SRI/USEPA-GHG-VR-10
September 2001

Environmental Technology Verification Report

Honeywell Power Systems, Inc.
Parallon® 75 kW Turbogenerator

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

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

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

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The Greenhouse Gas Technology Center wishes to thank the following staff of the University of Maryland, College Park - Center for Environmental Energy Engineering (CEEE) for their service in hosting this test: Predrag Popovic, Aris Marantan, Eric Griff, and Werner Wongsosaputro. The CEEE group operated the microturbine and provided technical support during the installation and shakedown of the technology, installed the GHG Center's metering equipment, and provided key station operating data. Thanks are also extended to the members of the GHG Center's Electricity Generation Stakeholder Group and Distributed Generation Technical Panel for reviewing and providing input on the testing strategy and this Verification Report. The GHG Center also wishes to acknowledge the technical support provided by Todd Kollross and Ted Bronson of the Gas Technology Institute.

ACRONYMS/ABBREVIATIONS

acf	actual cubic feet
BCHP	Building Combined Heat and Power
Btu/ft^3	British thermal units per cubic foot
Btu/hr	British thermal units per hour
CEEE	University of MD, College Park - Center for Environmental Energy Engineering
CEM	Continuous Emissions Monitoring
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DG	distributed generation
DP	differential pressure
DQI	data quality indicator
DQO	data quality objective
dscf/MMBtu	dry standard cubic feet per million British thermal units
EGRID	Emissions and Generation Resource Integrated Database
EPA	Environmental Protection Agency
ETV	Environmental Technology Verification
^oF	degrees Fahrenheit
FID	flame ionization detector
ft^2	square feet
ft^3/min	cubic feet per minute
gal	U.S. Imperial gallons
GC	gas chromatograph
GHGs	greenhouse gases
GHG Center	Greenhouse Gas Technology Center
HI	heat input, Btu/hr
Honeywell	Honeywell Power Systems, Inc.
hr	hours
HVAC	heating, ventilation, and air conditioning
Hz	hertz
in.	inches
ISO	International Standards Organization
kW	kilowatts
kWh	kilowatt hours
lb	pounds
lb/dscf	pounds per dry standard cubic foot
lb/hr	pounds per hour
lb/kWh	pounds per kilowatt-hour
LHV	lower heating value
mL	milliliters
N_2	nitrogen
NDIR	nondispersive infrared spectroscopy
NIST	National Institute for Standards and Technology
NO	nitrogen oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

O_2	oxygen
O_3	ozone
ORD	Office of Research and Development
PEPCO	Potomac Electric Power Company
Pf	power factor
ppm	parts per million
ppmvd	parts per million volume dry
psia	pounds per square inch absolute
psig	pounds per square inch gauge
QA/QC	Quality Assurance/Quality Control
QMP	Quality Management Plan
RH	relative humidity
RTD	resistance temperature detector
SCADA	Supervisory Control and Data Acquisition system
scfm	standard cubic feet per minute
SO_2	sulfur dioxide
SRI	Southern Research Institute
Test Plan	Test and Quality Assurance Plan
THCs	total hydrocarbons
THDs	total harmonic distortions
Turbogenerator	Parallon® 75 kW Turbogenerator
VAC	volts alternating current
VOCs	volatile organic compounds

1.0 INTRODUCTION

1.1. BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates a program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of the Environmental Technology Verification (ETV) program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. ETV is funded by Congress 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 ETV, 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 several verification organizations operating under ETV. The GHG Center is managed by the U.S. 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 test data, obtaining independent peer review input, and reporting findings. Performance evaluations are conducted according to externally reviewed Verification Test and Quality Assurance Test Plans (Test Plans) 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 Verification Reports. The GHG Center's stakeholder groups consist of national and international experts in the areas of climate science and environmental policy, technology, and regulation. Members include industry trade organizations, technology purchasers, environmental technology finance groups, governmental organizations, and other interested groups. In certain cases, industry-specific stakeholder groups and technical panels are assembled for technology areas where specific expertise is needed. The GHG Center's Electricity Generation Stakeholder Group and a specially formed Distributed Generation (DG) Technical Panel offer advice on next-generation power technologies where independent performance testing is needed. They also assist in selecting verification factors and provide guidance to ensure that the performance evaluation is based on recognized and reliable field measurement and data analysis procedures.

One technology of interest to the GHG Center's stakeholders is microturbines as a distributed energy source. DG generally refers to power generation equipment, typically in the range of 5 to 1000 kilowatts (kW) power output, that provide electricity at a site closer to customers than a central power station. A distributed power unit can be connected directly to the customer's source, and/or to a utility's transmission and distribution system. These technologies provide customers one or more of the following main services: stand-by generation, peak shaving capability (generation during expensive high demand periods), baseload generation (constant generation), or cogeneration (combined heat and power generation). Examples of technologies available for DG include gas turbine generators, internal combustion engine generators (e.g., gas, diesel), photovoltaics, wind turbines, fuel cells, and microturbines.

To pursue independent performance verification testing of microturbines, the GHG Center placed formal announcements in the Commerce Business Daily and industry trade journals, and invited vendors of commercial products to participate in independent testing. Honeywell Power Systems, Inc. (Honeywell) committed to participate in the independent verification of their microturbine. The technology is referred to as the Parallon® 75 kW Turbogenerator (Turbogenerator). The Turbogenerator is designed to produce electric power in stand-alone and grid-connected applications or isolated modes. When the unit is connected to the utility grid, it supplies electrical power to the facility where it is installed, or to the grid at large, during periods when its generation exceeds the needs of the facility. When configured to operate isolated, the Turbogenerator supplies electricity to specific equipment dedicated to consume the power generated.

A comprehensive performance evaluation of the Turbogenerator was carried out by the GHG Center at a commercial office building at the University of Maryland, College Park. The University's Center for Environmental Energy Engineering (CEEE) has established a test facility at this building to evaluate distributed energy conversion systems and HVAC systems for buildings in cooperation with private industry and government groups. Testing began in December 2000 and continued through April 2001. The Turbogenerator is one of the first systems to be tested, and remains in operation at the facility. It is connected to the University's electric grid system, and provides about 30 percent of the building's electricity requirements.

Details on the verification test design, measurement test procedures, and Quality Assurance/Quality Control (QA/QC) procedures can be found in the Test Plan titled *Testing and Quality Assurance Plan for the Honeywell Power Systems, Inc. Parallon® 75 kW Turbogenerator* (SRI 2000). It can be downloaded from the GHG Center's Web site (www.sri-rtp.com). The Test Plan describes the rationale for the experimental design, the testing and instrument calibration procedures planned for use, and specific QA/QC goals and procedures. The Test Plan was reviewed and revised based on comments received from Honeywell, CEEE, selected members of the GHG Center's stakeholder groups, and the EPA Quality Assurance Team. The Test Plan meets the requirements of the GHG Center's Quality Management Plan (QMP), and thereby satisfies ETV QMP requirements. In some cases, deviations from the Test Plan were required. These deviations, and the alternative procedures selected for use, are discussed in this report.

The remaining discussion in this section lists the performance verification parameters, describes the Turbogenerator technology, presents the operating schedule of the test facility, and lists the performance verification parameters that were quantified. Section 2 presents the verification test results, and Section 3 assesses the quality of the data obtained. Section 4, provided by Honeywell, provides additional information regarding the Turbogenerator. Information provided in Section 4 has not been independently verified by the GHG Center.

1.2. PARALLON 75 KW TURBOGENERATOR DESCRIPTION

Large- and medium-scale gas-fired turbines have been used to generate electricity since the 1950s. Recently, medium-scale turbines have become a source of additional generation capacity because of their ability to provide electricity at the point of use. Technical and manufacturing developments have occurred in the last decade that have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW. The Turbogenerator represents a new generation of compact natural-gas-fired microturbine with the capability to produce a nominal 75 kW of 3-phase electricity at 275 volts alternating current (VAC).

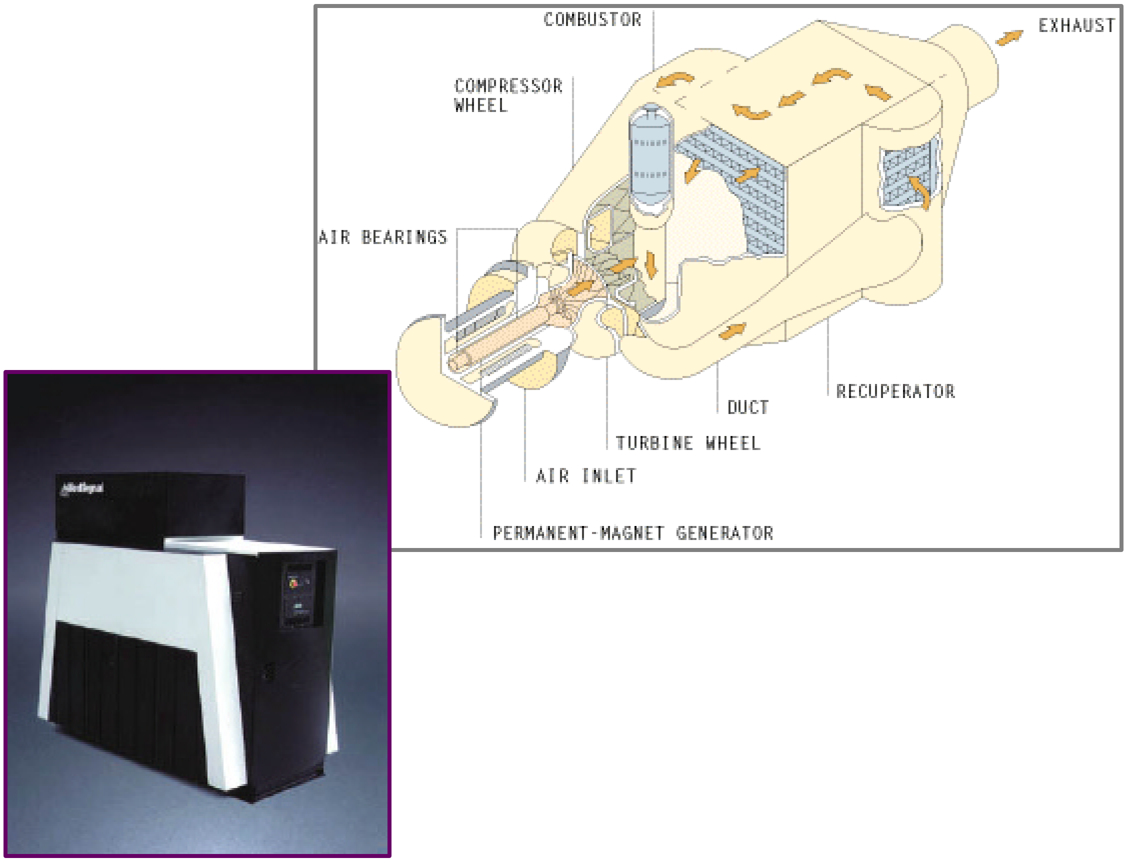
The Turbogenerator operates on natural gas at a fuel pressure ranging from 75 to 125 psig. An optional booster compressor is offered which allows low-pressure natural gas to be pressurized to these operating conditions. Table 1-1 summarizes the physical and electrical specifications supplied by Honeywell for the unit tested. The Turbogenerator is marketed both as an alternative electrical generation source and as a source of backup power. The standard Turbogenerator comes from the factory outfitted with hardware to allow it to be connected to the grid. A stand-alone or isolated configuration requires an optional "black start" battery to provide starting current to the power system.

The Turbogenerator is comprised of two main sections: an engine section and an electrical section (Figure 1-1). In the engine section, filtered air enters the compressor, where the air is pressurized. It then enters the recuperator, which is a heat exchanger that adds heat to the compressed air using exhaust heat. The air then enters the combustor where it is mixed with fuel and heated further by combustion. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine shaft to turn the generator shaft which produces electricity. The compressor is mounted on the same shaft as the electrical generator, and consists of only one rotating part. Because of the inverter-based electronics that enable the generator to operate at high speeds and frequencies, the need for a gearbox and associated moving parts is eliminated. The high-speed rotating shaft is supported by air-foil bearings, and does not require lubrication, as compared to the oil-lubricated bearings used in other designs. 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 with sufficient heat energy for cogeneration applications or, alternatively, for release to the atmosphere.

Table 1-1. Turbogenerator Physical and Electrical Specifications
(Source: Honeywell Power Systems, Inc.)

Dimensions	Width Length Height	48.0 in. 91.9 in. 93.4 in.
Weight	Standard Power System Black Start Module (optional) Natural Gas Compressor (optional, installed on test unit) 120/208 Autotransformer	< 3,000 lbs (excluding options) 475 lb 350 lb 326 lb
Electrical Inputs	Power (startup) Communications	Utility Grid or Black Start Battery (optional) SCADA (optional)
Electrical Outputs	Power Communications	275 VAC, 50/60 Hz SCADA (optional)
External Transformers Available	United States	120/240 VAC ± 15 % (Delta), 57- 63 Hz 277/480 VAC ± 15 % (Wye), 57 - 63 Hz
	Canada	346/600 VAC ± 15 % (Wye), 57 - 63 Hz
	Korea	220/380 VAC ± 15 % (Wye), 57 - 63 Hz
	China	220/380 VAC ± 15 % (Wye), 47 - 53 Hz
	Europe	230/400 VAC ± 15 % (Wye), 47 - 53 Hz
	India	239/415 VAC ± 15 % (Wye), 47 - 53 Hz
	Africa	300/520 VAC ± 15 % (Wye), 47 - 53 Hz
Inlet Air Required	Core Engine	1220 scfm
Fuel Pressure Required	W/o Natural Gas Compressor W/ Natural Gas Compressor (optional)	75 to 125 psig 15 to 30 psia
Fuel Flow Rate for Standard Unit	Steady State Full Power, ISO Condition	44.5 lb/hr or 16.44 scfm

Figure 1-1. Honeywell Parallon® 75 kW Turbogenerator



The permanent-magnet generator produces high-frequency alternating current which is rectified, inverted, and filtered by the line power unit into conditioned alternating current at 275 volts. This can be converted to the voltage level required by the facility using either an optional internal transformer (120/208 VAC) or external transformers (see Table 1-1 for complete listing) for distribution. The unit supplies a variable electrical frequency of 50 or 60 hertz (Hz). The Turbogenerator is supplied with a control system that allows for automatic and unattended operation. All operations, including startup, synchronization with the grid, dispatch, and shutdown, can be performed manually or remotely using an optional Supervisory Control and Data Acquisition (SCADA) system.

