SRI/USEPA-GHG-QAP-21
July 2002

Test and Quality Assurance Plan

Ingersoll-Rand Energy Systems
IR PowerWorks™
70 kW Microturbine System

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

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

and

Under a Contract With
New York State Energy Research and Development Authority

EPA REVIEW NOTICE

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Greenhouse Gas Technology Center

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

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Ingersoll-Rand Energy Systems
IR PowerWorks™ 70 kW Microturbine System

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IR PowerWorks™ 70 kW Microturbine System

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

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Center Director
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Test Plan Final: July 2002

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ACRONYMS/ABBREVIATIONS

Abs. Diff.	absolute difference
AC	alternating current
ADQ	Audit of Data Quality
Amp	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
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 cubit feet
C1	quantification of methane
C6+	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
DG	distributed generation
DHW	domestic hot water
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
EA	Engineering Assistant
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ETV	Environmental Technology Verification
°C	degrees Celsius
^oF	degrees Fahrenheit
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
gpm	gallons per minute
GU	generating unit

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ACRONYMS/ABBREVIATIONS
(continued)

hr	hours
Hz	hertz
IC	internal combustion
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
IR PowerWorks	Ingersoll-Rand PowerWorks™ 70 kW microturbine system
kVA	kilovolt-amperes
kVAr	kilovolt reactive
kW	kilowatts
kWh	kilowatt hours
kWh/yr	kilowatt hours per year
lb	pounds
lb/Btu	pounds per British thermal unit
lb/dscf	pounds per dry standard cubic foot
lb/ft^3	pounds per cubic feet
lb/hr	pounds per hour
lb/kWh	pounds per kilowatt-hour
lb/yr	pounds per year
ISO	International Standards Organization
LHV	lower heating value
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
NYSEG	New York State Electric and Gas Corporation
NYSERDA	New York State Energy Research and Development Authority
O_2	oxygen
ORD	Office of Research and Development
PEA	Performance Evaluation Audit
PG	propylene glycol
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
QA/QC	Quality Assurance/Quality Control
QMP	Quality Management Plan
Rel. Diff.	relative difference
Report	Environmental Technology Verification Report
RH	relative humidity
rms	root mean square
rpm	revolutions per minute
RTD	resistance temperature detector

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
SRI	Southern Research Institute
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
VAC	volts alternating current
WRAP	Western Regional Air Partnership
WRI	World Resources Institute

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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 ETV 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 permitters 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 (SRI) , 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 Plan) and established protocols for quality assurance.

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 (Report). 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 peer-review key documents prepared by the GHG Center.

One technology of interest to some GHG Center's stakeholders is the use of microturbines as a distributed energy source. Distributed generation (DG) refers to power generation equipment, typically ranging from 5 to 1,000 kilowatts (kW) that provide electric power at a site closer to customers than central station generation. A distributed power unit can be connected directly to the customer or to a utility's transmission and distribution system. Examples of technologies available for DG include gas turbine generators, internal combustion (IC) engine generators (e.g., gas, diesel), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: stand-by generation (i.e., emergency backup power), peak shaving capability (generation during high demand periods), baseload generation (constant generation), or cogeneration [combined heat and power (CHP) generation].

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 throughout the state of New York. This verification will evaluate the performance of the IR PowerWorks™ 70 kW microturbine system offered by Ingersoll-Rand Energy Systems (IR PowerWorks). The cost to conduct this verification is being funded jointly by EPA's ETV program and NYSERDA. The test unit is currently in use at the Crouse Community Center in Morrisville, New York. The IR PowerWorks system uses a natural-gas-fired 70 kW microturbine for electricity generation and a heat recovery unit to provide hot water throughout the complex. Facility electrical and thermal demand exceeds the IR PowerWorks capacity, so the facility can operate the system continuously at full load. The system is interconnected to the electric utility grid, but the facility does not anticipate exporting power for sale. The overall energy conversion efficiency is estimated to range from 50 to 70 percent, which is high enough to significantly reduce greenhouse gas emissions and provide end users with high-quality energy services at competitive prices.

Field tests will be performed over a five-day verification period to independently verify the electricity generation and use rate, thermal energy recovery and use rate, electrical power quality, energy efficiency, emissions, and GHG emission reductions for the Crouse Community Center facility.

This document is the Test Plan for performance verification of the IR PowerWorks system at the Crouse Community Center facility. It contains the rationale for the selection of verification parameters, the verification approach, data quality objectives (DQOs), and Quality Assurance/Quality Control (QA/QC). This Test Plan has been reviewed by NYSERDA and its appropriate partners, Crouse Community Center representatives, selected members of the GHG Center's DG Stakeholder Panel (Appendix D), and the U.S. EPA QA team. 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 and conform with U.S. EPA's standard for environmental testing. This Test Plan has been prepared to guide implementation of the test and to document planned test operations. Once testing is completed, the GHG Center will prepare a Technology Verification Report (Report) and Verification Statement, which will first be reviewed by NYSERDA. Once all comments are addressed, the Report will be peer-reviewed by the stakeholders, the host facility, and the U.S. EPA QA team. Once completed, the GHG Center Director and the U.S. EPA Laboratory Director will sign the Verification Statement, and the final Report will be posted on the Web sites maintained by the GHG Center (www.sri-rtp.com) and ETV program (www.epa.gov/etv).

The remaining discussion in this section provides a description of the IR PowerWorks technology and the Crouse Community Center facility. This is followed by a list of performance verification parameters that will be quantified through independent testing at the site. A discussion of key organizations participating in this verification, their roles, and the verification test schedule is provided at the end of this section. Section 2.0 describes the technical approach for verifying each parameter, including the sampling procedures, analytical procedures, and QA/QC procedures that will be followed to assess data quality. Section 3.0 identifies the DQOs 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.

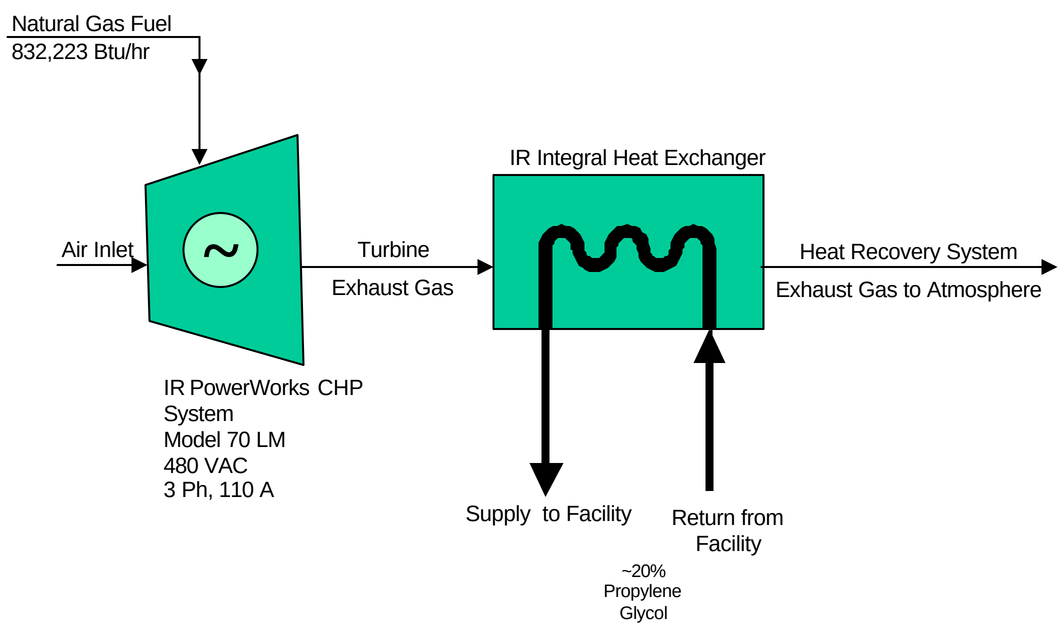
1.2 IR POWERWORKS TECHNOLOGY DESCRIPTION

Large- and medium-scale gas-fired turbines have been used to generate electricity since the 1950s. Recently they have become more widely used to provide additional generation capacity because of their ability to be quickly deployed and provide electricity at the point of use. Technical and manufacturing developments during the last decade have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW. The IR PowerWorks is one of the first cogeneration installations that integrate the microturbine technology to produce electric power, heat, and hot water (Figure 1-1).

Figure 1-1. IR PowerWorks CHP System

Figure 1-2 illustrates a simplified process flow diagram of the IR PowerWorks system, and a discussion of key components is provided below.

Figure 1-2. IR PowerWorks Process Diagram



Electric power is generated with an integrated Ingersoll-Rand microturbine with a nominal power output of 70 kW (59 ^oF, sea level). Table 1-1 summarizes the physical and electrical specifications reported by IR. The system incorporates an air compressor, recuperator, combustor, power turbine, and permanent magnet generator. In the compressor section compressed air is mixed with fuel, and this compressed fuel/air mixture is burned in the combustor under constant pressure conditions. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine blades to turn a generator that produces electricity. The rotating components are of a two-shaft design with the power turbine connected to a gear box, and supported by oil lubricated bearings. The generator is cooled by air flow into the gas turbine. The exhaust gas exits the turbine and enters the recuperator, which captures some of the energy and uses it to pre-heat the air entering the combustor, improving the efficiency of the system. The exhaust gas then exits the recuperator through a muffler and into the integrated IR heat recovery unit.

The IR PowerWorks is connected to a synchronous generator produces high frequency alternating current (AC) at 480 volts. The unit supplies an electrical frequency of 60 hertz (Hz), and is supplied with a control system which allows for automatic and unattended operation. An active filter in the turbine is reported by the turbine manufacturer to provide clean power, free of spikes and unwanted harmonics. The unit operates at 44,000 revolutions per minute (rpm) regardless of load. All operations, including start-up, setting of programmable interlocks, grid synchronization, power command, dispatch, and shutdown, can be performed manually or remotely using an internal power controller system. The Crouse Community Center IR PowerWorks system runs parallel with the local power utility. If the power demand exceeds the available capacity of the turbine, additional power is drawn from the grid. In the event of a power grid failure, the system is designed to automatically shut down, to isolate system from grid faults. When grid power is restored, the IR PowerWorks system can be restarted manually.

Table 1-1. IR PowerWorks Physical, Electrical, and Thermal Specifications
(Source: Ingersoll-Rand Energy Systems)

Electrical Efficiency	Lower heating value (LHV) basis	28 % (± 2 %)
Electrical Inputs	Power (start-up) Communications	Utility grid or black start battery Ethernet IP or modem
Electrical Outputs	Power at ISO Conditions (59 ^oF @ sea level)	70 kW, 480 VAC, 60 Hz, 3-phase
Emissions (full load)	Nitrogen oxides (NO_X) Carbon monoxide (CO) Total hydrocarbon (THC)	< 9 ppmv @ 15 % O_2 < 9 ppmv @ 15 % O_2 < 9 ppmv @ 15 % O_2
Fuel Consumption Rate	Natural gas	832,230 Btu/hr
Fuel Supply Pressure	Maximum Minimum	5 psig 0.29 psig
Heat Output	Total	51,100 Btu/hr
Noise Level	Crouse Community Center IR Powerworks	73 dbA at 1 m
Size	Length Width Weight	69 in. 42 in. 4100 lbs

The turbine at the Crouse Community Center facility uses natural gas supplied at about 2 pounds per square inch gauge (psig). The IR PowerWorks system includes a booster compressor which increases fuel pressure to 50 psig prior to the combustor.

The integral heat recovery system consists of a fin-and-tube heat exchanger, which circulates a mixture of approximately 16 percent propylene glycol (PG) in water through the heat exchanger at approximately 20 gallons per minute (gpm). The heating loop is driven by an internal circulation pump, and no additional pumping is required. The recovered heat is circulated through the facility's mechanical room to offset or supplement heat generated by two gas-fired boilers. The resultant, cooler PG mixture is circulated back to the heat exchanger, energy is exchanged between the PG mixture and the hot turbine exhaust gas, and the entire circulation loop is repeated. If overheating of the glycol loop should occur due to the Crouse Community Center heat load being significantly lower than the heat transferred with the IR PowerWorks system, the system will automatically shut off.

The thermal control system is programmable for individual site requirements. Minimum settings may vary, but the maximum fluid temperature entering the PowerWorks may never exceed 200^{o}F. Section 1.3 below contains further discussion regarding the use of recovered heat.

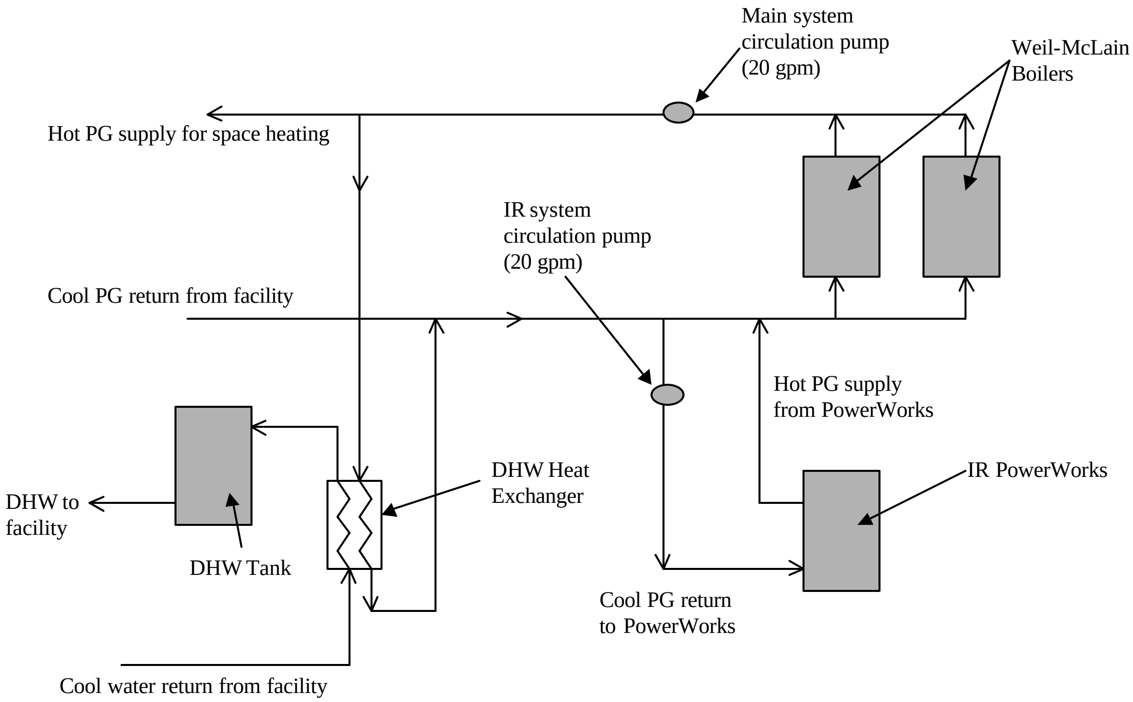
1.3 TEST FACILITY DESCRIPTION

The Crouse Community Center is located in Morrisville, New York. The facility is a 60,000 square foot skilled nursing facility providing care for approximately 120 residents. Similar to a hospital, the facility includes private residential rooms, social and recreational areas, industrial-scale laundry facilities, and cafeterias. The IR PowerWorks system was installed to provide electricity and domestic hot water (DHW) to the facility, and to supplement the facility's production of hot water for space heating.

During normal occupancy and facility operations, electrical demand exceeds the IR PowerWorks generating capacity, and additional power is purchased from the grid. On rare occasions, when facility electrical demand is below 70 kW (demand can drop as low as 50 kW in some instances), the excess power is exported to the grid.

Prior to installation of the IR PowerWorks, the facility used two gas-fired boilers to generate hot water for space heating and DHW throughout the complex. The two boilers are Weil-McLain Model Number BG-688 units, installed in 1996. Each boiler has a rated heat input of 1,700 million British thermal units per hour (MMBtu/hr), gross output capacity of 1,358 MMBtu/hr, and a net hot water production rate of 1,181 MMBtu/hr. The IR PowerWorks is configured in line with the boiler supply and return PG lines (Figure 1-3).

Figure 1-3. Crouse Community Center Space Heating and Hot Water System



During normal facility occupancy and operation, the IR PowerWorks system provides enough heat to provide all of the facility's DHW needs throughout the year. Space heating demand at the facility varies greatly by season. During warm seasons, the IR PowerWorks system usually provides all of the heat for space heating as well as DHW. The boilers remain idle unless DHW demand is very high, at which time one boiler may operate for short periods of time. During colder periods, the boilers are used as needed to provide additional space heating requirements. At times when the space heating and DHW demand is low, the return PG fluid temperature becomes elevated. Should this temperature reach 200^{o}F, the PowerWorks automatically shuts down.

1.4 PERFORMANCE VERIFICATION PARAMETERS

The verification test is scheduled to take place during the summer of 2002. It is expected that the facility will be at or near capacity occupancy at the time of testing. The IR PowerWorks system will be set to operate 24 hours per day at maximum electrical power output (70 kW). The space heating and DHW demands will be dependent on ambient temperatures, and may be less than the maximum heat recoverable with the IR PowerWorks system. However, the facility will be able to dump heat in the form of hot water during the test periods to ensure that all of the energy generated by IR PowerWorks will be consumed during testing at full load. All of the heat recovered by the IR PowerWorks system will offset heat normally supplied by the two gas-fired boilers.

The verification parameters selected for testing are intended to evaluate the performance of the CHP system only, and not the overall facility integration or specific management strategy. The parameters are listed below, and detailed descriptions of the testing and analysis methods to be used are presented in Section 2.0.

Verification Parameters

- Power and Heat Production Performance
- Electrical Power Quality Performance
- GHG and Conventional Air Pollutant Emission Performance

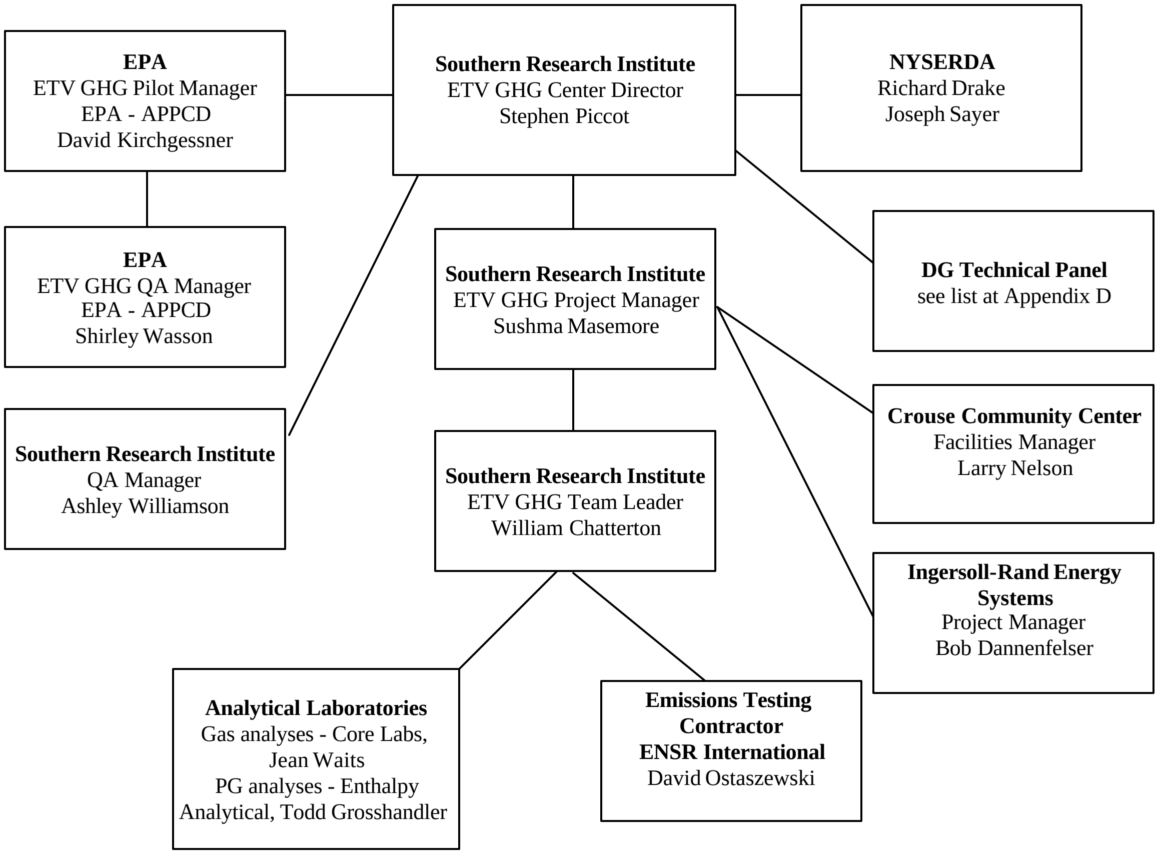
The verification test will include periods of load testing, in which the GHG Center will intentionally modulate the unit to operate at four electrical loads: 50, 75, 90, and 100 percent of the maximum 70 kW capacity. A unit ramping test will also be conducted to profile system emissions throughout the entire turbine operating range. During load tests, simultaneous monitoring for power output, heat recovery rate, fuel consumption, ambient meteorological conditions, and exhaust emissions will be performed. Average electrical power output, heat recovery rate, energy conversion efficiency (electrical, thermal, and net), and exhaust stack emission rates will be reported for each load factor. The testing period for each load is expected to be approximately two hours in duration, and the entire load testing period, plus the ramping test period, will take about two days to complete. The turbine will be allowed to stabilize at each load for 15 to 30 minutes before starting the test periods.

Throughout the five-day test period, the IR PowerWorks will be operated at full load (or the highest achievable load) during all times other than the reduced-load controlled test periods and the ramping test. GHG Center personnel will continuously monitor and record electric power generated, heat recovered, fuel consumed, ambient meteorological conditions, and power quality during this time (approximately 120 hours). The continuous test results will be used to report total electrical energy generated, total thermal energy recovered, GHG and NO_X emission reduction estimates, and power quality. GHG and NO_X emission reduction estimates for the Crouse Community Center will be based on measured IR PowerWorks emission rates, electrical and thermal energy produced at full load (generation off-sets), and baseline GHG and NO_x emissions for the nationwide, Mid-Atlantic census division, and New York state electrical grids. Further discussion of the verification strategy is provided in Section 2.0.

1.5 ORGANIZATION

Figure 1-4 presents the project organization chart. The following section discusses functions, responsibilities, and lines of communications for the verification test participants.

Figure 1-4. Project Organization



SRI'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 occur.

The GHG Center's Ms. Sushma Masemore will have the overall responsibility as Project Manager, under supervision of Mr. Stephen Piccot, the GHG Center Director. Ms. Masemore will be responsible for overseeing field data collection activities of the GHG Center's Field Team Leader, including determination of data quality indicators (DQIs) prior to completion of testing. Ms. Masemore will follow the procedures outlined in Sections 2.0 and 3.0 to make this determination, and she will have the authority to repeat tests as determined necessary to ensure that DQOs are met. Should a situation arise during testing that could affect the health or safety of any personnel, Ms. Masemore will have full authority to suspend testing. She will also have the authority to suspend testing if quality problems occur. In both cases, she may resume testing when problems are resolved. Ms. Masemore will be responsible for maintaining communication with NYSERDA, Crouse Community Center, EPA, and stakeholders.

Mr. Bill Chatterton will serve as Field Team Leader, and will support Ms. Masemore's data quality determination activities. Mr. Chatterton will provide field support for activities related to all measurements and data collected. He will install and operate the measurement instruments, supervise and document activities conducted by the emissions testing contractor (described in Section 3.4), collect gas samples and coordinate sample analysis with the laboratory, and ensure that the QA/QC procedures outlined in Section 2.0 are followed. He will submit all results to the Project Manager, such that it can be determined whether the DQIs are met. He will be responsible for ensuring that performance data collected by continuously monitored instruments and manual sampling techniques are based on the procedures described in Section 4.0.

SRI's Quality Assurance Manager, Mr. Ashley Williamson, will review this Test Plan. He will also review the results from the verification test, conduct an Audit of Data Quality (ADQ), and possibly a Technical Systems Audit (TSA) as described in Section 4.4.3. Mr. Williamson will report the results of the internal audits and corrective actions to the GHG Center Director. These results will be used to prepare the final Report.

Mr. Joseph Sayer, Senior Project Manager, will serve as the primary contact person for NYSERDA. Mr. Sayer will provide technical assistance and coordinate operation of the IR PowerWorks at the test site, and will be present during the verification testing. Mr. Sayer will coordinate with the facility operations engineer to ensure the unit and host site are available and accessible to the GHG Center for the duration of the test. NYSERDA's Manager of Power Systems Research, Mr. Richard Drake, will direct his activities.

Crouse Community Center will provide access to the test site during verification testing and ensure safe operation of the unit. They will also review the Test Plan and Report and provide written comments.

EPA-ORD's Air Pollution Prevention and Control Division (APPCD) 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 and Report. The APPCD QA Manager reviews and approves the Test Plan and final Report to ensure they meet the GHG Center QMP requirements and represent sound scientific practices.

