test, or substantially similar group of tests, will be subject of a TSA. This will include field verification in a representative number of tests (at least one per year). Such occasions will be specified in the Test/QA Plan. These will be conducted by Southern's QA staff.

This verification is one of several verifications of DG technologies either completed or in progress. On-site field TSAs have been conducted on three similar verifications including the following:

TSA's Conducted on DG/CHP Verifications

<u>Verification Title</u>	<u>Date of TSA</u>	<u>Auditor</u>
Honeywell Parallon 75 kW Turbogenerator	January 2001	GHG Center QA Manager
Ingersoll-Rand IR PowerWorks 70 kW Microturbine System	August 2002	GHG Center QA Manager
Capstone 60 kW Microturbine CHP System	June 2003	EPA QA Auditor

Therefore, it is the intention of the Center is to perform a TSA on this verification, excluding on-site field observation.

4.4.4 Audit of Data Quality

The audit of data quality (ADQ) is an evaluation of the measurement, processing, and data evaluation steps to determine if systematic errors have been introduced. The QA Manager, or designee, will randomly select approximately 10 percent of the data to be followed through the analysis and data processing during the ADQ. The scope of the ADQ is to verify that the data-handling system functions correctly and to assess the quality of the data generated.

The ADQ, as part of the system audit, is not an evaluation of the reliability of the data presentation. Data presentation review is the Project Manager’s and technical peer-reviewer(s) responsibility.

4.5 DOCUMENTATION AND REPORTS

Documentation and proper information reporting for the different project activities is critical. The Project Manager, field personnel, NYSERDA and vendor representatives, and QA personnel must be involved. The GHG Center will prepare the following field test documentation, QC documentation, corrective action/assessment report, and verification report/statements to insure the complete transfer of information to all parties involved in this project.

4.5.1 Field Test Documentation

The Field Team Leader will record all important field activities. The Field Team Leader will review all data sheets and maintain them in an organized file. Sections 2.0 and 3.0 describe the required test information. The Field Team Leader will also maintain a daily test log that documents the field team’s activities, significant events, and any schedule deviations from the schedule or Test Plan. The Field Team Leader will immediately report any major problems that require corrective action to the Project Manager through a CAR.

The Project Manager will check the test results with the Field Team Leader’s assistance to determine whether the QA criteria were satisfied. The GHG Center Director will be notified following this review and confirmation that the appropriate data were collected and DQOs were satisfied,

4.5.2 QC Documentation

The GHG Center will archive test data, sampling logs, calibration records, certificates of calibration, and other relevant information at the GHG Center’s RTP office. Calibration records will include information

about the instrument being calibrated, raw calibration data, calibration equations, analyzer identifications, calibration dates, calibration standards used and their traceabilities, calibration equipment, and staff conducting the calibration. These records will provide source material for the Data Quality section in the Verification Report, and will be available to the QA Manager during audits.

4.5.3 Corrective Action and Assessment Reports

A corrective action must occur when the result of an audit or quality control measurement is shown to be unsatisfactory, as defined by the DQOs or by the measurement objectives for each task. The corrective action process involves the Field Team Leader, Project Manager, and QA Manager. A written CAR (Appendix A-6) is required on major corrective actions that deviate from the Test Plan.

This Test plan includes validation processes to ensure data quality and establishes predetermined limits for data acceptability. Consequently, data determined to deviate from these objectives require evaluation through an immediate correction action process.

Immediate corrective action responds quickly to improper procedures, indications of malfunctioning equipment, or suspicious data. The Field Team Leader, as a result of calibration checks and internal quality control sample analyses, will most frequently identify the need for such an action. The Field Team Leader will immediately notify the Project Manager and will take and document appropriate action. The Project Manager is responsible for and is authorized to halt work if it is determined that a serious problem exists. The Field Team Leader is responsible for implementing corrective actions identified by the Project Manager and is authorized to implement any procedures to prevent the recurrence of problems.

The QA Manager will route the Audit of Data Quality results to the Project Manager for review, comments, and corrective action. Project records will document the results. The Project Manager will take any necessary corrective action needed and will respond by addressing the QA Manager's comments in the final verification Report.

4.5.4 Verification Report and Verification Statement

The Project Manager will coordinate preparation of a draft Verification Report and Statement within 8 weeks of completing the field test, if possible. The Verification Report will summarize the results for each verification parameter discussed in Section 2.0 and will contain sufficient raw data to support findings and allow others to assess data trends, completeness, and quality. Clear statements will be provided which characterize the performance of the verification parameters identified in Sections 1.0 and 2.0. The Report will contain a Verification Statement, which is a 3 to 4 page summary of the PC25 technology, the test strategy used, and the verification results obtained.

The Project Manager will submit the draft Report and Statement to the QA Manager and Center Director for review. A preliminary outline of the report is shown below.

Preliminary Outline**PC25 Verification Report***Verification Statement*

- Section 1.0: Verification Test Design and Description*
Description of the ETV program
PC25 system and site description
Overview of the verification parameters and evaluation strategies
- Section 2.0: Results*
Power and heat production performance
Power quality performance
Emissions performance
Emissions Reductions
GPU Performance
- Section 3.0: Data Quality*
- Section 4.0: Additional Technical and Performance Data (optional) supplied by the test facility*
- Section 5.0: References:*
Appendices: Raw Verification and Other Data

4.6 TRAINING AND QUALIFICATIONS

The GHG Center's Field Team Leader has extensive experience (+15 years) in field testing of air emissions from many types of sources. He is also familiar with gas flow measurements from production, processing, and transmission stations. He is familiar with the requirements of all of the test methods and standards that will be used in the verification test.