Installation requires a suitable location and connection to a natural gas supply line and electrical power lines. For a typical grid-interconnected installation, the Turbogenerator requires a firm, level base (concrete pad, steel rails, or other suitable supports) in a dry area with good air circulation and room for maintenance access. The Turbogenerator is anchored to the base consistent with local codes, and is connected to a natural gas supply line with an external shutoff valve. If the internal transformer is used, the power output can be connected to the main circuit breaker at the facility. Otherwise, the power output is connected to an external transformer (supplied by Honeywell as optional equipment) which is then connected to the facility's power system.

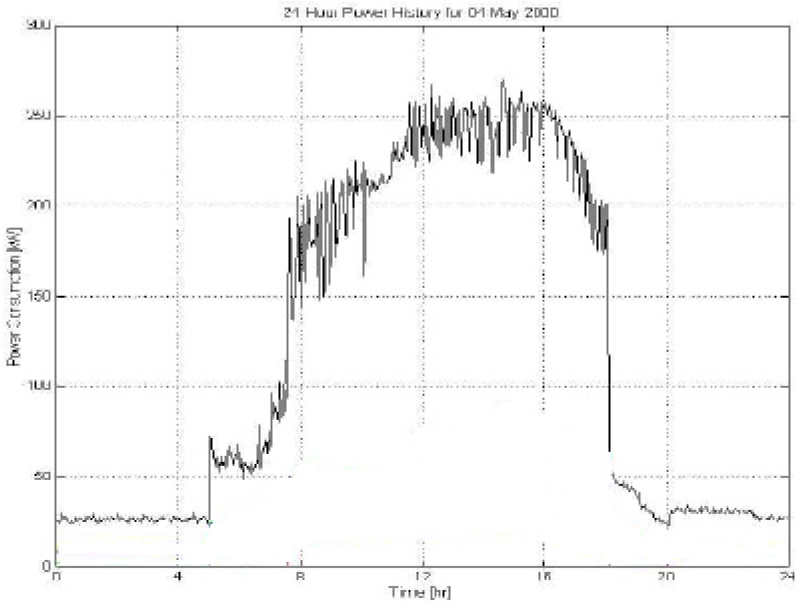
1.3. TEST FACILITY DESCRIPTION

The BCHP test facility consists of a 55,000 ft^2 building that has been converted into a research and demonstration facility. It has been developed to optimize the integration of DG technologies and to demonstrate the benefits and implementation issues to the engineering community, equipment manufacturers, and building owners. CEEE projects are executed in collaboration with the U.S. Department of Energy - Oak Ridge National Laboratory, ETV, and industry partners (e.g., ATS Engineering, Broad, Baltimore Gas and Electric, Potomac Electric Power Company - PEPCO, Washington Gas, Electric Power Research Institute). Installation and operation of the Turbogenerator is one of the first series of DG projects undertaken by CEEE. The Turbogenerator at this test facility is shown in Figure 1-2.

Figure 1-2. The Turbogenerator at the College Park BCHP Test Facility

The Turbogenerator is installed to reduce grid electrical consumption at the test facility. The facility has a peak electrical load of approximately 275 kW, with 65 to 75 percent electricity consumed by HVAC equipment, and the rest used for lighting, convenience outlets, office machines (e.g., computers, fax), and others (e.g., vending machines). Figure 1-3 illustrates a daily profile of the electricity consumed at the facility. The highest electricity consumption occurs when the building is fully occupied, between 9:00am and 5:00pm. During these periods, the Turbogenerator operates at full capacity, and is programmed to produce full power (about 75 kW). Electrical demand in excess of the capacity of the unit is automatically supplied by the grid. During hours surrounding the building's high occupancy periods, the Turbogenerator remains down.

Figure 1-3. Typical Daily Power Consumption Profile



The Turbogenerator and transformer are located outside the building on a concrete pad. Natural gas is supplied to the building and the Turbogenerator at about 2 psig (17 psia) fuel pressure, which is within the 15 to 30 psia (Table 1-1) range required by the optional booster compressor. The booster compressor increases the gas pressure to about 75 psig, so it can be fed to the turbine for combustion. The compressor is powered directly by the 275 VAC primary output from the generator. An external transformer is added to convert the 275 VAC output from the Turbogenerator inverter to the 480 VAC required by the facility. To facilitate remote operation, analysis, and optimization of the Turbogenerator operation, the optional SCADA system has also been installed.

During verification, the Turbogenerator's performance was monitored using a dedicated desktop computer where the data from continuously monitored verification meters were collected and compiled. These data and the turbine operating data, continuously logged by the SCADA system, were downloaded and analyzed on a weekly basis. The data were also accessible through the facility's network so they could be readily available to facility personnel for operational purposes.

1.4. OVERVIEW OF VERIFICATION PARAMETERS AND EVALUATION STRATEGIES

The Turbogenerator was operated between 9:00am and 5:00pm each day, and was set to produce maximum power during these periods. The verification test occurred while the Turbogenerator was operating during these time periods. The verification strategy consisted of a series of short periods of "load testing," in which the GHG Center intentionally modulated the unit to produce electricity at 50, 75, 90, and 100 percent of rated capacity. During these load tests, electric power output, fuel consumption, ambient meteorological conditions, and exhaust emissions were monitored simultaneously. Fuel samples were collected to enable natural gas heating value determination. Average electrical power output, electrical energy conversion efficiency, exhaust stack emission rates, and emission reductions are verified for each operating load.

Following the load tests, daily performance of the Turbogenerator was characterized as it cycled through its weekday schedule of operation. During a 6-week extended test period, the GHG Center monitored and recorded electric power output, fuel consumption, ambient meteorological conditions, power quality output (Turbogenerator and the site), and operational performance. The results from the extended tests are reported as total electrical energy generated, power quality, and operational availability.

The specific verification factors associated with the testing are listed below, followed by a discussion of each verification factor and its method of determination. Detailed descriptions of testing and analysis methods are not provided here, but can be found in the Test Plan.

Electric Power Production Performance

- Power output and electrical efficiency at selected loads
- Total electrical energy generated

Power Quality Performance

- Electrical frequency
- Voltage output and voltage transients
- Voltage and current total harmonic distortion (THD)
- Power factor

Operational Performance

- Cold-start time
- Number of successful and unsuccessful starts
- Operational availability

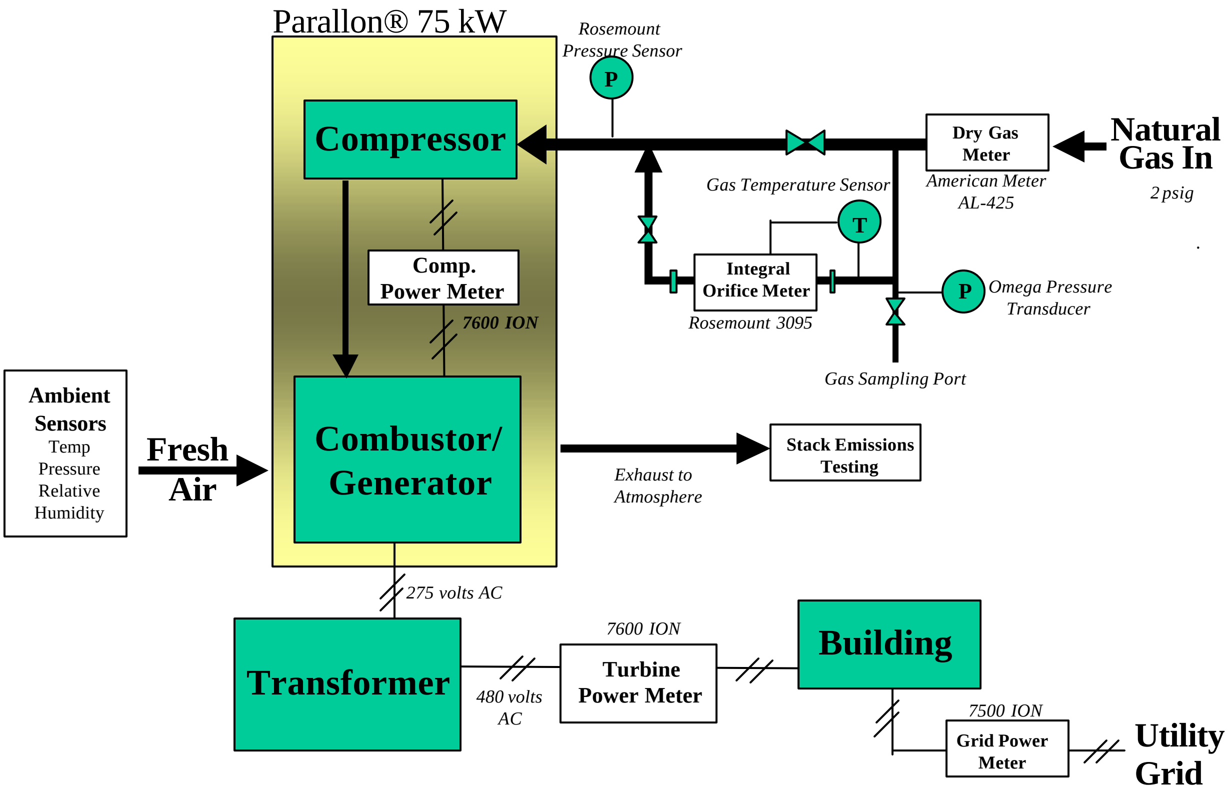
Emissions Performance

- Nitrogen oxides (NO_X) concentrations and emission rates
- Carbon monoxide (CO) concentrations and emission rates
- Total hydrocarbon (THC) concentrations and emission rates
- Carbon dioxide (CO_2) and methane (CH_4) concentrations and emission rates
- Greenhouse gas (GHG) and NO_X emission reduction estimates

1.4.1. Electric Power Production Performance

Power production performance is an operating characteristic of microturbines that is of great interest to purchasers, operators, and users of electricity generating systems. The electrical efficiency determination strategy was based upon guidelines listed in ASME PTC22, which require test runs of 4 to 30 minutes in duration at constant operating load settings (ASME 1997). Electrical efficiency was calculated using directly measured average power output, average fuel flow rate, and fuel lower heating value (LHV). The electrical power output in kW was measured with a 7600 ION Power Meter (Power Measurements Ltd.). Fuel input was determined using an in-line orifice type flow meter (Rosemount, Inc.), and a diaphragm-type gas meter. Fuel gas sampling and energy content analysis (via gas chromatograph) were conducted to determine the LHV of natural gas. Ambient temperature, relative humidity (RH), and barometric pressure were measured near the turbine inlet air to support determination of electrical conversion efficiency as required in PTC22. Figure 1-4 illustrates the measurement equipment used in the verification. Energy to electricity conversion efficiency was computed by dividing the average electrical energy output by the average energy input using Equation 1 (per ASME PTC22).

Figure 1-4. Schematic of Measurement System



$$h = \frac{3412.14\ kW}{HI} \qquad (Eqn. 1)$$

where :

h = *efficiency (%)*

kW = *average electrical power output (kW)*

HI = *average heat input (Btu/hr); determined by multiplying the average mass flow rate of natural gas to the turbine (scfm) times the natural gas LHV (Btu/std ft^3) times 60 (min/hr)*

The 7600 ION electrical power meter continuously monitored the kW of real power at a rate of one reading per minute. These readings recorded power output for the last complete cycle during each minute. The electric meter was located after the optional 480 volt transformer, and represented power delivered to the tenants occupying the test facility. The real-time data collected by the 7600 ION were downloaded and stored on the BCHP data acquisition computer using Power Measurements' PEGASYS software. The logged kW readings were averaged over the duration of the load test periods (30 minutes) to compute electrical efficiency. For the extended test period, kW readings are integrated over the duration of the verification period to calculate total electrical energy generated in kilowatt hours (kWh).

During load testing, natural gas samples were collected and analyzed to determine gas composition and heating value. At least one gas sample was collected in a 500 milliliter (mL) evacuated stainless steel canister during each load condition. This sampling interval was selected based on pre-test sampling and analysis, which showed that heating value does not change significantly at the test facility. Replicate samples were collected every third sample to quantify potential errors introduced by manual gas sampling and analysis. The collected samples were returned to a certified laboratory (Core Laboratories, Inc. of Houston, Texas - ISO 9002 Certification Number 31012) for compositional analysis in accordance with ASTM Specification D1945 for quantification of methane (C1) to hexanes plus (C6+), nitrogen, oxygen, and carbon dioxide (ASTM 2001a). The compositional data were then used in conjunction with ASTM Specification D3588 to calculate the high and low heat values, and the relative density of the gas (ASTM 2001b). Duplicate analyses were performed by the laboratory to determine the repeatability of the LHV results.

The mass flow rate of the fuel supplied to the Turbogenerator was measured using an integral orifice meter (Rosemount Model 3095/1195) and a dry gas meter in series. As shown in Figure 1-4, the two meters were installed in series to allow natural gas to flow through both meters while the turbine was operating. This configuration allowed independent performance checks to be performed. The orifice meter contained a 0.500 in. orifice plate to enable flow measurements to be conducted at the ranges expected during testing (5 to 20 scfm natural gas or 13 to 54 lb/hr). The meter was temperature and pressure compensated to provide mass flow output at standard conditions (60 ^{o}F, 14.696 psia). The meter was configured to continuously monitor flows at a rate of one reading per minute. Prior to testing, the orifice type flow meter was factory calibrated, and a calibration certificate traceable to the National Institute for Standards and Technology (NIST) was obtained. The dry gas meter (American Meter Company Model AL-425) was provided and calibrated to NIST traceable standards by the Washington Gas Company. It served as an independent check on the orifice meter.

During performance checks, discrepancies between the flow measured by the orifice meter and that measured by the dry gas meter were observed. After comparative analysis of the data, it was determined that the orifice meter flows were biased high near the full range of the instrument because of flow disturbance induced by fittings installed too close to the meter. Detailed documentation of these findings, and of QA/QC checks performed to arrive at this conclusion, is provided in Section 3.2.3. To provide the most accurate results, the data collected by the orifice meter were invalidated, and electrical efficiency was calculated using the dry gas meter data. These data, corresponding to the time intervals during which load tests were performed, were used in conjunction with data from the electrical power meter and fuel heating value results to make the efficiency calculations.