1.6 SCHEDULE

The tentative schedule of activities for testing the IR PowerWorks is as follows:

Verification Test Plan Development	
GHG Center Internal Draft Development	May 1 - June 13
NYSERDA, Vendor and Host Site Review/Revision	June 17 – June 28
EPA and Industry Peer-Review/Revision	June 17 – July 25
Final Test Plan Posted	July 26
Verification Testing and Analysis	
Measurement Instrument Installation/Shakedown	July 29 – August 2
Field Testing	August 7 – August 16
Data Validation and Analysis	August 7 – August 23
Verification Report Development	
GHG Center Internal Draft Development	August 19 – September 20
Vendor and Host Site Review/Revision	September 23 – October 4
EPA and Industry Peer-Review/Revision	October 7 – October 18
Final Report Posted	October 31

2.0 VERIFICATION APPROACH

2.1 OVERVIEW

Microturbine CHP systems are a relatively new technology, and the availability of performance data is limited and in great demand. The GHG Center's Stakeholder groups and other organizations concerned with DG have a specific interest in obtaining verified field data on the emissions, and technical and operational performance of microturbine systems. Performance parameters of greatest interest include electrical power output and quality, thermal-to-electrical energy conversion efficiency, thermal energy recovery efficiency, exhaust emissions of conventional pollutants and GHGs, GHG emission reductions, operational availability, maintenance requirements, and economic performance. The test approach described here focuses on assessing those performance parameters of significant interest to potential future customers of IR PowerWorks systems. Long-term evaluations cannot be performed with available resources so economic performance and maintenance requirements will not be evaluated.

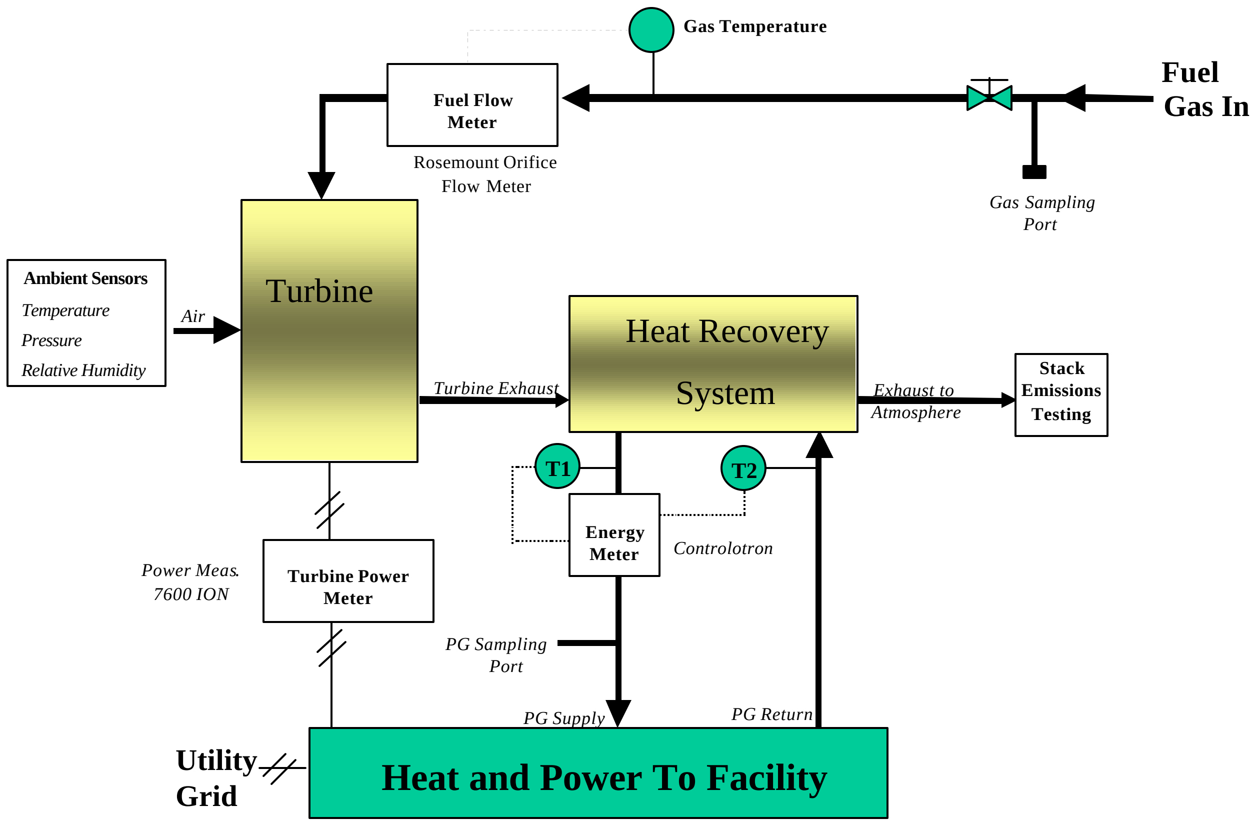
In developing the verification strategy, the GHG Center has applied existing standards for large gas-fired turbines, engineering judgement, and technical input from the verification team. Electrical power output and efficiency determination guidelines in the American Society of Mechanical Engineers *Performance Test Code for Gas Turbines, PTC-22-1997* (ASME 1997) have been adopted to evaluate electric power production and energy conversion efficiency performance. Some variations in the PTC-22 requirements were made to reflect the small scale of the microturbine. The strategy for determining thermal energy recovery was adopted from guidelines described in American National Standards Institute/American Society of Heating, Refrigeration and Air-Conditioning Engineers *Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems* (ANSI/ASHRAE, 1992). Exhaust stack emissions testing procedures, described in U.S. EPA's New Source Performance Standards (NSPS), *Standards of Performance for Stationary Gas Turbines, 40CFR60, Subpart GG* (EPA 1999) have been adopted for GHG and criteria pollutant emissions testing. Power quality standards used in this verification are based on the Institute of Electrical and Electronics Engineers *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* (IEEE, 1993).

Tests at four operating loads (50, 75, 90, and 100 percent) and continuous monitoring during the five-day test period will be performed to address the following verification factors:

- Power and Thermal Energy Production Performance
- Electrical Power Quality Performance
- GHG and Conventional Air Pollutant Emission Performance

Figure 2-1 illustrates the measurement system to be employed. Following is a brief discussion of each verification factor and their method of determination. Detailed descriptions of testing and analytical methods are provided sequentially in Sections 2.2 through 2.5.

Figure 2-1 Schematic of Measurement System



Power and Heat Production Performance

Power production performance represents a class of microturbine/CHP system operating characteristics that are of great interest to purchasers, operators, and users of these systems. Key parameters that will be characterized on the test unit include:

- Electrical power output at selected loads (kW)
- Electrical efficiency at selected loads (%)
- Heat recovery rate at selected loads (MMBtu/hr)
- Thermal energy efficiency at selected loads (%)
- CHP production efficiency (%)

The GHG Center will install a watt meter to measure the electrical power generated by the turbine. Fuel input will be determined using a mass flow meter which will monitor the natural gas flow rate. Fuel gas sampling and energy content analysis (via gas chromatography) will be conducted to determine the LHV of the fuel.

The thermal energy recovery rate of the IR PowerWorks is defined as the amount of heat recovered from the turbine exhaust, and the facility will have or create sufficient demand to use all of the heat recovered. Thermal energy recovery rates will be verified by metering the flow, differential temperatures, and physical properties of the heat transfer fluid. The heat transfer fluid is a mixture of PG and water. The

PG mixture flow rate and temperatures will be measured with an energy meter provided by the GHG Center (Figure 2-1). Manual samples of the PG mixture will be collected and analyzed to determine PG concentration. These results will be used to assign fluid density and specific heats, such that heat recovery and use rate can be calculated at actual conditions. The heat recovery rate measured at full load will represent maximum heat recovery potential of the IR PowerWorks system. This rate will be used to compute GHG and NO_X emission reductions for sites that are able to fully utilize all energy recoverable with the IR PowerWorks system (Section 2.5).

Fuel energy-to-electricity conversion efficiency will be determined by dividing the average electrical power output by the heat input. Similarly, thermal energy conversion efficiency will be determined by dividing the average heat recovered by the heat input. CHP production efficiency or net system efficiency will be reported as the sum of electrical and thermal efficiencies at each operating load. Ambient temperature, relative humidity, and pressure will be measured throughout the verification period to support determination of electrical conversion efficiency as required in PTC-22.

A detailed discussion of sampling procedures, analytical procedures, and QA/QC procedures related to heat and power production performance parameters is provided in Section 2.2.

Power Quality Performance

The monitoring and determination of power quality performance is required to ensure compatibility with the electrical grid, and to demonstrate that the electricity will not interfere with, or harm microelectronics and other sensitive electronic equipment within the facility. Power quality data is used to report exceptions, which describe the number and magnitude of incidents that fail to meet or exceed a power quality standard chosen. The *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* (IEEE, 1993) contains standards for power quality measurements that will be followed here. Power quality parameters will be determined over the five-day test period using the electric power meter installed by the GHG Center. The approach for verifying these parameters is described in Section 2.3. Power quality variables to be examined include:

- Electrical frequency (Hz)
- Power factor (%)
- Voltage and current total harmonic distortion (THD) (%)

Emissions Performance

The measurement of the emissions performance of the microturbine system is critical to the determination of the environmental impact of the technology. Emission rate measurements for CO, carbon dioxide (CO_2), methane (CH_4), NO_X, and THCs will be conducted in the IR PowerWorks exhaust stack during controlled test periods at various operating loads. Exhaust stack emission testing procedures, described in U.S. EPA's NSPS for stationary gas turbines (EPA 1999), will be adapted to verify the following verification parameters at the selected loads:

- CO Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- CO_2 and CH_4 Emission Rates (lb/hr, lb/Btu, lb/kWh)
- NO_X Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- THCs Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- Estimated NO_X emission reductions for Crouse Community Center (lb NO_x/yr)
- Estimated GHG emission reductions for Crouse Community Center (lb CO_2/yr)

For the conventional pollutants listed above, emission rates (e.g., mass/hour, mass/heat input, mass/power output) will be measured and reported. CO_2 and CH_4 emission rates will also be measured. CO_2 emissions from the system will be calculated for the verification period using measured GHG emission rates, operating hours, and thermal/electrical generation and use data.

The verification will report GHG and NO_X emission reduction estimates based on actual emissions and reductions for Crouse Community Center. The IR PowerWorks emissions will be compared to emissions from a baseline system. The baseline system is that which would have been installed to meet the site's energy needs in the absence of the IR PowerWorks system. For this application, the baseline system defined for Crouse Community Center consists of electricity supplied by the New York state utility grid and thermal energy supplied by the facility's natural-gas boilers. Subtraction of the annual IR PowerWorks' emissions from the baseline emissions yield an estimate of the emission reduction for the facility.

The procedures for estimating emission reduction from utility grid electricity production are provided in Section 2.5.2. GHG emissions for the standard gas-fired boiler will be determined by estimating fuel needed to generate equivalent amounts of heat with the baseline boilers. The baseline gas-fired boilers are reasonably new and were installed in 1996. Detailed procedures for estimating annual emission reduction from thermal energy production is provided in Section 2.5.3.

2.2 POWER AND HEAT PRODUCTION PERFORMANCE

The IR PowerWorks system will be evaluated for the performance factors listed above at the four specified operating loads. The loads selected bound the range expected to occur at Crouse Community Center. A step-by-step procedure for conducting the test is provided in Appendix A-1, and a log form associated with this activity is provided in Appendix A-2. The test period at each load is expected to be 30 minutes in duration, and will be repeated three times. The triplicate measurement design is based on U.S. EPA NSPS guidelines for measuring emissions from stationary gas turbines (EPA, 1999). The following sections discuss the measurements, calculations, and associated determinations in detail.

2.2.1 Electrical Power Output and Efficiency Determinations

Simultaneous measurements of electric power output, heat recovery rate, heat use rate, fuel consumption, ambient meteorological conditions, and exhaust emissions will be performed during testing at each load. The time-synchronized measurements data will be used to compute electrical efficiency as specified in PTC-22. PTC-22 mandates using electric power data collected over time intervals of not less than 4 minutes and not greater than 30 minutes (PTC-22, Section 3.4.3 and 4.12.3) to compute electrical efficiency. This restriction minimizes electrical efficiency determination uncertainty due to changes in operating conditions (e.g., turbine speed, ambient conditions). Within this time period, PTC-22 specifies the maximum permissible limits in power output, power factor, fuel input, and atmospheric conditions 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. Should the variation in power output, power factor, fuel flow, or ambient conditions exceed the levels, the load test will be considered invalid and the test will be repeated.

Table 2-1. Permissible Variations in Power, Fuel, and Atmospheric Conditions	
Measured Parameter	**Maximum Permissible Variation**
Ambient air temperature	± 4 °F
Barometric pressure	± 0.5 %
Fuel flow	± 2 %
Power factor	± 2 %
Power output	± 2 %

Electrical efficiency at the selected loads will be computed as shown in Equation 1 (per ASME PTC-22, Section 5.3).

$$\eta = \frac{3412.14\, kW}{HI} \qquad \text{(Eqn. 1)}$$

where:

η = efficiency (%)
kW = average electrical power output (kW), Equation 2
HI = average heat input using LHV (Btu/hr), Equation 3

Average electrical power output will be computed as the mathematical average of the 1-minute instantaneous readings over the sampling period (4 to 30 minutes), as shown in Equation 2.

$$kW = \frac{\sum_{i=1}^{i=nr} kWi}{nr} \qquad \text{(Eqn. 2)}$$

where:

kW = average electrical power output (kW)
kW_i = instantaneous reading of the kW sensor at each minute (kW)
nr = number of 1-minute readings logged by the kW sensor

The average heat input will be determined using data collected with a mass flow meter and a gas chromatograph. The flow meter will be installed in the fuel supply line of the IR PowerWorks, and will be programmed to continuously monitor and record 1-minute flow readings. Fuel gas samples will be collected by the GHG Center at a frequency of one extraction per load condition. Based on the GHG Center's experience during similar verifications, the heating value of the natural gas is not expected to vary greatly at the site and therefore, this sampling frequency is considered to be adequate for determining efficiency. The GHG Center will obtain multiple gas samples prior to testing to determine the variability in heating values over 30 minute sampling intervals. If the variability is greater than 1 percent as specified in PTC-22, the sample frequency during controlled testing will be increased, and the average heating value during a test period will be used to determine efficiency. The gas samples will be shipped to a certified laboratory for compositional analysis in accordance with ASTM Specification D1945, and LHV determination using ASTM Specification D3588. Using the fuel flow rate data and the LHV results, average heat input will be computed as shown in Equation 3.

$$HI = 60\ F_m\ LHV \qquad \text{(Eqn. 3)}$$

where:

HI = average heat input using LHV (Btu/hr)
F_m = average mass flow rate of natural gas to turbine (scfh)
LHV = average LHV of natural gas (Btu/scf)

Power Output Corrections for Standard Conditions

The above calculations reflect power output and efficiency results at actual site conditions (i.e., temperature, pressure, and relative humidity observed during testing). For assessing the performance of this technology in different geographic regions, it is useful to correct the actual test data to standard conditions. A standard temperature of 60 ^{o}F, barometric pressure of 14.7 pounds per square inch absolute (psia), and a relative humidity of 60 percent, as defined by the International Standards Organization (ISO 2314: 1989), is often used to correct for standard conditions.

Because it is unlikely ISO conditions will be encountered during the verification, directly verified performance results will not be obtainable at standard conditions. For readers interested in such data, the GHG Center will obtain from IR derated performance curves which allow conversion of the verified data to standard conditions. This data will be presented in a separate section of the final Report, and because the charts were not developed by the GHG Center readers of this section will be informed that the results have not been verified by the GHG Center.

2.2.1.1 7600 ION Electrical Meter

The electric power output to the system will be measured by a digital power meter, manufactured by Power Measurements Ltd. (Model 7600 ION). The 7600 ION will continuously monitor the kilowatts of real power at a rate of one reading per second, averaged at 1-minute intervals. It will be installed after the 480 volt transformer (Figure 2-1), such that the electricity measured is the electricity that is ultimately used by the site or supplied to the utility grid. The power output measured with the 7600 ION will be slightly less than actual power generated by the turbine, and will account for losses in the transformer.

The GHG Center's data acquisition system (DAS) will download and store the 7600 ION data. Further discussion of the communication and data acquisition is provided in Section 4.0. After installation the meter will continuously operate unattended, and will not require further adjustments. QA/QC procedures associated with instrument setup, calibration, and sensor function checks are discussed below. The meter will be factory calibrated to IEC687 SO.2 and ANSI C12.20 CAO.2 standards for accuracy. Details regarding this calibration and additional QA/QC checks on this instrument are provided in Section 3.2.

2.2.1.2 Rosemount 3095 Mass Flow Meter

The mass flow rate of the fuel supplied to the turbine will be determined using an integral orifice meter (Rosemount Model 3095). The meter will contain an orifice plate which will enable flow measurements to be conducted at the ranges expected during testing (8 to 17 scfm natural gas). The meter will be temperature- and pressure-compensated, providing mass flow output at standard conditions (60 ^{o}F, 14.7 psia). The meter will continuously monitor flows at a rate of one instantaneous reading per minute, and will be capable of providing an accuracy of ± 1 percent of reading. The meter will be fitted with a transmitter providing a 4 to 20 mA output over the meter's range. The GHG Center's DAS will convert the analog signals to digital format and then store the data as 1-minute averages. The meter will be factory calibrated to IEC687 SO.2 and ANSI C12.20 CAO.2 standards for accuracy. Details regarding this calibration and additional QA/QC checks on this instrument are provided in Section 3.3.1.1.

2.2.1.3 Fuel Heating Value Measurements

Fuel heating value measurements will be conducted to determine the actual LHV of natural gas, such that electrical and thermal efficiency calculations can be performed. Samples will be collected at an access port in the fuel line located prior to the flow meter (Figure 2-1). The port is downstream of a ball valve and consists of 0.25-inch NPT union. Gas samples will be manually collected in stainless steel canisters provided by the analytical laboratory. The canisters are 600-ml vessels with valves on the inlet and outlet sides. Prior to sample collection, canister pressure will be checked using a vacuum gauge to document that the canisters are leak free. Canisters that are not fully evacuated upon receipt from the laboratory will not be used for testing. During testing, the connections between the canisters and the fuel sampling port will be screened with a hand-held hydrocarbon analyzer to check for leaks in the system. In addition, the canisters will be purged with fuel for approximately five seconds to ensure that a pure fuel sample is collected. Appendix A-3 contains detailed procedures that will be followed, and Appendices A-4 and A-5 contains sampling log and chain-of-custody forms.

Two preliminary gas samples will be collected prior to the test period to characterize gas composition. The average value of these analyses will be used to program the mass flow meter during instrument installation. (Section 3.3.1.1) During verification testing, a minimum of one gas sample will be collected during each of the 50, 75, 90, and 100 percent load tests. This sampling frequency is expected to be sufficient because during previous verifications conducted by the GHG Center, daily variation in pipeline quality gas composition has been less than one percent. The collected samples will be returned to the laboratory for compositional analysis in accordance with ASTM Specification D1945 for quantification of methane (C1) to hexanes plus (C6+), nitrogen (N_2), oxygen (O_2), and CO_2.

During analysis, sample gas will be injected into a Hewlett Packard 589011 gas chromatograph (GC) equipped with a silicon and molecular sieve column. Components will be physically separated on the columns and their concentrations measured with a flame ionization detector (FID). The resultant areas under each peak will be compared to the corresponding calibration data. Data will be acquired and recorded by a Hewlett Packard 339611 integrator. The useful range of the detectable concentrations (mole percent) is specified in Table 1 of the method (D1945). Appendix C-1 presents an example analytical report for gas composition. The GC is calibrated weekly as a continuing calibration verification check using a certified natural gas standard. Details regarding this calibration and additional QA/QC checks on gas sampling and analysis are provided in Section 3.3.1.2.

2.2.1.4 Ambient Conditions Measurements

Meteorological data will be collected to determine if the maximum permissible limits for determination of electrical efficiency are satisfied (Table 2-1). The ambient meteorological conditions (temperature, relative humidity, and barometric pressure) will be monitored using a Setra pressure sensor and a Vaisala Model HMD 60YO integrated temperature/humidity unit located in close proximity to the air intake of the turbine. The integrated temperature/humidity unit uses a platinum 100 Ohm, 1/3 DIN resistance temperature detector (RTD) for temperature measurement. As the temperature changes, the resistance of the RTD changes. This change in resistance is detected and converted by associated electronic circuitry that provides a linear DC (4 to 20mA) output signal.

The integrated unit uses a thin film capacitive sensor for humidity measurement. The dielectric polymer capacitive element varies in capacitance as the relative humidity varies, and this change in capacitance is detected and converted by internal electronic circuitry that provides a linear DC (4 to 20mA) output signal. This sensor features electronic compensation to maintain accuracy over a broad range of temperature conditions.

The barometric pressure is measured by a variable capacitance sensor. As pressure increases, the capacitance decreases. This change in capacitance is detected and converted by internal electronic circuitry that provides a linear DC (4 to 20 mA) output signal. The range and accuracy of each sensor are given in Table 3-2. The response time of the temperature and humidity sensors is 0.25 seconds and the response time of the pressure sensor is under two seconds. The GHG Center's DAS will convert the analog signals to digital format and then store the data as 1-minute averages.

Electrical efficiency determinations require variability in ambient temperature and barometric pressure to be less than ± 4 ^{o}F and ± 0.5 percent, respectively. The instruments selected for the verification are capable of providing ± 0.2 ^{o}F for temperature and ± 0.06 percent for barometric pressure, which exceed the PTC-22 requirements for meteorological data. The temperature and humidity measurement equipment will be factory calibrated to National Institute for Standards and Technology (NIST)-traceable standards for accuracy. Details regarding this calibration and additional QA/QC checks on these instruments are provided in Table 3-3 in Section 3.2.

2.2.2 Heat Recovery Rate and Thermal Efficiency Measurements

An energy meter will be used to monitor and record the thermal energy generated by the IR PowerWorks system. The GHG Center will use a portable Controlotron Model 1010EP1 to measure the volume of working fluid circulated through the heat exchanger and its supply and return temperatures. As shown in Figure 2-1, the temperature readings at T1 and T2 will be used to compute heat recovered by the IR PowerWorks system. System heat recovery rates are computed according to ANSI/ASHRAE Standard 125 (ASHRAE, 1992), as follows:

$$Q_{avg}\ (Btu/min) = V\ r\ Cp\ (T1-T2) \qquad \text{(Eqn. 4)}$$

where:

Q_{avg} = average heat recovered (Btu/min)
V = total volume of working fluid passing through the system during a minute (ft^3)
ρ = density of working fluid (lb/ft^3), evaluated at the avg. fluid temp. (T2+T1)/2
Cp = specific heat of liquid (Btu/lb °F), evaluated at the avg. fluid temp. (T2+T1)/2
T1 = temperature of heated fluid exiting heat exchanger, (^oF)
T2 = temperature of cooled fluid entering heat exchanger (^oF), Figure 2-1

The heat recovery performance of the IR PowerWorks system will be a function of the return working fluid temperature and the overall heat demand associated with the system. The maximum average heat recovery rate measured during full load testing will be used to represent maximum heat recovery potential of the IR PowerWorks for this application.

The heat recovery rate determination requires physical properties of the heat transfer fluid at actual operating temperatures to be defined. To specify these properties, it is necessary to accurately characterize the composition of the working fluid, and select published density and specific heat data from reliable sources (ASHRAE publications). The fluid used in the heat recovery unit is a mixture of PG in water. Samples of this fluid will be collected during the verification and analyzed for PG (or other) content. Appendices A-9 and A-10 provide an example of mixture density and specific heat data as a function of temperature for systems that use a mixture of PG and water. The GHG Center will use ASHRAE published data to interpolate working fluid properties at the conditions encountered during testing, and to compute heat recovery rates.

The time intervals for reporting average heat recovered and thermal efficiency at the selected loads will correspond to those used in computing electrical efficiency. The following equation will be used to compute thermal efficiency:

$$\eta_T = 60 * Q_{avg} / HI \qquad \text{(Eqn. 5)}$$

where:

η_T = thermal efficiency (%)
Q_{avg} = average heat recovered (Btu/min)
HI = average heat input using LHV (Btu/hr), Equation 3

2.2.2.1 Controlotron Energy Meter

The Controlotron (Model 1010EP1) 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 the application characteristics described below. The system can be used on pipe sizes ranging from 0.25 to 360 inches in diameter with fluid flow rates ranging from 0 to 60 feet per second (fps) (bi-directional).

The flow transducers are surface mounted units that operate on an ultrasonic transit-time principle. They have a rated sensitivity of 0.001 fps and repeatability of 0.25 percent. Transit-time signals are reported to the flow computer at intervals in the millisecond range and converted in the computer to fluid velocity. The RTDs have a rated accuracy of 0.02 °F. These sensors provide continuous supply and return line temperature signals to the computer to record ΔT (at ± 0.04 °F). Depending on pipe size and configuration, the RTDs can be surface mounted or inserted into thermowells. For this verification the insulated clamp-on RTDs will be used on the 1.25-inch diameter copper tubing used to route the supply and return fluid.