The Project Manager has performed numerous field verifications under the ETV program and is familiar with requirements mandated by the EPA and GHG Center QMPs. The QA Manager is an independently appointed individual whose responsibility is to ensure the GHG Center's activities are performed according to the EPA approved QMP.

4.7 HEALTH AND SAFETY REQUIREMENTS

This section applies to GHG Center personnel only. Other organizations involved in the project have their own health and safety plans specific to their roles in the project.

GHG Center staff will comply with all known host, state/local, and federal regulations relating to safety at the test facility. This includes use of personal protective gear (e.g., safety glasses, hard hats, hearing protection, safety toe shoes) as required by the host and completion of site safety orientation (i.e., site hazard awareness, alarms, and signals).

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Appendix A

Test Procedures and Field Log Forms

	<u>Page</u>
Appendix A-1. Load Testing Procedures	A-2
Appendix A-2. Load Test Log	A-3
Appendix A-3. Fuel Gas Sampling Procedures.....	A-4
Appendix A-4. Fuel Gas Sampling Log	A-6
Appendix A-5. Sample Chain-of-Custody Record.....	A-7
Appendix A-6. Corrective Action Report	A-8
Appendix A-7. DAS Analog Channel Setup.....	A-9
Appendix A-8. Fuel Gas Moisture Sampling Log (Low Pressure Biogas).....	A-10

Appendix A-1. Load Testing Procedures

1. Enter the load setting, unit controller, nameplate, and other information onto the Load Test Log form.
2. Synchronize all clocks (e.g., test personnel, analyzer) with the DAS time display. Coordinate with emissions testing personnel to establish a test run start time. Record this time on the Load Test Log form.
3. Operate microturbines for a minimum of 0.5 hour during gas analyzer emissions test runs and a minimum of 1 hour for particulate runs. All reciprocating engine test runs are a minimum of 1 hour. Test duration for fuel cells and other technologies varies. Refer to the Test and Quality Assurance Plan for details.
4. For pipeline quality natural gas, obtain a minimum of two (2) fuel gas samples on each day of emissions testing: one immediately before test runs commence, one following their completion. During extended test periods, obtain a minimum of two (2) fuel gas samples per week. Sampling frequency for other fuels (ADG, etc.) varies. Refer to the Test and Quality Assurance Plan for details.
5. During emissions testing at CHP facilities which use glycol solutions as a heat transfer fluid, obtain a minimum of one (1) glycol sample per day. During extended test periods, obtain a minimum of two (2) glycol samples per week. Heat transfer fluid samples are not required at facilities which use pure water.
6. At the end of each test run, review the data on the Load Test Log form and compare with the maximum permissible variations for microturbines, reciprocating engines, and fuel cells. If the criteria are met, declare an end for the test run. If not, continue operating the unit until the criteria are satisfied. Refer to the Test and Quality Assurance Plan for maximum permissible variations for other technologies.
7. Repeat each emission test run until three (3) valid runs are completed at each of the required load settings.

Appendix A-2. Load Test Log

Project ID: _____ Location (city, state): _____

Date: _____ Signature: _____

Unit Description: _____ Run ID: _____

Clock synchronization performed (Initials): _____

	Start	End	Diff	% Diff ([Diff/Start]*100)	Acceptable? (see below)
Time					
Load Setting, kW					
Load Setting, %					
Actual kW (DAS)					
Fuel Flow, scfm					
Fuel Gas Pressure, psia					
Fuel Gas Temp., °F				n/a	
Ambient Temp., °F				n/a	
Ambient Pressure, psia					
Heat Recovery Rate, BTU/min					

Maximum Permissible Variations			
	Microturbines (PTC-22)	Reciprocating Engines (PTC-17)	Fuel Cells (PTC-50)
Power Output	± 2.0 %	± 3.0 %	± 2.0 %
Power Factor	± 2.0 %	--	± 2.0 %
Fuel Flow	± 2.0 %	--	± 2.0 %
Fuel Gas Pressure	--	± 2.0 %	± 1.0 %
Fuel Gas Temp.	--	--	± 3.0 °F
Inlet/Ambient Temp.	± 4.0 %	± 5.0 °F	± 5.0 °F
Inlet/Ambient Pressure	± 0.5 %	± 1.0 %	± 0.5 %

Notes: _____

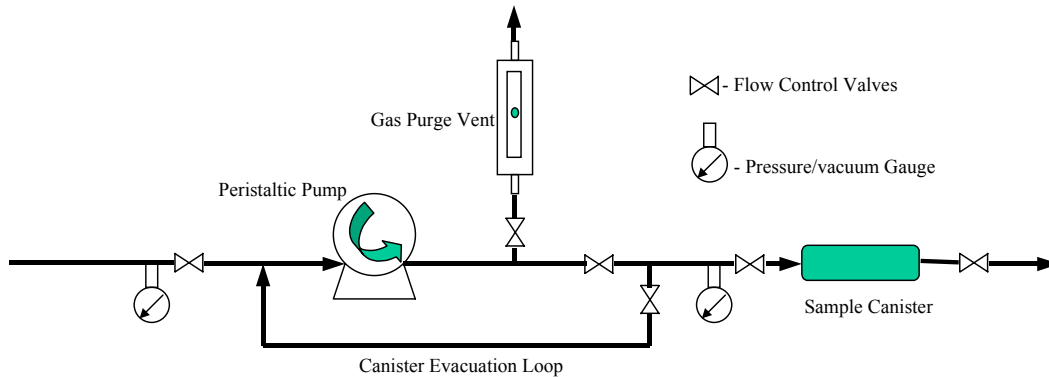
Appendix A-3. Fuel Gas Sampling Procedures

Important: Follow these procedures when the gas pressure is > 5 psi above atmospheric pressure.