The Test Plan required estimation of electrical efficiency for sites that may not need an optional booster compressor. To do this, required measurement of electricity consumed by the booster compressor was planned to be metered using an electronic watt transducer. However, problems with a lack of weatherproofing at the physical location of the meter led to unreliable data from the transducer, and the data from this meter were invalidated. At the end of the verification, a 7500 ION power meter was connected to the booster compressor motor, and the Turbogenerator was operated at various loads to determine compressor power consumption at the four test conditions. These measurements were added to the average power output measured at each load to estimate total electrical power output without the booster compressor. Using these data and Equation 1, electrical efficiency without the use of the booster compressor was estimated.

1.4.2. Power Quality Performance

When an electrical generator is connected in parallel and operated simultaneously with the utility grid, operational characteristics should closely match grid performance. Parameters such as voltage frequency indicate synchronization with the utility grid, and time series voltage output readings indicate "voltage following" with the grid. The frequency and voltage generated by the power system must be aligned to match conditions of the power grid. The Turbogenerator 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 this test, out-of-tolerance conditions were defined as grid voltage outside the range of 480 volts ± 10 percent (line-to-line and line-to-neutral) and electrical frequency of 60 Hz ± 0.01 percent. To characterize the Turbogenerator's ability to operate in parallel with the grid, voltage and frequency measurements were collected for the Turbogenerator. The 7600 ION, used for the electrical power output measurement, was also used to monitor voltage and frequency. Simultaneous to these measurements, voltage and frequency data were collected on the electricity supplied by the utility grid using a second 7500 ION.

Other power quality performance parameters such as power factor and THDs characterize the quality of electricity supplied to the building occupants. The power factor delivered by the Turbogenerator must be of sufficient quality to allow successful operation of sensitive electronic equipment. The Turbogenerator electronics allow an operator to manually set a target power factor. Typically, the power factor of the unit is adjusted and set to bring the site power factor closer to unity (1.0 or 100 percent). This power factor setting was assigned throughout the verification period. This level was also required by the test facility operators to reduce potential problems with sensitive office equipment at lower power factors. To determine the Turbogenerator's ability to produce power at this factor, 1-minute average measurements data were collected with the 7600 ION. Simultaneous measurements were collected on the electricity supplied by utility grid using a 7500 ION electric meter. Baseline grid power factor data were also collected prior to the Turbogenerator starting each morning. The baseline data are used to characterize the levels at which the grid-supplied electricity was operating prior to the Turbogenerator's coming on line.

Similar to power factor, harmonic distortions in voltage and current were also measured for the duration of the verification period. Harmonic distortions can damage or disrupt the proper operation of many kinds of industrial and commercial equipment. Voltage distortion is defined as any deviation from the nominal sine waveform of AC line voltage. 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. The guidelines listed in the Institute of Electrical and Electronics Engineers' Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems (IEEE 519) were followed in determining current and voltage THDs. Baseline THD measurements were also collected on the electricity supplied by the grid to evaluate net effects on the quality of the electricity supplied to the building occupants.

1.4.3. Operational Performance

The Turbogenerator was started each weekday during office business hours. The unit's ability to produce power when called upon was documented with the following performance parameters: cold-start time, number of successful and unsuccessful starts, and operational availability.

It is useful to know the time required to reach full power when backup power (grid parallel mode) is needed or when electrical power is needed during peak demand periods. Cold-start time represents the number of seconds required to obtain full power. It was verified on four occasions after a minimum of 8 hours of Turbogenerator shutdown had occurred (typically during each morning). Cold-start times were determined from the time a start command was given to the software system until the time the unit reached full power. Full power was achieved when the differences between 1-minute power output values were less than 0.5 percent.

The continuous power measurements data were used to determine the number of successful starts achieved during each morning of the verification test period. Turbogenerator availability represents the percentage of time the unit is available to serve the load when called upon (8-hour daily operating period). Turbogenerator availability accounts for unscheduled downtimes due to failures of the unit, and is defined as the percentage of time the unit was operating relative to the total available operating hours. For this study, the GHG Center evaluated operational availability for the 6-week test period only, and long-term monitoring was not performed to reduce testing costs.

1.4.4. Emissions Performance

Determination of the emissions performance of the microturbine system is needed to evaluate the environmental impact of the technology. Pollutant concentration and emission rate measurements for NO_X, CO, THCs, CO_2, and CH_4 were conducted on the turbine exhaust stack during the four load conditions. The emissions load tests coincided with the electrical efficiency determination at the four power commands described earlier. All of the test procedures used in the verification are U.S. EPA Federal Reference Methods, which are well documented in the Code of Federal Regulations. The Reference Methods include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations (40CFR60, Appendix A). Table 1-2 summarizes the standard Test Methods that were followed.

Though not expected, there was a potential for leaks to occur at the internal booster compressor where natural gas is pressurized to meet the Turbogenerator's fuel specifications. Manual checks for the presence of methane leaks were conducted in conjunction with the exhaust emissions. Total methane emission rates were to be determined as the sum of stack emissions and any methane leak rates found at the compressor.

Table 1-2. Summary of Emissions Testing Methods

Exhaust Stack			
Pollutant	**EPA Reference Method**	**Number of Loads Tested**	**Number of Tests**
NO_X	20	4	3 per load (30 minutes each)
CO	10	4	3 per load (30 minutes each)
THC[a]	25A	4	3 per load (30 minutes each)
CO_2	3A	4	3 per load (30 minutes each)
CH_4	18	4	3 per load (30 minutes each)
O_2	3A	4	3 per load (30 minutes each)
Methane Leaks at Booster Compressor			
Pollutant	**Test Method**	**Sampling Frequency**	**Number of Tests**
CH_4	EPA tent/bag protocol for equipment leak estimates	2 times during verification period	3

[a] VOC emissions were determined as measured THC minus measured CH_4.

Three test runs were conducted at 50, 75, 90, and 100 percent capacity. Following Method 20 sampling procedures, nine traverse points were selected within the 23- by 19-in. rectangular stack extension placed on top of the Turbogenerator's short stack. A preliminary oxygen/nitrogen oxides (O_2/NO_X) stratification test confirmed that pollutant stratification was not present in the exhaust stack. During each test, sampling was conducted for approximately 30 minutes at a single point near the center of the stack. Results of the instrumental testing are reported in units of parts per million by volume dry (ppmvd) and ppmvd corrected to 15 percent O_2. The emissions were tested by TRC Environmental Corporation of Raleigh, North Carolina, under the on-site supervision of the GHG Center Field Team Leader.

A mobile laboratory housed the instrumentation and record emissions data throughout the testing periods. A detailed description of the sampling system used for determination of concentrations of criteria pollutants, GHGs, and O_2 is provided in the Test Plan, and is not repeated in this report. A brief description of key features is provided below.

In order for the CO_2, O_2, NO_X, and CO instruments used to operate properly and reliably, the flue gas must be conditioned prior to introduction into the analyzers. The gas conditioning system used for this test was designed to remove water vapor and/or particulate from the sample. Gas was extracted from the turbine exhaust gas stream through a stainless steel probe and heated sample line and transported to two ice-bath condensers on each side of a sample pump. The condensers removed moisture from the gas stream. The clean, dry sample was then transported to a flow distribution manifold where sample flow to each analyzer was controlled. Calibration gases were routed through this manifold to the sample probe to perform bias and linearity checks.

For CO_2 and O_2 determination, a continuous sample was extracted from the emission source and passed through a Servomex Model 1400 analyzer. For determination of CO_2 concentrations, the Model 1400 was equipped with nondispersive infrared (NDIR) spectroscopy. The CO_2 analyzer range was set at 0 to 20 percent. The same Model 1400 is also equipped with a micro-fuel-cell O_2 sensor. The fuel-cell technology used by this instrument determines levels of O_2 based on partial pressures. The O_2 analyzer range was set at 0 to 25 percent.

NO_X concentrations were determined utilizing a Thermo Environmental Model 10 chemiluminescence analyzer. This analyzer catalytically reduces NO_X in the sample gas to nitrogen oxide (NO). The gas is then converted to excited nitrogen dioxide (NO_2) molecules by oxidation with ozone (O_3) (normally generated by ultraviolet light). 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 setup and checkout. The NO_X analyzer was operated on a range of 0 to 100 parts per million (ppm).

A Thermo Environmental Model 48C gas filter correlation analyzer with an optical filter arrangement and NDIR detector was used to determine CO concentrations. This method provides high specificity for CO. Gas filter correlation uses a constantly rotating filter with two separate 180-degree sections (much like a pinwheel). One section of the filter contains a known concentration of CO, and the other section contains an inert gas without CO. These two values are “correlated,” based upon the known concentrations of CO in the filter, to determine the concentration of CO in the sample gas. The CO analyzer was operated on a range of 0 to 100 ppm for the 100, 90, and 75 percent load tests. The analyzer range was increased to 1,000 ppm during the 50 percent load tests.

THC concentrations in the exhaust gas were measured using a JUM Model VE-7 flame ionization analyzer. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second heated sample line was used to deliver unconditioned exhaust gases directly to the THC analyzer. All combustible hydrocarbons were being analyzed and reported, and the emission value was calculated on a methane basis.

Concentrations of VOC were determined as THCs less the CH_4 content in the gas stream in accordance with EPA Method 18. Integrated gas samples were collected in Tedlar bags and shipped to a certified laboratory for analysis. In the laboratory, samples were directed to a Hewlett Packard 5890 Series II gas chromatograph (GC) using a VICI 6-port gas loop injection system. The GC was equipped with a flame ionization detector (FID). The GC/FID was calibrated with appropriate certified calibration gases. Two replicate samples were collected, and all samples submitted were analyzed in triplicate.

The instrumental testing for CO_2, O_2, NO_X, CO, and THCs yielded concentrations in units of ppm and ppm corrected to 15 percent O_2. EPA Method 19 was followed to convert the concentration values into exhaust gas emission rates in units of pounds per hour (lb/hr). The calculated lb/hr emission rates were also normalized to turbine power output reported as pounds per kilowatt-hour (lb/kWh).

The fundamental principle of Method 19 is based upon "F-factors." F-factors are the ratio of combustion gas volume to the heat content of the fuel, and are calculated as a volume/heat input value (e.g., standard cubic feet per million Btu). This method includes all calculations required to compute the F-factors and provides guidelines on their use. The F-factors used to determine emission rates during each test period were calculated using the actual gas composition as determined using the fuel samples collected in the field. Equation 19-13 of Method 19 was followed to calculate the F-factors in units of dry standard cubic feet per million Btu (dscf/MMBtu). After converting the pollutant concentrations from ppm basis to lb/dscf, the calculated F-factor was used in conjunction with the measured heat input to the turbine (MMBtu/hr) and the measured oxygen concentration (dry basis) to determine emission rates in lb/hr using Equation 2.

$$\textit{Mass Emission Rate (lb/hr)} = \quad HI * Concentration * F\text{-}Factor * [20.9 / (20.9 - \%\ O_{2,d})] \qquad (Eqn.\ 2)$$

Where:

HI = heat input (MMBtu/hr)
Concentration = measured pollutant concentration (lb/dscf)
F-factor = calculated exhaust gas flow rate (dscf/MMBtu)
$O_{2,d}$ = measured oxygen level in exhaust stack, dry basis (%)

1.4.4.1. NO_X and CO_2 Emission Reductions

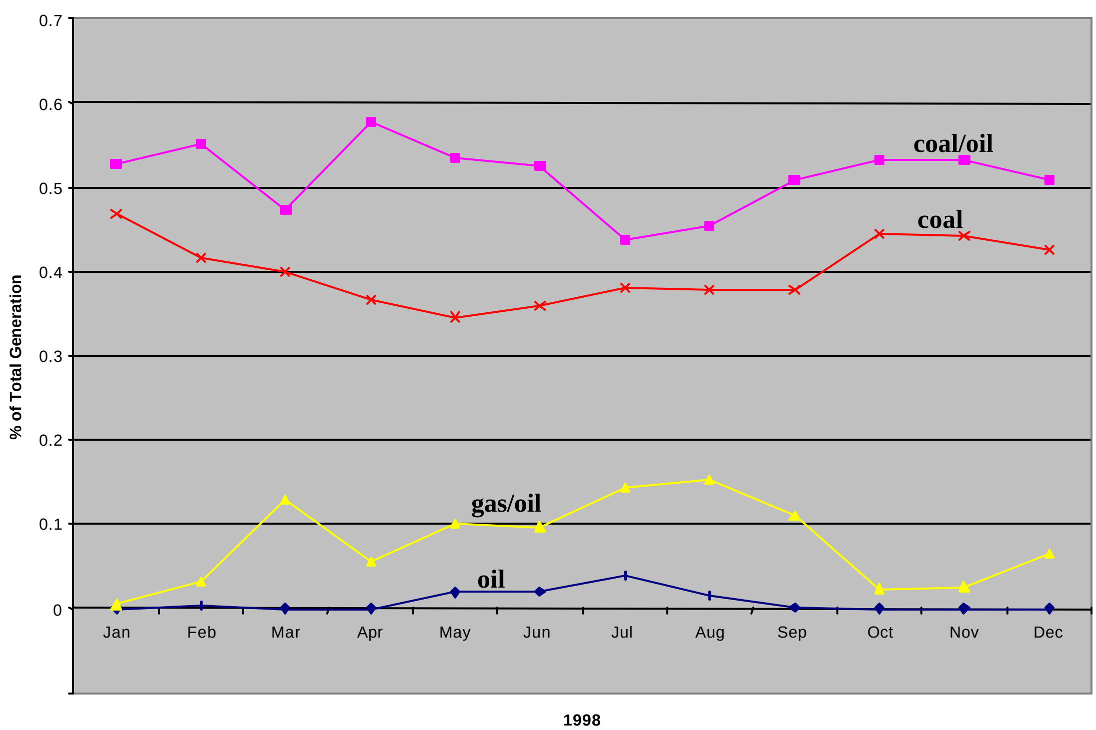
The power generated by the Turbogenerator will offset the electricity supplied by an electric utility. Identifying a specific power plant that experiences a displacement in electricity as a result of the electricity produced by the Turbogenerator is complex, and not easily attained. This is because the energy supplied by a utility has a potential to originate from the supplier's own power plants or from any number of over thousands of electric power plants in the country. To overcome this limitation, two assumptions are made. First, it is assumed the utility operator that supplies the electricity to the end-user will experience a reduction in electricity demand as a new distributed source of energy comes on line. Potomac Electric Power Company (PEPCO) is the local power company that supplies the electricity to the test area, and was selected as the baseline against which electricity and emissions offsets are computed.