To operate the energy metering system, several critical parameters must be programmed into the computer including:

- pipe diameter
- pipe wall material and thickness
- distances between ultrasonic transducers
- working fluid density and specific heat

The accuracy of these parameters will directly impact the overall accuracy of the meter. Pipe material and exact pipe diameter and wall thickness will be obtained from manufacturer specifications. The transducer mounting system is designed to provide precise measurement of the distance between transducers.

The energy meter software contains lookup tables that provide the ASHRAE working fluid density and specific heat values corrected to the average fluid temperature measured by the RTDs. In order for these values to be correct, the fluid composition must be known or determined, and programmed into the computer. Fluid composition testing will be conducted by the GHG Center before and during testing as described below to ensure proper system programming.

The ultrasonic transducers are mounted on the pipe at a location with at least ten diameters of undisturbed flow upstream and five diameters of undisturbed flow downstream. The RTDs are mounted as close to the heat recovery unit as configuration allows. During use the heat recovery rate is continuously calculated using the fluid flow and temperature inputs, and the system parameters programmed into the computer. Data are logged and stored by the energy meter in units of Btu/min. The meter can also total the energy recovered. Using an RS-232 serial port connection to the GHG Center's DAS, the following measurements will be logged as 1-minute averages throughout all test periods.

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

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 conducted in the field, are detailed in Section 3.3.2.

2.2.2.2 PG Solution Sampling and Analysis

Samples will be collected from a fluid discharge spout located on the hot side of the heat recovery unit using pre-cleaned glass vials of 100 to 500 ml capacity. One sample will be collected during each day of the verification period. Preliminary samples will also be collected prior to testing for use in programming the Controlotron energy meter. Each sample collection event will be recorded on field logs (Appendix A-7) and shipped to an analytical laboratory along with completed chain-of-custody forms (Appendix A-8).

Samples will be analyzed for PG concentration (percent) at the laboratory using a gas chromatography/flame ionization detector (GC/FID). The GC/FID is calibrated with standards ranging from 10 to 1,000 ppm PG to establish instrument linearity and a calibration curve. Because the instrument is calibrated to 1,000 ppm and sample concentrations of PG are expected to be around 23 percent (230,000 ppm), appropriate sample dilution will be performed prior to direct injection into the instrument. PG reactions in the GC column typically exhibit significant variability, and therefore the accuracy of the glycol content analyses is limited to approximately ± 10 percent (or ± 2.3 percent for a mixture of approximately 23 percent glycol).

As a QA check on the glycol fluid sampling and analyses, a blind audit sample will be submitted to the laboratory along with the samples. The GHG Center will procure pure ACS reagent grade PG from a qualified reagent manufacturer (J.T. Baker or equivalent). ACS reagent grade PG is minimum 99.5 percent pure, with actual purity reported per lot manufactured. A mixture of glycol in distilled water (in the range of 20 to 25 percent) will be prepared by GHG Center personnel, recorded at the GHG Center's laboratory, and submitted to the analytical laboratory for analysis. The analytical laboratory will be requested to conduct duplicate analyses on the audit sample, and the reported values will be compared to the mixture recorded by the GHG Center to evaluate analytical accuracy.

2.3 POWER QUALITY PERFORMANCE

There are a number of issues of concern when an electrical generator is connected in parallel and operated simultaneously with the utility grid. The voltage and frequency generated by the power system must be aligned the same as the power grid. While in grid parallel mode, the turbine detects the utility voltage and frequency to ensure proper synchronization before actual grid connection occurs. The turbine power electronics contain circuitry to detect and react to abnormal conditions that, if exceeded, cause the unit to automatically disconnect from the grid. These out-of-tolerance operating conditions include overvoltages, undervoltages, and over/under frequency. For the test situation, out-of-tolerance conditions are defined as grid voltage outside the range of 480 volts ± 10 percent and electrical frequency of 60 Hz ± 0.01 percent.

The power factor delivered by the turbine must be of sufficient quality to allow successful operation of sensitive office equipment. Harmonic distortions in voltage and current must also be minimized to reduce damage or disruption to electrical equipment (e.g., lights, motors, office equipment). Industry standards for harmonic distortion have been established within which power generation equipment, such as the turbine, must operate.

Power quality parameters such as electrical frequency, power factor, and THD cannot be isolated from the grid. The quality of power delivered by the turbine actually represents an aggregate of disturbances already present in the utility grid, and is a measure of how the turbine works to reduce the disturbances by compensating for extreme variations in power quality. In the case of the power factor, the turbine electronics follow the demand load (i.e., if there is an inductive demand, the turbine will provide a lower power factor).

The power quality evaluation approach has been developed to account for these issues, and will report electrical frequency output, voltage output, power factor, and THD. Each parameter provides an understanding of the quality of electrical power produced by the turbine, and its ability to maintain synchronization with the power grid. To report power quality performance relative to the grid power quality, baseline measurement data will be collected by shutting the turbine off each day for one hour, and taking direct measurement of the grid power quality. The turbine will then be turned on, and additional data will be collected to determine improvements in the quality of power generated by the turbine. The difference between before and after readings will represent the actual power quality delivered by the turbine. The same electrical meter (7600 ION) used for electrical power output measurements will be used to make these measurements. The methods for determining and reporting power quality parameters are discussed below.

2.3.1 Electrical Output Frequency

Electricity supplied in the U.S. and Canada is typically 60 Hz AC. Electrical frequency measurements will be monitored continuously, and average 1-minute readings will be recorded. The data collected by the electrical meter will be analyzed to determine maximum, minimum, average, variance, and standard deviation of the frequency during each test period. The GHG Center will also record and report these values for those periods that the microturbine is shut off (i.e., for baseline data collection).

Equation 6 will be used to compute the average frequency.

$$F = \frac{\sum_{i=1}^{i=nr} Fi}{nr} \qquad \text{(Eqn. 6)}$$

where:

F = average frequency for baseline and turbine operating periods (Hz)
F_i = instantaneous frequency reading of the electric meter (Hz)
nr = number of 1-minute readings logged by the electric meter

The variance and standard deviation are related measures of how widely values are dispersed from the average value (the mean). The following equations will be used to compute the variance and standard deviation:

$$F\,var = \frac{\sum_{i=1}^{i=nr} (F - Fi)^2}{nr - 1} \qquad Fstd = \sqrt{F\,var} \qquad \text{(Eqns. 7, 8)}$$

where:

F_{var} = variation in frequency for baseline and turbine operating periods (Hz)
F_{std} = sample standard deviation in frequency for baseline and turbine operating periods
F = average frequency (Hz)
F_i = instantaneous frequency reading of the electric meter (Hz)
nr = number of 1-minute readings logged by the electric meter

The performance of electrical frequency output will be reported as the percent difference between baseline averages and averages during turbine operation.

2.3.2 Voltage Output

The IR PowerWorks generator An internal transformer provides 480-volt output. The electric power industry accepts that voltage output can vary within ± 10 percent of the standard voltage (480 volts) 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.

Voltage output will be continuously monitored and recorded throughout testing using the 7600 ION meter. The 7600 ION meter will be capable of measuring 0 to 600 volts (AC) at a rate of one reading per minute, and detecting surges up to 8 kV at a rate of one reading per 60 microseconds. All voltage readings will be reported as root mean square (rms) voltage, which is the most common approach for measuring AC voltage. The data listed below will be reported on a daily basis, as well as the cumulative results for the entire testing period:

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

The following equations will be used to compute the average, variance, and standard deviation of the voltage output.

$$V = \frac{\sum_{i=1}^{i=nr} Vi}{nr} \qquad V\,var = \frac{\sum_{i=1}^{i=nr} (V - Vi)^2}{nr - 1} \qquad Vstd = \sqrt{V\,var} \qquad \text{(Eqns. 9, 10, 11)}$$

where:

V	=	average voltage output (volts)
V_i	=	instantaneous voltage reading from the electric meter (volts)
nr	=	number of readings logged by the electric meter
V_{var}	=	variation in voltage output (volts)
V_{std}	=	sample standard deviation in voltage output

2.3.3 Voltage and Current Total Harmonic Distortion

Harmonic distortion of the voltage and current results from the operation of non-linear loads and devices on the power system. Harmonic distortion can damage or disrupt the proper operation of many kinds of industrial and commercial equipment. Voltage distortion is any deviation from the nominal AC line voltage sine waveform. A similar definition applies for current distortion; however, voltage distortion and current distortion are not the same. Each affects loads and power systems differently, and thus are considered separately.

In quantifying harmonic distortion, several parameters related to distortion are addressed, specifically the definition of a harmonic and how it is quantified. Fourier analysis breaks down a distorted waveform into a set of sine waves with two specific characteristics. The first characteristic deals with frequency of the waveform. The distorted waveform repeats itself with some basic frequency. The sine wave associated with this frequency, which is usually 60 Hz, is called the fundamental. The frequency of each harmonic is an integer multiple of the fundamental. So, the 2nd harmonic has a frequency of 120 Hz, the 3rd is at 180 Hz, the 4th is at 240 Hz, and so on.

The second characteristic is the magnitude of the distortion, also called the harmonic distortion factor. Each of these sine waves may have a different magnitude from each other, depending on the actual distorted signal. The magnitude is determined by a harmonic analyzer. Typically, the magnitude of each harmonic is represented as a percentage of the RMS voltage of the fundamental, not the RMS voltage of the distorted waveform. The aggregate effect of all harmonics is THD. THD equals the RMS voltage of all harmonics divided by the RMS voltage of the fundamental, converted to a percentage.

Based on IEEE 519 Standard, the turbine's specified values for total harmonic voltage and current distortion, are as follows:

Maximum Voltage THD: 5 percent
Maximum Current THD: 5 percent

For the verification, harmonic distortion (up to the 63rd harmonic) will be recorded for all voltage and current inputs using the 7600 ION. The meter will report 1-minute average THD for voltage and current, and are computed internally as shown below. The results will be analyzed to compute the average, maximum, and minimum THD for the baseline period and during turbine operation. The current and voltage harmonics present in the grid (i.e., during the baseline period) will be subtracted from the harmonics present during turbine operation to determine true contributions from the turbine.

$$Voltage\ THD = \frac{\sum_{j=1}^{j=nr}\left[\frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Volt_i}{Volt_1}\right]}{nr}$$

$$Current\ THD = \frac{\sum_{j=1}^{j=nr}\left[\frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Current_i}{Current_1}\right]}{nr}$$

(Eqns. 12, 13)

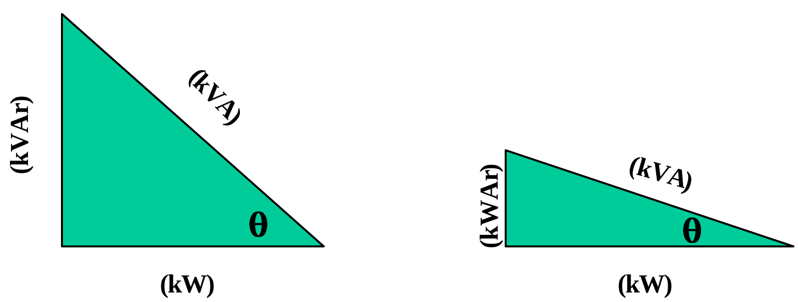
where:

Voltage THD	=	average voltage THD for baseline and turbine and operating periods (%)
Current THD	=	average current THD for baseline and turbine and operating periods (%)
$Volt_i$	=	RMS voltage reading for each harmonic in a minute (volts)
$Current_i$	=	current reading for each harmonic in a minute (amps)
$Volt_1$	=	RMS voltage reading for first harmonic in a minute (volts)
$Current_1$	=	current reading for first harmonic in a minute (amps)
nr	=	number of 1-minute readings logged by an electric meter

2.3.4 Power Factor

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. Under ideal conditions, current and voltage are in phase, which results in a power factor equal to 1.0. If reactive loads (e.g., motors) are present, power factors are less than this optimum value. Although it is desirable to maintain the power factor at 1.0, the actual power factor of the electricity supplied by the utility may be much lower because of load demands of the different end users. Typical values ranging between 0.8 and 0.9 are common. Low power factor causes higher current to flow in power distribution lines in order to deliver a given number of kilowatts to an electrical load.

Figure 2-2. Determination of Power Factor



Power Factor = cosine θ

Mathematically, electricity consists of three components which form a power triangle (Figure 2-2): Real power (kW), reactive power (kVAr), and apparent power (kVA). Real power (kW) is the part of the triangle which results in actual work being performed, in the form of heat and energy. This is the power that is verified in Section 2.2. Reactive power, which accounts for electromagnetic fields produced by equipment, always acts at right angle or 90^{o} to real power. Reactive power does not contribute to the work for which electricity was supplied, and the amount of current used to accomplish this work is increased, causing increased energy losses. The greater the reactive power, the worse the losses. Real power and reactive powers create a right triangle where the 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 power factor, which is inversely proportional to the amount of reactive power that is being generated. In summary, the larger the amount of reactive power, the lower the power factor will be.

The turbine is specified by the manufacturer to operate at a power factor setting of 1.0. One-minute average power factor measurements (before and after turning the turbine on) will be analyzed to determine if the unit maintained this setting. Maximum, minimum, average, standard deviation, and variance in the power factor will be reported for the test period.

2.4 EMISSIONS PERFORMANCE

2.4.1 Stack Emission Rate Determination

Exhaust stack emissions testing will be conducted to determine emission rates for criteria pollutants (CO, NO_X, and THCs) and greenhouse gases (CH_4 and CO_2). Stack emission measurements will be conducted at the same time as electrical power output measurements in the controlled test periods.

Following NSPS guidelines for evaluation of emissions from stationary gas turbines, IR PowerWorks system exhaust stack emissions testing will be conducted at four loads within the normal operating range of the turbine, including the minimum load in the range and the peak load. As discussed earlier, the loads selected are 50, 75, 90, and 100 percent of the normal full load capacity (70 kW). The turbine will be allowed to stabilize at each load for 15 to 30 minutes before starting the tests. To verify testing precision, three replicate test runs, each approximately 30 minutes long, will be conducted for each parameter at each load selected. The average results of three valid replicates will be reported.

In addition to the load tests, an additional test will be conducted to document emissions throughout the entire range of operation to further understand the IR PowerWorks system performance. The additional test run will be conducted at loads ranging between 40 and 100 percent of rated capacity. The test will be conducted by collecting approximately 10 minutes of data at power commands starting at full power and incrementally decreasing by 3 kW to a low of 30 kW. The only deviations from the standard test methods during this test are that three replicates will not be conducted, and the duration of sampling at each power command will be shorter. Power command changes between successive load changes will occur relatively rapidly, and the system will be allowed to stabilize for approximately 5 minutes at each point before data recording begins.

Because this test does not adhere to all of the reference method requirements, precautions will be taken to document the data quality of this test run. The sampling procedures and analytical instruments used during this test will be the same as those used during the official verification tests. The same analyzers, sampling system, calibration gases, and calibration procedures will be followed to ensure that accurate emissions concentrations are recorded (results will be presented only as concentrations for this test). Since the test may be of considerable duration (nearly 3 hours), the test will be interrupted at least once to test for analyzer drift.

The average emission rate measured during each load test run will be reported in units of parts per million volume dry (ppmvd) for CH_4, CO, NO_X, and THCs, percent for CO_2 and O_2 pounds per hour (lb/hr), and pounds per kilowatt hour energy produced (lb/kWh). Using an appropriate DAS, analyzer outputs will be compiled as 1-minute averages throughout each test and averaged over the entire test period. Concentrations of NO_X, CO, and THCs will then be reported as ppmvd corrected to 15 percent O_2 (ppmvd @ 15 % O_2) using Equation 14.

$$ppmvd \ @ \ 15 \% \ O_2 = ppmvd * [(20.9 - 15.0) / (20.9 - \text{exhaust gas } O_2)] \qquad \text{(Eqn. 14)}$$

where:

ppmvd = average of 1-minute measurements for each pollutant
exhaust gas O_2 = average of 1-minute O_2 concentrations

Appendix C-3 illustrates an example of the emissions test results. As with the power production and efficiency performance testing, IR PowerWorks operators will maintain steady unit operation and load for the duration of each emissions test. Variability in unit operation is not specified in the testing methods, but the variability criteria presented in Table 2-1 will be used as a guideline to verify that the tests were conducted during steady operation. Variability in fuel flow to the turbine (limited to one percent variability for the efficiency measurements) may exceed the limits specified in Table 2-1 slightly over the 30 minute test period, but small exceptions up to two percent are not expected to affect the emission rate measurements. An organization specializing in air emissions testing will be contracted to perform all stack testing. The testing contractor will provide all equipment, sampling media, and labor needed to complete the testing and will operate under the supervision of a GHG Center representative.

All of the emission test procedures to be utilized in this verification are U.S. EPA Federal Reference Methods. The Reference Methods are well documented in the Code of Federal Regulations, most often applied to determine pollutant levels, and include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations (40CFR60, Appendix A). Table 2-2 summarizes the standard Test Methods that will be followed.

Each of the selected methods utilizing an instrumental measurement technique 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. Each test method is discussed in more detail in the following sections. The entire Reference Method will not be repeated here, but will be available to site personnel during testing.

Table 2-2. Summary of Emission Testing Methods

Air Pollutant	U.S. EPA Reference Method	Principle of Detection	Proposed Analytical Range[a]	Accuracy	Loads Tested (% nominal capacity 70kW)	No. of Test Replicates
CH_4	18	GC/FID	0 - 25 ppm	± 5 %	50, 75, 90, and 100	3 per load (30 minutes)
CO	10	NDIR-Gas Filter Correlation	0 - 25 ppm	± 5 %		
CO_2	3A	NDIR	0 - 20 %	± 5 %		
NO_x	20[b]	Chemiluminescence	0 - 25 ppm	± 2 %		
O_2	3A	Paramagnetic	0 - 25 %	± 5 %		
THCs[a]	25A	Flame ionization	0 - 25 ppm	± 5 %		
Moisture	4	Gravimetric	0 - 25 %	± 5 %		1 per load

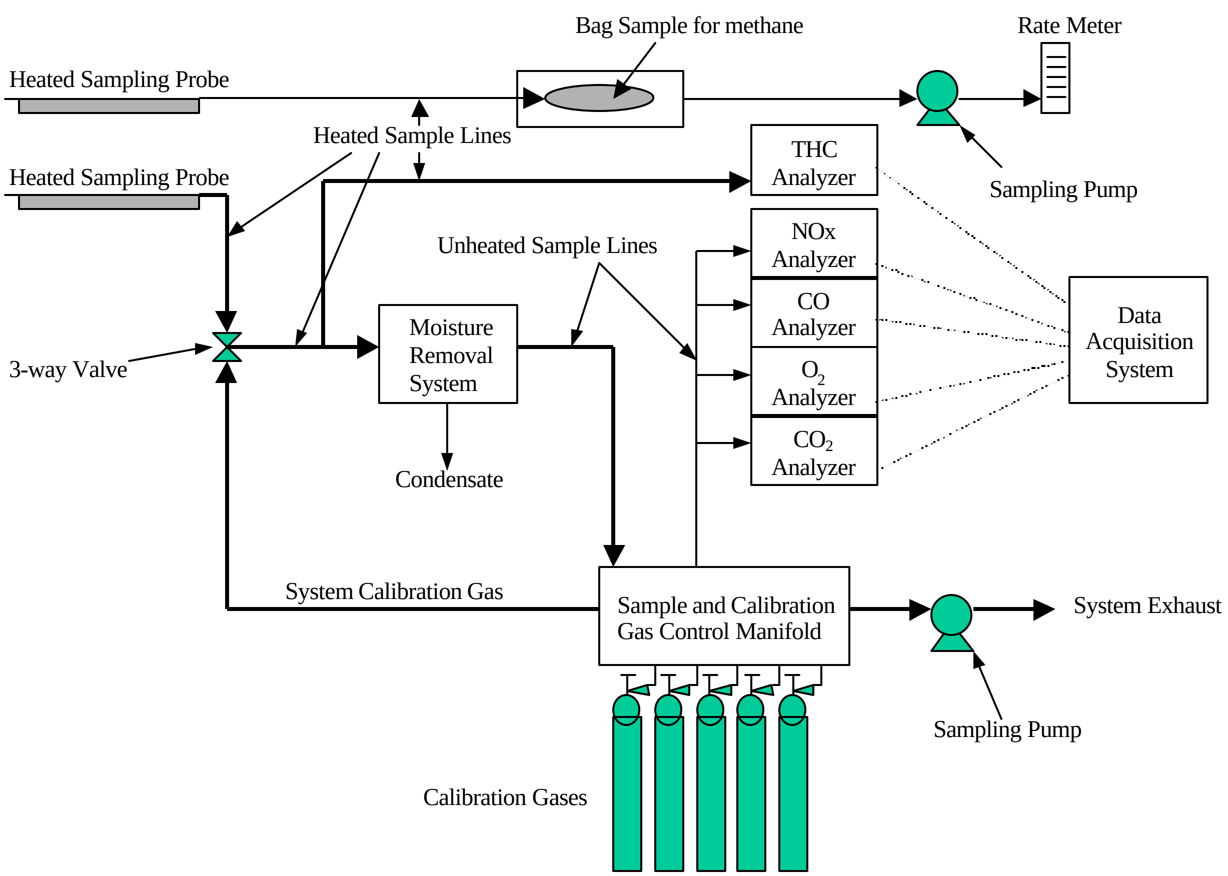
a. Actual ranges will be determined prior to testing, and may change with changes in operating loads.
b. Due to the small stack diameter (10-in.), Method 20 will be modified to incorporate single point sampling.

2.4.1.1 Gaseous Sample Conditioning and Handling

A schematic of the sampling system to be used to measure concentrations of CO_2, CO, NO_x, O_2, and THCs is presented in Figure 2-3. In order for the CO_2, CO, NO_x, and O_2, instruments used to operate properly and reliably, the flue gas must be conditioned prior to introduction into the analyzer. The gas conditioning system is designed to remove water vapor from the sample. All interior surfaces of the gas conditioning system are made of stainless steel, Teflon™, or glass to avoid or minimize any reactions with the sample gas components. Gas is extracted from the turbine exhaust through a stainless steel probe and Teflon sample line. The gas is then transported using a sample pump to a gas conditioning system that removes moisture. After moisture removal, the dry sample gas is transported to a flow distribution manifold where sample flow to each analyzer is controlled. A separate Teflon line routes calibration gases through this manifold to 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, when linearity checks are made on each analyzer.

The THC analyzer is equipped with a FID as the method of detection. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second heated sample line is used to deliver unconditioned exhaust gases from the probe to the THC analyzer.

Figure 2-3. Gas Sampling and Analysis System



2.4.1.2 Gaseous Pollutant Sampling Procedures

For CO and CO_2 determinations, a continuous sample will be extracted from the emission source and passed through a nondispersive infrared (NDIR) analyzer (California Analytical Model CA-300P or equivalent). For each pollutant, the NDIR analyzer compares the amount of infrared light that passes through the sample gas to that which passes through the gas reference cells. Because CO and CO_2 absorb light in the infrared region, light attenuation is proportional to the CO/CO_2 concentrations in the sample. The CO/CO_2 analyzer ranges will be set at or near 0 to 20 percent for CO_2 and 0 to 25 ppm for CO at full load (0 to 50 ppm at reduced loads).

O_2 content will also be analyzed using a paramagnetic reaction cell analyzer. This type of analyzer uses a measuring cell that consists of a mass of diamagnetic material (dumbbell), which is temperature controlled electronically at 50 °C. The higher the sample O_2 concentration, the greater the dumbbell is deflected from its rest position. This deflection is detected by an optical system connected to an amplifier. Surrounding the dumbbell is a coil of wire; a current passes through the wire to return the dumbbell to its original position. The current applied is linearly proportional to the O_2 concentration in the sample. The O_2 analyzer range will be set at or near 0 to 25 percent.

NO_X will be determined on a continuous basis using a chemilumenescence analyzer (Monitor Labs Model 8840 or equivalent). This analyzer catalytically reduces NO_X in the sample gas to NO. The gas is then converted to excited NO_2 molecules by oxidation with O_3 (normally generated by ultraviolet light). The resulting NO_2 luminesces in the infrared region. The emitted light is measured by an infrared detector and reported as NO_X. The intensity of the emitted energy from the excited NO_2 is proportional to the concentration of NO_2 in the sample. The efficiency of the catalytic converter in making the changes in chemical state for the various NO_X is checked as an element of instrument set up and checkout (Section 2.4.1.3). The NO_X analyzer range will be operated on a range of 0 to 25 ppm at full load and 0 to 50 ppm at reduced loads, if necessary.

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). The intensity of the resulting ionization is amplified, measured, and then converted to a signal proportional to the concentration of hydrocarbons in the sample. Unlike the other methods, this sample stream which could be scavenged by moisture removal does not pass through the condenser system; it is kept heated until analyzed. This is necessary to avoid loss of the less volatile hydrocarbons in the gas sample. Because many types of hydrocarbons are being analyzed, THC results will be normalized and reported as CH_4 equivalent. The calibration gas for THC will be propane. Concentrations of CH_4 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.