1. Collect at least two gas samples during each load test condition and 2 samples during the extended monitoring period.
2. Attach a leak free vacuum gauge to the sample canister inlet. Open the canister inlet valve and verify that the canister vacuum is at least 15 “Hg. Record the gage pressure on the Fuel Sampling Log form.
3. Close the canister inlet valve, remove the vacuum gauge, and attach the canister to the fuel line sample port.
4. Open the fuel line sample port valve and check all connections for leaks with bubble solution or a hand-held analyzer. Repair any leaks, then open the canister inlet valve. Wait five (5) seconds to allow the canister to fill with fuel.
5. Open the canister outlet valve and purge the canister with fuel gas for at least fifteen (15), but not more than thirty (30) seconds. Close the canister outlet valve, canister inlet valve, and fuel line sampling port valve in that order.
6. Obtain the fuel gas pressure and temperature from the DAS display. Enter the required information (date, time, canister ID number, etc.) on the Fuel Sampling Log (Appendix A-4a) and Chain-of-Custody Record (Appendix A-5) forms. Remove the canister from the sampling port.

Important: Follow these procedures when the gas pressure is < 5 psi above atmospheric pressure.

1. Construct a leak free gas extraction and collection system such as shown in the following sketch.



2. Make a leak free connection from the gas source to the inlet of the gas collection system.
3. Using the control valves and vacuum gauge, check and record the sample canister vacuum. If necessary, fully evacuate the canister using the peristaltic pump and control valves. Record the final canister vacuum (should be -25 in. Hg or less).
4. Isolate the evacuated canister and configure the valves so that gas is slowly vented through the purge vent (ensure proper ventilation of gas before starting the purge). Purge for 10 seconds.

(continued)

Appendix A-3 Fuel Gas Sampling Procedures (continued)

5. Close the purge vent and slowly open the valves upstream of the canister and allow the canister to pressurize to no less than 2 psig.
6. With the pump still running, open the canister outlet valve and purge the canister for 5 seconds. Sequentially close the canister outlet valve, canister inlet valve, and pump inlet valve. Turn off pump.
7. Record the date, time, gas temperature (from DAS), canister ID number, and final canister pressure on log form (Appendix A-4b).
8. Return collected sample(s) to laboratory with completed chain-of-custody form (Appendix A-6).

Appendix A-4. Fuel Gas Sampling Log

Project ID: _____ Location (city, state): _____

Date: _____ Signature: _____

Unit Description: _____ Fuel Source (e.g., pipeline, digester): _____

Note: If desired, assign random sample ID numbers to prevent the lab from attributing analysis results to a particular test or audit sample. Transfer sample ID numbers to Chain-of-Custody Record prior to sample shipment.

Obtain sample pressure and temperature from the DAS display.

Date	Time	Run ID	Sample ID	Canister ID	Initial Vacuum ("Hg)	Fuel Pressure (DAS)	Fuel Temperature (DAS)

Notes: _____

Appendix A-6. Corrective Action Report

Corrective Action Report

Verification Title: _____

Verification Description: _____

Description of Problem: _____

Originator: _____

Date: _____

Investigation and Results: _____

Investigator: _____

Date: _____

Corrective Action Taken: _____

Originator: _____

Date: _____

Approver: _____

Date: _____

cc: GHG Center Project Manager, GHG Center Director, Southern QA Manager

Appendix A-7. DAS Analog Channel Setup

Date: _____ Job: _____ DAS *.mdb Filename (include path): _____

Signature: _____

DAS Analog Channel Setup								
Channel	Name ^a	Units ^a	Span	Analog Type (mA or V)	Sensor/Transducer			Notes
					Manufacturer	Model	Serial #	
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								

^a Enter this information into DAS Analog Tag Configuration form exactly as it appears here

Appendix A-8. Fuel Gas Moisture Sampling Log (Low-Pressure Biogas)

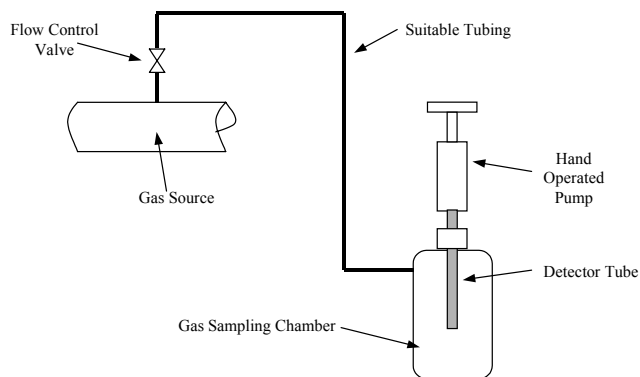
Project ID: _____ Location (city, state): _____

Date: _____ Signature: _____

Unit Description: _____ Sampling Location : _____

Pump Type/Volume: _____ Tube Type/Range: _____

Assemble the sampling train as shown below, and follow the sampling procedures.