The second assumption identifies specific power generation plant(s) and fuel types that are likely to experience a displacement in electricity production. A review of the Federal Regulatory Commission's Electric Utility Annual Report – Form 1 indicated that of the total electricity supplied by PEPCO, about

75 percent was generated by seven power plants located in Maryland, Virginia, and the Washington, D.C. area (FERC 2000). In 1998, the latest year for which complete data set was available, coal represented about 84 percent of the total generation, and oil- and natural-gas-fired power plants comprised 13 and 3 percent of total generation, respectively. The remaining 25 percent of the electricity was purchased from other utilities, and this fraction was consistent for all years between 1997 and 1999. Based on this information, it is assumed that the electricity purchased will remain the same (perhaps due to long-term purchase agreements with other utilities), and any reduction in electricity demand will result in a reduction in power generated from one or more of the seven PEPCO power plants.

Typically, a utility operator will dispatch specific generation units or power plants as electricity demands vary with the time of day and season. Depending upon availability, the plant that produces power at the lowest cost will usually be dispatched first, and the plant that produces power at the highest cost will be dispatched last (DOE 1994). To determine which power plants serve these roles, the annual operating hours for 7 PEPCO power plants and their 22 power generation units were processed using U.S. EPA's Emissions and Generation Resource Integrated Database (EGRID) and Energy Information Administration's Annual Utility Plant Operations and Design Database - Form 767 (EPA 2000, EIA 2000b). Based on a monthly review of plant-specific production records, it was determined that, during the verification period (December through April), over 95 percent of total electricity was supplied by base-loaded coal and dual-fired coal and oil generation units (Figure 1-5). For this time period, dual-fired gas/oil units were brought on line to meet the monthly electricity demand changes. Oil-fired units were operating only during peak summer months (May through August). Based on this information, it is concluded that electricity produced by the Turbogenerator at the test site is likely to displace electricity produced by gas/oil-fired units. The reduction in electricity demand will reduce emissions associated with producing an equivalent amount of electricity at these plants, plus losses incurred in transporting the electricity to the test facility.

Figure 1-5. Monthly PEPCO Plant Power Generation by Fuel Type
(Source: EPA 2000, EIA 2000b)



Plant-specific emission rates for PEPCO were extracted from U.S. EPA's Emissions and Generation Resource Integrated Database (EGRID). EGRID is developed under U.S. EPA's Acid Rain Program, which requires electric utilities to establish Continuous Emissions Monitoring (CEM) systems for measuring and reporting emissions of nitrogen oxides, sulfur dioxide, and CO_2. EGRID contains air pollutant emission and fuel grid mix for thousands of individual power plants and generating units (EPA 2000). The 1998 emissions and electricity generation data for the PEPCO power plants were reviewed, and emissions per unit of electricity (generated) were compiled for gas/oil power plants, and are summarized in Table 1-3. The data for other fuel types (coal, coal/oil, and oil only plants) are also shown for comparison.

Table 1-3. Emission Rates for PEPCO Plants
(Source: EPA 2000)

	Emission Rate (lb/kWh)[a]		
	CO_2	NO_X	SO_2
Electricity from Oil Plants	2.6455	0.0036	0.0160
Electricity from Gas/Oil Plants[b]	2.2329	0.0065	0.0182
Electricity from Coal/Oil Plants	2.0957	0.0066	0.0211
Electricity from Coal Plants	2.2814	0.0056	0.0114
Average for All Plants[c]	2.3030	0.0057	0.0149

[a] kWh represents electricity generated at the plant fence-line, and does not include transmission and distribution losses.
[b] Selected as the plants whose electricity will likely be displaced by the Turbogenerator.
[C] Average is not a straight average. It is based on sum of emissions for all power plants divided by the total energy generated.

The electricity generated by the central power plants is delivered through electrical transmission and distribution systems. Electrical energy losses in transformers, transmission wires, distribution wires, and other equipment are incurred as the electricity is distributed from the power plant to the end-user. To determine transmission and distribution losses, the "Annual Electric Utility Data, Form EIA-861," published by the U.S. Department of Energy, Energy Information Administration was used (EIA 2000a). Form EIA-861, completed by each electric utility in the U.S., contains information on the status of electric utilities and their generation, transmission, and distribution of electric energy. Based on these data, national average electricity loss from transmission, distribution, and/or unaccounted electricity losses is estimated to be 5.1 percent (averaged from about 3100 electric utilities records). For PEPCO plants, the losses are slightly lower, at 4.7 percent. This means that, for every 1 kW of electricity supplied to an end-user, about 1.047 kW must be generated at the power station. The emission factors shown in Table 1-3 must be increased by this 4.7 percent to represent power plant emissions associated with electricity supplied to a customer.

Emissions per unit of electricity (lb/kWh) associated with the Turbogenerator (at full load) are compared with the emissions per unit of electricity from the gas/oil-fired units, to determine the net emissions effect (locally) of displacing central-plant-generated electrical power with Turbogenerator-produced electrical power. For this verification, emission reductions for NO_X and CO_2 are estimated. Emission reductions for methane are not reported because emission factors are not available for electric utilities.

2.0 VERIFICATION RESULTS

2.1. OVERVIEW

The verification testing and data collection period started on December 14, 2000, and continued through April 10, 2001. A series of load tests were conducted, followed by an extended period of continuous monitoring of Turbogenerator power and operational performance. The load tests were designed to evaluate Turbogenerator emissions and electrical efficiency performance at 50, 75, 90, and 100 percent of rated power output.

Emissions and efficiency testing at the four operating loads first occurred on December 19, 2000, but, after measuring unexpectedly high emissions, the Turbogenerator software system was reported by Honeywell to be malfunctioning, and the tests were invalidated. Unexpectedly high levels of NO_X and CO were measured at all load conditions (> 100 and > 30 ppm, respectively). Upon further investigation by Honeywell, an error was discovered in the module that controls burner fuel distribution. As a result of this finding, Honeywell developed a new version of the software (Version 2.4F) which corrected the error, and requested a re-test with the GHG Center. On April 10, 2001, the load tests were repeated. This report presents electrical power production and emission performance results of the April 2001 tests. Turbogenerator cold-start times were evaluated after the December 19, 2000, load testing. They were not repeated during the April re-test (i.e., after the software error was fixed). As a result, it was not possible to verify if the fuel distribution correction results in improvements in cold-start times. Honeywell has cited that the software change should not effect the time required to reach full power. The results presented in this report represent 4 days of cold-start times verified with the original software configuration.

The Turbogenerator was continuously monitored over a period of 24 days to examine power quality and operational performance. This evaluation is based on data collected while the Turbogenerator was operating on the following days:

- December 14, 15, and 16, 2000
- January 3, 4, 5, 8, 9, 11, 12, 15, 16, 17, 24, 25, 29, 30, and 31, 2001
- February 1, 5, 7, 8, 9, and 12, 2001

These days were selected because they are the days when the site's normal Turbogenerator operating schedule was possible (weekdays, between 9:00am and 5:00pm). It excludes days when the Turbogenerator was manually shut down by operators to perform activities unrelated to the turbine or when short-term load testing was being conducted by the GHG Center. Measurements data, collected prior to fixing the software error, are used to report power quality and operational performance parameters because these parameters are not expected to be affected by the software problem. Although the GHG Center has made every attempt to obtain a reasonable set of data to examine daily trends in electricity production and power quality, the reader is cautioned that these results may not necessarily indicate performance over long operating periods or at significantly different operating conditions.

Test results are presented in the following subsections:

Section 2.2 - Electric Power Production Performance
Section 2.3 - Power Quality Performance
Section 2.4 - Operational Performance
Section 2.5 - Emissions Performance

As the results will show, the power generated by the Turbogenerator was of generally high quality, and was capable of operating in parallel with the utility grid. The Turbogenerator consistently provided over 70 kW of power during scheduled periods and had no failed starts. NO_X emissions from the Turbogenerator at full load were lower than the average emission rates published by the local utility. Electrical efficiency at full load was about 23.5 percent at an ambient temperature of 62 ^oF and 63 percent RH. NO_X emission reduction of about 86 percent and GHG emission reduction of about 27 percent are estimated with the Turbogenerator.

An assessment of the quality of data collected throughout the verification period is provided for each measurement in Section 3.0. The data quality assessment is then used to demonstrate whether the data quality objectives (DQOs) introduced in the Test Plan were met for this verification.

2.2. ELECTRIC POWER PRODUCTION PERFORMANCE

The power production performance evaluation includes electrical power output and efficiency at selected loads, and total electric energy generated during the verification period. Results of the testing conducted to evaluate these parameters are discussed below.

2.2.1. Electrical Power Output and Efficiency at Selected Loads

The Turbogenerator output was modulated by specifying power commands of 50, 75, 90, and 100 percent of its rated capacity (75 kW) using the Turbogenerator software system. Three test runs, each with a duration of about 30 minutes, were executed and power output, fuel flow rate, ambient temperature, barometric pressure, and RH were continuously recorded at the four power commands. For determination of fuel heating value, three gas samples were collected during each load condition, and were submitted to a certified laboratory for LHV analyses. One of these samples, collected during the full load condition, was invalidated. The LHV results for the next most recently collected sample (90 percent test condition) was assigned to the full load test runs. The time-synchronized measurements of power output, fuel flow rate, and fuel quality were then used to compute average electrical power output and efficiency at each power command.

Following the PTC22 guidelines, electric power output and fuel flow rate were collected over time intervals of not less than 4 minutes and not greater than 30 minutes to compute electrical efficiency. This restriction minimizes the uncertainty in efficiency determination due to varying operating conditions. The maximum variation allowed in power output, power factor, fuel input, and atmospheric conditions were satisfied for each of these parameters (see Section 3.2.1 for discussion of data quality), and the PTC22 criteria for stable operation were satisfied for each load test. Table 2-1 summarizes the power output, fuel input, and efficiency results.

All load testing occurred during relatively consistent atmospheric conditions and were near the levels defined as standard conditions by the International Standards Organization (temperature of 60 ^oF, barometric pressure of 14.696 psia, and RH of 60 percent). The LHV results were consistent for the three samples collected, with values ranging between 946.10 and 950.30 Btu/ft^3. The specific gravity and gas density were about 0.59 and 0.045 lb/ft^3, respectively. Due to the small variability observed in ambient conditions and natural gas heating value, cross comparisons between operating loads can be made. The reader is cautioned that the results shown in Table 2-1 and the discussion that follows are representative of conditions encountered during testing, and do not necessarily indicate performance at other operating conditions (e.g., warmer temperatures).

The average electrical power delivered at the point of measurement (after the transformer) was about 71 kW at full load, and the average electrical efficiency corresponding to these measurements was about 23.5 percent. The efficiency drops to about 19.8 percent as power output is reduced by half. Heat rate, which is an industry accepted term to characterize the ratio of heat input to electrical power output, was about 14,552 Btu/kWh at full power. The average natural gas consumption rate at full load was 18.19 scfm or 49.12 lb/hr.

Table 2-1. Power and Electrical Efficiency Performance

	Test Condition		**Power Delivered**[a]	**Fuel Input (Natural Gas)**			**Ambient Conditions**[b]		**Electrical Efficiency**[c]
	% of Rated Power	Power Command (kW)	(kW)	Flow Rate[d] (scfm)	LHV[e] (Btu/ft^3)	Heat Input (Btu/hr)	Temp. (^{o}F)	RH (%)	(%)
Run 1			71.28	18.19	950.30	1,037,157	61.78	65	23.45
Run 2			71.25	18.14	950.30	1,034,307	61.69	64	23.51
Run 3	100	75	71.24	18.23	950.30	1,039,438	62.71	61	23.39
Average			**71.26**	**18.19**	**950.30**	**1,036,967**	**62.06**	**63**	**23.45**
Run 4			64.63	16.58	950.30	945,358	64.44	58	23.33
Run 5			64.71	16.74	950.30	954,481	65.78	56	23.13
Run 6	90	68	64.78	16.72	950.30[f]	953,341	67.13	55	23.19
Average			**64.71**	**16.68**	**950.30**	**951,060**	**65.78**	**56**	**23.22**
Run 7			53.40	14.12	946.60	801,960	66.68	56	22.72
Run 8			53.35	14.08	946.60	799,688	66.12	55	22.76
Run 9	75	56	53.33	14.14	946.60[c]	803,095	65.63	56	22.66
Average			**53.36**	**14.11**	**946.60**	**801,581**	**66.14**	**56**	**22.71**
Run 10			35.91	10.93	946.10	620,452	67.79	57	19.75
Run 11			35.91	10.86	946.10[c]	616,479	66.20	61	19.88
Run 12	50	38	35.88	10.88	946.10	617,614	64.76	62	19.82
Average			**35.90**	**10.89**	**946.10**	**618,182**	**66.25**	**60**	**19.82**

[a] Represents actual power available for consumption at the test site. Includes losses from booster compressor and 480 volt transformer.
[b] Barometric pressure remained relatively consistent throughout the test runs (14.64 to 14.65 psia).
[c] Includes power consumed by booster compressor and 480 volt transformer.
[d] As measured with certified dry gas meter (Section 3.2.3).
[e] Lower Heating Value (LHV). For Runs 6, 9, and 11, LHV results are based on actual gas samples collected during these runs. For Runs 1 through 3, LHV is assigned same as Run 6. LHV for all remaining runs are assigned same value as directly measured data for the most recently collected samples (e.g., Runs 7 and 8 are assigned same as Run 9).
[f] Represents results of actual gas samples collected during that run.

As shown in Table 2-1, the power delivered is about 95 percent of the power level specified in the Turbogenerator software system. This suggests that energy loss through the voltage transformer and electricity consumption by the booster compressor is about 5 percent of the electricity production potential. The booster compressor is optional equipment for commercial buildings and other urban area applications where high-pressure gas is often not available. For some industrial facilities, high-pressure gas may be available on-site, and an optional gas compressor may not be needed. For such facilities, actual power delivered will be higher because a portion of the total power generated by the Turbogenerator is not needed to energize the compressor's electric motor, and will result in an increase in electrical efficiency.

To estimate the increase in power output without the gas compressor, limited tests were conducted about 1 week after the load tests were completed. The same electric meter which was used to measure grid power quality was relocated to the booster compressor, and measurements data were collected at the four test loads. Table 2-2 summarizes the results to pressurize natural gas from an initial supply pressure of 1.6 to 75 psig. At full load, the compressor consumed about 4.36 kW at 275 volts. Without the booster compressor, this power would be available as additional capacity. Assuming an average power loss of about 2 percent to convert the 275 volt power to 480 volts, about 4.27 kW additional power or 75.53 kW total power would be available for use. This equates to about a 1.40 percent increase in electrical efficiency at full load.