2.4.1.3 Determination of Emission Rates

The instrumental testing for CH_4, CO, CO_2, NO_X, O_2, and THCs provides results of exhaust gas concentrations in units of percent for CO_2 and O_2 and ppmvd corrected to 15 percent O_2 for CH_4, CO, NO_X, and THCs. The THC and CH_4 results are as ppmv on a wet basis, but will be corrected to ppmvd based on measured exhaust gas moisture measurements made in conjunction with the testing. No less than once at each load tested, an EPA Reference Method 4 test will be conducted to determine the moisture content of the exhaust gases.

Since turbine exhausts tend to be turbulent, EPA Method 19 will be used for calculating emission rates instead of measuring the gas flow rate using EPA Method 2 procedures. Method 19 employs fuel factors (i.e., F-factors) and the turbine heat input rate (MMBtu/hr) to convert the pollutant ppmvd concentrations to emission rates in pounds per hour (lb/hr).

F-factors are the ratio of combustion gas volume to the heat content of the fuel, and are calculated as a volume/HI value, (e.g., standard cubic feet per million Btu). This method applies only to combustion sources for which the heating value for the fuel can be determined. The F-factor can be calculated from CO_2 or O_2 values, on a wet or dry basis, as dictated by the measurement conditions for the gas concentration determinations. Method 19 includes all calculations required to compute the F-factors and guidelines on their use. The F-factor for natural gas can be calculated from the fuel compositional analyses, or Method 19 allows the use of the published F-factor for natural gas [8,710 dry standard cubic feet per million British thermal units (dscf/MMBtu)]. This verification will calculate the F-factor based on the average composition of gas samples collected during the test periods.

Measured pollutant concentrations (ppmvd) will first be converted to pounds per dry standard cubic foot (lb/dscf) using the following unit conversion factors:

CH_4: 1 ppmvd = 4.15E-08 lb/dscf
CO: 1 ppmvd = 7.264E-08 lb/dscf
CO_2: 1 ppmvd = 1.142E-07 lb/dscf
NO_X: 1 ppmvd = 1.194E-07 lb/dscf
THC: 1 ppmvd = 4.15E-08 lb/dscf (THC emissions are quantified as CH_4)

Emission rates for each pollutant can then be calculated using Equation 15.

$$\text{Emission rate (lb/kWh)} = [Ci * HI * \text{F-factor} * (20.9/(20.9-O_2))] / kW \quad \text{(Eqn. 15)}$$

where:

C_i	=	pollutant concentration (lb/dscf)
HI	=	average engine heat input during test (MMBtu/hr)
F-factor	=	calculated fuel F-factor (dscf/MMBtu), approx. 8,710 dscf/MMBtu
O_2	=	average measured exhaust gas O_2 concentration (%)
kW	=	average microturbine power output during test (kW)

2.5 ELECTRICITY OFFSETS AND ESTIMATION OF EMISSION REDUCTIONS

This section presents the approach for estimating emission reductions from the IR PowerWorks installation. The GHG Center will first determine emission rates from the CHP system through direct measurements as described in Section 2.4. Those actual emissions, compared with baseline emissions that would occur if the CHP system were not in place, form the basis of the emission reduction estimation.

The CHP system supplies two types of energy: electrical power and thermal energy (domestic hot water and/or comfort heating). If the CHP system were absent or offline, the host facility would purchase electricity from the utility grid and operate two 1.7 MMBtu/hr Weil-McLain gas-fired boilers as replacement energy sources. These, then, are the baseline energy sources. Subtraction of the baseline emissions for both energy types from the CHP emissions will yield the net emission reduction estimate according to Equation 16.

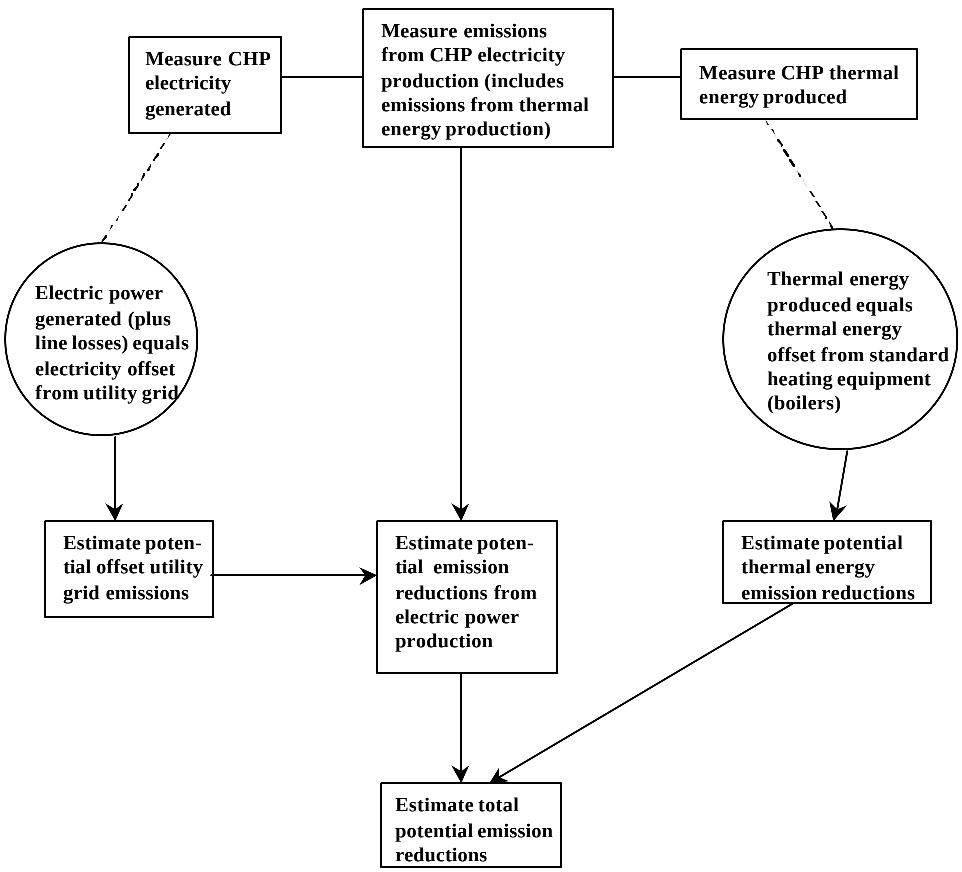
$$Reduction = Emsn_{CHP} - (Emsn_{GRID} + Emsn_{BOILER}) \quad \text{(Eqn. 16)}$$

where:

Reduction	=	potential annual emission reductions (lb/yr)
$Emsn_{CHP}$	=	potential annual CHP emissions (lb/yr), Section 2.5.1
$Emsn_{GRID}$	=	potential annual grid emissions offset (lb/yr), Section 2.5.2
$Emsn_{BOILER}$	=	potential annual boiler emissions offset (lb/yr), Section 2.5.3

CO_2 and NO_X will be considered here because CO_2 is the primary greenhouse gas emitted from combustion processes and NO_X is a primary pollutant of regulatory interest. Reliable emission factors for electric utility grid and boilers are available for both gases. Figure 2-4 is a schematic of the emission reduction estimation methodology.

Figure 2-4. IR PowerWorks CHP Emission Reduction Estimation Methodology



The following subsections describe the approach for estimating annual emissions for the CHP system, potential utility grid emission reductions, and the natural gas boiler emission reductions.

2.5.1 Estimation of Annual IR PowerWorks CHP CO_2 and NO_X Emissions

The first step in calculating emission reductions is to estimate the emissions associated with generating electricity on site over a given period of time (e.g., 1-year). Section 2.4 provided procedures for verifying the IR PowerWorks emission rates at four operating loads. This unit is projected to operate only at full load, so the full load emission rate, along with projected annual operating hours (provided by the host facility), allows the calculation of annual emissions pounds per year (lb/yr), as shown in Equation 17.

$$Emsn_{CHP} = E_{CHP,100\%} * kWh_{CHP} \qquad \text{(Eqn. 17)}$$

where:

$Emsn_{CHP}$ = total microturbine CO_2 or NO_X emissions (lb/yr)
$E_{CHP,100\%}$ = microturbine CO_2 or NO_X emission rate at full load (lb/kWh)
kWh_{CHP} = projected (or proven) power generated (kWh/yr)

2.5.2 Estimation of Electric Grid Emissions

The electric energy generated by the IR PowerWorks will offset electricity supplied by the grid. Consequently, the reduction in electricity demand from the grid caused by this offset will result in changes in GHG (primarily CO_2 and NO_X) emissions associated with producing an equivalent amount of electricity at a central power plant. If the emissions per kWh associated with the IR PowerWorks system are less than the emissions per kWh produced from an electric utility, it can be implied that a net reduction in emissions will occur at the site. Total emission reductions could be even greater because the boiler emissions offset by the thermal energy produced will be added to the grid emission offsets as described in Section 2.5.3 below. This combination of grid emission and boiler emission reductions is the primary environmental benefit of the IR PowerWorks system.

If the emissions from the IR PowerWorks are greater than the emissions from the grid, possibly due to the use of higher efficiency power generation equipment or zero emissions generating technologies (nuclear and hydroelectric) at the power plants, a net increase in emissions may occur when considering CHP electricity generation alone. This would be mitigated by the boiler emission reductions.

Utility power systems and regional grids consist of aggregated power typically provided by a wide variety of generating unit (GU) types. Each type of GU emits differing amounts of GHG (and other pollutants) per kWh generated. In the simplest case, for a single GU, total CO_2 emissions (lb) divided by the total power generated by that GU (kWh) yields the CO_2 emission rate for the selected GU (lb/kWh).

More complex analyses require determination of an aggregated baseline emission rate derived from multiple grid-connected GUs. The method to develop an aggregate emission rate is to divide the total emission by the total power generated from the GUs under consideration, as shown for CO_2 in Equation 18.

$$E_{baselineCO_2} = \frac{\sum_{1}^{n} CO_{2i}}{\sum_{1}^{n} kWh_n} \qquad \text{(Eqn. 18)}$$

where:

$E_{baselineCO_2}$	=	aggregated grid CO_2 emission rate (lb/kWh)
CO_{2i}	=	individual GU_n CO_2 emissions for the period (lb)
kWh_n	=	individual GU_n power generated for the period (kWh)
n	=	number of GU in the baseline selection set

The particular grid-connected GUs chosen for the baseline emission rate calculation have a strong effect on the potential microturbine emissions reductions. The microturbine power may offset generation from an individual grid-connected GU or from many GUs on a utility-side, regional, or national basis. Depending on the control system operator, the combination of connected GUs can change frequently (hourly or less). Some considerations, which may confound the choice of GUs to be offset, are:

- The GU inventory in the geographic region, how they are connected to the grid, local utility fuel mix, and the local dispatch protocol can affect whether or not a particular GU is offset
- Microturbine operating schedules (i.e., in a baseload, peak shaving, or other mode) should be comparable to the offset GU
- Transmission and distribution (T&D) line losses should be considered for the offset GU and for the microturbine if it exports power to the grid
- Several different databases provide emission factor, power generation, cost, and other data in varying formats
- In most cases, real-time electrical production data is not publicly available

If the analyst proposes that GUs that operate on the margin (i.e., those dispatched last and offset first) are to be offset, then marginal fuel prices, dispatchability, and economics at the local and regional level may need to be considered.

Because of such complex issues, the GHG Center undertook a review of regulatory guidance and industrial community practice on how to choose the grid-connected emissions that would be offset by DG installations. The review included procedures used by EPA, U.S. Department of Energy (DOE), Western Regional Air Partnership (WRAP), World Resources Institute (WRI), Intergovernmental Panel on Climate Change (IPCC), and other emission trading organizations. The guidance provided by these organizations ranged from vague to explicit and the analyses ranged from simple to complex. Procedures included all levels of refinement from readily available national or regional emission factors to detailed analysis of grid control area boundaries and the GUs therein, hourly operating data, peaks, peak shaving, and/or imports and exports.

After completing the reviews, it was concluded that the method used for choosing the baseline emissions to be offset is arbitrary; clear and consistent guidance does not exist at present. Judgment about whether or not a particular assumption (i.e., selection of a marginal GU to be offset) is reasonable or supportable is subject to opinion and case-by-case review. The best strategy may be to perform analyses using several baselines and allow the reader to rank their value according to preference or local administrative policy. The GHG Center will adopt this strategy for this verification.

The host facility's utility provider is New York State Electric and Gas Corporation (NYSEG). According to Federal Energy Regulatory Commission documents (FERC 1999), NYSEG's in-house generation capacity consists primarily of two hydroelectric facilities and an 18 percent interest in a nuclear power station. In 1999, NYSEG generated approximately 9.2 percent and purchased 90.8 percent of the 20,321,602 MWh of electric power it dispositioned. The purchased power originated from about 91 different vendors who supplied amounts ranging from 13 to 2,814,475 MWh. Identifiable GU ranged from city- or village-operated micro-hydroelectric plants to coal-fired facilities located in Pennsylvania, the Carolinas, Texas, etc. NYSEG also obtained power from brokers (such as Enron) who pool power from an even wider variety of sources. This means that rigorous identification of specific GUs which would be offset by the CHP system would be extremely complex and beyond the scope of this verification.

Therefore this verification will compare the IR PowerWorks system emissions to aggregated emission data for the three major types of fossil fuel-fired power plants: coal, natural gas, and petroleum. The GHG Center will employ well-recognized data from the U.S. Department of Energy, Energy Information Administration (EIA) for the computations (EIA, 1999 and EIA, 2001). These data consist of the total emissions and total power generated for each fuel type and are available at increasing levels of refinement for the nationwide, middle Atlantic (NJ, NY, PA) census division, and New York state power grids. Total emissions divided by total generated power for each of these three geographical regions yields the emission rate in lb/kWh for CO_2 and NO_X as described above. Table 2-3 presents the resulting emission rates for 1999. Data for other years and geographical regions are available from EIA if required.

Table 2-3. CO_2 and NO_X Emission Rates for Three Geographical Regions

Region	Fuel	CO_2 lb/kWh	NO_X lb/kWh
Nationwide	coal	2.15	0.00741
	gas	1.34	0.00254
	petroleum	1.73	0.00283
Middle Atlantic Census Region (NJ, NY, PA)	coal	2.09	0.00530
	gas	1.32	0.00207
	petroleum	1.89	0.00209
New York	coal	2.21	0.00512
	gas	1.31	0.00186
	petroleum	1.77	0.00188

The T&D system delivers electricity from the power station to the customer. Power transformers increase the voltage of the produced power to the transmission voltage (generally 115 to 765 kV) and, in turn, reduce it for distribution (25 to 69 kV). Additional transformers reduce the voltage further (to 220 V, 440 V, etc.) at the host facility. This means that for each kWh used at the host facility, the grid's GU must provide additional power to overcome the transformer, powerline, and other losses. EIA data indicate that NYSEG's sources of power in 1999 totaled 20,321,602 MWh while losses amounted to 1,586,130 MWh. This equates to a 7.8 percent T&D loss and means that for every kilowatt-hour generated by the CHP and used at the host facility, grid GU would have had to provide 1.078 kWh.

Offset power grid emissions, therefore, are based on the number of kWh generated by the CHP, line losses, and the grid emission rate for CO_2 or NO_X as shown in Equation 19.

$$Emsn_{GRID} = kWh_{CHP} * E_{CO2,NOX} *1.078 \qquad \text{(Eqn. 19)}$$

where:

$Emsn_{GRID}$	= grid CO_2 or NO_X emissions offset by the CHP (lb/year)
kWh_{CHP}	= CHP Projected (or proven) power generated (kWh/yr)
$E_{CO2,NOX}$	= CO_2 or NO_X emission rates from Table 2-3 (lb/kWh)
1.078	= total T&D losses

The host facility's electrical load will normally exceed the CHP's potential generation capacity (i.e. 70 kW). This is a key assumption because it means that, although the CHP is connected to the electrical grid, there are no plans to export power to the grid.

As was discussed in Section 2.5, the GHG Center will use the $Emsn_{GRID}$ estimate to calculate the potential annual GHG emission reductions according to Equation 19.

2.5.3 Estimation of Boiler Emission Reductions

For each BTU of thermal energy recovered by the IR PowerWorks (and used by the host facility), an equivalent amount of energy is no longer needed from the baseline gas-fired boilers. For this verification, all CHP emissions are associated with electricity production. This means that CHP emissions associated with thermal energy production are zero for both CO_2 and NO_X; each BTU of thermal energy recovered from the CHP will offset all the CO_2 and NO_X that would have been emitted by the boilers.

The first step in estimating the boilers' avoided emissions is to measure the CHP heat recovery rate at 100 percent load as described in Section 2.2.2. These heat rates (MMBtu/hr) combined with the projected annual operating hours at each load factor allows the calculation of annual heat recovered as shown in Equation 20.

$$Q_{CHP,Ann} = Q_{CHP} * h * 60 \qquad \text{(Eqn. 20)}$$

where:

$Q_{CHP,Ann}$	= maximum total CHP heat recovered (MMBtu/yr)
Q_{CHP}	= CHP heat recovery rate at 100 percent load factor (MMBtu/min)
h	= projected (or proven) operating hours at 100 percent

The host facility's baseline heating units are two identical natural gas-fired Weil-McNeal boilers (Model BG-688) with a manufacturer's specified gross combustion efficiency of 81.4 percent. Weil-McNeal designed the units to provide 1.181 MMBtu/hr of heated water with 1.703 MMBtu/hr natural gas fuel input. After accounting for boiler insulation, heat transfer, and other losses, the net boiler efficiency for hot water production is 69.5 percent. They were installed new in 1996. This means that, for every Btu of heat recovered from the CHP, 1/0.695 or 1.439 Btu of heat derived from the fuel would have been supplied to the boilers. The total amount of avoided heat input to the boilers, then, is:

$$Q_{BOILERS} = \frac{Q_{CHP,Ann}}{0.695} \qquad \text{(Eqn. 21)}$$

where:

$Q_{BOILERS}$ = Avoided heat input to the boilers (MMBtu/yr)

The carbon in the natural gas, when combusted, forms CO_2. The resulting CO_2 emission rate is:

$$E_{BoilerCO2} = \frac{44}{12} * (CC) * (FO) \qquad \text{(Eqn. 22)}$$

where:

$E_{BoilerCO2}$ = Boiler CO_2 emission rate, approx. 116.4 lb/MMBtu of fuel heat input
44 = Molecular weight of CO_2 (lb/lb.mol)
12 = Molecular weight of carbon (lb/lb.mol)
CC = Measured fuel carbon content
(Section 2.2.1; 2.2.1.3; approx. 31.9 lb/MMBtu) (EPA 2001)
FO = 0.995; Fraction of natural gas carbon content oxidized
during combustion (EPA 2001)

The EPA has compiled emission factors for natural gas burners in AP-42 (EPA 1995). The NO_X emission factor for commercial boilers from 0.3 to 10 MMBtu/hr heat input is 100 lb/10^6 scf of natural gas. The GHG Center will measure the LHV for the natural gas used at the host facility as described in Section 2.2.1. It is expected to be approximately 950 Btu/scf. This means that 10^6 scf of natural gas will supply approximately 950 MMBtu of heat to the boiler. The resulting NO_X emission rate is expected to be approximately 100/950 or 0.1053 lb/MMBtu.

The CO_2 and NO_X emission rates, combined with the avoided heat input to the boilers yields the potential boiler emissions eliminated by use of the CHP system as follows:

$$Emsn_{BOILER} = Q_{BOILERS} * E_{Boiler} \qquad \text{(Eqn. 23)}$$

where:

$Emsn_{BOILER}$ = potential annual boiler emissions offset, lb/yr
$Q_{BOILERS}$ = avoided heat input to the boilers, MMBtu/yr
E_{Boiler} = boiler emission rate; approx. 116.4 lb/MMBtu CO_2 and 0.1053 lb/MMBtu NO_X

As was discussed in Section 2.5, the GHG Center will use the $Emsn_{BOILER}$ estimate to calculate the potential annual GHG emission reductions according to Equation 17.

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. Each test measurement that contributes to the determination of a verification parameter has stated 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. The next step is to identify all measured values which affect the verification parameter, and 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 summarizes the DQOs for each verification parameter to be evaluated during this test.

Table 3-1. Verification Parameter DQOs

Parameter	Units	Total Error[a]	
		Absolute	Relative, %
Power and Heat Production Performance			
Electrical power output at selected loads	kW	*1.05*[b]	**1.5**
Electrical efficiency at selected loads (%)	%	*0.51*[b]	**1.8**[c]
Heat recovery rate at selected loads (MMBtu/hr)	MMBtu/hr	*0.0075*[b]	**2.15**[c]
Thermal energy efficiency at selected loads (%)	%	*1.00*[b]	**2.4**[c]
CHP production efficiency (%)	%	*0.79*[b]	**1.1**[c]
Power Quality Performance			
Electrical frequency (Hz)	Hz	**0.006**	0.01
Power factor (%)	--	TBD	**0.50**
Voltage and current total harmonic distortion (THD) (%)	%	TBD	**1.00**
Emissions Performance			
CO, NO_X, O_2, CO_2 and CH_4 Concentration (ppmv, %)	ppmv	TBD	**2.0**
THC Concentration (ppmv)	ppmv	TBD	**5.0**
CO, NO_X, CO_2 and CH_4 Emission Rates	lb/hr, lb/Btu, lb/kWh	TBD	**12.7**[c]
THC Emission Rates	lb/hr, lb/Btu, lb/kWh	TBD	**13.5**[c]
Estimated NO_X emission reductions for Crouse Community Center	lb NO_x/yr	TBD	**12.7**[c]
Estimated GHG emission reductions for Crouse Community Center	lb CO_2/yr	TBD	**12.7**[c]

[a] bold column entries are DQO; italic entries informational expected value
[b] Assumes full load operation70 kW: 480 V, 145.8 A
[c] Calculated composite error described in text

The following sections describe the measurements which contribute to the determination of the verification parameters, how measurement uncertainties affect the determination, and the resulting DQO.

Each section concludes with a discussion of the applicable DQIs and their associated quality assurance/quality control (QA/QC) checks.

3.2 ELECTRICAL POWER OUTPUT AND QUALITY DQOS

The ION 7600 power meter will directly determine electrical power output and quality. The inherent instrument error constitutes the DQO for each of these parameters as listed in Table 3-1.

Table 3-2 summarizes the instrument specifications, DQI goals, and the primary method of evaluating the DQI achieved for each of the critical measurements associated with heat and electrical power generation. Achievement of the DQIs will be documented by factory calibrations, sensor function checks, and reasonableness checks in the field as outlined in Table 3-3. These tables also present instrument specifications and QA/QC checks for the electrical power efficiency, heat recovery efficiency, and total efficiency verification parameters and their contributing measurements.

The manufacturer will issue a certificate of compliance for the ION 7600 power meter certifying that the instrument met or exceeded published specifications. Consistent with ISO 9002-1994 requirements, the manufacturer will supply calibration documents which certify traceability to national standards. The GHG Center will review the certificate and traceability records to ensure that the ± 0.35 percent accuracy goal was achieved or exceeded. Note that this accuracy standard, compounded with the ± 1.0 percent accuracy specification for the current and potential transformers yields the ± 1.5 percent DQO specified in Table 3-2.

The 7600 ION is intended for electric utility custody transfer applications; its calibration records are reported to be valid for a minimum of 1 year of use, provided the manufacturer-specified installation and setup procedures are followed. GHG Center personnel will perform the related QC checks listed in Table 3-3 and described in detail in Appendix B-2. The manufacturer will repeat the factory calibration at the end of the test to ensure that instrument accuracy remained within the specified limits.

Comparisons of the 7600 ION power output readings with the power output recorded by the turbine's instrumentation will constitute the reasonableness check. At full load, the power meter and turbine instruments must read between 63 and 70 kW at Standard Conditions and after derating for elevation differences.