Procedures:

- Make a leak free connection between the hand pump and the gas sampling chamber.
- Control gas flow from source using flow control valve and purge the chamber for 1 minute
- Connect a fresh detector tube to the pump, insert assembly into chamber, and pump the specified volume of gas through the tube.
- Read the moisture content on the tube and record below.
- Record the date, time, volume samples, and gas temperature (from DAS display) below.

Date	Time (24 hr)	Run ID	Sample ID	Gas Temp	Sample Volume	Moisture Content

Notes: _____

Appendix B

Quality Assurance/Quality Control Checks and Log Forms

	<u>Page</u>
Appendix B-1. 7600/7500 ION Installation and Setup Checks	B-2
Appendix B-2. 7600/7500 ION Sensor Function Checks	B-3
Appendix B-3. Gas Meter Transmitter Calibration.....	B-4
Appendix B-4. Ambient Monitor Instrument Checks	B-5
Appendix B-5. Measurement Error Propagation	B-6
Appendix B-6. Heat Meter RTD QA Check	B-8
Appendix B-7. Heat Meter Setup and Reasonableness Check.....	B-9
Appendix B-8. DAS Calibration and Verification	B-10

Appendix B-1. 7600/7500 ION Installation and Setup Checks

Project ID: _____ Location (city, state): _____

Date: _____ Signature: _____

Unit Description: _____

IMPORTANT: *Conformance to applicable local codes supercede the instructions in this log sheet or the 7600/7500 ION installation manual*

Only qualified personnel shall install current transformers (CTs) or voltage transformers (PTs). To avoid risk of fire or shock, be sure that the CT shorting switch(es) are installed and operated properly.

Note: Instructions below pertain to both the 7600-ION and 7500-ION power meters. Initial each item upon completion.

_____ Obtain and read the ION Installation and Basic Setup Manual (manual). It is the source of the items outlined below and is the reference for further questions.

_____ Verify that the ION calibration certificate(s) and supporting data are on hand.

_____ Mount the meter(s) in a well-ventilated location free of moisture, oil, dust, and corrosive vapors. Ensure that all wiring conforms to NEC standards.

_____ Verify that the ION power source is 110 VAC, nominal, protected by a switch or circuit breaker. If used with the DAS, plug the meter into the DAS uninterruptable power supply (UPS).

_____ Connect each ION ground terminal (usually the “Vref” terminal) directly to the switchgear earth ground with a dedicated AWG 12 gauge wire or larger. In most 4-wire WYE setups, jumper the “V4” terminal to the “Vref” terminal. Refer to the manual for specific instructions.

_____ Choose the proper CTs and PTs for the application. Install them in the power circuit and connect them to the ION power meters according to the directions in the manual (pages 8-14).

_____ Trace or color code each CT and PT circuit to ensure that they go to the proper meter terminals. Each CT must match its corresponding PT (i.e. connect the CT for phase A to meter terminals I_{11} and I_{12} and connect the PT for phase A to meter terminals V_1 and V_{ref}).

_____ Use a digital volt meter (DVM) to measure each phase’s voltage and current. Enter the data on the ION Sensor Function Checks form and compare with the ION front panel.

_____ Confirm that the ION front panel readings agree with the DAS display.

_____ Compare the ION and DAS readings to the unit’s panel or controller display. Enter this information in the daily test log as is appropriate.

_____ Verify that the DAS is properly logging and storing data by downloading data to the laptop computer and reviewing it.

Appendix B-2. 7600/7500 ION Sensor Function Checks

Project ID: _____ Location (city, state): _____
 Date: _____ Signature: _____
 Unit Description: _____ Nameplate kW: _____ Expected max. kW: _____
 Type (delta, wye): _____ Voltage, Line/Line: _____ Line/Neutral: _____
 Current (at expected max. kW): _____ Conductor type & size: _____
 Voltage Transformer (PT) Spec. (480/208, other): _____ Current Transformer (CT) Spec. (100:5, 200:5, other): _____

Sensor Function Checks

Note: Acquire at least five (5) separate readings for each phase. All ION voltage readings must be within 2.01 % of the corresponding DVM reading.

Voltage										
Date	Time (24 hr)	Phase A			Phase B			Phase C		
		ION	DVM	Diff	ION	DVM	Diff	ION	DVM	Diff

Note: Acquire at least five (5) separate readings for each phase. All ION current readings must be within 3.01 % of the corresponding DVM reading.

Current										
Date	Time (24 hr)	Phase A			Phase B			Phase C		
		ION	DVM	Diff	ION	DVM	Diff	ION	DVM	Diff

Appendix B-3. Gas Meter Transmitter Calibration

Project ID: _____

Location (city, state): _____

Date: _____

Signature: _____

1. Confirm stable fuel cell operations at full load.
2. Reading the meter's odometer type index, begin a calibration run by recording a start volume to the nearest 0.2 actual cubic feet (acf), and starting a stopwatch timer to record elapsed time (Sec_{elapsed}). Log the entries below.
3. After at least 100 acf of gas has been recorded on the meter index, take a final meter reading to the nearest 0.2 acf and stop the timer. Log the entries below and calculate gas flow rate (acfm).
4. Record the average gas flow rate (acfm) logged by the DAS during the test period.
5. Repeat the procedure two more times at full load.
6. Calculate the average difference between the meter index and the DAS readings. Log the entries below.
7. Repeat the entire procedure while operating the fuel cell at 75 and 50 percent of full load.
8. Record the DAS gas flow reading with the gas flow turned off (zero check).