Table 2-2. Booster Compressor Power Requirements and Its Effects on Electrical Efficiency

		With Compressor[a]		**Without Compressor**		
Test Condition		**Average Power Delivered (480 Volts)**	**Average Electrical Efficiency**	**Power Consumption By Compressor (275 Volts)**	**Estimated Total Power Delivered (480 Volts)**	**Estimated Electrical Efficiency[b]**
% of Rated Power	Power Command (kW)	(kW)	(%)	(kW)	(kW)	(%)
100	75	71.26	23.45	4.36	75.53	24.85
90	68	64.71	23.22	4.15	68.78	24.68
75	56	53.36	22.71	3.77	57.05	24.28
50	38	35.90	19.81	3.28	39.11	21.58

[a] Based on test results presented in Table 2-1.

[b] Voltage transformer loss of 2 percent is assumed when 277 volt electrical power from the booster compressor is transformed to 480 volts.

2.2.2. Electrical Power Output Over the Verification Period

Figure 2-1 presents a time series plot of power production during the 24-day verification period. The plot includes only times when the Turbogenerator was operating and excludes scheduled and unscheduled down times (see Section 2.3 for description). During this period, the Turbogenerator operated for 179 hours, with an average daily operating time of about 7.7 hours. About 12,704 kWh of electricity was delivered to the building and used on-site during the verification period. The average power output was about 70.9 kW, which supplied about 32 percent of the site's power requirement (daily average power demand was about 220 kW).

Turbogenerator power output generally followed the trend shown in Figure 2-1. The data indicate a gradual increase in power output during the course of each day, peaking in the late afternoon. Daily changes in output were small and typically ranged between 0.5 and 1 kW.

Figure 2-1. Turbogenerator Power Output at Full Power Command

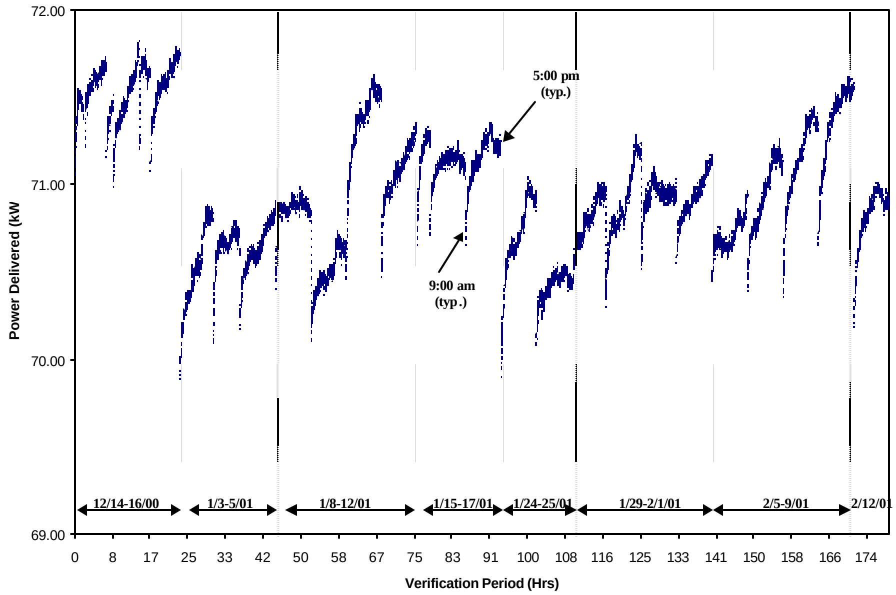
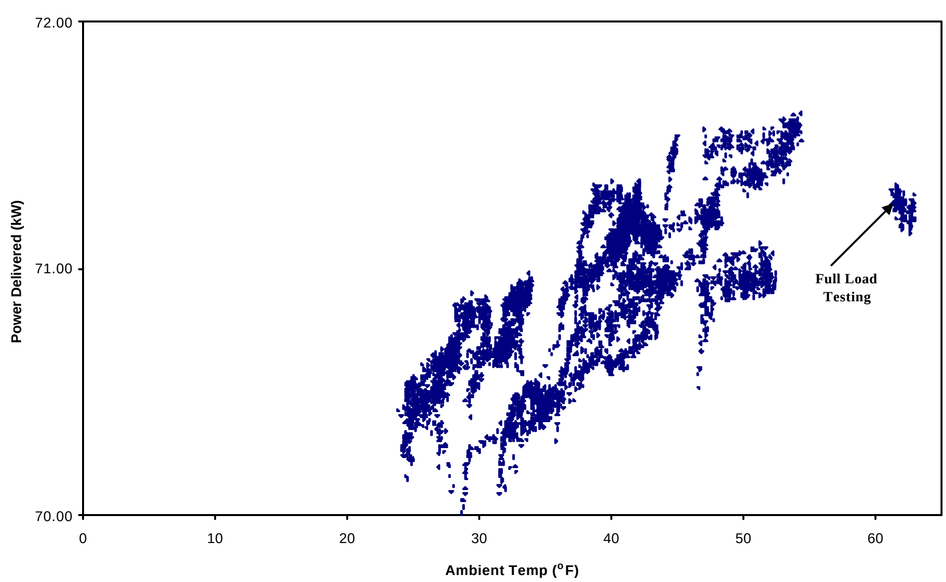


Figure 2-2 illustrates the relationship observed between ambient temperatures and power output. Atmospheric temperatures ranging between 25 and 63 ^{o}F were encountered during the verification period, and the highest power output occurred near the standard temperature. These results are consistent with performance ratings specified by Honeywell, and agree with results in Table 2-1, in which highest electrical efficiency was observed near the standard temperature

High ambient temperature (greater than 70 ^{o}F) were not observed during the verification period. Thus, it was not possible to report power output levels at warmer temperatures. The unit is designed to automatically derate itself at ambient temperatures exceeding standard ISO conditions.

Figure 2-2. Power Output vs. Ambient Temperature at Full Power Command



2.3. POWER QUALITY PERFORMANCE

2.3.1. Electrical Frequency

Electrical frequency measurements (voltage and current) were monitored simultaneously for the Turbogenerator and the site electricity supplied by the grid. The 1-minute average data collected by the electrical meters were analyzed to determine maximum frequency, minimum frequency, average frequency, standard deviation, and 95 percent confidence interval over the verification period. These results are summarized in Table 2-3. The average of measured electrical frequency for the Turbogenerator was 60.000 Hz, while the frequency of the grid was 60.001 Hz.

Table 2-3. Summary of Electrical Frequency Measurements

Parameter	Turbogenerator	Grid
Average Frequency (Hz)	60.000	60.001
Maximum Frequency (Hz)	60.045	60.060
Minimum Frequency (Hz)	59.942	59.945
Standard Deviation (Hz)	0.014	0.016

2.3.2. Voltage Output and Transients

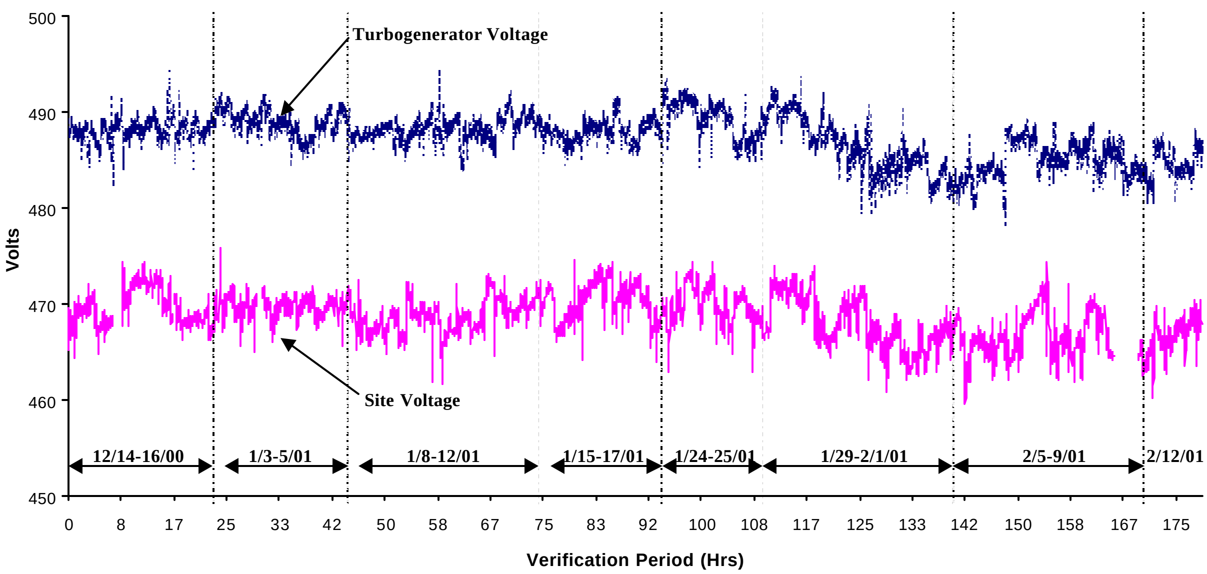
Traditionally, it is accepted that voltage output can vary within ± 10 percent of the standard voltage (480 volts) without causing significant disturbances to the operation of most end-use equipment (ANSI 1996). Voltage was monitored on the Turbogenerator and the utility grid using the 7600 ION and 7500 ION electrical meters, respectively. Each meter was configured to measure 0 to 600 VAC at a rate of one reading per minute. Table 2-4 compares statistical data for the voltages measured on the Turbogenerator and grid throughout the verification period. The Turbogenerator produced power at about 4 percent higher voltage than the grid. The feeder impedance dictates this increase in voltage. This means that there is about a 4 percent impedance distribution feeder to the Turbogenerator. The feeder impedence inherent in the grid generally ranges between 3 and 5 percent. The 4 percent increase in the Turbogenerator voltage overcomes this impedance in the distribution feeder.

Figure 2-3 plots 1-minute average voltage readings for the Turbogenerator and the grid-supplied electricity for the verification period. The voltage output from the Turbogenerator was within the normal range (480 ± 48 volts), and the data show that the Turbogenerator voltage generally follows the grid voltage. This is especially observed in the 125- to 150-hour monitoring period, during which the grid voltage decreased and the Turbogenerator voltage output dropped by essentially the same amount. The voltage output from the Turbogenerator was within the normal range (480 ± 48 volts), which demonstrates that the unit is capable of operating in parallel with the grid.

Table 2-4. Summary of Voltage Measurements

Parameter	Turbogenerator	Grid
Average Voltage (volts)	487.27	468.69
Maximum Voltage (volts)	494.29	475.66
Minimum Voltage (volts)	478.22	459.52
Standard Deviation (volts)	2.36	2.33

Figure 2-3. Site and Turbogenerator Voltage During Verification Period



A voltage transient is a sub-cycle disturbance in the alternating-current waveform that is evidenced by a sharp brief change in the system voltage. Transients are also known as spikes or surges that are normally on-line for a few seconds, and are often not detected by the 1-minute average voltage measurements described above. Turbogenerator voltage transients were continuously monitored and recorded throughout testing. The 7600 ION was configured to identify line-to-neutral surges up to 8 kV at a rate of one reading per 60 milliseconds. The number of transient occurrences and magnitude of the transients (greater than 480 volts ± 10 percent) were logged. Voltage transients were not measured for the utility grid because the meter used did not have the capability to monitor sub-cycle disturbances. After consultation with industry experts, it was decided not to report the transient results because grid measurements data could not be collected. Consequently, it was not possible to identify the origin of transients, and such data were deemed not useful to the reader.

2.3.3. 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 or 100 percent. If inductive loads (e.g., motors) are present, power factors can be less than this value. Although it is desirable to maintain the power factor at 100 percent, the actual power factor of the electricity delivered to the site by the grid may be much lower because of load demands of different end users. A low power factor causes heavier current to flow in power distribution lines in order to deliver a given number of kilowatts to an electrical load.

Throughout the verification test period, the Turbogenerator was pre-programmed to operate near unity (or 100 percent) power factor, as requested by the site operator. Figure 2-4 illustrates time series power factor data for the turbine and the grid. Table 2-5 summarizes the average, minimum, maximum, and standard deviation of the entire data set. Figure 2-5 shows that the Turbogenerator was able to maintain its setpoint power factor with low variability (overall average of 99.98 percent). The occasional drops in power factor that are shown occurred during Turbogenerator shutdown (the lowest 1-minute average was about 92 percent). The overall average power factor of the grid was slightly less than the Turbogenerator (about 96 percent).