Table 3-2. Measurement Instrument Specifications and DQI Goals										
							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 70 kW	Electric Meter/ Power Measurements 7600 ION	0 to 260 kW	± 1.50[c] % reading	once per sec.; DAS records 1 - min averages	± 1.50 % reading[c]	100 % for controlled test periods, 90 % for continuous test period.	Review manufacturer calibration certificates, Perform sensor function checks in field
	Voltage[b]	480 V (3 - phase) ± 10 %		0 to 600 V	± 1.01 % reading		± 1.01 % reading		
	Frequency[b]	60 Hz		57 to 63 Hz	± 0.01 % reading		± 0.01 % reading		
	Current[b]	0 to 200 Amps		0 to 200 Amps	± 1.01 % reading		± 1.01 % reading		
	Voltage THD[b]	0 to 100 %		0 to 100 %	± 1 % FS		± 1 % FS		
	Current THD[b]	0 to 100 %		0 to 100 %	± 1 % FS		± 1 % FS		
	Power Factor[b]	0 to 1.0		0 to 1.0	± 0.5 % reading		± 0.5 % reading		
Heat Recovery	Heat Recovery Rate	0 to 360,000 Btu/hr	Controlotron Model 1010WP	Approx. 0 to 5.0 x 10^7 Btu/hr	± 2.0 %		± 2.0 %		
	Temperature[b]	TBD		37 to 356 ° F	± 0.02 ° F		± 0.02 ° F		
	Liquid Flow[b]	TBD		0.1 to 42,000 cfm	± 1to 2 %		± 2 %		
	PG Concentration	10 to 20 %	GC/FID	10 to 1000 ppm	± 0.02% FS	1 per day	± 3 % for 23 % PG mixture		Independent check with blind sample
Ambient Meteorological Conditions	Ambient Temperature[b]	30 to 90 °F	Vaisala HMD 60Y0	-40 to 140 °F	± 0.2 °F	1 - min averages	± 0.2 ° F		Review manufacturer calibration certificates
	Relative Humidity[b]	0 to 100 %		0 to 100 %	± 2 % (0 to 90 % RH,) ± 3 % (90 to 100 % RH)		± 3 %		
	Ambient Pressure[b]	28 to 31 in. Hg	SETRA Model 280E or equiv.	0 to 51 in Hg	± 0.11 % FS		± 0.11 % FS		

(continued)

Table 3-2. Measurement Instrument Specifications and DQI Goals (continued)

Measurement Variable	Operating Range Expected in Field		Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Data Quality Indicator Goals: Accuracy[a]	Data Quality Indicator Goals: Completeness	How Verified / Determined
Fuel Input	Mass Flow Rate	7 to 15 scfm	Mass Flow Meter / Rosemount 3095	5 to 20 scfm	± 1.0 % reading	1-min. averages	± 1.0 % reading	100 % for controlled test periods, 90 % for continuous test period.	Review manufacturer calibration certificates, Perform sensor function checks in field
	Gas Pressure[b]	50 to 55 psi	Pressure Transducer / Rosemount or equiv.	0 to 150 psig	± 0.075 % FS		± 0.075 % FS		
	Gas Temperature[b]	50 to 90 °F	RTD / Rosemount Series 68	-58 to 752 °F	± 0.09 % reading		± 0.09 % reading		
	LHV	94 to 98 % CH_4 (900 to 1,005 Btu/scf)	Gas Chromatograph / HP 589011	0 to 100 % CH_4	± 0.2 % accuracy for CH_4 ± 0.1 % repeatability for LHV	min. 1 sample at each load test	± 0.2 % for LHV	100 % for controlled test periods	Repeatability check - duplicate analyses on the same 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 IR PowerWorks system performance.

[c] Includes instrument, 1.0 % current transformer (CT), and 1.0 % potential transformer (PT) errors.

Table 3-3. Summary of QA/QC Checks				
Measurement Variable	**QA/QC Check**	**When Performed/Frequency**	**Expected or Allowable Result**	**Response to Check Failure or Out of Control Condition**
Power Output	Instrument Calibration by Manufacturer[a]	Beginning and end of test	± 0.35 % reading	Identify cause of any problem and correct, or replace meter
	Sensor Diagnostics in Field	Beginning and end of test	Voltage and current checks within ± 1 % reading	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	Readings should be between 63 and 70 kW at full load	Identify cause of any problem and correct or replace meter
Fuel Flow Rate	Instrument Calibration by Manufacturer[a]	Beginning and end of test	± 1.0 % reading	Identify cause of any problem and correct, or replace meter
	Sensor Diagnostics	Beginning and end of test	Pass	Identify cause of any problem and correct, or replace meter
	Comparison with facility gas flow meter	Throughout test	Readings should be within 3 percent of the facility gas meter readings	Perform sensor diagnostic checks
Fuel Heating Value	Duplicate analyses performed by laboratory[a]	At least twice during test period and on one blind audit sample	Refer to Table 3-4	Repeat analysis
	Confirm canister is fully evacuated	Before collection of each sample	canister pressure < 1.0 psia	Reject canister
	Calibration with gas standards by laboratory	Prior to analysis of each lot of samples submitted	± 1.0 % for each gas constituent	Repeat analysis
	Independent performance check with blind audit sample	One time during test period	± 3.0 % for each gas constituent	Apply correction factor to sample results
Heat Recovery Rate	Review manufacturer's calibration records for heat meter[a]	Prior to testing	Heat recovery rate: ± 2.0 % Temp: ± 0.02°F Flow: ± 1 to 2%	Recalibrate heat meter
	Independent performance check of PG analysis with blind sample	One time	PG concentration should be accurate to within ± 3 %.	Recalculate DQO achieved for heat recovered and thermal efficiency
	Meter zero check	Prior to testing	Reported heat recovery < 0.5 Btu/min	Recalibrate heat meter
	Fluid index check	Each day of testing	± 5.0 % of reference value	Recalibrate heat meter
	Independent performance check of temperature readings	Beginning of test period	Difference in temperature readings should be < 1.5 °F	Identify cause of discrepancy and recalibrate heat meter
Ambient Meteorological Conditions	Instrument calibration by manufacturer or certified laboratory	Beginning and end of test	Temp: ± 0.2 °F Pressure: ± 0.11 % FS RH: ± 3 %	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	Recording should be comparable with handheld digital temp/RH meter	Identify cause of any problem and correct, or replace meter

[a]Results of these QA checks will be used to reconcile DQIs

Independent field verification with a second meter cannot be conducted to verify the accuracy of the 7600 power readings because the electrical power system is closed. However, GHG Center personnel will perform QC checks in the field for two key measurements, voltage and current output, which are directly related to the power output measurement. 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 each phase's voltage and current readings to the 7600 ION readings as recorded by the DAS.

Appendix B-2 presents the procedures for these checks. The Field Team Leader will obtain a minimum of five individual voltage and current readings for the given load. The 7600 ION voltage and current accuracies are ± 1.01 percent while the DMM is ± 1.0 percent. The percent difference between the DMM reading and the 7600 ION reading will be computed to determine it is within ± 2.01 percent for voltage and current. In these cases, the 7600 ION will be confirmed to be functioning properly.

3.3 ELECTRICAL POWER, HEAT RECOVERY, AND TOTAL EFFICIENCY DQOS

These verification parameters require determination of electrical power output, recovered heat, and fuel input. The errors in these determinations compound as described in the following subsections to yield the specified DQOs.

3.3.1 Electrical Power Efficiency

The electrical power efficiency is the electrical power output divided by the heat input to the turbine, normalized for consistency in the units (Equation 1, Chapter 2.2.1). The manufacturer's specifications state that at 70 kW (238850 Btu/hr) power output, nominal electrical power efficiency will be 28 percent. This means that fuel heat input will be approximately 853036 Btu/hr.

Determination of the heat input requires multiplication of the fuel flow rate by the fuel heating value. Errors for these measurements are ± 1.0 and ± 0.2 percent, respectively. Errors in multiplication and division compound as follows (Skoog, 1982):

$$err_{c,rel} = \sqrt{\left(\frac{err_1}{value_1}\right)^2 + \left(\frac{err_2}{value_2}\right)^2} \qquad \text{(Eqn. 24)}$$

where:

$err_{c,rel}$ = compounded error, relative
err_1 = error in first multiplied value, absolute value
err_2 = error in second multiplied value, absolute value
$value_1$ = first multiplied value
$value_2$ = second multiplied value

For this example, heat input compounded error is:

$$Error\ in\ Heat\ Input = \sqrt{(0.01)^2 + (0.002)^2} = 0.0102$$

At a given heat input of 853036 Btu/hr, the measurement error amounts to approximately ± 8701 Btu/hr, or 1.02 percent relative error.

For the electrical efficiency determination, the errors in the divided values compound according to Equation 24. The electrical power measurement error is ± 1.5 percent relative (Table 3.1) and the heat input error is ± 1.02 percent relative. For this example, compounded relative error for the electrical efficiency determination is therefore:

$$Error\ in\ Elec.\ Power\ Efficiency = \sqrt{(0.015)^2 + (0.0102)^2} = 0.0181$$

This means that for the assumptions above, electrical power efficiency will be 28.00 ± 0.51 percent, or a relative compounded error of 1.8 percent. This compounded relative error is the data quality objective for this verification parameter.

Data quality indicators include the 7600 ION equipment calibrations, sensor function checks, and reasonableness checks described in Section 3.2. They also include QA/QC procedures for fuel flow rate and heating value as outlined in Tables 3-2 and 3-3 and described below.

3.3.1.1 Fuel Flow Rate

Prior to testing, the GHG Center will send the Rosemount gas flow meter to the factory for calibration. The calibration certificate will be NIST-traceable; GHG Center personnel will review the calibration to ensure satisfaction of the ± 1.0 percent accuracy specification. The factory certified calibration data are reported to be valid for three years, provided manufacturer-specified installation and set-up procedures are followed.

The Field Team Leader will program the transmitter electronics in the field to enable the meter to calculate compensated flow. Input parameters will be the gas composition based on the average results from the pre-test gas samples (Section 2.2.1.3) and operating ranges (i.e., gas temperature and pressure) expected at the site during testing. To program the transmitter, Rosemount's Engineering Assistant (EA) Software interfaces with the transmitter *via* a HART protocol serial modem. Appendix B-3 provides the specific setup parameters required in the EA and installation/setup checks and log forms for this meter. The Field Team Leader will log all data entered into the EA on field data forms; the GHG Center will maintain an electronic copy of the configuration file.

To validate the performance of the meter in the field, the Field Team Leader will perform sensor diagnostic checks. He will establish zero flow conditions by isolating the meter from the flow, equalizing the pressure across the differential pressure (DP) sensors using a crossover valve on the orifice assembly, and reading the pressure differential and flow rate. The sensor output must read zero flow during these checks. He will also conduct transmitter analog output checks at the beginning and end of the test. In this loop test, a current of known amount will be checked against a DMM to ensure that 4 mA and 20 mA signals are produced. Appendix B-4 presents the procedures and log forms for conducting flow meter sensor diagnostic checks.

In addition, meter readings will be compared to readings obtained from the facility's gas meter for the PowerWorks. This meter is a Roots displacement type meter with a rated accuracy of ± 1 percent and is supplied and calibrated by the local utility. Readings between the two meters should agree within 3 percent.

3.3.1.2 Fuel Composition and Heating Value

QA/QC procedures for assessing gas composition data quality include duplicate analyses on at least two samples, review of laboratory instrument calibrations, analysis of a blind audit gas sample, and confirmation of vessel pressure prior to sampling. The primary method of reconciling the DQI goal for gas composition will be the duplicate analysis results. The GHG Center will conduct the other three procedures as additional QA/QC checks.

Duplicate analyses must conform to ASTM Specification D1945 repeatability guidelines. These guidelines vary according to the component's concentration as illustrated in Table 3-4. The definition of repeatability is the difference between two successive results obtained by the same operator with the same apparatus under constant operating conditions.

Table 3-4. ASTM D1945 Repeatability Specifications

Component Concentration (mol %)	Repeatability (absolute difference between 2 results)
0 to 0.1	± 0.01
0.1 to 1.0	± 0.04
1.0 to 5.0	± 0.07
5.0 to 10	± 0.08
over 10	± 0.1

Using these guidelines, and the anticipated ranges of gas component concentrations, Table 3-5 summarizes the target repeatability goals of primary gas components (i.e., components present in concentrations greater than 1 percent) for the duplicate analyses.

Table 3-5. DQIs for Anticipated Component Concentrations

Gas Component	Expected Concentration Range (mol %)	Repeatability DQI Goal (absolute difference of 2 results)
Butane	0.1 – 0.5	NA (not applicable)
Ethane	3.0 – 5.0	± 0.08
Heptane	< 0.1	NA
Hexane	< 0.1	NA
Methane	90 – 95	± 0.1
Pentane	< 0.1	NA
Propane	1.0 – 3.0	± 0.07

Additional QA/QC checks include instrument calibrations, analysis of a blind audit sample, and confirmation of canister pressures. The analytical laboratory conducts the calibrations on a weekly basis or whenever equipment changes are made on the instrument with a Natural Gas GPA Reference Standard such as the example in Appendix C-2. ASTM Specification D1945 criteria for calibration states that consecutive analytical runs on the gas standard must be accurate to within ± 1 percent of the certified concentration of each component. The laboratory will be required to submit calibration results for each day samples are analyzed.

During field testing, the GHG Center will supply one blind/audit gas sample to the laboratory for analysis. The audit gas will be an independent Natural Gas GPA Reference Standard manufactured by Scott Specialty Gases with a certified analytical accuracy of ± 2 percent. The audit gas will be shipped to the test location and the Field Team Leader will collect a canister sample of it immediately after one of the fuel gas samples is collected. He will ship the audit sample to the laboratory with the other fuel samples. The laboratory will analyze the audit sample in duplicate. The GHG Center will compute the average result from the two analyses and will compare the results to the certified concentration of each constituent. Allowable error, which is the sum of the instrument calibration criteria and the analytical accuracy of the audit gas, must be ± 3 percent for each gas constituent.

Finally, the Field Team Leader will check sample canister pressures before collection of each sample to confirm that the canisters were properly evacuated at the laboratory prior to shipment to the site. He will employ an electronic vacuum gauge to measure the absolute pressure in each canister and will record the results on log forms (Appendix A-3). Any canisters with absolute pressures greater than 1 psi will not be used for sampling.

Following ASTM Specification D3588 guidelines, gas LHV and density are calculated based on the gas compositional analysis. The GHG Center will therefore evaluate these parameters' validity based on the compositional analyses. The specification provides the equations that are used to calculate repeatability of the LHV calculations provided the analytical repeatability criteria (Table 3-5) are met. The repeatability expected for duplicate samples is approximately 1.2 Btu/1,000 ft^3, or about 0.1 percent. Using input from the oil and gas industry and the GHG Center's experience with these analyses, a conservative DQI goal of ± 0.2 percent is established. If the GHG Center determines that the DQI goal for compositional analyses are met, then it can be deduced that the DQI goal for LHV has been met.

3.3.2 Heat Recovery Efficiency

Heat recovery efficiency is the heat recovered divided by the turbine fuel heat input. Precise determination of the thermal heat recovery rate is required because it is a key performance parameter for the CHP system. At full load (70 kW), the manufacturer specifies that 20 to 42 percent of the turbine's fuel heat input will be recovered as useful heat. This means that with 835,035 Btu/hr fuel heat input, the heat recovery unit will provide between 167,000 and 351,000 Btu/hr.

The Controlotron heat meter determines the heat recovery rate by measuring the glycol solution heat exchanger temperature difference (delta T) and flow rate. It then multiplies delta T, flow rate, glycol solution specific heat, and density to yield the heat recovery rate (Equation 4, Section 2.2.2). For a given glycol solution volume percent, the manufacturer specifies an overall heat recovery rate accuracy of ± 2.0 percent. The meter obtains specific heat and density data from an internal "look up" table, based on ASHRAE data (Appendices A-9, A-10; ASHRAE, 1997) and the glycol solution volume percent as input by the Field Team Leader at the beginning of the test campaign.

Section 2.2.2.2 states that the GHG Center will collect and the laboratory will analyze glycol solution samples from the CHP system prior to the start of testing. The Field Team Leader will compute the average volume percent glycol and input it into the heat meter as described above. The laboratory's specified analytical error for the glycol concentration is ± 3.0 volume percent, absolute. This means that, for an example 23.0 percent glycol solution, actual concentration could range between 20.0 and 26.0 percent (relative error in this case is ± 13.0 percent). Because specific heat and density vary with different glycol compositions, the laboratory analytical error will introduce additional error into the heat meter's heat recovery rate determination.

Quantification of the additional error requires evaluation of the density and specific heat at the conditions expected during testing. Given an average 140 °F temperature across the heat exchanger, the following table shows these values for glycol concentrations of 23.0 and 26.0 percent. Appendices A-9 and A-10 contain the source data for the interpolations presented here.

Table 3-6. Glycol Solution Density and Specific Heat Analytical Error

	ρ_{23}, lb/ft^3	ρ_{26}, lb/ft^3	Cp_{23}, Btu/lb.F	Cp_{26}, Btu/lb.F
	62.59	62.72	0.9628	0.9555
Abs. Diff.	0.13		0.0073	
Rel. Diff (%)	0.208		0.758	

These errors compound multiplicatively according to Equation 24 as follows:

$$Error\ from\ Glycol\ Analysis = \sqrt{(0.00208)^2 + (0.00758)^2} = 0.00786$$

This error compounds multiplicatively with the Controlotron system error of 2.0 percent as follows:

$$Overall\ Heat\ Meter\ Error = \sqrt{(0.02)^2 + (0.00786)^2} = 0.0215$$

This means that for the given assumptions, heat recovery rate will be 350715 ± 7540 Btu/hr, or a relative compounded error of ± 2.15 percent.

For the heat recovery efficiency determination, the errors in the divided values compound according to Equation 24. The heat input is approximately 853,036 ± 8701 Btu/hr or ± 1.02 percent relative error (Section 3.3.1). For this example, compounded relative error for the heat recovery efficiency determination is therefore:

$$Error\ in\ Heat\ \mathrm{Re}\ cov ery\ Efficiency = \sqrt{(0.0215)^2 + (0.0102)^2} = 0.0238$$

This means that for the assumptions above, heat recovery efficiency will be 42.00 ± 1.00 percent, or a relative compounded error of 2.4 percent. This compounded relative error is the data quality objective for this verification parameter.

Tables 3-2 and 3-3 summarize the DQIs and QA/QC checks associated with this verification parameter. The following paragraphs discuss these checks.

To ensure the energy meter's accuracy requirements are met, the GHG Center will obtain factory calibrations for the flow transducers and RTDs. 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 employs 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 pipe specifications and fluid composition. After installation of the meter components, the Field Team Leader will compare the actual transit-time signal to the reference value. Differences between the actual and reference values in excess of 5.0 percent indicate and 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 pipe 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 ^{o}F, the meter RTDs will be sent for re-calibration. Appendix B-6 contains the field data form.

A final quality assurance check consists of laboratory analysis of the working fluid mixture (see Section 2.2.2.2 for further detail). The lab will quantify volume percent of PG and provide instrument calibration records. In addition, a blind/audit sample of known PG concentration will be submitted to the laboratory for analysis, and results will be used to determine errors between laboratory reported values and the true concentration of the audit samples. The GHG Center will compare the average glycol composition analysis results to the value input to the heat meter. Values within ± 3.0 percent (i.e. the accuracy of the laboratory analysis) will ensure that the glycol composition did not change during the test campaign.

3.3.3 Total Efficiency

Total efficiency is the sum of the electrical power and heat recovery efficiencies. Continuing with the given example, total efficiency is 28.00 ± 0.51 percent (±1.81 percent relative error) plus 42.00 ± 1.00 percent (± 2.4 percent relative error) or 70.00 percent. For additive errors, the absolute errors compound as follows (EPA 1999):

$$err_{c,abs} = \sqrt{err_1^{\,2} + err_2^{\,2}} \qquad \text{Eqn. 25}$$

Relative error, then, is:

$$err_{c,rel} = \frac{err_{c,abs}}{Value_1 + Value_2} \qquad \text{Eqn. 26}$$

where:

$err_{c,abs}$ = compounded error, absolute
err_1 = error in first added value, absolute value
err_2 = error in second added value, absolute value
$err_{c,rel}$ = compounded error, relative
$value_1$ = first added value
$value_2$ = second added value

For this example, total efficiency compounded error is:

$$Error\ in Total\ Efficiency = \sqrt{(0.51)^2 + (1.00)^2} = 0.0112$$

The total efficiency is 70.00 ± 0.79 percent, or 1.1 percent relative error. This compounded relative error is the data quality objective for this parameter. Sections 3.3.1 and 3.3.2 described the data quality indicators for the measurements which contribute to this determination.

3.4 AIR POLLUTANT EMISSIONS

Air pollutant emissions in pounds per hour divided by the electrical power production rate in kilowatts yields the air pollutant emission rate in pounds per kilowatt hour. (Equation 17, Section 2.4.1.3). The manufacturer states that the turbine's NO_X emissions are less than 9 ppmv when corrected to 15 percent O_2. This equates to 4.42 ppmv at the 18 percent stack gas O_2 expected during testing. The resulting NO_X emission rate is 2.768×10^{-2} lb/hr for a heat input of 835035 Btu/hr. Dividing by the turbine's electrical power production of 70 kW yields 3.954×10^{-2} lb/kWh of NO_X emissions. This is the value expected during field testing.

The contributing measurements for the NO_X emission rate are stack gas concentration (ppmv), heat input (MMBtu/hr), and the O_2 concentration (percent) in the stack gas; their accumulated errors are ± 2.0, ± 1.02, and ± 2.0 percent, respectively. Compounding of errors in each of these measurements is similar to the discussion in Sections 3.3.1 and 3.3.2. The result is an overall ± 12.7 percent relative error in the NO_X lb/kWh emission rate. Note that the ± 2.0 percent error in the O_2 measurement magnifies the total error because it is part of a subtraction in the numerator of Equation 15 (conversion of pollutant concentration to mass emissions using EPA Method 19). Compounded errors for CO, CO_2, and CH_4 will be identical; errors for THC compound to ± 13.5 percent due to the ± 5.0 percent analyzer error (instead of 2.0 percent for the other analyzers).

As summarized in Table 3-1, the DQOs for CH_4, CO, CO_2, and NO_X lb/kWh will be ± 12.7 percent relative error. The DQO for THC lb/kWh will be 13.5 percent relative error.

The GHG Center will employ the EPA Reference Methods listed in Table 2-2, Section 2.4.1 to determine emission rates of criteria pollutants and greenhouse gases. Table 3-7 summarizes the instruments, ranges, accuracies, and DQI goals for this verification.

Table 3-7. Pollutant Measurement Instrument Specifications and DQI Goals

Measurement Variable		Operating Range Expected in Field	Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Data Quality Indicator Goals: Accuracy[a]	Data Quality Indicator Goals: Completeness	How Verified / Determined
Exhaust Stack Emissions	NO_x Levels	0 to 50 ppm	Chemiluminescence / Monitor Labs Model 8840	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS	three 30 minute replicates per load	± 2 % FS	Load tests - 100 %	Follow EPA Reference Method calibration and QC criteria
	CO Levels	0 to 50 ppm	California Analytical CA-300P	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS		± 2 % FS		
	O_2 Levels	0 to 25 %	California Analytical CA-300P	0 to 25 %	± 1 % FS		± 2 % FS		
	CO_2 Levels	0 to 20 %	California Analytical CA-300P	0 to 20 %	± 1 % FS		± 2 % FS		
	CH_4 content	0 to 50 ppm	GC / FID HP Model 5890	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 0.1 % FS		± 5 % FS		
	THC Levels	0 to 50 ppm %	California Analytical 300 FID	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS		± 5 % FS		
	Temperature	400 to 600 °F	Thermocouple / Omega Type K	up to 2100 °F	± 1 % reading	twice per week	± 1 % reading		

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

The Reference Methods specify the sampling methods, calibrations, and data quality checks that must be followed to achieve a data set that meets the DQOs. These procedures ensure the quantification of run-specific instrument and sampling errors and that runs are repeated if the specific performance goals are not met. The GHG Center will assess emissions data quality, integrity, and accuracy through these system checks and calibrations.

The corresponding Reference Methods document QA/QC procedures, and they will not be repeated here in entirety. However, specific procedures to be conducted during this test are outlined below. Table 3-8 summarizes the QA/QC checks that the GHG Center will perform during field testing. Satisfaction and documentation of each of the calibrations and QC checks will verify the accuracy and integrity of the measurements with respect to the DQIs listed in Table 3-7, and subsequently the DQOs for each pollutant.

Table 3-8. Summary of QA/QC Checks for Pollutants

Measurement Variable		QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Response to Check Failure or Out of Control Condition
Emission Rates	NO_x	Analyzer interference check	Once before testing begins	± 2 % of analyzer span	Repair or replace analyzer
		NO_2 converter efficiency		98 % efficiency	
		Sampling system calibration error and drift checks	Before and after each test run	± 2 % of analyzer span	Repeat test
	CO, 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	± 5 % of analyzer span	Correct or repair sampling system
		Calibration drift test	After each test	± 3 % of analyzer span	Repeat test
	THC	System calibration error test	Daily before testing	± 5 % of analyzer span	Correct or repair sampling system
		System calibration drift test	After each test	± 3 % of analyzer span	Repeat test
	CH_4	Calibration with gas standards by certified laboratory	Prior to analysis of each lot of samples submitted	± 2 % for CH_4 concentration	Repeat analysis

Emissions of NO_X will be measured using Method 7E, CO will be determined in accordance with Method 10, and emissions of O_2 and CO_2 in accordance with Method 3A. Method 10 does not define QC criteria well for CO measurements. Methods 7E and 3A refer to EPA Method 6C (determination of sulfur dioxide emissions) for QC criteria, and the GHG Center will follow these criteria for this verification.

<u>Sampling System Calibration Error, Drift, and Bias</u>

The criteria specified in Method 6C include determination of analyzer calibration error, sampling system bias, and calibration drift. The testing contractor will conduct calibration error checks once per day of testing. The tester will sequentially introduce a suite of calibration gases to the sampling system at the sampling probe, and then record the system response. All calibration gases will conform to EPA Protocol No. 1. The three gases used for CO_2, NO_X, O_2, and THC include zero, 40 to 60 percent of span, and 80 to 100 percent of span. The CO analyzer requires four calibration gases: zero, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. The maximum allowable error (bias) in response to any of the calibration gases is ± 2 percent of span for NO_x and ± 5 percent of span for THC.