Fuel Cell Power Setting (kW)	Run Number	Roots Meter Readings						DAS Flow Rate ^b (acfm)	Difference ^c (%)
		Start Time	Initial Reading (acf)	Stop Time	Final Reading (acf)	Elapsed Time (sec.)	Flow Rate ^a (acfm)		
	1								
	2								
	3								
	Avg								
	1								
	2								
	3								
	Avg								
	1								
	2								
	3								
	Avg								

^a Gas flow rate (acfm) = (final reading (acf) - initial reading (acf)) / elapsed time (sec.) * 60

^b DAS gas flow rate (acfm) = average gas flow rate recorded by DAS during test run period

^c Difference (%) = (gas flow from meter (acfm) - gas flow from DAS (acfm)) / gas flow from meter (acfm) * 100

Appendix B-4. Ambient Monitor Instrument Checks

Note: Route all signal wires away from motors, power mains, or other electrically noisy equipment. Do not use 2-way radios near instruments.

Project ID: _____ Location (city, state): _____

Ambient Pressure Reasonableness Check

Date: _____ Signature: _____

Site elevation, ft: _____ Source of elevation data: _____

Note: Obtain local barometric pressure from airport, National Weather Service, Internet, weather radio, or other. Altitude correction ($Corr_{alt}$) is $\approx 1''$ Hg per 1000 ft elevation. For exact values, refer to Instruction Booklet for use with Princo Fortin Type Mercury Barometers, <http://www.princoinstruments.com/barometers.htm>, Table 8, "Pressure Altitude ..."

P_{bar} , "Hg: _____ Source of Data: _____ $Corr_{alt}$, "Hg: _____

$P_{sta} = P_{bar} - Corr_{alt}$: _____ P_{sta} , "Hg: _____

$P_{sta} * 0.491 = P_{sta}$, psia: _____ DAS Amb. press., psia: _____

Difference, psia: _____ Difference should be < 0.2 psia.

Temperature, Relative Humidity Reasonableness Checks

Place Omega temp/RH meter in shade adjacent to the Visala sensor shield. Compare DAS temperature and relative humidity display to handheld Omega temp/RH meter display.

Date: _____ Signature: _____

DAS Temp	Omega Temp	Difference	Acceptable? (within 2 °F)	DAS RH	Omega RH	Difference	Acceptable ? (within 8 %)

Notes: _____

Appendix B-5. Measurement Error Propagation

Each contributing measurement has uncertainty (or error) which propagates into the overall performance determination uncertainty. Absolute or relative errors compound differently, depending on the algebraic operation required for the overall determination (12). Absolute error is expressed in the units of measurement while relative error is a proportion or percent. Examples are: “980 ± 9.8 Btu (absolute error),” or “980 Btu ± 1.00 % (relative error).” In general, absolute errors compound for added or subtracted measurements while relative errors compound for multiplication and division.

For added or subtracted measurements:

$$err_{c,abs} = \sqrt{err_1^2 + err_2^2} \tag{Eqn. B-5.1}$$

Where:

- err_{c,abs} = Compounded error, absolute
- err₁ = Absolute error in first added (or subtracted) value
- err₂ = Absolute error in second added (or subtracted) value

The relative error of the sum (or difference), then, is:

$$err_{c,rel} = \frac{err_{c,abs}}{value_1 + value_2} \tag{Eqn. B-5.2}$$

Where:

- err_{c,rel} = Compounded error, relative
- value₁ = First added value
- value₂ = Second added value

The following table provides an example.

Compounded Uncertainty for Added (or Subtracted) Values			
Description	Magnitude	Absolute Error	Relative Error (%)
Value 1	15	± 0.80	± 5.333 [(0.80/15)*100]
Value 2	2	± 0.20	± 10.000 [(0.20/2)*100]
Value 1 minus Value 2	13	± 0.825 [(0.8 ² +0.2 ²) ^{1/2}]	± 5.497 [(0.825/13)*100]

For measurements which are multiplied or divided by each other, relative errors compound as follows:

$$err_{c,rel} = \sqrt{\left(\frac{err_1}{value_1}\right)^2 + \left(\frac{err_2}{value_2}\right)^2} \tag{Eqn. B-5.3}$$

Where:

- err_{c,rel} = Compounded error, relative
- err₁ = Error in first multiplied (or divided) value, absolute value
- err₂ = Error in second multiplied (or divided) value, absolute value

value₁ = First multiplied (or divided) value
 value₂ = Second multiplied (or divided) value

The following table provides an example.

Compounded Uncertainty for Multiplied (or Divided) Values			
Description	Magnitude	Relative Error (%)	Absolute Error
Value 1	15	± 5.333	± 0.80
Value 2	2	± 10.000	± 0.20
Value 1 divided by Value 2	7.5	± 11.333 [(0.05333 ² +0.1 ²) ^{1/2}]	± 0.85 [(11.333/7.5)*100]
Value 1 times Value 2	30	± 11.333 [(0.05333 ² +0.1 ²) ^{1/2}]	± 3.40 [(11.333/30)*100]

Note that all errors can occur above or below the measured (or compounded) quantity. Analysts express the uncertainty as the result ± the error and whether it is absolute or relative.