Figure 2-4. Site and Turbogenerator Power Factors During Verification Period

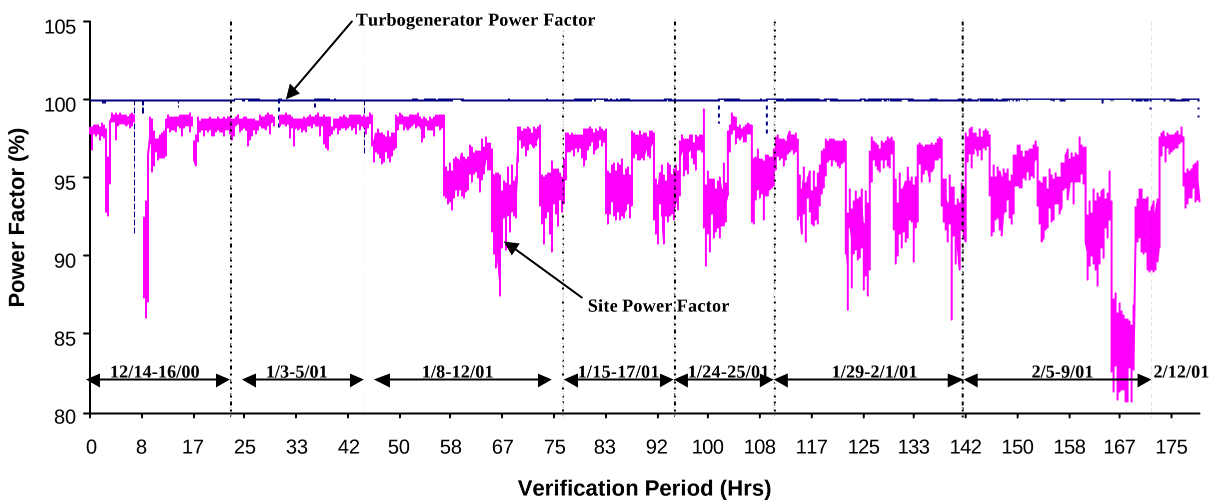
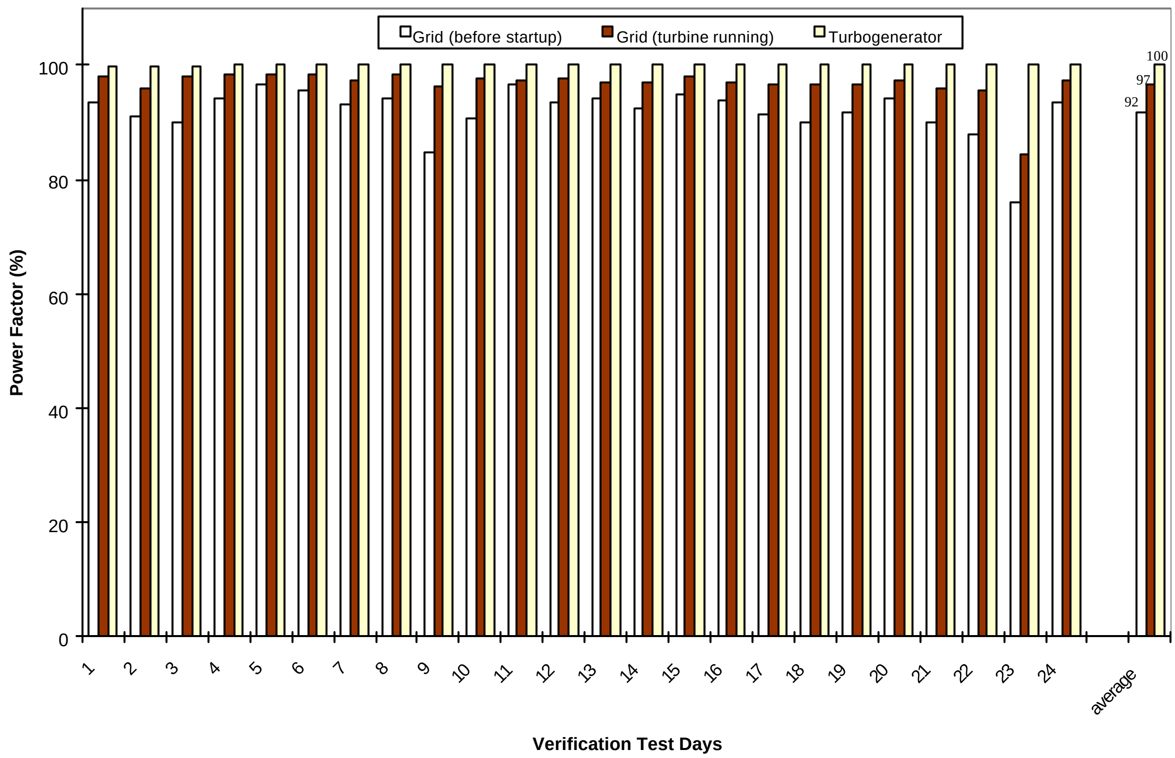


Table 2-5. Summary of Power Factor Measurements

	Turbogenerator	Grid
Average Power Factor (%)	99.98	95.79
Minimum Power Factor (%)	91.50	80.66
Maximum Power Factor (%)	100.00	99.43
Standard Deviation (%)	0.10	2.94

The power factors of the grid and Turbogenerator were also examined on a daily basis. Baseline data, collected prior to starting the turbine, were averaged to determine the initial power factor of the grid. Figure 2-5 shows that, on average, the power factor of the grid was about 92 percent between 6:00 and 9:00am. After the Turbogenerator was started (after 9:00am), the daily average grid power factor was 97 percent. It is anticipated that this increase may be due to electricity demand changes occurring in the early business hours. As shown in Figure 2-5, the power factor of the Turbogenerator remained near the setpoint for all days.

Figure 2-5. Comparison of Site Power Factor Before and After Turbogenerator Startup



2.3.4. Current and Voltage Total Harmonic Distortion

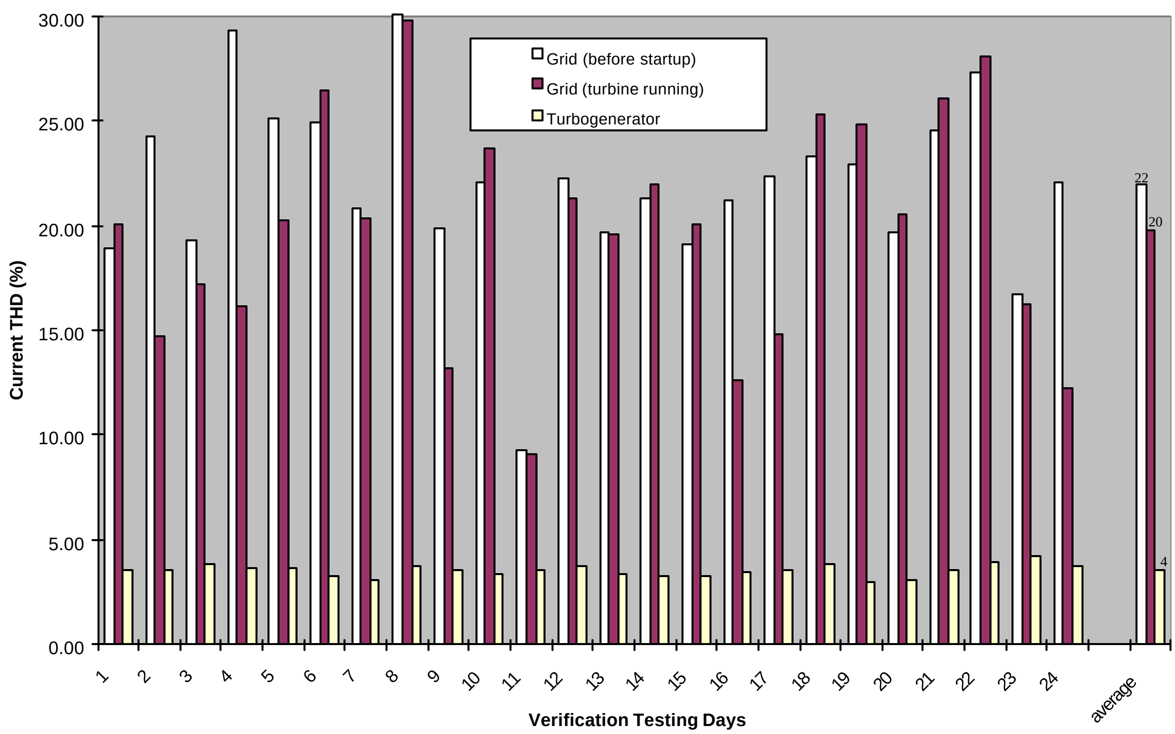
During the verification, the Turbogenerator and grid total harmonic distortions (up to the 63rd harmonic) were recorded for all voltage and current inputs using the electric meters. Table 2-6 summarizes the average, minimum, maximum, and standard deviation of the data collected during the entire test period. On average, the grid current THD was 12.78 percent. The Turbogenerator current THD was 3.56 percent, and ranged between 2.53 and 4.98 percent. All 1-minute current THD measurements were below the 5 percent maximum limit specified in IEEE 519.

Table 2-6. Summary of Current THD Measurements

	Turbogenerator	Grid
Average (%)	3.56	12.78
Minimum (%)	2.53	7.75
Maximum (%)	4.98	25.93
Standard Deviation (%)	0.40	3.38

Similar to the power factor, current THD measurements were also analyzed before and after turbine startup. Figure 2-6 illustrates the current THD for the grid before and after startup for each of the 24 monitoring days. The daily average current THD for the grid was 22 and 20 percent, before and after startup, respectively, which indicates a relatively small change. During this time period, the daily average current THD for the Turbogenerator was 3.54 percent, and ranged between 3.01 and 4.21 percent. These results are very similar to the overall averages cited above, which further shows that the Turbogenerator is capable of meeting the ± 5 percent threshold.

Figure 2-6. Daily Current Harmonic Distortions

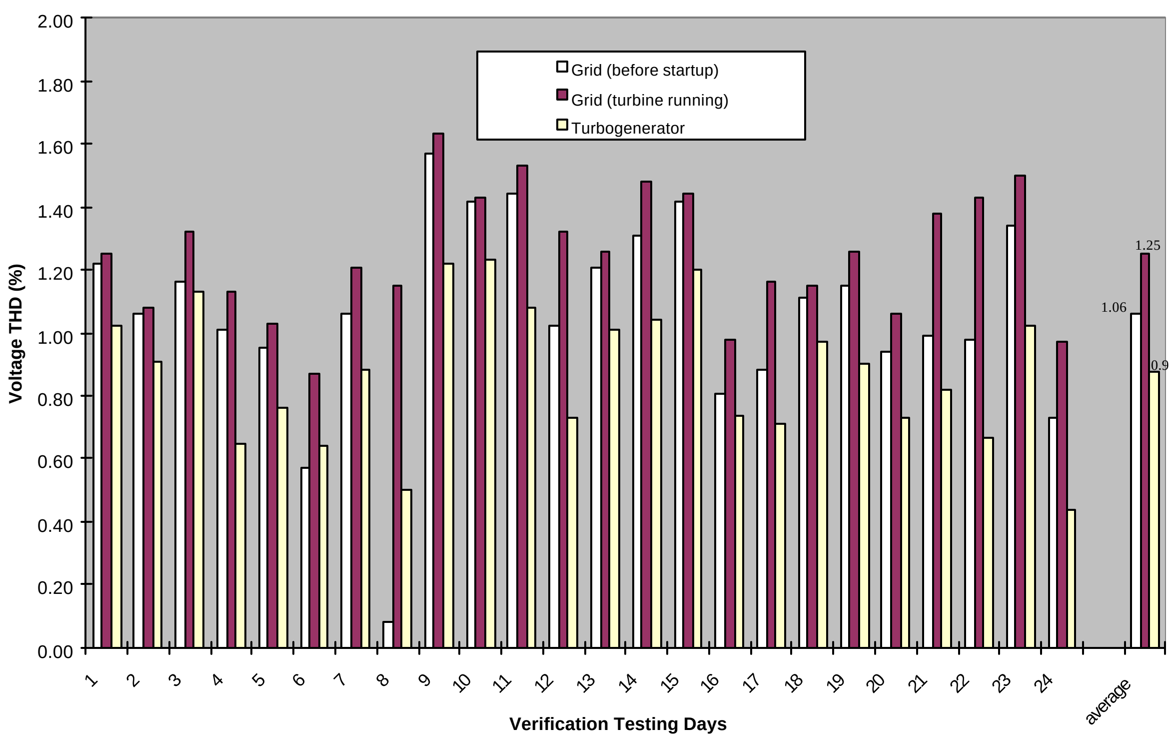


Turbogenerator and grid voltage THD were analyzed similar to current THD. Table 2-7 summarizes the statistical data for the entire test period. The overall average voltage THD for the Turbogenerator was 0.94 percent, and ranged between 0.25 and 1.82 percent. Based on this, Turbogenerator voltage THDs satisfied the ± 5 percent IEEE 519 threshold.

Figure 2-7 illustrates the daily voltage THDs for the grid (before and after turbine startup) and the Turbogenerator. The daily average voltage THD for the grid was 1.06 percent before startup and 1.25 percent after startup. The relatively small increase in grid THD is not considered statistically significant.

Table 2-7. Summary of Voltage THD Measurements		
	Turbogenerator	**Grid**
Average (%)	0.94	1.20
Minimum (%)	0.25	0.66
Maximum (%)	1.82	1.79
Standard Deviation (%)	0.28	0.20

Figure 2-7. Daily Voltage Harmonic Distortions



2.4. OPERATIONAL PERFORMANCE

Operational performance of the Turbogenerator was evaluated by documenting cold-start time, the number of successful and unsuccessful startup sequences, and the overall unit availability during the verification period. Each of these parameters is discussed in the following sections.

2.4.1. Cold-start Time

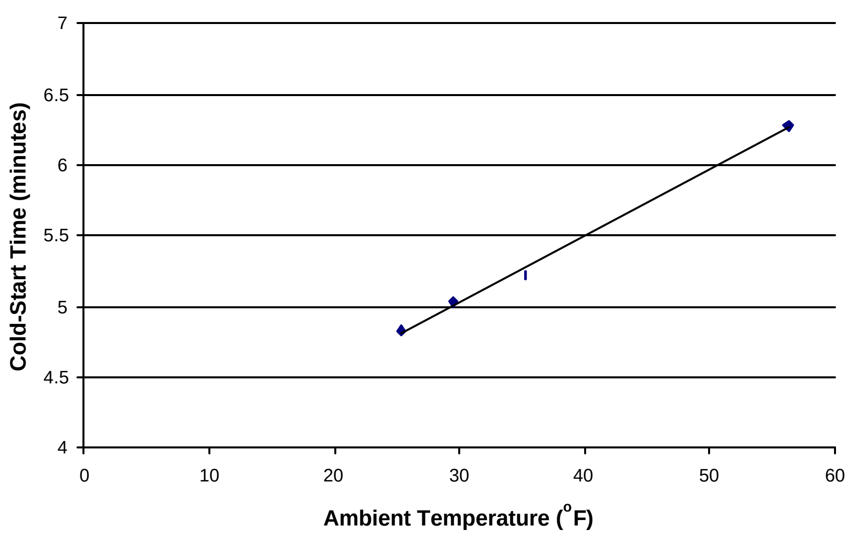
A total of four Turbogenerator cold-starts were documented, and were measured during 4 consecutive days after the December 19, 2000, load tests. For each test, the Turbogenerator was shut down for more than 8 consecutive hours to enable true cold-start determination. All measurements were collected using a stop watch, and manually recording the time when power command was entered into the Turbogenerator software system and the time when the full power was actually achieved. Results of the cold-start tests are summarized in Table 2-8. As noted earlier, these tests were performed with the original software configuration.

Table 2-8. Summary of Turbogenerator Cold-Start Tests

Date	Ambient Temp. (°F)	Time of Start Command	Time Full Power Achieved	Elapsed Cold-start Time (min.)
12/15/00	29.5	09:00:00	09:05:02	5.03
12/16/00	35.3	09:17:00	09:22:13	5.22
12/17/00	56.2	09:34:00	09:40:17	6.28
12/18/00	25.3	09:00:09	09:04:59	4.83
			Average	5.34

Measured cold-start times ranged from a low of 4.83 to a high of 6.28 minutes. The time required to achieve full power appears to depend on ambient temperature. As illustrated in Figure 2-8, colder air intake temperatures result in quicker startup. This may be due to the fact that fuel flow from the gas compressor is slightly less at hotter temperatures; therefore, taking longer to achieve full power. The cold-start tests were not repeated after the software error was corrected by Honeywell. Thus, it could not be verified if the fuel distribution changes result in improvements in cold-start times.