At the conclusion of each test run, the operator again introduces zero and mid-level calibration gases to the sampling system at the probe and records the response. Comparison of the resulting initial and final system responses allow the determination of system drift. Drifts which are within ± 2.0 percent for CO, CO_2 NO_X, and within ± 3.0 percent for THC are acceptable. The applicable methods include procedures to correct for acceptable calibration drift during each test run. The testing team will repeat test runs for which drifts exceed these amounts.

NO_x Analyzer Interference Test

In accordance with Method 20, testers will conduct a NO_X analyzer interference test once before the testing begins. This test is conducted by injecting the following calibration gases into the analyzer:

CO – 500 ± 50 ppm in balance N_2
SO_2 – 200 ± 20 ppm in N_2
CO_2 – 10 ± 1 % in N_2
O_2 – 20.9 ± 1 %

For acceptable analyzer performance, the sum of the interference responses to all of the interference test gases must be within ± 2 percent of the analyzer span value. Analyzers failing this test will be repaired or replaced.

NO_2 Converter Efficiency Test

The NO_x analyzer converts any NO_2 present in the gas stream to NO prior to gas analysis. The tester will conduct a converter efficiency test immediately prior to beginning the testing. The test operator introduces a mixture of mid-level calibration gas and air to the analyzer and records its response every minute for 30 minutes. If the NO_2 to NO conversion is 100 percent efficient, the response will be stable at the highest peak value observed. If the response decreases by more than 2 percent from the peak value observed during the 30-minute test period, the converter is faulty. A NO_x analyzer failing the convertor efficiency test will be either repaired or replaced prior to testing.

3.5 INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE REQUIREMENTS

The equipment used to collect verification data will be subject to the pre- and post-test QC checks discussed earlier. Before the equipment leaves the GHG Center or analytical laboratories, it will be assembled exactly as anticipated to be used in the field and fully tested for functionality. For example, all controllers, flow meters, computers, instruments, and other sub-components of the measurements system (Figure 2-2) will be operated and calibrated 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. A small amount of consumables and frequently needed spare parts will be maintained at the test site. Major sub-component failures will be handled on a case-by-case basis (e.g., by renting replacement equipment or buying replacement parts).

The instruments used to make gas flow rate measurements will be inspected at the GHG Center's laboratory prior to installation in the field to ensure all parts are in good condition. The equipment used to make gas pressure and temperature, and ambient measurements are maintained by the GHG Center's

Environmental Studies Group. The mass flow meters, temperature, gas pressure, and other sensors will be submitted to the manufacturer for calibration prior to being transported to the test site.

3.6 INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES

Natural Gas Reference Standard gases will be used to calibrate the GC used for fuel analyses, and to prepare and blind audit sample for submittal to the laboratory. The concentrations of components in the audit gas are certified 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.

EPA Protocol gases will be used to calibrate the gaseous pollutant measurement system. Calibration gas concentrations meeting the levels stated in Section 2.4 will either be generated from high concentration gases for each target compound using a dilution system or supplied directly from gas cylinders. Per EPA Protocol gas specifications, the actual concentration must be within ± 2 percent of the certified tag value. 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, gas pressure, gas temperature, power output and quality, heat recovery, and ambient conditions, to be collected by the GHG Center's DAS)
- Fuel gas compositional data from canister samples collected by the Field Team Leader and submitted to laboratory for analysis
- Emissions testing data from test contractor
- PG compositional analyses from analytical laboratory
- IR PowerWorks and facility operating data to be supplied by the test facility

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.

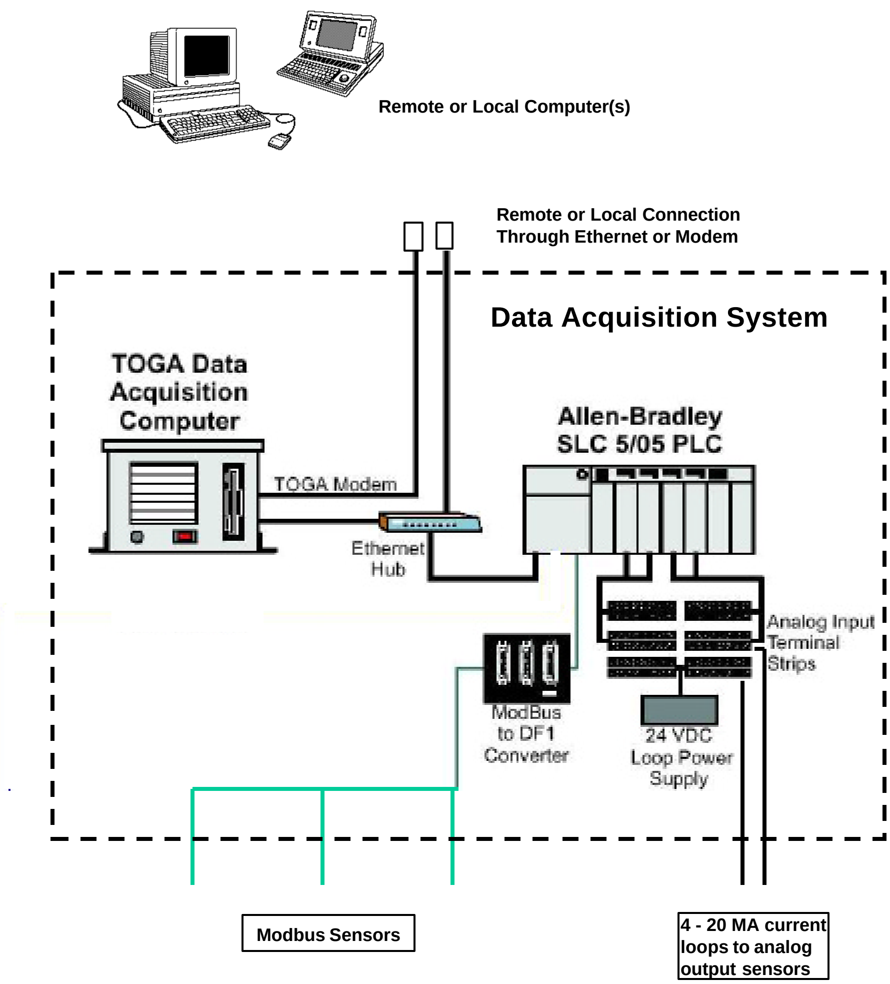
The Field Team Leader will submit digital data files, gas analyses, chain of custody forms, and the Daily Test Log to the Project Manager. The Project Manager will initiate the data review, validation, and calculation process. These submittals will form the basis of the Verification Report which will present data analyses and results in table, chart, or text format as is 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 TOGA Gladiator Unix-based data acquisition computer (data server). 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 realtime data source. The DAS can accommodate any combination of up to 16 analog signal channels with 4 to 20 mA current or DC 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 data server and applies a common time stamp to facilitate data synchronization of all measurements.

Figure 4-1. DAS Schematic



The 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 ODBC-compliant, which means that almost any MS Windows program can easily use the data. The data server includes an internal modem and Ethernet card for remote and local communications. During normal operations, the user accesses the data server with a portable laptop or remote computer (PC) *via* its communications port, Ethernet link, or telephone connection. 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.

During the verification testing, GHG Center personnel will configure the DAS to acquire the process variables listed in Table 4-2. The table also lists operational parameters provided by the IR PowerWorks internal software. These data will not be directly logged on the GHG Center's DAS, but will be copied and stored on a personal computer.

During field testing, the Field Team Leader will retrieve, review, and validate the electronically collected data at the end of each load test run. He will use standard statistical methods to determine if the variation in power output, power factor, gas flow rate, ambient temperature, and ambient pressure meet the maximum permissible limits specified in Table 2-1. If the PTC criteria are met, test results will be stated as mean values with an associated 90 percent confidence interval for each variable. The width of the confidence interval depends on the number of data points (1-minute averages) in the test run and the sample standard deviation as shown in Equation 27.

$$err_{abs} = t_{.05,n-1} \frac{s}{\sqrt{n}} \qquad \text{(Eqn. 27)}$$

where:

err_{abs} = Half width of the 90 percent confidence interval
$t_{.05,n-1}$ = T distribution value for a 90 percent confidence interval and n-1 degrees of freedom
s = Sample standard deviation of the test run data
n = Number of 1-minute averages in the test run

To conform to PTC-22 requirements, each test run will last 30 minutes or less. For a 30-minute test run, n-1 is 29 and $t_{.05,29}$, or 1.699, would be used in Equation 27. For reference, the following table presents the T distribution values for the expected test run durations.

Table 4-1. T Distribution Values for 90 Percent Confidence Intervals

n	n-1	$t_{.05,n-1}$
20	19	1.729
21	20	1.725
22	21	1.721
23	22	1.717
24	23	1.714
25	24	1.711
26	25	1.708
27	26	1.706
28	27	1.703
29	28	1.701
30	29	1.699
31	30	1.697
41	40	1.684

The relative error is:

$$err_{rel} = \frac{err_{abs}}{\overline{X}} * 100 \qquad \text{(Eqn. 28)}$$

where:

err_{rel} = Relative error, percent
$\overline{X}$ = Mean value for the test run in question

For this task, the Field Team Leader will enter the appropriate data and results on the log forms in Appendix A-2. Load tests will be repeated until the maximum permissible limits are attained.

Table 4-2. Data to be Collected for IR PowerWorks Evaluation

Sensor / Source	Measurement Parameter	Purpose[1]	Significance
Rosemount 3095 Flow Meter	Natural gas flow rate (scfm)	P	System performance parameter
	Natural gas temperature (^oF)	S	System operational parameter
Rosemount pressure transducer	Natural gas pressure (psi)	S	System performance parameter
Vaisala Model HMP60YO	Ambient temperature (^oF)	P	System performance parameter
	Ambient relative humidity (% RH)	P	System performance parameter
Setra ambient pressure sensor	Ambient pressure (psi)	D/S	System operational 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
IR PowerWorks Communication System (logged by facility)	Power Command (kW)	P	User input parameter
	Start / Stop schedule	P	User input parameter
	Date, time	D/S	System operational parameter
	Turbine speed (rpm)	D/S	System operational parameter
	Compressor inlet temperature (^oC)	D/S	System operational parameter
	Power supply voltage (volt)	D/S	System operational parameter
	Fuel inlet pressure (psi)	D/S	System operational parameter
	Electrical frequency (Hz)	D/S	System operational parameter
	Current – Phase A (amps)	D/S	System operational parameter
	Current – Phase B (amps)	D/S	System operational parameter
	Current – Phase C (amps)	D/S	System operational parameter
	Current – Neutral (amps)	D/S	System operational parameter
	Voltage RMS - Phase A	D/S	System operational parameter
	Voltage RMS - Phase B	D/S	System operational parameter
	Voltage RMS - Phase C	D/S	System operational parameter
	Average power - Phase A (kW)	D/S	System operational parameter
	Average power - Phase B (kW)	D/S	System operational parameter
	Average power - Phase C (kW)	D/S	System operational parameter
	Total average power (kW)	D/S	System operational parameter
Controlotron Energy Meter	Temperature of heated liquid exiting heat exchanger (^oF)	S	System operational parameter
	Temperature of cooled liquid entering heat exchanger (^oF)	S	System operational parameter
	Liquid flow rate (gpm)	S	System operational parameter
	Heat recovery rate (Btu/min)	P	System performance parameter

[1] D - Documentation/Diagnostic
P - Primary value; verification employs these data points
S - Secondary value, used as needed to perform comparisons and assess apparent abnormalities

During field testing, the Field Team Leader will retrieve, review, and validate the electronically collected data at the end of each load testing. To determine if the criteria for electrical efficiency determinations are met, time series power output, power factor, gas flow rate, ambient temperature, and ambient pressure will be processed using the statistical analysis tool in Microsoft Excel®. If it is determined that maximum permissible limits for each variable, calculated at a 95 percent confidence level, are satisfied, the electrical efficiency measurement goal will be met. Conversely, the load testing will be repeated until maximum permissible limits are attained. Data for this task will be maintained by computer and by handwritten entries. Observations and test run sheets will be recorded manually in a log form developed exclusively for this task (Appendix A-2). 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
- Fuel flow rate at selected loads
- Electrical efficiency at selected loads (estimated until gas analyses results are submitted)
- Heat recovery and use rate at selected loads (estimated until PG analyses results are submitted)
- Thermal efficiency at selected loads
- Net IR PowerWorks system efficiency

Data quality assurance checks for the instruments illustrated in Figure 2-1 were discussed in Section 3.0. Manual and electronic records (as required) resulting from these checks will be maintained by the Field Team Leader.

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

4.1.2 Emission Measurements

The emissions testing contractor will be responsible for all emissions data, Q/A 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. The typical data acquisition system records instrument output at one-second intervals, and averages those signals into 1-minute averages. At the conclusion of a test run, the pre- and post-test calibration results and test run values will be electronically transferred from tester's DAS into a Microsoft Excel spreadsheet for data calculations and averaging.

The emissions contractor will report emission measurements results to the Field Team Leader as:

- Parts per million by volume (ppmv)
- ppmv connected to 15 percent O_2
- Emission rate (lb/hr)

Upon completion of the field test activities, the emissions contractor will provide copies of records of calibration, pre-test checks (O_2 stratification checks, system response time, and NO_2 converter), and field test data to Field Team Leader prior to leaving the site. A formal report will be prepared by the contractor and submitted to Center Field Team Leader within three weeks of completion of the field activities. The report will describe the test conditions, documentation of all QA/QC procedures, including copies of calibrations, certificates of calibration gases, and the results of the testing. Field data will be included as an appendix and an electronic copy of the report will be submitted. The submitted information will be stored at the GHG Center's RTP office per guidelines defined in the QMP.

4.1.3 Fuel Gas Sampling and PG Mixture Sampling

Fuel gas and PG solution sampling and QA/QC procedures are discussed in Section 2.0. The Field Team Leader will maintain manual fuel sampling logs and chain-of-custody records. After the field test, the laboratory will submit results for each sample, calibration records, and repeatability test results to the Field Team Leader. Original lab reports and electronic copies of data output and statistical analyses will be stored at the GHG Center's RTP office per guidelines described in the GHG Center's QMP. After receipt of the laboratory analyses, the Field Team Leader will compute the actual electrical and thermal efficiency at each load tested and report the results to the Project Manager.

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

Figure 1-5 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. In the field, the Team Leader will review collected data for reasonableness and completeness. The data from each of the controlled test periods will also be reviewed on-site to determine if PTC 22 variability criteria are met and if not, the test run will be rejected. The emissions testing data will be validated by reviewing instrument and system calibration data and ensuring that those and other reference method criteria are met. Factory calibrations for fuel flow, pressure, and temperature, electrical and thermal power output, and ambient monitoring instrumentation will be reviewed on-site to validate instrument functionality. Other data, such as fuel LHV and glycol solution analysis results, must be reviewed, verified, and validated after testing has ended. The Project Manager holds overall responsibility for these tasks.

Upon review, all collected data will be classed as valid, suspect, or invalid. The GHG Center will employ the QA/QC criteria discussed in Section 3.0; and specified in Tables 3-2 through 3-7. Review criteria are in the form of factory and on-site calibrations, maximum calibration and other errors, and audit gas analyses results, and lab repeatability results.

In general, valid results are based on measurements which meet the specified DQIs and QC checks, that were collected when an instrument was verified as being properly calibrated, and that 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.

All data, valid, invalid, and suspect will be included in the Verification Report. However, report conclusions will be based only on valid data 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. If the DQI goals cannot be met due to excessive data variability, the Project Manager will decide to either continue the test, collect additional data, or terminate the test and report the data obtained.

The QA Manager reviews and validates the data and the draft Verification Report using the Test Plan and test method procedures. 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 employed 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.

In general, when data are collected, the Field Team Leader and Project Manager will review them 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 employ to ensure that DQIs are achieved; they need not be repeated here. If the test data show that DQI goals were met, then it will be concluded 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 verified after field tests have concluded.

4.4 ASSESSMENTS AND RESPONSE ACTIONS

The quality of the project and associated data are assessed by the Field Team Leader, Project Manager, QA Manager, GHG Center Director, and technical peer reviewers. The Project manager and QA Manager independently oversee the project and assess its quality through project reviews, inspections if needed, and an ADQ.

4.4.1 Project reviews

The review of project data and the writing of project reports are the responsibility of the Project Manager, who also is responsible for conducting the first complete assessment of the project. Although the project's data are reviewed by the project personnel and assessed to determine that the data meet the measurement quality objectives, it is the Project Manager who must assure that project activities meet the measurement and DQO requirements.

The second review of the project is performed by the GHG Center Director, who is responsible for ensuring that the project's activities adhere to the requirements of the program and expectations of the stakeholders. The GHG Center Director's review of the project will also include an assessment of the overall project operations 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 program management systems are established and functioning as required by the QMP and corporate policy. The QA Manager is the final reviewer within the SRI organization, and is responsible for assuring that QA requirements have been met.

The draft document will be then reviewed by NYSERDA. This will be followed by a review from the host site and selected members of the DG Technical Panel (minimum of two industry experts). 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. These 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 comments will be addressed by the Project Manager. Following this review, the Verification Report and Statement will undergo their EPA management reviews, including the GHG Center Program Manager, EPA ORD Laboratory Director, and EPA Technical Editor.

4.4.2 Inspections

Although not planned, inspections may be conducted by the Project Manager or the QA Manager. Inspections assess activities that are considered important or critical to key activities of the project. These critical activities may include, but are not limited to, pre- and post-test calibrations, the data collection equipment, sample equipment preparation, sample analysis, or data reduction. Inspections are assessed with respect to the Test Plan or other established methods, and are documented in the field records. The results of the inspection are reported to the Project Manager and QA Manager. Any deficiencies or problems found during the inspections must be investigated and the results and responses or corrective actions reported in a Corrective Action Report (CAR), shown in Appendix B-8.

4.4.3 Audits

Following the GHG Center's Quality Management Plan (QMP) requirements, an ADQ will be conducted. The ADQ is an evaluation of the measurement, processing, and evaluation steps to determine if systematic errors have been introduced. During the ADQ, the QA Manager, or designee, will randomly select approximately 10 percent of the data to be followed through the analysis and data processing. 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 is not an evaluation of the reliability of the data presentation. The review of the data presentation is the responsibility of the Project Manager and the technical peer-reviewer.

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 SRI's QA staff.

The current verification is one of five verifications of CHP technologies planned during 2002-2003, several of which are in progress. The intention of the Center is to perform a detailed TSA, including on-site field observation, on one of the earliest of these substantially similar tests, followed by less intensive audits on the remaining tests. These subsequent audits will focus on elements which are unique to the specific tests, and will probably involve interviews and inspection of records rather than field observation. The current verification will receive a TSA in one of these forms.

Since the current schedule of projects suggests that this verification will be the first of these substantially similar tests, it is a candidate for the detailed field audit. However, if schedule changes alter the order of the verifications, the "baseline" audit may be performed on another verification, and the TSA for this test will be of the "derivative" or update scope.

Lastly, this verification will include two performance evaluation audits (PEA), on in the form of the natural gas reference standard blind audit sample submitted to the gas analysis laboratory, and another in the form of the blind PG sample submitted along with those samples. Both will represent direct assessment of sampling and analytical accuracy.

4.5 DOCUMENTATION AND REPORTS

During the different activities on this project, documentation and reporting of information to management and project personnel is critical. To insure the complete transfer of information to all parties involved in this project, the following field test documentation, QC documentation, corrective action/assessment report, and verification report/statements will be prepared.

4.5.1 Field Test Documentation

The Field Team Leader will record all important field activities. The Field Team Leader reviews all data sheets and maintains them in an organized file. The required test information was described earlier in Sections 2.0 and 3.0. The Field Team Leader will also maintain a field notebook that documents the activities of the field team each day and any deviations from the schedule, Test Plan, or any other significant event. Any major problems found during testing requiring corrective action will be reported immediately by the Field Team Leader to the Project Manager through a CAR. The Field Team Leader will document this in the project files and report it to the QA Manager.

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

4.5.2 QC Documentation

After the completion of verification test, test data, sampling logs, calibration records, certificates of calibration, and other relevant information will be stored in the project file in 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 be used to prepare the Data Quality section in the Verification Report, and made available to the QA Manager during audits.

4.5.3 Corrective Action and Assessment Reports

A corrective action is the process that occurs 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 Corrective Action Report, included in Appendix B-8, 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 Project Manager will immediately be notified of the problem and will take and document appropriate action. The Project Manager is responsible for, and is authorized to halt the 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 results of the ADQ conducted by the QA Manager will be routed to the Project Manager for review, comments, and corrective action. The results will be documented in the project records. The Project Manager will take any necessary corrective action needed and will respond by addressing the QA Manger's comments in the final Verification Report.

4.5.4 Verification Report and Verification Statement

A draft Verification Report and Statement will be prepared within 8 weeks of completing the field test by the Project Manager if possible. The Verification Report will specifically address the results of the verification parameters identified in the Test Plan.

The Project Manager will submit the draft Report and Statement to the QA Manager and Center Director for review. The final verification Report will contain a verification Statement, which is a 3 to 4 page summary of the IR PowerWorks technology, the test strategy used, and the verification results obtained. 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. A preliminary outline of the report is shown below.

Preliminary Outline
IR PowerWorks Verification Report

Verification Statement

Section 1.0: *Verification Test Design and Description*
Description of the ETV program
Turbine system and site description
Overview of the verification parameters and evaluation strategies

Section 2.0:	*Results* *Power production performance* *Power quality performance* *Operational performance* *Emissions performance*
Section 3.0:	*Data Quality*
Section 4.0:	*Additional Technical and Performance Data (optional) supplied by NYSERDA*
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 natural 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

Appendix A-1. Load Testing Procedures

1. In the System Communications Software, select desired load in the Power Command box. Record these user specified settings in the log form (Appendix A-2).

2. Synchronize clocks with DAS, coordinate with emissions testing personnel to establish a start time. Record this time in the log form.

3. Continue operating the IR PowerWorks system at the selected load for a minimum of 4 minutes.

4. Obtain a minimum of one gas sample from the fuel supply line. Follow procedures outlined in Appendix A-3.

5. Obtain a minimum of one PG sample per day from the fluid return line. Follow procedures outlined in Appendix A-6.

6. After 30 minutes of data are collected, review power output, ambient temperature, and barometric pressure to determine if all of the following criteria are satisfied:

Power output (kW)	± 2 %
Power factor	± 2 %
Fuel heating value	± 1 %
Fuel flow	± 2 %
Barometric pressure	± 0.5 %
Ambient air temperature	± 4 ^{o}F

7. If the above criteria are not satisfied, continue operating the turbine at the selected load. After each 30 minute interval, repeat Step 6 until the uncertainty criteria are met. Record the time intervals when valid data were obtained (minimum of 4 minutes and maximum of 30 minutes).

8. Repeat test sequence two more times (3 test runs total).

9. Repeat Steps 1 through 8 after changing the operating load to the remaining three desired loads. Data and calculations for each load test repetition will be maintained independently using the log forms provided in Appendix A-2.

Appendix A-2. Load Test Log

Date __________

Test technician name ______________________________

Load Test Begin Time ____________ *(from DAS)*

Synchronize Emissions Test Equipment to DAS time ______ *(initial upon synchronization)*

Beginning of test

Turbine Load Setting.............. _______ %

Turbine Power Factor Setting.. _______ %

Power Output .... _______ kW

Power Factor .... _______ %

Fuel Flow .... _______ lbm/min

Barometric pressure .... _______ in Hg

Ambient air temp .... _______ °F

Relative humidity .... _______ %

Heat Recovery Rate _________ Btu/min

Emissions Test

First data point Date ____________ Time ____________

Final data point Date ____________ Time ____________

End of test

Turbine Load Setting _______ kW

Power Output _______ kW

Power Factor _______ %

Fuel Flow _______ lbm/min

Barometric pressure _______ in Hg

Ambient air temp _______ °F

Relative humidity _______ %

Heat Recovery Rate _______ Btu/min

Heat Use Rate _______ Btu/min

Load Testing End Time ____________ *(from DAQ system)*

Load Testing Duration Time ____________ minutes

If for any reason the test is invalid, repeat the procedure.

Appendix A-3. Fuel Gas Sampling Procedures

Collect at least one (1) fuel sample during each load test (i.e., 50, 75, 90, and 100 percent).

1. Attach a leak free vacuum gauge to the inlet of two pre-evacuated stainless steel sample canisters. Open each canister inlet valve and verify that the canisters are fully evacuated. Record the absolute pressures.

2. Close the inlet valves, remove the vacuum gauge, and attach a canister to the sample port on the fuel line.

3. Open the fuel line valve upstream of the canisters, and open the inlet valve. Wait 5 seconds to allow the canister to fill with fuel.

4. Open the outlet valve and purge the canister for 5 more seconds. Close the canister outlet valve, then the inlet valve, and then the fuel line valve.

5. Remove canister from port. Record date, time, canister ID number, and final canister pressure (Appendix A-4) on proper chain-of-custody form (Appendix A-5).