Appendix B-6. Heat Meter RTD QA Check

The heat meter receives temperature signals from two resistance temperature devices (RTDs), mounted upstream and downstream of the heat recovery unit. The data acquisition system (DAS) displays and records these temperatures. The GHG Center will evaluate the RTD performance by comparing the DAS displayed temperature values with a calibrated digital thermometer. As calibrated, the accuracy of the digital thermometer is 0.5 percent of reading plus a constant value of 1.3 °F. That is, the accuracy specification is $\pm 0.5 \% \text{ Reading} \pm 1.3 \text{ }^\circ\text{F}$ or $\pm 2.2 \text{ }^\circ\text{F}$ at 190 °F.

GHG Center personnel will conduct the performance check at least once prior to the start of testing as follows:

1. Simultaneously immerse the digital thermometer thermocouple and the RTD under test. **IMPORTANT:** On direct contact RTDs, do not allow the top of the unit (with nameplate and electrical connector) to get wet.

While stirring, obtain the digital thermometer and DAS readings. Record below.

Repeat the procedure for hot water and ice baths.

Compare the RTD DAS readings to the digital thermometer readings. If differences exceed 2.2 °F, the RTDs should be submitted for recalibration.

Project ID: _____ Location (city, state): _____

Date: _____ Signature: _____

Digital Thermometer Make: _____ Model: _____ Serial No. _____

Thermocouple ID No. _____ Last Calibration Date: _____

Performance Check Location (laboratory or field): _____

Heat Meter Make: _____ Model: _____ Serial No. _____

RTD1 Model _____ ID No. _____ Type (contact/immersion) _____

RTD2 Model _____ ID No. _____ Type (contact/immersion) _____

Bath Description	RTD1 or RTD2?	RTD DAS Value	Digital Thermometer	Difference	Acceptable ?

Appendix B-7. Heat Meter Setup and Reasonableness Check

Date: _____ Unit: _____

Heat Meter Make: _____ Model #: _____ Serial #: _____

Signature: _____

Enter the following values into the heat meter software:

Pipe or Tubing OD: _____ Material: _____ Wall Thickness: _____

Nom. Dia	Schedule 40 Steel Pipe			Type L Copper Tubing		
	Actual OD	Wall Thickness	Actual ID	Actual OD	Wall Thickness	Actual ID
1 ¼	1.660	0.140	1.380	1.375	0.055	1.265
1 ½	1.900	0.145	1.610	1.625	0.060	1.505
2	2.375	0.154	2.067	2.125	0.070	1.985
2 ½	2.875	0.203	2.469	2.625	0.080	2.465
3	3.500	0.216	3.068	3.125	0.090	2.945
3 ½	4.000	0.226	3.548	3.625	0.100	3.425

Source: T. Baumeister, Ed. *Standard Handbook for Mechanical Engineers*, 7th Ed, McGraw Hill, NY, NY 1967

Acquire the following data from the DAS and perform the applicable calculations. Interpolate density and specific heat for T_{avg} from the reference table below or ASHRAE publications.

Date: _____ Time (24-Hr): _____

DAS t_1 _____

t_{avg} _____ $t_1 - t_2$ _____

DAS t_2 _____

DAS Gal/min _____ $\frac{(Gal/min)}{7.4805} = ft^3/min$ _____

DAS Btu/min _____ C_p _____
 ρ _____

$$Q = V\rho C_p (t_1 - t_2) \text{ _____}$$

Percent Difference: $\frac{(DAS Btu/min) - Q}{Q} * 100$ _____

Acceptable? (< 5 %) (Y/N) _____

Reference -- Water Specific Heat and Density								
Temp, °F	ρ , lb/ft ³	C_p , Btu/lb.°F	Temp, °F	ρ , lb/ft ³	C_p , Btu/lb.°F	Temp, °F	ρ , lb/ft ³	C_p , Btu/lb.°F
100	61.9951	0.99799	140	61.3818	0.99943	180	60.5821	1.00272
110	61.8616	0.99817	150	61.1955	1.00008	190	60.3552	1.00388
120	61.7132	0.99847	160	61.0027	1.00082	200	60.1234	1.00517
130	61.5548	0.99889	170	60.7956	1.00172	210	59.8784	1.00388

Source: Interpolated from R. Weast, Ed., *CRC Handbook*, 60th Ed., CRC Press, Inc., Boca Raton, FL. 1979

Appendix C

Emissions Estimates for the Utility Grid

	<u>Page</u>
Appendix C-1. Methodology for Estimating Emissions From the Utility Grid.....	C-2

Appendix C-1. Methodology for Estimating Emissions From the Utility Grid

EPA has long recognized that clean energy technologies have the potential for significant emission reductions through displaced generation. However, a robust and analytically sound method to quantify the potential of displaced emissions has yet to be developed. Displaced generation is defined as the total electrical output (measured in kWh) from conventional electricity sources that is either displaced by or avoided through the implementation of energy efficient measures. Displaced emissions is defined as the change in emissions (measured in lb) that results when conventional electrical generation is displaced by energy efficient measures. On-site heat and power generation with a distributed energy technology (e.g., PC25) is an example of a clean energy source, provided its emissions are less than conventional sources. DG systems can result in displaced generation, and ultimately displace emissions.

Several different methodologies have been developed and employed by various organizations to estimate emissions displaced by on-site electricity generation. Although there are many variations of such methodologies, they are all derived from the average emission rate method, the marginal unit method, or historical emissions/generation data.