Figure 2-8. Turbogenerator Start Time vs. Temperature



2.4.2. Number of Successful and Unsuccessful Starts

During the 24-day verification period, no unsuccessful starts were encountered. The Turbogenerator operating system is normally maintained in automatic mode where the unit's start command is controlled by the operating system which starts the Turbogenerator each weekday at a predetermined time. For each of the automated start commands encountered during the verification period, the unit always delivered the requested power without a second restart attempt.

2.4.3. Operational Availability

Site operators were required to record information related to all Turbogenerator shutdowns that occurred during the verification period. These records included the date, time, reason, and duration of each shutdown. The shutdowns documented by the site are summarized in Table 2-9.

Table 2-9. Summary of Turbogenerator Unscheduled Downtime

Date	Event	Duration of Downtime
12/18/00 – 12/20/00	Load testing by the GHG Center	2 days
12/21/00 – 1/1/01	Manual shutdown by site operator during Christmas holiday	11 days
1/2/01	Unit shutdown to remove emissions testing stack extension	1 hour
1/4/01	Unit shutdown, electrician working on GHG Center's power meter	20 minutes
2/4/01	Unit shutdown to replace gas compressor rigid lines with flexible lines	8 hours

The first four shutdowns occurred as a result of the GHG Center's verification activities. The only unscheduled idle period that is recognized as a period when the unit was unavailable was the single day during which the gas compressor lines were replaced. This shutdown occurred in response to a parts safety recall by the compressor manufacturer, and Honeywell required the unit to be shut off until the appropriate parts were replaced. Using the equation in the Test Plan for determination of operational availability, the calculated availability for the verification period was 95.7 percent. This represents 179.32 hours of operating time and 8 hours of down time. The reader is cautioned that these results are based on a relatively short period of monitoring, and do not necessarily represent performance over longer operating periods.

2.5. EMISSIONS PERFORMANCE

2.5.1. Turbogenerator Exhaust Emissions

Turbogenerator emissions were tested to determine emission rates for criteria pollutants (NO_X, CO, and THCs) and greenhouse gases (CO_2 and CH_4). Stack emissions were measured at 50, 75, 90, and 100 percent of rated power output, and coincided with the electrical power output and efficiency measurements. At each operating condition, three replicate test runs, each approximately 30 minutes in duration, were conducted. All testing was conducted in accordance with EPA Reference Methods as described in the Test Plan, and was listed in Table 1-2. The Turbogenerator was maintained in a stable mode of operation during each test run. The PTC22 variability criteria described in Section 2.2 and presented in Section 3.2.1 were used as a guideline to verify that the tests were conducted during stable operation. The Turbogenerator was allowed to stabilize for at least 15 minutes after changing loads before testing was started.

Emissions in units of parts per million corrected to 15 percent O_2 (ppm @ 15 percent O_2) for NO_X, CO, and THC, and percent for O_2 and CO_2 are reported. The concentration and volume percent data were converted to mass emission rates using computed exhaust stack flow rates, and are reported in units of pounds per hour (lb/hr). Appendix A-3 contains run specific f-factors and exhaust gas flow rate data that were used to compute pollutant specific emission rates. The emission rates are also reported in units of pounds per kilowatt hour (lb/kWh), and were computed by dividing the mass emission rate by the power delivered. The data reported here characterize Turbogenerator emissions after the Honeywell software error, described in Section 2.1, was fixed.

To ensure the collection of accurate emissions data, sampling system QA/QC checks were conducted in accordance with Test Plan specifications, including analyzer linearity tests, sampling system bias and drift checks, interference tests, and challenging the sampling system with audit gases. Results of the QA/QC checks are discussed in Section 3.2.5 of this report, and will show that the DQOs for these measurements were satisfied. A complete summary of emissions testing equipment calibration data is presented in Appendix A. Appendix A-1 presents results of the analyzer linearity tests that were conducted at the beginning of each day of testing, or after making adjustments to the analyzers. Appendix A-2 presents the pre- and post-system bias and drift checks for each of the tests reported here.

Table 2-10 summarizes the emission results for each run and the overall average Turbogenerator emissions at each power command. Figure 2-9 shows Turbogenerator emissions in units of lb/kWh at each of the four load test conditions. All of the tests were conducted on April 10, 2001, and ambient conditions were consistent throughout the day. Temperatures ranged from 61.4 to 67.8 ^{o}F, and the RH ranged from 55.1 to 65.2 percent.

Figure 2-9. Emission Rates at Various Power Outputs

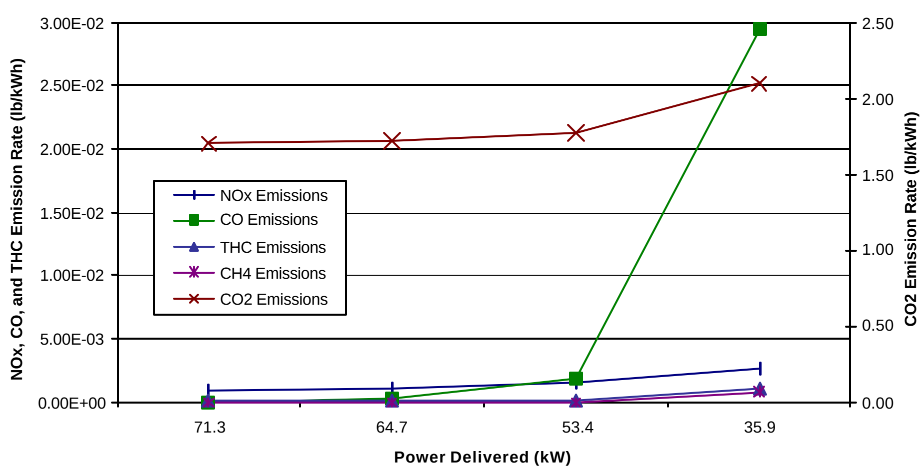


Table 2-10. Summary of Turbogenerator Emissions Performance

	Power Delivered	Ambient Conditions		Exhaust Gas	CO Emissions			NO_x Emissions			THC Emissions*			CO_2 Emissions		
		Temp.	Relative Humidity													
	(kW)	(°F)	(%)	O_2 (%)	(ppm @ 15% O_2)	lb/hr	lb/kWh	(ppm @ 15% O_2)	lb/hr	lb/kWh	(ppm @ 15% O_2)	lb/hr	lb/kWh	%	lb/hr	lb/kWh
Run 1	71.28	61.78	65	18.73	1.4	0.0031	4.3E-05	18.8	0.0702	9.85E-04	< 2.00	<7.07E-03	<9.92E-05	1.27	124	1.73
Run 2	71.25	61.69	64	18.71	1.6	0.0037	5.2E-05	18.4	0.0684	9.59E-04	< 2.00	<6.99E-03	<9.81E-05	1.24	119	1.67
Run 3	71.24	62.71	61	18.71	2.0	0.0043	6.0E-05	18.5	0.0697	9.79E-04	< 2.00	<7.02E-03	<9.86E-05	1.26	122	1.71
Average	**71.26**	**62.06**	**63**	**18.72**	**1.7**	**0.0037**	**5.2E-05**	**18.6**	**0.0694**	**9.74E-04**	**< 2.00**	**<7.03E-03**	**<9.86E-05**	**1.26**	**122**	**1.70**
Run 4	64.63	64.44	58	18.79	7.1	0.015	2.3E-04	20.0	0.0687	1.06E-03	< 2.00	<6.63E-03	<1.03E-04	1.21	110	1.71
Run 5	64.71	65.78	56	18.80	7.8	0.016	2.5E-04	19.6	0.0677	1.05E-03	< 2.00	<6.73E-03	<1.04E-04	1.22	113	1.74
Run 6	64.78	67.13	55	18.79	6.1	0.013	2.0E-04	19.6	0.0673	1.04E-03	< 2.00	<6.68E-03	<1.03E-04	1.21	111	1.72
Average	**64.71**	**65.78**	**56**	**18.79**	**7.0**	**0.015**	**2.3E-04**	**19.7**	**0.0679**	**1.05E-03**	**< 2.00**	**<6.68E-03**	**<1.03E-04**	**1.21**	**111**	**1.72**
Run 1	53.40	66.68	56	18.97	61.4	0.11	2.0E-03	28.4	0.0823	1.54E-03	< 2.00	<6.15E-03	<1.15E-04	1.13	95.6	1.79
Run 2	53.35	66.12	55	18.94	54.1	0.10	1.8E-03	27.7	0.0799	1.50E-03	< 2.00	<6.04E-03	<1.13E-04	1.13	93.8	1.76
Run 3	53.33	65.63	56	18.94	56.1	0.10	1.9E-03	27.6	0.0803	1.51E-03	< 2.00	<6.06E-03	<1.14E-04	1.13	94.3	1.77
Average	**53.36**	**66.14**	**56**	**18.95**	**57.2**	**0.10**	**1.9E-03**	**27.9**	**0.0808**	**1.51E-03**	**< 2.00**	**<6.08E-03**	**<1.14E-04**	**1.13**	**94.6**	**1.77**
Run 1	35.91	67.79	57	19.24	730.5	1.0	2.8E-02	42.7	0.0956	2.66E-03	40.20	3.10E-02	8.63E-04	1.00	76.2	2.12
Run 2	35.91	66.20	61	19.24	780.3	1.1	2.9E-02	42.4	0.0941	2.62E-03	47.80	3.68E-02	1.03E-03	1.00	75.6	2.11
Run 3	35.88	64.76	62	19.22	831.4	1.1	3.1E-02	41.5	0.0924	2.58E-03	59.90	4.66E-02	1.30E-03	0.99	74.2	2.07
Average	**35.90**	**66.25**	**60**	**19.23**	**780.7**	**1.1**	**3.0E-02**	**42.2**	**0.0940**	**2.62E-03**	**49.30**	**3.81E-02**	**1.06E-03**	**1.00**	**75.3**	**2.10**

* During each load test, gas samples were collected in Tedlar bags for determination of methane emissions. Samples with THC emissions below the field analyzer detection limit (Runs 1 through 9) did not contain measurable concentrations of methane. However, the sample collected at 50 percent load test returned a methane concentration of 11.2 ppm (uncorrected for excess oxygen), which indicated that most of the 13.9 ppm THC (uncorrected for oxygen) measured was methane.

During these tests, NO_X emissions at full power command averaged 18.6 ppm corrected to 15 percent O_2 (6.87 ppm uncorrected), which corresponds to an emission rate of 0.0009 lb/kWh. This emission rate is well below the 0.0057 lb/kWh reported for the local utility. It is also below the average rate for coal- and natural-gas-fired power plants, 0.0074 and 0.0025 lb/kWh, respectively (EIA 2000c). NO_X emissions increased slightly as power output was reduced, reaching a maximum average emission rate at half load of 42.2 ppm @ 15 percent O_2 (11.9 ppm uncorrected), or 0.0026 lb/kWh.

Emissions of CO were low at full power and within the lower detection limit of the sampling system (less than 2 ppm). As power output from the Turbogenerator was reduced to 75 percent load, CO emissions increased to an average of about 57 ppm @ 15 percent O_2 (18.9 ppm uncorrected), or 0.002 lb/kWh. When operating the Turbogenerator at 50 percent of rated capacity (about 36 kW output), CO emissions increased to an average of 781 ppm @ 15 percent O_2 (220 ppm uncorrected), or approximately 0.029 lb/kWh. As discussed earlier, the performance of an optional CO control device was also verified during the test, and its ability to reduce CO levels was determined. This performance test result can be found in a separate Verification Report (SRI 2001).

Emissions of THC were lower than the sensitivity of the sampling system during all of the tests other than the testing conducted at the lowest test load (36 kW). Emission rates reported in Table 2-8 are based on a lower detectable limit of 2 percent of instrument span, or 2 ppm. With the Turbogenerator producing 36 kW, THC emissions averaged 49.3 ppm @ 15 percent O_2.

The Test Plan specified determination of methane emissions by collecting integrated gas samples in Tedlar bags and analyzing collected samples using GC/FID procedures. Samples were collected at each load but analyses were not conducted whenever THC emissions were below the field analyzer detection limit. One sample from the full load testing was submitted as a QC check, and returned a non-detectable test result, confirming the field analyzer results. The sample collected at 50 percent of capacity was also submitted for analysis since measurable THC concentrations were detected at that load. This sample returned a methane concentration of 11.2 ppm, indicating that most or all of the THC measured during the low load tests was methane (measured concentrations of THC before correcting for excess oxygen averaged 13.9 ppm).

Concentrations of CO_2 in the Turbogenerator exhaust gas ranged from a low of 1.00 percent at 50 percent of full load to 1.26 percent at full power command. These concentrations correspond to average CO_2 emission rates of 2.10 lb/kWh at low power to 1.71 lb/kWh at full power. The emission rate at full power is well below the average emission rate for the seven PEPCO power generation plants (2.41 lb/kWh electricity delivered - includes line losses), and is slightly below the average emission rate for coal-fired power plants in the U.S. (2.26 lb/kWh). Compared to natural-gas-fired power plants in the U.S., whose average CO_2 emission rate is 1.41 lb/kWh, the Turbogenerator emissions are higher (DOE/EPA 2000). This is because the average electrical efficiency of gas-fired power plants is over 30 percent, which results in lower CO_2 emissions, even after line losses are accounted for. The national average emission factors reported here account for about 5.1 percent losses in electricity from plant fence-line to the end user.

2.5.2. Estimated Emission Reductions

The electricity generated by the Turbogenerator and used on-site will offset the electricity supplied by the local utility. The electricity offset is defined as the energy used plus additional energy that must be generated at central power stations to account for transmission and distribution-line and transformer losses between the central power station fence-line and the end user. The reduction in electricity demand will result in changes in emissions at the central power plant. PEPCO was identified as the local power company that supplies electricity to the test facility, and its gas/oil-fired power plants were selected as the baseline plants against which electricity offsets and emission reductions are estimated. The emission reduction estimation methodology and assumptions related to computing this verification parameter were described in Section 1.4.4.1, and are not repeated here.