6. Return collected samples to laboratory along with completed chain-of-custody form.

Laboratory' Analytical Procedures (for reference only):

Samples are received with proper chain-of-custody form and logged into the laboratory system for analysis.
Samples are injected and analyzed. The GC determines gas constituent concentrations based on the areas of the chromatograph peaks relative to the gas standard.
Duplicate analysis is conducted on one sample per lot.
Fuel LHV is calculated using results of each analysis and equations provided in ASTM D3588.
Hard copies of calibration records and LHV results will be submitted to the GHG Center.

Appendix A-4. Fuel Sampling Log

Project: ______________________________

Location: ______________________________

Source: ______________________________

Signature: ______________________________

Ambient Pressure: ________________

Ambient Temperature: ______________

Sample ID	Date	24-hr Time	Canister ID	Initial Pressure (psig)	Final Pressure (psig)	Comments

NOTES: ____

____

____

Appendix A-5. Fuel Sampling Chain of Custody Record

Project: ______________________________
Location: ______________________________
Source: ______________________________
Signature: ______________________________

Sample Date(s): __________________
Shipping Date: __________________
Laboratory: __________________
Lab Address: __________________
____
____

Sample ID	Date / 24-hr Time	Canister ID	Laboratory Sample ID	Analyses Required

Relinquished by: ______________________________ Date/Time: __________________
Received by: ______________________________ Date/Time: __________________

Relinquished by: ______________________________ Date/Time: __________________
Received by: ______________________________ Date/Time: __________________

Relinquished by: ______________________________ Date/Time: __________________
Received by: ______________________________ Date/Time: __________________

Appendix A-6. Propylene Glycol Sampling Procedures

Collect at least one sample during each load test (i.e., 50, 75, 90, and 100 percent)

1) Connect pre-cleaned, 100 to 500 ml glass vials to the fluid discharge spout located on the hot side of the heat recovery unit.

2) Open fluid discharge spout, collect sample until vials are at least 1/2 full.

3) Close the spout. Record date, time, and vial ID number (Appendix A-7) on proper chain-of-custody form (Appendix A-8).

4) Return collected samples to the laboratory along with completed chain-of-custody form.

   Laboratory analytical procedures (for reference only):

   a) Samples are received with proper chain-of-custody form and logged into the laboratory system for analysis.
   b) Samples are injected and analyzed. The GC determines concentrations based on the areas of the chromatograph peaks relative to the gas standard.
   c) Duplicate analysis is conducted on one sample per lot.
   d) Hard copies of calibration records, fluid concentration, and fluid density will be submitted to the GHG Center.

Appendix A-7. Propylene Glycol Sampling Log

Project: ______________________________
Location: ______________________________
Source: ______________________________
Signature: ______________________________

Ambient Pressure: ________________
Ambient Temperature: ______________

Sample ID	Date	24-hr Time	Fluid Temp. (°C)	Sample Size (mL)

NOTES: ____

Appendix A-8. Example Propylene Glycol Sampling Chain-of -Custody Record

PSC PHILIP SERVICES

PHILIP ANALYTICAL SERVICES CORPORATION

Anjou: (514) 493-4733 Burlington: (800) 668-1639 Burnaby: (800) 440-4808 Calgary: (403) 250-3225
Edmonton: (877) 463-8889 Halifax: (800) 565-7227 London: (800) 268-7396
Mississauga: (800) 263-9040 Reading: (800) 345-4806 St. John's: (800) 492-7227

LABORATORY USE ONLY

Work Order: ______

Comments: ______

CHAIN OF CUSTODY RECORD

Client: ______

Contact: ______

Phone: ______ Fax: ______

PASC Quote #: ______

Client P.O. #: ______

Client Project #: ______

Sampled By: ______

Please Specify Guideline (if applicable) ______

Page ____ of ____

Invoice to (if other than above): ______

Analysis Required:

TAT (Turnaround Time)

PLEASE PROVIDE ADVANCE NOTICE FOR RUSH PROJECTS

* some exceptions apply, please contact lab

STANDARD ☐

RUSH Specify Date ______

Time ______

Sample #	Client Sample ID	Date Sampled	Analysis Required														Sample Matrix	No. of Containers	Comments/Contamination/ Site History
1																			
2																			
3																			
4																			
5																			
6																			
7																			
8																			
9																			
10																			
11																			
12																			

Samples Relinquished to PASC by: (Client Signature)	Date:	Time:	Method of Shipment:
Samples Received in lab by:	Date:	Time:	Condition of samples upon receipt at lab:

Appendix A-9. Density of Propylene Glycol (lb/ft^3)

Concentrations in Volume Percent Propylene Glycol

Source: ASHRAE 1997 (pg. 20.8)

Temp (F)	10%	20%	30%	40%
-30				
-20				
-10				
0				65.71
10			65	65.6
20		64.23	64.9	65.48
30	63.38	64.14	64.79	65.35
40	63.3	64.03	64.69	65.21
50	63.2	63.92	64.53	65.06
60	63.1	63.79	64.39	64.9
70	62.98	63.66	64.24	64.73
80	62.86	63.52	64.08	64.55
90	62.73	63.37	63.91	64.36
100	62.59	63.2	63.73	64.16
110	62.44	63.03	63.54	63.95
120	62.28	62.85	63.33	63.74
130	62.11	62.66	63.12	63.51
140	61.93	62.46	62.9	63.27
150	61.74	62.25	62.67	63.02
160	61.54	62.03	62.43	62.76
170	61.33	61.8	62.18	62.49
180	61.11	61.56	61.92	62.22
190	60.89	61.31	61.65	61.93
200	60.65	61.05	61.37	61.63
210	60.41	60.78	61.08	61.32
220	60.15	60.5	60.78	61
230	59.89	60.21	60.47	60.68
240	59.61	59.91	60.15	60.34
250	59.33	59.6	59.82	59.99

Appendix A-10. Specific Heat of Propylene Glycol (Btu/lb F)

Concentrations in Volume Percent Propylene Glycol
Source: ASHRAE 1997 (pg. 20.8)

Temp (F)	10%	20%	30%	40%
-30				
-20				
-10				
0				0.855
10			0.898	0.859
20		0.936	0.902	0.864
30	0.966	0.938	0.906	0.868
40	0.968	0.941	0.909	0.872
50	0.97	0.944	0.913	0.877
60	0.972	0.947	0.917	0.881
70	0.974	0.95	0.92	0.886
80	0.976	0.953	0.924	0.89
90	0.979	0.956	0.928	0.894
100	0.981	0.959	0.931	0.899
110	0.983	0.962	0.935	0.903
120	0.985	0.965	0.939	0.908
130	0.987	0.967	0.942	0.912
140	0.989	0.97	0.946	0.916
150	0.991	0.973	0.95	0.921
160	0.993	0.976	0.953	0.925
170	0.996	0.979	0.957	0.929
180	0.998	0.982	0.961	0.934
190	1	0.985	0.964	0.938
200	1.002	0.988	0.968	0.943
210	1.004	0.991	0.971	0.947
220	1.006	0.994	0.975	0.951
230	1.008	0.996	0.979	0.956
240	1.011	0.999	0.982	0.96
250	1.013	1.002	0.986	0.965

APPENDIX B
Quality Assurance/Quality Control Checks and Log Forms

Appendix B-1. 7600 ION Installation and Setup Checks

Date __________ Lead installer name ______________________________

Initial all items after they have been completed.

NOTE: In all events, conformance to applicable local codes will supercede the instructions in this log sheet or the installation manual.

_____ Prior to commencement of installation, **obtain and read the *7600 ION INSTALLATION & BASIC SETUP MANUAL***. The points outlined here were developed as a guideline using the instructions in the *7600 ION INSTALLATION & BASIC SETUP MANUAL,* but should any information or instructions in the manual not be listed here, those steps should not be skipped or ignored. A reference page number listed as [#] will be included for each point, as appropriate.

_____ Verify that the meter enclosure is mounted in a location to provide ventilation around the case in an area free of oil, moisture, excessive dust and corrosive vapors. All wiring will conform to applicable NEC standards.

_____ Connect to power supply to the 7600 ION (**85 to 240 VAC**) via a **switch or circuit breaker** using **AWG 12** to **AWG 14 wire**. Connect the line supply wire to the L/+ terminal and the neutral supply wire to the N/- using a compatible plug [7].

_____ Connect the ground terminal of the 7600 ION to the switchgear earth ground using AWB 12 wire or larger [8].

_____ Make voltage and current transformer (CT) connections to the 7600 ION according to the type of electrical connection according to the directions in the Manual [pages 8-14]. To provide a maximum input of 25 amps for a current flow of 200 amps, 40:1 ratio CTs should be used.

Only qualified personnel should install CTs or voltage connections. To avoid risk of fire or shock, be sure that CT shorting switch is closed at all times, except when CTs are physically connected to the 7600 ION.

AWG 12 to 14 wire is recommended for all phase voltage and current connections.

_____ Use a digital multimeter (DMM) to check that the phase and polarity of the AC voltage inputs are correct. Verify this with the 7600 ION "Basic Setup" screen on front panel.

_____ Connect the DAS to the DB9 serial connector on the back of the 7600 ION via a **null modem** [18].

_____ Set-up the 7600 ION according to the instructions in the Manual [pages 24-29].

_____ Verify the operation of the 7600 ION according to the instructions in the Manual [30].

_____ Using a DMM measure each of the phase voltage and currents and compare them to the readings on the display of the 7600 ION. The readings on the DMM should agree (within the tolerance of the meters) with the readings from the 7600 ION. If they do not agree, modify the connections to the 7600 ION until they are correct. Also check both readings for reasonability.

_____ Compare the 7600 ION readings to the microturbine instrumentation for reasonableness.

_____ Confirm that the readings on the 7600 ION agree with the corresponding readings on the DAS. If they do not agree, troubleshoot the communications link until proper readings are obtained by the DAS.

_____ Verify that the readings are being properly stored on the DAS harddisk or other non-volatile memory.

Appendix B-2. 7600 ION Sensor Function Checks

Date: ______________________ Project: ______________________________

QA/QC Test Leader Name: ____

Phase Wiring (Delta or Wye): ______________________________

Initial all items after they have been completed.

_____ 7600 ION calibration certificates and supporting data are on-hand.

_____ Check power supply voltage with a DMM (should be between 85 and 240 VAC.)

_____ Check the 7600 ION ground terminal connection for continuity with the switchgear earth ground.

_____ Use a digital multimeter (DMM) to check that the phase and polarity of the AC voltage inputs are correct.

_____ Verify the operation of the 7600 ION according to the instructions in the *7600 ION INSTALLATION & BASIC SETUP MANUAL* [page 30].

_____ Using a DMM measure the voltage and current for each phase and compare them to the readings on the display of the 7600 ION. The readings on the DMM should agree (within the tolerance of the meters) with the readings from the 7600 ION.

_____ Confirm that the readings on the 7600 ION agree with the corresponding readings on the DAS. If they do not agree, troubleshoot the communications link until proper readings are obtained by the DAS.

_____ Verify that the readings are being properly stored on the DAS hard disk or other non-volatile memory.

Load %	24-hr Time	Voltage, V						Current, Amps					
		Phase A		Phase B		Phase C		Phase A		Phase B		Phase C	
		7600 ION	DVM	7600 ION	DVM	7600 ION	DVM	7600 ION	DVM	7600 ION	DVM	7600 ION	DVM
Average													
% Diff = [(ION-DVM) / ION] * 100													

Appendix B-3. Rosemount 3095 Installation and Setup Checks/Log Form

Manufacturer's installation checks: The meter consists of a two-piece spool, orifice plate and manifold assembly, mass flow transmitter, and separate RTD process temperature sensor. Field installation procedures are well documented in Rosemount's "Model 3095 MV Product Manual", and will not be repeated here in entirety. Center testing personnel will follow all required procedures to ensure that checks for process connections, leaks, field wiring, and ground wiring are conducted properly. The Product Manual will be made available during installation. Following manual specifications, meter installation will be conducted using the following considerations:

1. The meter will be installed in the fuel line in a safe, accessible, and vibration free section of pipe.
2. Installation will include sufficient straight run of pipe (no less than 20 diameters) upstream and downstream of the meter.
3. The separate temperature sensor will be installed in the piping just downstream of the spool and wired to the transmitters for continuous temperature compensation.
4. All mechanical connections will be leak checked.
5. All electrical connections will be made following manufacturer specifications and tested.

Manufacturer's setup and start-up checks: In each flow sensor element, a transmitter calculates mass from differential pressure across an integral orifice element. To perform this calculation, the transmitter electronics must be programmed with information on the gas being metered and the operating conditions. This is accomplished using Rosemount's Engineering Assistant (EA) Software, which is interfaced to the transmitter via a HART protocol serial modem. Specific setup parameters required in the EA are listed in the following pages. The GHG Center testing personnel will maintain field logs of all data entered into the EA, and subsequently transmitted to the instrument. An electronic copy of the configuration file will be maintained. Detailed guidelines are provided in the Product Manual.

(Continued)

MODEL 3095 MV CONFIGURATION DATA SHEET

00806-0100-4716
English
Rev. AA

Complete this form to define a Custom Flow Configuration for the Model 3095 MV.
Unless specified, the Model 3095 MV will ship with the default values identified by the ★ symbol.

For technical assistance in filling out this CDS, call Rosemount Customer Central at 1-800-999-9307.

NOTE: Any missing information will be processed with the indicated default values.

OPTION CODE C2

Customer: ____________________

Customer P.O. No.: ____________________

Customer Line Item: ____________________

Model No.:[1] ____________________

Tag Type: ☐ SST Wire-on Tag (85 characters maximum) ☐ Stamped on Nameplate (65 characters maximum)

Tag Information: ____________________

TRANSMITTER INFORMATION (optional)

Software Tag: |__|__|__|__|__|__|__|__| (8 characters)

Descriptor: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (16 characters)

Message: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|
|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (32 characters)

Date: |__|__| (dd) |__|__|__| (mmm) |__|__| (yy)

TRANSMITTER INFORMATION (required)

Failure Mode Alarm Direction (select one): ☐ Alarm High ★ ☐ Alarm Low

(1) A complete model number is required before Rosemount Inc. can process this custom configuration order.

★ ***Indicates default value.***

For RMD internal use only:

House Order No: ____________________

Line Item No: ____________________

Transmitter Serial No: ____________________

RCC Tech: ____________________

Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form
(Continued)

LCD Meter Configuration

Process Variables displayed on LCD:

☐ Absolute Pressure
☐ Analog Output Current
☐ Differential Pressure
☐ Flow
☐ Flow Total
☐ Gauge Pressure
☐ Percent of Range
☐ Process Temperature

Number of seconds to display each variable: ____________________
(available ranges from 2–10 seconds, in one second increments)

FLOW CONFIGURATION (required)

Select units for each Process Variable, then enter *sensor* Lower Trim Value (LTV) and *sensor* Upper Trim Value (UTV).
Note: LTV and UTV must be within the range limits stated in the Range Limits Table (see page 6-26).

Differential Pressure:

DP Units ☐ inH_2O–68 °F★ ☐ inHg–0 °C ☐ ftH_2O–68 °F ☐ mmH_2O–68 °F ☐ mmHg–0 °C ☐ psi ☐ bar ☐ mbar ☐ g/SqCm ☐ Kg/SqCm ☐ Pa ☐ kPa ☐ torr ☐ Atm ☐ inH_2O–60 °F

Trim Values LTV:____________________(0 ★) UTV:____________________(URL inH_2O–68 °F ★)

Static Pressure:

Static Units ☐ inH_2O–68 °F ☐ inHg–0 °C ☐ ftH_2O–68 °F ☐ mmH_2O–68 °F ☐ mmHg–0 °C ☐ psi ★ ☐ bar ☐ mbar ☐ g/SqCm ☐ Kg/SqCm ☐ Pa ☐ kPa ☐ torr ☐ Atm ☐ MPa ☐ inH_2O–60 °F

Trim Values(2) LTV:____________________(0 ★) UTV:____________________(URL psi ★)

Process Temperature:

PT Units ☐ °F ★ ☐ °C

Trim Values LTV:____________________(–300 ★) UTV:____________________(1500 °F ★)

Flow Rate:

Flow Units: ☐ StdCuft/s ☐ StdCuft/min ☐ StdCuft/h ☐ StdCuft/d ☐ StdCum/h ☐ StdCum/d ☐ lbs/sec ☐ lbs/min ☐ lbs/hour ★ ☐ lbs/day ☐ grams/sec ☐ grams/min ☐ grams/hour ☐ kg/sec ☐ kg/min ☐ kg/hour ☐ NmlCuM/hour ☐ NmlCuM/day ☐ Special (see Flow Rate Special Units)

Flow Rate Special Units (use if "Special" is checked in Flow Rate above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Rate units): ____________________

Conversion Factor: ____________________

Display As: |__|__|__|__|__| *(available units A–Z, 0–9)*

Flow Rate Output:

Low PV (4 mA) ____________________(0.00 ★) High PV (20 mA)____________________

Rosemount Model 3095 MV

FLOW CONFIGURATION CONT. (required)

Flow Total:

Flow Units: ☐ Grams ☐ Kilograms ☐ Metric Tons ☐ Pounds ☐ Short Tons ☐ Long Tons ☐ Ounces ☐ NmlCuM ☐ Normal Liters ☐ StdCuM ☐ StdCuFt ☐ Special (see Flow Total Special Units)

Flow Total Special Units (use this section if "Special" is checked in Flow Total above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Total units): ____________________________

Conversion Factor: ____________________________

Display As: |___|___|___|___|___| *(available units A–Z, 0–9)*

Flow Total Output:

Low PV (4 mA) ________________________(0.00 ★) High PV (20 mA)____________________________

Damping: Enter a damping value for each variable (valid range: 0.1 – 29 seconds).
(Transmitter will round to nearest available damping value.)

Differential Pressure = _____________(0.864★) Temperature = _____________(0.864★)

Static Pressure = _____________(0.864★)

(2) If absolute pressure module, then lower static pressure values must be ≥ 0.5 psia (3.45 kPa).

★ ***Indicates default value.***

Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form
(Continued)

NOTE *The information on Pages 6-21–6-25 can be sent in on a floppy disk by creating a .MFL file with the EA Software or EA Demo Disk. Call 1-800-999-9307 for more information.*

PRIMARY ELEMENT INFORMATION

Select Differential Producer (Select One)

- ☐ 1195 Integral Orifice
- ☐ Annubar® Diamond II+/Mass ProBar+
- ☐ Nozzle, Long Radius Wall Taps, ASME
- ☐ Nozzle, Long Radius Wall Taps, ISO
- ☐ Nozzle, ISA 1932, ISO
- ☐ Orifice, 2½D & 8D Taps
- ☐ Orifice, Corner Taps, ASME
- ☐ Orifice, Corner Taps, ISO
- ☐ Orifice, D & D/2 Taps, ASME
- ☐ Orifice, D & D/2 Taps, ISO
- ☐ Orifice, Flange Taps, AGA3
- ☐ Orifice, Flange Taps, ISO
- ☐ Small Bore Orifice, Flange Taps, ASME
- ☐ Venturi Nozzle, ISO
- ☐ Venturi, Rough Cast/Fabricated Inlet, ASME
- ☐ Venturi, Rough Cast Inlet, ISO
- ☐ Venturi, Machined Inlet, ASME
- ☐ Venturi, Machined Inlet, ISO
- ☐ Venturi, Welded Inlet, ISO

Selecting Area Averaging Meter or V-Cone® requires a constant value for discharge coefficient: ____________________

☐ Area Averaging Meter ☐ V-Cone

Primary Element Minimum Diameter (d) ________________ ☐ in. ☐ mm at ___________ ☐ °F ☐ °C in. at 68 °F ★

or

Diamond II Sensor Series No. ______ (see table on page 6-26)

Differential Producer Material (Select One) ☐ Carbon Steel ☐ SST 304 ☐ SST 316★ ☐ *Hastelloy C* ☐ *Monel*

Pipe Tube Diameter (Pipe ID) (D) ________________ ☐ in. ☐ mm at ___________ ☐ °F ☐ °C in. at 68 °F ★

Pipe Tube Material: ☐ Carbon Steel★ ☐ SST 304 ☐ SST 316 ☐ *Hastelloy C* ☐ *Monel*

PROCESS OPERATING CONDITIONS

Operating Pressure Range ___________ to ____________ ☐ psia ☐ psig ☐ kPa (absolute) ☐ kPa (gage) ☐ bar

Operating Temperature Range ___________ to ____________ ☐ °F ☐ °C

For fixed process temperatures (Model Code = 0), enter value ____________________.

Valid range: –459 to 3500 °F (–273 to 1927 °C)

NOTE: For steam applications, temperatures must be equal to or greater than the saturation temperature at the given pressures.

ATMOSPHERIC PRESSURE

Atmospheric Pressure = ___________ ☐ psia ☐ kPa(absolute) ☐ bar 14.696 psia ★

STANDARD REFERENCE CONDITIONS

NOTE: This information is only required if any of the following flow units were selected: StdCuft/s, StdCuft/min, StdCuft/h, StdCuft/d, StdCum/h, StdCum/d

Standard Reference Conditions:

Standard Pressure = ________________ ☐ psia ☐ bar ☐ kPa(absolute) 14.696 psia ★
(gas/steam only)

Standard Temperature = ______________ ☐ °F ★ ☐ °C 60 °F ★ (For Steam, 212 °F ★)

★ *Indicates default value.*

Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form
(Continued)

Rosemount Model 3095 MV

FLUID TYPE (Select One)

☐ Gas ☐ Liquid

FLUID INFORMATION (Complete one section only)

☐ **Steam (ASME) Saturated and/or Superheated**

==

☐ **Natural Gas**

NOTE: If you selected Natural Gas, complete the information on page 6-23.

==

☐ **Gas or Liquid from AIChE database**: Circle **ONE** fluid name below:

Acetic Acid
Acetone
Acetonitrile
Acetylene
Acrylonitrile
Air
Allyl Alcohol
Ammonia
Argon
Benzene
Benzaldehyde
Benzyl Alcohol
Biphenyl
Carbon Dioxide
Carbon Monoxide
Carbon Tetrachloride
Chlorine
Chlorotrifluoroethylene
Chloroprene
Cycloheptane
Cyclohexane
Cyclopentane
Cyclopentene

Cyclopropane
Divinyl Ether
Ethane
Ethanol
Ethylamine
Ethylbenzene
Ethylene
Ethylene GlycolEthylene
Oxide
Fluorene
Furan
Helium–4
Hydrazine
Hydrogen
Hydrogen Chloride
Hydrogen Cyanide
Hydrogen Peroxide
Hydrogen Sulfide
Isobutane
Isobutene
Isobutylbenzene
Isopentane
Isoprene

Isopropanol
Methane
Methanol
Methyl Acrylate
Methyl Ethyl Ketone
Methyl Vinyl Ether
m–Chloronitrobenzene
m–Dichlorobenzene
Neon
Neopentane
Nitric Acid
Nitric Oxide
Nitrobenzene
Nitroethane
Nitrogen
Nitromethane
Nitrous Oxide
n–Butane
n–Butanol
n–Butyraldehyde
n–Butyronitrile
n–Decane
n–Dodecane
n–Heptadecane

n–Heptane
n–Hexane
n–Octane
n–Pentane
Oxygen
Pentafluorothane
Phenol
Propane
Propadiene
Pyrene
Propylene
Styrene
Sulfer Dioxide
Toluene
Trichloroethylene
Vinyl Acetate
Vinyl Chloride
Vinyl Cyclohexane
Water
1–Butene
1–Decene
1–Decanal
1–Decanol
1–Dodecene

1–Dodecanol
1–Heptanol
1–Heptene
1–Hexene
1–Hexadecanol
1–Octanol
1–Octene
1–Nonanal
1–Nonanol
1–Pentadecanol
1–Pentanol
1–Pentene
1–Undecanol
1,2,4–Trichlorobenzene
1,1,2–Trichloroethane
1,1,2,2–Tetrafluoroethane
1,2–Butadiene
1,3–Butadiene
1,3,5–Trichlorobenzene
1,4–Dioxane
1,4–Hexadiene
2–Methyl–1–Pentene
2,2–Dimethylbutane

==

☐ **Custom Gas or Liquid**

Enter your custom fluid name ______________________________

NOTE: If you are defining a custom fluid, complete the density and viscosity information on page 6-25.

★ *Indicates default value.*

Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form
(Continued)

NOTE ***Only fill out this page if you selected natural gas.***

COMPRESSIBLITY FACTOR INFORMATION:

Choose desired characterization method, and only enter values for that method:

☐ Detail Characterization Method, (AGA8 1992)

		Mole	Valid Range
CH4	Methane mole percent	______ %	0–100 percent
N2	Nitrogen mole percent	______ %	0–100 percent
CO2	Carbon Dioxide mole percent	______ %	0–100 percent
C2H6	Ethane mole percent	______ %	0–100 percent
C3H8	Propane mole percent	______ %	0–12 percent
H2O	Water mole percent	______ %	0–Dew Point
H2S	Hydrogen Sulfide mole percent	______ %	0–100 percent
H2	Hydrogen mole percent	______ %	0–100 percent
CO	Carbon Monoxide mole percent	______ %	0–3.0 percent
O2	Oxygen mole percent	______ %	0–21 percent
C4H10	i-Butane mole percent	______ %	0–6 percent (1)
C4H10	n-Butane mole percent	______ %	0–6 percent (1)
C5H12	i-Pentane mole percent	______ %	0–4 percent (2)
C5H12	n-Pentane mole percent	______ %	0–4 percent (2)
C6H16	Hexane mole percent	______ %	0–Dew Point
C7H16	n-Heptane mole percent	______ %	0–Dew Point
C8H18	n-Octane mole percent	______ %	0–Dew Point
C9H20	n-Nonane mole percent	______ %	0–Dew Point
C10H22	n-Decane mole percent	______ %	0–Dew Point
He	Helium mole percent	______ %	0–3.0 percent
Ar	Argon mole percent	______ %	0–1.0 percent

(1) The summation of i-Butane and n-Butane cannot exceed 6 percent.