The average emission rate method uses the average emission rate of electricity generating units in a particular region or nationally. It is usually based on the average emission characteristics of all electricity generating units or fossil-fired units only, and is often derived from historic generation and emissions data or projections of future generation and fuel use patterns. This approach is most widely used due to its simplicity and wide availability of average rates for many U.S. regions. Unfortunately, there is little or no correlation between the average emission rate and the emission rate at which the emissions are displaced by energy efficient measures. As a result, estimates of emissions impacts can be inaccurate and may not adequately reflect the realities of power markets.

The marginal unit method is an attempt to improve on the average emission rate approach by identifying a particular unit or type of unit that may be displaced. Similar to the average emission rate method, the average emission characteristics of the displaced units are applied to total electricity saved to estimate displaced emissions. The marginal unit method assumes that at any point in time, the marginal unit, by virtue of being the most expensive generating unit to operate, will be the unit that is displaced. Although this approach conceptually appears to be more reasonable than simply using an average emission rate, identifying the marginal unit is difficult, particularly in regions with large and frequent variations in hourly electricity demand.

Displaced emissions are also estimated using statistical techniques based on historical data. This approach seeks to forecast how displaced emissions arise from observed changes in electricity demand/supply, instead of identifying the average or marginal emission rate of particular units. This approach requires statistical modeling, and data such as regional generation, emissions, and electricity demand. Its primary limitation is that actual site-specific and electricity control area specific data must be available.

EPA has been developing a newer approach that utilizes region/time specific parameters to represent average displaced emission rate (ADER). The ADER methodology accounts for the complexities of electricity markets in assessing how displaced emissions result from changes in electric demand or supply, and produces regional, national, short-term, and long-term estimates of displaced emissions of CO₂, NO_x, SO₂, and Hg from electric generation. The results of the ADER analysis are not currently available; as such, the GHG Center is unable to apply this methodology for this verification. However, at

the suggestion of the EPA project officer leading this effort, a similar approach, developed by the Ozone Transport Commission (OTC) has been adopted for this verification to estimate displaced emissions, and is described below.

OTC is a multi-state organization focused on developing regional solutions to the ground-level ozone problem in the Northeast and Mid-Atlantic region of the U.S., with special emphasis on the regional transport of ground-level ozone and other related pollutants. It was created by Congress in 1990, and consists of the jurisdictions within Connecticut, Delaware, D.C., Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. OTC has recently developed an Emission Reduction Workbook (Workbook) to provide a method of assessing the emissions impacts of a range of energy policies affecting the electric industry (19). The geographic focus of the Workbook is the three northeastern electricity control areas: Pennsylvania/New Jersey/Maryland (PJM), the New York ISO (NY ISO), and ISO New England.

The three energy programs evaluated by the Workbook are: (1) programs that displace generation (e.g., DG or DG-CHP systems), (2) programs that alter the average emission rate of the electricity used in a state or region (e.g., emissions performance standard), and (3) programs that reduce emission rates of specific generating units (e.g., multi-pollutant regulations applied to existing generating units). To evaluate these programs, the Workbook contains default displaced emission rates for the three northeastern control areas. The default displaced emission rates are divided into three time periods: near term (2002-2005), medium term (2006-2010), and long term (2011-2020). For this verification, the short-term default emission rates for the NY ISO control area will be used to represent the ER_{Grid} variable shown in Equation 13.

The near-term rates for the NY ISO are summarized in Table C-1. These rates were compiled using the PROSYM electricity dispatch model, and are reported to be representative of actual operations because the identity of generating units that constitute each regional power system are known with a relatively high level of certainty.

Table C-1. Displaced Emission Rates For the NY ISO (2002)		
	NO_x (lb/kWh_e)	CO₂ (lb/kWh_e)
Ozone season weekday ^a	0.0021	1.37
Ozone season night/weekend ^b	0.0028	1.67
Non-ozone season weekday ^c	0.0021	1.46
Non-ozone season night/weekend ^d	0.0028	1.61
^a Average of all hourly marginal emission rates during weekdays, May through September, 7:00 am through 10:59 pm		
^b Average of all hourly marginal emission rates during all nights, May through September, 11:00 pm through 6:59 am, and all weekend days during this period		
^c Average of all hourly marginal emission rates during weekdays, October through April, 7:00 am through 10:59 pm		
^d Average of all hourly marginal emission rates during all nights, October through April, 11:00 pm through 6:59 am, and all weekend days during this period		

PROSYM is a chronological, multi-area electricity market simulation model that is often used to forecast electricity market prices, analyze market power, quantify production cost and fuel requirements, and estimate air emissions. It simulates system operation on an hourly basis by dispatching generating units

each hour to meet load. The simulation is based on unit-specific information on the generating units in multiple interconnection areas (unit type and size, fuel type, heat rate curve, emission and outage rates, and operating limitations), and detailed data on power flows and transmission constraints within and between ISOs. Because the simulation is done in chronological order, actual constraints on system operation (such as unit ramp times and minimum up and down times) are taken into account. The resulting emission rates in one control region take into account emission changes in neighboring regions. PROSYM has been used by many organizations, including the EPA and Department of Justice to pursue New Source Review violations, DOE, numerous utility companies, Federal Energy Regulatory Commission (FERC), and Powering the South organization to simulate electric power system in the Southern U.S.