(2) The summation of i-Pentane and n-Pentane cannot exceed 4 percent.

☐ Gross Characterization Method, Option 1 (AGA8 Gr-Hv-CO2)

		Valid Range
Specific gravity at 14.73 psia and 60 °F	______	0.554–0.87
Volumetric Gross Heating Value at Base Conditions	______ BTU/SCF	477–1150 BTU/SCF
Carbon dioxide mole percent	______ %	0–30 percent
Hydrogen mole percent	______ %	0–10 percent
Carbon monoxide mole percent	______ %	0–3 percent

☐ Gross Characterization Method, Option 2 (AGA8 Gr-CO2-N2)

		Valid Range
Specific Gravity at 14.73 psia and 60 °F	______	0.554–0.87
Carbon dioxide mole percent	______ %	0–30 percent
Nitrogen mole percent	______ %	0–50 percent
Hydrogen mole percent	______ %	0–10 percent
Carbon monoxide mole percent	______ %	0–3 percent

★ ***Indicates default value.***

Appendix B-4. Rosemount 3095 Sensor Function Checks/Log Form

Sensor function checks: A series of meter and transmitter function checks will be conducted before the verification period begins and again at the end of the testing. The following checks will be included.

- Power supply test to document that the facility DAS is supplying sufficient power (no less than 11 vDC) to the tranmitter.
- Analog output checks where a current of known amount will be checked against a secondary device to ensure that 4 mA and 20 mA signals are produced.
- Reasonableness checks will be performed by ensuring that the mA signal produced at the transmitter is recorded correctly in the DAS.
- Zero checks will be conducted by isolating the transmitter from the differential pressure taps using valves built into the meter, and recording the transmitter output. The sensor output must read zero flow during these checks.

Procedures for performing these checks are documented in the Product Manual. All records will be logged in the following form.

(Continued)

Appendix B-4. Rosemount 3095 Sensor Function Checks/Log Form
(Continued)

SENSOR FUNCTION CHECKS

1) Analog Loop Test (Rosemount Mass Flowmeter Manual, pages 4 – 53)

Date ___________ Signature ____

24-hr Time ____________ ____________ ____________ ____________

Meter Output (mA) ____________ ____________ ____________ ____________

OVM Reading mA) ____________ ____________ ____________ ____________

% Difference (Must be within ± 2.2 %) ____________ ____________ ____________ ____________

Corrective Action/Notes ____

2) Analog Output to DAS Terminal

Date ___________ Signature ____

24-hr Time ___________ ___________

Meter Output (mA) ___________ ___________

DVM "raw data" reading at DAS terminal (mA) ___________ ___________

% Difference (Must be within ± 2.2 %) ___________ ___________

Corrective Action/Notes ____

CALIBRATION CHECKS

1) Bench Calibration

Date _______________ 24-hr Time _____________ Signature _________________________

Absolute Pressure Offset Trim Point (psi) ______________________

Absolute Pressure Slope Trim Point (psi) ______________________

Absolute Temperature Offset Trim Point (°F) ______________________

Absolute Temperature Slope Trim Point (°F) ______________________

Corrective Action/Notes ____

2) Zero Check

Date _______________ 24-hr Time _____________ Signature _________________________

Initial reading __________mA __________lbs/hr

Reading after adjustment __________mA __________lbs/hr
(should be zero, enter n/a if no adjustment)

Corrective Action/Notes ____

Appendix B-5. Ambient Monitor Installation, Setup, and Sensor Function Checks

INSTALLATION AND SETUP CHECKS:

Field installation procedures are detailed in the documentation provided for the integrated temperature/ humidity unit by Vaisala and for the pressure sensor by Setra and will not be discussed here. Center testing personnel will follow all required procedures to ensure that checks for appropriate installation locations, length of cable, process connections, leaks, field wiring and ground wiring are conducted properly, including:

1. All wires will not be located near motors, power supply cables, or other such electrically "noisy" equipment

2. No hand-held radios will be used near the instruments

In each of these sensors, the parameter monitored creates a small electrical change in capacitance or resistance which corresponds to the variation in the monitored parameter. This change is measured, amplified and converted by the electronics package associated with each sensor. Unless catastrophic damage (which should be visible) has occurred to the sensors, their accuracy at setup should correspond precisely to the initial factory calibration performed before shipping. Visual checks for damage both before and after installation will be performed, and appropriateness checks of the outputs will be performed at start-up.

The signal inputs are scaled and converted into the proper units and logged on the computer hard drive by the DAS. The GHG Center testing personnel will maintain field logs of all data entered into this program. An electronic copy of the configuration file will be maintained. Detailed guidelines are provided in the software Programming Manual.

Sensor function checks:

Analog output checks will be conducted a minimum of two times during the test. In this loop test, a current of known quantity will be checked against a secondary device to ensure that 4 mA and 20 mA signals are produced. Reasonableness checks will also be performed by ensuring that the signal produced at the transmitter is recorded correctly by the A/D module and the DAS computer.

Reasonableness checks will be performed by examining the ambient temperature, pressure, and relative humidity recorded by the test instruments with those reported by a hand held instrument (Table 3-3), or the nearest national Weather Station (Syracuse International Airport). If the airport data are used, ambient pressure readings at the site will be corrected for elevation. All suspect data will be flagged, and the measurement instruments will be examined for damage or failure.

Appendix B-6. Heat Exchanger RTD Performance Testing

The Controltron heat meter used at the test site to monitor heat recovery receives temperature signals from two resistance temperature devices (RTDs), mounted upstream and downstream of the heat recovery unit. The accuracy of the RTDs will be determined by comparing RTD signals to temperatures measured by the GHG Center using a calibrated Type K thermocouple. Prior to this evaluation, the thermocouple will be calibrated in the laboratory using an ice bath and boiling water at or near sea level conditions. A thermocouple that is determined to be accurate within 0.5 percent of reading or better will be used for the performance check. The performance check will be conducted once prior to the verification period using the procedures outlined below. Data will be recorded on field logs such as the example on the following page using the procedures outlined below.

Laboratory calibration of reference thermocouple (TC):

1. Insert TC into ice bath while stirring the bath. Record the stable reading in degrees Kelvin. Calculate the percent error as ((TC response (^oK))/273.15] * 100.
2. Insert TC into boiling water while stirring the bath. Record the stable reading in degrees Kelvin. Calculate the percent error as ((TC response (^oK))/373.15] * 100.
3. Use the higher of the two errors to determine if the TC accuracy is within 0.5% of reading.

Performance testing of Arigo RTDs:

1. Remove the two RTDs from the pipe and immerse in an ice-water bath.
2. Simultaneously immerse the reference thermocouple and, while stirring, obtain and record stable readings from the three devices.
3. Repeat the process in a hot-water bath.
4. Compare the RTD readings to the reference reading at each of the two calibration points. If the RTD readings differ by more than 1.8^oF, the RTDs should be submitted for recalibration.

(Continued)

Appendix B-6. Heat Exchanger RTD Performance Testing
(Continued)

Project: ______________________________ Date: ______________________

Inlet RTD ID: ____________________________ Ambient Temperature: __________

Outlet RTD ID: ___________________________ Signature: __________________

Reference TC ID: _________________________ Date of Reference Call: _________

Location: ____
(Laboratory calibration or field performance check)

Reference Temp (°F)		Inlet RTD Reading (°F)	Difference (°F)		Outlet RTD Reading (°F)	Difference (°F)

NOTES: ____

Appendix B-7. 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:** ________

Carbon copy: GHG Center Project Manager, GHG Center Director, SRI QA Manager, APPCD Project Officer

APPENDIX C
Example Test and Calibration Data

Appendix C-1. Example of Core Laboratories Gas Analysis Results

SENT BY:CORE LABORATORIES ; 7-25- 0 ; 3:42 ; HOUSTON PETROLEUM→ 919 606 2306;# 6/ 6

Core Lab

CORE LABORATORIES

EXAMPLE RPT

L A B O R A T O R Y T E S T S R E S U L T S

[redacted]

JOB NUMBER: [redacted] CUSTOMER: [redacted] ATTN: [redacted]

CLIENT I.D..........:
DATE SAMPLED.......:
TIME SAMPLED.......:
WORK DESCRIPTION...:

LABORATORY I.D...:
DATE RECEIVED....:
TIME RECEIVED....:
REMARKS..........:

TEST DESCRIPTION	FINAL RESULT	LIMITS/*DILUTION	UNITS OF MEASURE	TEST METHOD	DATE	TECHN
Natural Gas Analysis		*1		ASTM D-1945	[redacted]	
Oxygen	0.06	0.01	Mol %	ASTM D-1945		
Nitrogen	0.80	0.01	Mol %	ASTM D-1945		
Carbon Dioxide	12.03	0.01	Mol %	ASTM D-1945		
Methane	79.42	0.01	Mol %	ASTM D-1945		
Ethane	5.30	0.01	Mol %	ASTM D-1945		
Propane	1.81	0.01	Mol %	ASTM D-1945		
Isobutane	0.12	0.01	Mol %	ASTM D-1945		
n-Butane	0.20	0.01	Mol %	ASTM D-1945		
Isopentane	0.02	0.01	Mol %	ASTM D-1945		
n-Pentane	0.09	0.01	Mol %	ASTM D-1945		
Hexanes Plus	0.05	0.01	Mol %	ASTM D-1945		
Total	100.00	0.01	Mol %			
Relative Density	0.72728	0		ASTM D-3588		
Compressibility Factor	0.99721	0		ASTM D-3588		
Gross Heating Value (Dry)	963.0	0	BTU/CF (Real)	ASTM D-3588		
Pressure Base	14.696	0	psia			
Sample Collection Pressure	596.4	1	psi	Field		
Sample Collection Temperature	59.53	1	Deg. F.	Field		

Note: Both high and low (gross and net) H.V. can be reported as required

P O BOX 34766
HOUSTON, TX 77234-4282
(713) 943-9776

PAGE: 1

[illegible]

Appendix C-2. Example of Core Laboratories Calibration Data

LCN 3619

Sheet1

24-Jul	TRUE	MEAS	NORMAL	'[A-B]	%DIFF	ALLOWED	OK
HELIUM	0.546	0.546	0.546	0.000		N/A	NOT OK
OXYGEN	0.001	0	0.000	0.001			
NITROGEN	4.93	4.93	4.930	0.000	0.0	2.0	OK
METHANE	70.414	70.414	70.413	0.001	0.0	0.2	OK
CO2	0.997	0.997	0.997	0.000	0.0	3.0	OK
ETHANE	9.009	9.008	9.008	0.001	0.0	1.0	OK
PROPANE	6.085	6.085	6.085	0.000	0.0	1.0	OK
ISOBUTANE	3.02	3.02	3.020	0.000	0.0	2.0	OK
N-BUTANE	2.992	2.992	2.992	0.000	0.0	2.0	OK
ISOPENTANE	1.005	1.005	1.005	0.000	0.0	3.0	OK
N-PENTANE	1.004	1.004	1.004	0.000	0.0	3.0	OK
	100.003	100.001	100.000				

Natural Gas Std

Analyzed weekly as a Continuing Calibration (CCV) verification check. Instrument is recalibrated if outside acceptance limits

Page 1

Appendix C-3. Example of Exhaust Stack Emission Rate Results

Example Summary of Results
Turbine Generator

Company: XYZ
Plant: Power Prodcution Facility
Location: Florida
Technicians: LJB, RPO, DLD
Source: a Solar Centaur T-4500 Gas Turbine Generator Set

Test Number	1C-1	1C-2	1C-3	
Date	xx/xx/xx	xx/xx/xx	xx/xx	
Start Time	xx:xx	xx:xx	xx:xx	
Stop Time	xx:xx	xx:xx	xx:xx	
Power Turbine Operation				*Averages*
Generator Output (kW, kilowatts)	2820	2830	2820	*2823*
Percent Load (% of mfg.'s rated capacity of 2970 kW)	94.9	95.3	94.9	*95.1*
Ammeter (AC Amperes)	386	386	390	*387*
Voltmeter (AC Volts)	437	433	433	*434*
Frequency Meter (Hz, herz)	60.4	60.4	60.4	*60.4*
Power Factor Meter (Below 100 is lag)	96.4	96.6	96.4	*96.5*
Engine Speed (%, NGP)	100.2	100.1	100.1	*100.1*
Engine Compressor Discharge Pressure (psia, PCD)	130.0	129.5	130.0	*129.8*
Mean Turbine Exhaust Temperature (°F, T-5)	1161	1160	1160	*1160*
Turbine Fuel Data (Landfill Gas)				
Fuel Heating Value (Btu/SCF, HHV)	631.6	631.6	631.6	*631.6*
Fuel Specific Gravity	0.8817	0.8817	0.8817	*0.8817*
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	9150	9150	9150	*9150*
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1501	1501	1501	*1501*
Fuel Flow (scfm, landfill gas)	1167.2	1164.3	1164.8	*1165.4*
Heat Input (MMBtu/hr, Higher Heat Value)	44.23	44.12	44.14	*44.17*
Heat Input (MMBtu/hr, Lower Heat Value)	39.8	39.7	39.7	*39.7*
Brake-specific Fuel Consumption (Btu/kW-hr)	14,117	14,032	14,088	*14,079*
Ambient Conditions				
Atmospheric Pressure ("Hg)	29.93	29.93	29.89	*29.92*
Temperature (°F): Dry bulb	83.4	83.1	80.1	*82.2*
(°F): Wet bulb	69.9	69.9	69.0	*69.6*
Humidity (lbs moisture/lb of air)	0.0122	0.0123	0.0123	*0.0123*
Measured Emissions				
NO_X (ppmv, dry basis)	31.03	31.15	31.28	*31.15*
NO_X (ppmv, dry @ 15% O_2)	46.1	47.2	46.3	*46.5*
SO_2 (ppmv, dry basis via EPA Method 6c)	1.10	1.13	1.28	*1.17*
SO_2 (ppmv, dry @ 15% O_2)	1.63	1.71	1.89	*1.75*
CO (ppmv, dry basis)	9.94	9.80	9.81	*9.85*
THC (ppmv, wet basis)	1.62	1.63	1.75	*1.67*
Visible Emissions (% opacity)		0		*0*
H_2O (% volume, from Method 4 sample train)	5.55	5.37	5.30	*5.41*
O_2 (% volume, dry basis)	16.93	17.01	16.91	*16.95*
CO_2 (% volume, dry basis)	3.26	3.29	3.25	*3.27*
Stack Volumetric Flow Rates				
via EPA Method 2, pitot tube (SCFH, dry basis)	2.17E+06	2.12E+06	2.22E+06	*2.17E+06*
via O_2 "F_d-factor" (SCFH, dry basis)	2.13E+06	2.17E+06	2.12E+06	*2.14E+06*
via CO_2 "F_c-factor" (SCFH, dry basis)	2.04E+06	2.01E+06	2.04E+06	*2.03E+06*
Calculated Emission Rates (via M-19 O_2 "F-factor")				
NO_X (lbs/hr)	8.05	7.90	8.29	*8.08*
CO (lbs/hr)	1.57	1.51	1.58	*1.56*
THC (lbs/hr)	0.16	0.15	0.17	*0.16*
SO_2 (lbs/hr)	0.40	0.40	0.47	*0.42*
NO_X (tons/yr)	35.3	34.6	36.3	*35.4*
CO (tons/yr)	6.88	6.63	6.93	*6.82*
THC (tons/yr)	0.68	0.00	0.75	*0.48*
SO_2 (tons/yr)	1.74	1.75	2.07	*1.85*

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida

Appendix C-4. Example of Exhaust Stack Raw Emission Measurements Data

Unit R-2, Logged Data Records

Run Number	Date	Time	NO_x	O_2	CO_2	AVE NO_x	AVE O_2	AVE CO_2
			(ppmv)	(% vol)	(% vol)	(ppmv)	(% vol)	(% vol)
START Run 2C-3	4/10/2000	1:51:57 PM	8.22	16.41	2.58	8.22	16.41	2.58
Run 2C-3	4/10/2000	1:52:57 PM	8.22	16.42	2.60	8.22	16.41	2.59
Run 2C-3	4/10/2000	1:53:57 PM	8.10	16.42	2.58	8.18	16.41	2.59
Run 2C-3	4/10/2000	1:54:57 PM	8.22	16.43	2.56	8.19	16.42	2.58
Run 2C-3	4/10/2000	1:55:57 PM	8.26	16.43	2.56	8.21	16.42	2.58
Run 2C-3	4/10/2000	1:56:57 PM	8.09	16.38	2.58	8.19	16.41	2.58
Run 2C-3	4/10/2000	1:57:57 PM	8.17	16.39	2.59	8.18	16.41	2.58
Run 2C-3	4/10/2000	1:58:57 PM	8.24	16.30	2.64	8.19	16.40	2.59
Run 2C-3	4/10/2000	1:59:57 PM	8.30	16.31	2.62	8.20	16.39	2.59
Run 2C-3	4/10/2000	2:00:57 PM	9.68	16.08	2.75	8.35	16.35	2.61
Run 2C-3	4/10/2000	2:01:56 PM	9.41	16.07	2.74	8.45	16.33	2.62
Run 2C-3	4/10/2000	2:02:56 PM	10.38	16.07	2.74	8.61	16.31	2.63
Run 2C-3	4/10/2000	2:03:56 PM	10.29	16.07	2.74	8.74	16.29	2.64
Run 2C-3	4/10/2000	2:04:56 PM	10.68	16.11	2.72	8.88	16.28	2.64
Run 2C-3	4/10/2000	2:05:56 PM	11.11	16.11	2.72	9.02	16.27	2.65
Run 2C-3	4/10/2000	2:06:56 PM	11.53	16.15	2.71	9.18	16.26	2.65
END Run 2C-3	4/10/2000	2:07:56 PM	11.87	16.15	2.71	**9.34**	**16.25**	**2.65**
START Run 2C-4	4/10/2000	2:17:36 PM	15.32	16.07	2.79	15.32	16.07	2.79
Run 2C-4	4/10/2000	2:18:36 PM	14.96	16.09	2.83	15.14	16.08	2.81
Run 2C-4	4/10/2000	2:19:36 PM	15.01	16.09	2.83	15.10	16.09	2.82
Run 2C-4	4/10/2000	2:20:36 PM	14.58	16.09	2.85	14.97	16.09	2.82
Run 2C-4	4/10/2000	2:21:36 PM	14.46	16.09	2.86	14.87	16.09	2.83
Run 2C-4	4/10/2000	2:22:36 PM	13.85	16.11	2.84	14.70	16.09	2.83
Run 2C-4	4/10/2000	2:23:36 PM	13.65	16.11	2.83	14.55	16.09	2.83
Run 2C-4	4/10/2000	2:24:36 PM	13.08	16.16	2.80	14.36	16.10	2.83
Run 2C-4	4/10/2000	2:25:36 PM	12.95	16.17	2.79	14.21	16.11	2.83
Run 2C-4	4/10/2000	2:26:36 PM	12.54	16.24	2.76	14.04	16.12	2.82
Run 2C-4	4/10/2000	2:27:36 PM	12.27	16.25	2.76	13.88	16.14	2.81
Run 2C-4	4/10/2000	2:28:36 PM	12.42	16.31	2.73	13.76	16.15	2.81
Run 2C-4	4/10/2000	2:29:36 PM	12.18	16.32	2.74	13.64	16.16	2.80
Run 2C-4	4/10/2000	2:30:36 PM	12.38	16.37	2.70	13.55	16.18	2.79
Run 2C-4	4/10/2000	2:31:36 PM	12.33	16.37	2.73	13.46	16.19	2.79
Run 2C-4	4/10/2000	2:32:36 PM	12.50	16.41	2.70	13.40	16.20	2.79
END Run 2C-4	4/10/2000	2:33:35 PM	12.29	16.41	2.69	**13.34**	**16.22**	**2.78**
START Run 2C-5	4/10/2000	2:42:03 PM	12.46	16.40	2.74	12.46	16.40	2.74
Run 2C-5	4/10/2000	2:43:03 PM	12.16	16.40	2.76	12.31	16.40	2.75
Run 2C-5	4/10/2000	2:44:04 PM	12.35	16.41	2.75	12.33	16.40	2.75
Run 2C-5	4/10/2000	2:45:03 PM	12.38	16.37	2.77	12.34	16.40	2.75
Run 2C-5	4/10/2000	2:46:03 PM	12.30	16.37	2.77	12.33	16.39	2.76
Run 2C-5	4/10/2000	2:47:03 PM	12.45	16.34	2.77	12.35	16.38	2.76
Run 2C-5	4/10/2000	2:48:03 PM	12.43	16.34	2.76	12.36	16.37	2.76
Run 2C-5	4/10/2000	2:49:03 PM	12.76	16.29	2.79	12.41	16.36	2.76
Run 2C-5	4/10/2000	2:50:03 PM	12.27	16.29	2.77	12.40	16.36	2.76
Run 2C-5	4/10/2000	2:51:03 PM	13.47	16.21	2.80	12.50	16.34	2.77
Run 2C-5	4/10/2000	2:52:03 PM	13.47	16.20	2.78	12.59	16.33	2.77
Run 2C-5	4/10/2000	2:53:03 PM	14.57	16.16	2.92	12.76	16.31	2.78
Run 2C-5	4/10/2000	2:54:03 PM	14.43	16.14	2.81	12.89	16.30	2.78
Run 2C-5	4/10/2000	2:55:03 PM	14.62	16.14	2.82	13.01	16.29	2.79
Run 2C-5	4/10/2000	2:56:03 PM	14.59	16.15	2.80	13.11	16.28	2.79
Run 2C-5	4/10/2000	2:57:03 PM	14.84	16.16	2.79	13.22	16.27	2.79
END Run 2C-5	4/10/2000	2:58:03 PM	15.35	16.17	2.79	**13.35**	**16.27**	**2.79**

Appendix C-5. Example of Exhaust Stack Emission Measurements Calibration Data

Unit R-2, Logged QA Calibration Records

Run 2C-3 4/10/2000 1:51:56 PM 2:07:56 PM

Initial Linearity Test	Zero	Low	Mid	Span	L-Lin	M-Lin	S-Lin
NOx (ppmv)	0	13.57	45.92	23.52	0.22	-0.84	-0.06
O2 (%)	0.09	4.64	12.03	20.68	-0.69	-0.07	0.47
CO2 (%)	0	8.01	12.45	4.57	-0.14	0.55	-0.34

Initial and Final Bias and Drift	I-Zero	I-Span	F-Zero	F-Span	Z-Bias	S-Bias	Z-Drift	S-Drift
NOx (ppmv)	0.08	24.14	0.07	24.34	0.14	1.64	0.02	-0.4
O2 (%)	0.25	20.83	0.24	20.84	0.58	0.63	0.06	-0.03
CO2 (%)	-0.15	4.28	-0.24	4.23	-1.63	-2.3	0.64	0.36

Run Results and Cal Gases Used	Raw	Corrected	Ranges	Low Gas	Mid Gas	Span Gas
NOx (ppmv)	9.34	9.01	50	13.68	45.5	23.49
O2 (%)	16.25	16.17	25	4.47	12.01	20.8
CO2 (%)	2.65	2.89	15	7.99	12.53	4.52

Run 2C-4 4/10/2000 2:17:35 PM 2:33:35 PM

Initial Linearity Test	Zero	Low	Mid	Span	L-Lin	M-Lin	S-Lin
NOx (ppmv)	0	13.57	45.92	23.52	0.22	-0.84	-0.06
O2 (%)	0.09	4.64	12.03	20.68	-0.69	-0.07	0.47
CO2 (%)	0	8.01	12.45	4.57	-0.14	0.55	-0.34

Initial and Final Bias and Drift	I-Zero	I-Span	F-Zero	F-Span	Z-Bias	S-Bias	Z-Drift	S-Drift
NOx (ppmv)	0.07	24.34	0.09	24.45	0.18	1.86	-0.04	-0.22
O2 (%)	0.24	20.84	0.28	20.89	0.75	0.81	-0.17	-0.18
CO2 (%)	-0.24	4.23	-0.15	4.35	-1.03	-1.44	-0.6	-0.86

Run Results and Cal Gases Used	Raw	Corrected	Ranges	Low Gas	Mid Gas	Span Gas
NOx (ppmv)	13.34	12.81	50	13.68	45.5	23.49
O2 (%)	16.22	16.11	25	4.47	12.01	20.8
CO2 (%)	2.78	3.00	15	7.99	12.53	4.52

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida R2-2

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