OTC generated the displaced emission rates for the Northeast control areas by first performing a “base case” model run, simulating plant dispatch across all three control areas for the year. OTC then performed three “decrement” model runs. In one decrement run, all hourly loads in PJM were reduced by 1 percent; loads in ISO NE, and NY ISO were not reduced. In another decrement run, loads in ISO NE were reduced by 1 percent, and in the third, NY ISO loads were reduced. To calculate marginal emission rates for different periods, OTC calculated the total difference in kWhs generated between the base case and decrement case and the total difference in emissions, and then divided the emissions by kWhs to derive the marginal emission rate for the time period. It should be noted that marginal rates shown in Table C-1 takes into account changes in generation in all areas resulting from the load reductions in the target DG use area. This includes analysis of emissions changes across six interconnected control areas: PJM, NY ISO, ISO NE, Maritimes, Ontario, and Quebec.

Appendix D
ADG Target Analytes

	<u>Page</u>
Appendix D-1. Volatile Organic Compounds.....	D-2
Appendix D-2. Sulfur Compounds.....	D-3
Appendix D-3. Analytical QC Checks.....	D-4

Appendix D-1. List of Target VOCs and Reporting Limits

Analyte	RL (ppbv)	Analyte	RL (ppbv)
1,1,2,2-Tetrachloroethane	0.5	m,p-Xylene	0.5
1,1,2-Trichloroethane	0.5	Methyl Chloroform	0.5
1,1-Dichloroethane	0.5	o-Xylene	0.5
1,1-Dichloroethene	0.5	Styrene	0.5
1,2,4-Trichlorobenzene	2.0	Tetrachloroethene	0.5
1,2,4-Trimethylbenzene	0.5	Toluene	0.5
1,2-Dibromoethane	0.5	trans-1,3-Dichloropropene	0.5
1,2-Dichlorobenzene	0.5	Trichloroethene	0.5
1,2-Dichloroethane	0.5	Vinyl Chloride	0.5
1,2-Dichloropropane	0.5	1,3-Butadiene	2.0
1,3,5-Trimethylbenzene	0.5	1,4-Dioxane	2.0
1,3-Dichlorobenzene	0.5	2-Butanone	2.0
1,4-Dichlorobenzene	0.5	2-Hexanone	2.0
Benzene	0.5	4-Ethyltoluene	2.0
Bromomethane	0.5	4-Methyl-2-Pentanone	2.0
Carbon Tetrachloride	0.5	Acetone	2.0
Chlorobenzene	0.5	Bromodichloromethane	2.0
Chloroethane	0.5	Bromoform	2.0
Chloroform	0.5	Carbon Disulfide	2.0
Chloromethane	0.5	Cyclohexane	2.0
Chlorotoluene	0.5	Dibromochloromethane	2.0
cis-1,2-Dichloroethene	0.5	Ethanol	2.0
cis-1,3-Dichloropropene	0.5	Heptane	2.0
Dichloromethane	0.5	Hexane	2.0
Ethylbenzene	0.5	Isopropanol	2.0
Freon 11	0.5	Methy t-Butyl Ether	2.0
Freon 113	0.5	Propylene	2.0
Freon 114	0.5	Tetrahydrofuran	2.0
Freon 12	0.5	trans-1,3-Dichloroethene	2.0
Hexachlorobutadiene	2.0	Vinyl Acetate	2.0

Appendix D-2. List of Sulfur Species and Reporting Limits

<u>Sulfur Compounds</u>	<u>RL (ppbv)</u>
2,5-Dimethylthiophene	4.0
2-Ethylthiophene	4.0
3-Methylthiophene	4.0
Carbon Disulfide	4.0
Carbonyl Sulfide	4.0
Diethyl Disulfide	4.0
Diethyl Sulfide	4.0
Ethyl Mercaptan	4.0
Ethyl Methyl Sulfide	4.0
Hydrogen Sulfide	4.0
Isobutyl Mercaptan	4.0
Isopropyl Mercaptan	4.0
Methyl Mercaptan	4.0
n-Butyl Mercaptan	4.0
n-Propyl Mercaptan	4.0
tert-Butyl Mercaptan	4.0
Tetrahydrothiophene	4.0
Thiophene	4.0

Appendix D-3. Definition of ADG Analytical QC Checks

The QC checks that will be performed by ATL are summarized in Tables 3-9 and 3-10. The following provides a brief description of each QC check performed.

Initial Calibration (ICAL) - Multipoint instrument calibrations are conducted using NIST traceable reference standards over the expected range of detection. Calibrations and acceptance criteria are generally conducted following the applicable Reference Method. All specific target analytes are included in the initial instrument calibrations.

Laboratory Control Sample (LCS) - An independent second source reference standard which goes through the same pretreatment and preparation procedures as the samples. It validates the accuracy of the ICAL.

Continuing Calibration Verification (CCV) - A standard that is analyzed to verify instrument linearity with respect to the ICAL. The CCV concentration may be identical to any given point contained with the ICAL, and is analyzed at the beginning of every analytical sequence and every 10 to 20 samples depending on the method.

Laboratory Blank - A sample that is known to not contain any of the target analytes that is used to check the cleanliness of sampling and analytical systems.

Duplicate Analyses - Separate aliquots of the same sample that are prepared and analyzed at the same time, in the same manner.

Surrogate - A substance that is unlikely to be found in the samples which has properties similar to the target analytes. A known quantity of the surrogate is added to a sample before analysis, and percent recovery is reported to evaluate analytical quality control.