Table 2-11 summarizes the NO_X and CO_2 emission factors for the Turbogenerator (at full load) and the emission factors for the baseline power plants. The emission factors are based on a unit of electricity delivered to the end user, which accounts for 480-volt transformer losses for the Turbogenerator and transmission and distribution system losses for the baseline power plants (4.7 percent). As shown in Table 2-11, both NO_X and CO_2 emission factors for the Turbogenerator at full load are lower than for the baseline power plants. This equates to about 86 percent reduction in NO_X emissions and about 27 percent in CO_2 emissions.

Table 2-11. Estimated NO_X and CO_2 Emission Reductions

	Emission Factor (lb/kWh)[a]		**Estimated Emission Reductions[d] (%)**
	Turbogenerator[b]	**PEPCO Gas/Oil Fired Units[c]**	
NO_X	0.000974	0.006806	86
CO_2	1.71	2.34	27

[a] kWh represents electricity delivered to end-user (i.e., includes transformer and line losses)
[b] Represents average emission factor at full load (Table 2-9)
[c] Includes an estimated 1.047 percent losses in transmission and distribution lines
[d] Defined as percent difference in emission factors (PEPCO –Turbogenerator)/PEPCO * 100

Using DOE-EIA reported average emission factors for the U.S. electric utility industry, NO_X emission reductions are estimated to range between 63 and 87 percent (for displacing gas-fired and coal-fired plants, respectively. CO_2 emission reductions are expected to be about 23 percent in regions where coal is displaced (e.g., Northeast). However, small increases in CO_2 emissions can occur in regions that are heavily dominated by natural-gas-fired power plants (-21 percent).

2.5.3. Fugitive Methane Emissions

The GHG Center conducted testing to account for fugitive emissions of methane from the natural gas delivery system and booster compressor. The testing was conducted by screening the system for leaks using soap solution and a portable hydrocarbon analyzer (sniffer). The Test Plan specified that any leaks detected with the sniffer that exceeded 1,000 ppm would be quantified using EPA procedures. Screening activities were conducted by GHG Center personnel at the beginning and end of the verification period. No leaks were detected during either set of screenings performed.

3.0 DATA QUALITY ASSESSMENT

3.1. DATA QUALITY OBJECTIVES

In verifications conducted by the GHG Center and EPA-ORD, measurement methodologies and instruments are selected to ensure that a desired level of data quality occurs in the final results. DQOs were specified for the following verification parameters: power output, electrical efficiency, and emission rate measurements. Table 3-1 lists the uncertainty levels targeted for these parameters.

Table 3-1. Data Quality Objectives

Verification Parameter	Required	Actual
Power Output	± 0.20 % at full load	± 0.05 % at full load
Electrical Efficiency	± 0.75 % at full load	± 0.08 % at full load
Emission Levels		
NO_X	Bias: ± 2 % of span	NO_X: ≤ 2.0 % of span
CO	Bias: ± 5 % of span	CO: ≤ 2.0 % of span
CO_2	Bias ± 5% of span	CO_2: ≤ 1.0 % of span
THCs	Bias: ± 5 % of span	THCs: ≤ 2.3 % of span

To determine if the DQOs were met, data quality indicator goals (DQIs) were established for key measurements performed in the verification test. The goals, specified in Table 3-2, identified accuracy, precision (emission testing only), and completeness DQIs that must be achieved. The following discussion illustrates that the accuracy and precision goals were met or exceeded, and completeness goals were met for the load tests. As such, the uncertainty objectives listed in Table 3-1 were satisfied.

3.2. EVALUATION OF DATA QUALITY INDICATORS

Table 3-2 includes the range of measurements observed in the field and accuracy and completeness goals. Completeness is defined as the number of valid determinations obtained as a percent of the total tests originally planned. The completeness goals for the load tests were to obtain electrical efficiency and emission rate data for all three test runs within each of four load conditions, and to analyze a minimum of one gas sample during each of the four load test conditions. These goals were met, except that the natural gas sample collected during the full load test was invalidated due to sample contamination with air. The completeness goal for the extended test was to obtain 90 percent of 6 weeks of power quality, power output, and ambient data (37 days). This equates to 26 actual monitoring days, excluding weekends, during which the Turbogenerator was not scheduled to operate. As discussed in Section 2, valid data for 24 days were obtained because some of the data during the extended test were invalidated due to incomplete data sets. As a result the completeness goal was not met. The performance results during this period were relatively consistent, which suggest that additional data may not significantly change the conclusions reached in Section 2.

Table 3-2 also includes accuracy goals for measurement instruments used in the verification. Measurement accuracy was evaluated using instrument calibrations conducted by manufacturers, field calibrations, reasonableness checks, and/or independent performance checks with a second instrument. The accuracy results for each measurement and reconciliation of the DQOs are discussed below.

Table 3-2. Summary of Data Quality Indicator Goals and Results

Measurement Variable		Instrument Type / Manufacturer	Instrument Range	Operating Range Observed in Field	Accuracy			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
Turbogenerator and Grid Power Output and Quality	Power	Electric Meter/ Power Measurements 7600 ION	0 to 75 kW	0 to 73 kW	± 0.20 % reading	± 0.05 % reading	Instrument calibration certificates from manufacturer just prior to testing, sensor function checks in field	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 89 %
	Voltage		0 to 480 V (3-phase)	0 to 480 V (3-phase)	± 0.1 % reading	± 0.1 % reading			
	Voltage Transients		600 to 8000 V	600 to 8000 V	Not defined	NA			
	Frequency		49 to 61 Hz	59-60 Hz	± 0.01 % reading	± 0.01 % reading			
	Current		0 to 200 amps	0 to 200 amps	± 0.1 % reading	± 0.1 % reading			
	Voltage THD		0 to 100 %	0 to 100 %	± 1 % FS	± 1 % FS			
	Current THD		0 to 100 %	0 to 100 %	± 1 % FS	± 1 % FS			
	Power Factor		0 to 100 %	0 to 100 %	± 0.5 % reading	± 0.5 % reading			
Booster Compressor Power Consumption	Power	Electric Meter/ Power Measurements 7600 ION	0 to 75 kW	3 to 4.5 kW	± 0.25 % reading	± 0.20 % reading		load tests: 100 %	load tests: 100 %
Utility Grid Power Quality	Voltage	Electric Meter/ Power Measurements 7500 ION	0 to 480 V	0 to 480 V	± 0.1 % FS	± 0.1 % FS		load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 89 %
	Frequency		60 Hz	59-60 Hz	Not defined	NA			
	Power Factor		0 to 100 %	0 to 100 %	± 0.5 % reading	± 0.5 % reading			
Ambient Conditions	Ambient Temperature	RTD / Vaisala Model HMP 35A	50 to 110 °F	25 to 65 ° F	± 0.2 °F	±-0.2 °F	Instrument calibration certificates from manufacturer just prior to testing	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 85 %
	Ambient Pressure (load tests)	Vaisala Model PTB220 Class B	14.80 to 32.56 in. Hg	28 to 31 in. Hg	± 0.1 % FS	0.1 % FS			
	Ambient Pressure (continuous tests)	SETRA Model 280E	0 to 25 psia	14 to 16 psia					
	Relative Humidity	Vaisala Model HMP 35A	0 to 100 %	40 to 95 % RH	± 2 % (0 to 90 % RH) ± 3 % (90 to 100 % RH)	± 2 % (0 to 90 % RH) ± 3 % (90 to 100 % RH)			
CH_4 Leaks at Gas Compressor	Screening	Bascum Turner Model CGI 201	0 to 100 % CH_4	0 % CH_4	1000 to 5000 ppmvd: ± 10 %	1000 to 5000 ppmvd: ± 10 %	Calibrated with 94 % CH_4 calibration gas prior to testing	2-4 times	2 times

(continued)

Table 3-2. Summary of Data Quality Indicator Goals and Results (continued)

Measurement Variable		Instrument Type / Manufacturer	Instrument Range	Measurement Range Observed	Accuracy			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
Fuel Input	Gas Flow Rate	American Meter AL-425	0 to 25 scfm	0 to 20 scfm	1.0 % of reading	0.4 % of reading	Calibrated by utility with volume prover	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 95 %
		Mass Flow Meter / Rosemount 3095 w/ 1195 orifice	0 to 20 scfm	0 to 20 scfm		+ 5.28 % at full load, +0.12 % at 50 % load	In-line comparison with calibrated dry gas meter in field and comparison with a calibrated dry gas meter in laboratory		
	Gas Pressure	Pressure Transducer / Rosemount or equiv.	0 to 20 psig	0 to 3 psig	± 0.75 % FS	± 0.75 % FS	Instrument calibration certificates from manufacturer just prior to testing, reasonableness checks in field		
	Gas Temperature	RTD / Rosemount Series 68	-58 to 752 °F	20 to 60 °F	± 0.09 % reading	± 0.09 % reading			
	LHV	Gas Chromatograph / HP 589011	0 to 100 % CH_4	90 to 95 % CH_4	± 0.2 % for CH_4 concentration ± 0.1 % for LHV for duplicate analyses	± 0.2 % for CH_4 concentration ± 0.1 % for LHV	Calibrated GC/MS with natural gas standard, compared analyses results with a single blind audit sample	load tests: 100 %	load tests: 100 %
Exhaust Stack Emissions	NO_X Levels	Chemiluminescence / TECO Model 10	0 to 100 ppm	7 to 12 ppm	± 2 % FS for system cal. error and drift	≤ 1.6 % FS for calibration error and <0.5 % for drift	Calculated following EPA Reference Method calibrations	load tests: Before and after each test run	load tests: Before and after each test run
	CO Levels	NDIR / TECO Model 48C	0 to 100 ppm/ 0 to 1000 ppm	0 to 240 ppm	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 2.0 % FS Drift: ≤ 0.6 % FS			
	THC Levels	FID / JUM Model VE-7	0 to 100 ppm	0 to 20 ppm	± 5 % FS for system cal. error and ± 3 % FS for drift	≤ 2.3 % FS for calibration error and < 2.1 % for drift			
	CO_2 Levels	NDIR / Servomex Model 1400	0 to 20 %	1 to 1.3 %	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 1.4 % FS Drift: ≤ 0.3 % FS			
	CH_4 Content	GC / FID HP Model 5890 Series II	0 to 100 ppm	0 to 13 ppm	± 5 % FS	± 10 % FS*			
	O_2 Levels	Micro-fuel cell/ Servomex Model 1400	0 to 25 %	18 to 20 %	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 1.1 % FS Drift: ≤ 0.2 % FS			
	H_2O Content	Gravimetric / NA	0 to 50 %	3 to 5 %	± 5 % FS	± 5 % FS			

FS: full scale
NA: not applicable
* The accuracy goal for CH_4 was misstated in the Test Plan and was not achieved. The nature of Method 18 is such that collection of gas in a bag, injection of a sample into the analytical equipment, and analytical quantification are generally expected to result in errors of around ± 10 percent of reading.

3.2.1. Electrical Efficiency Determination

The DQO for electrical efficiency was to achieve an uncertainty of ± 0.75 percent, which exceeds the "typical uncertainty" levels set forth in PTC22 of 1.7 percent. The DQIs specified to meet this objective consisted of achieving a ± 0.2 percent accuracy for the power meter, ± 1.0 percent accuracy for the fuel flow meter, and ± 0.2 percent accuracy goal for fuel heating value. The accuracy goals for each measurement were met, and in some cases they were exceeded. The following summarizes actual errors achieved, and the methods used to compute them.

Power Output: Factory calibrations of the 7600 ION with a NIST-traceable standard resulted in ± 0.05 percent error in power measurement. Reasonablness checks were performed in the field to ensure data quality. Comparisons of voltage and current output with a handheld digital multimeter, and comparisons with SCADA output passed the required criteria. As a result, the power meter was verified to be functioning properly and factory calibration result was used to compute errors in electrical efficiency. Complete documentation of data quality results is provided in Section 3.2.2.

Fuel Flow Rate: The dry gas meter was calibrated by the gas company using a volume prover, before and after testing. The calibration proof was 99.6 percent at full scale. The dry gas meter readings were corrected to standard conditions using actual gas temperature and pressure measurements. Both meters were calibrated with NIST-traceable standards prior to use in the field, and resulted in a ± 0.2 percent error in flow rates. This value was used to compute errors in electrical efficiency. Complete documentation of data quality results is provided in Section 3.2.3.

Fuel LHV: Data quality of fuel analysis was performed by comparing laboratory results with NIST-traceable audit gas, conducting duplicate analysis of the same sample, and collecting replicate samples in the field. The Test Plan specified using the results of duplicate analysis to compute electrical efficiency error. As discussed in Section 3.2.4, all QA/QC procedures resulted in generally good quality data. The LHV goal of ± 0.1 percent was satisfied exactly.

Based on actual errors achieved in power output, fuel flow rate, and fuel LHV measurements, electrical efficiency error was less than 0.08 percent at all loads (i.e., at full load, average efficiency was 23.44 ± 0.08 percent).

Per ASME PTC22 guidelines, efficiency determinations were to be performed within time intervals in which maximum variability in key turbine operational parameters did not exceed specified levels. Table 3-3 summarizes the maximum permissible variations observed in power output, power factor, fuel flow rate, barometric pressure, and ambient temperature. As shown in Table 3-3, the requirements for all parameters were generally met for each of the 12 test runs. Thus, it can be concluded that the PTC22 requirements were met, and the efficiency determination is representative of stable operating conditions.

Table 3-3. Variability Observed In Operating Conditions

Measured Parameter	Maximum Allowed Variation[a] In Measured Parameters												
	Allowed Under PTC 22	Actual (Run Number)											
		1	2	3	4	5	6	7	8	9	10	11	12
Power Output (%)	± 2	0.08	0.17	0.11	0.09	0.12	0.18	0.12	0.10	0.11	0.17	0.18	0.17
Power Factor (%)	± 2	0.00	0.01	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.02	0.02
Fuel Flow Rate[b] (%)	± 2	1.40	1.26	1.71	1.87	1.86	1.37	1.63	1.57	2.06	0.82	0.48	0.42
Inlet Air Pressure (%)	± 0.5	0.05	0.05	0.05	0.05	0.05	0.06	0.10	0.07	0.06	0.07	0.07	0.08
Inlet Air Temperature (°F)	± 4	0.46	0.90	0.33	0.37	1.53	1.50	2.30	1.07	1.02	0.84	1.02	0.67

[a] = (Average of Test Run – Observed Value) / Average of Test Run * 100

[b] As discussed earlier, a positive bias in the integral orifice readings was observed. These data were not used to compute electrical efficiency, but are used to demonstrate the overall stability in gas flow rates within a test run. The data in the table are corrected per the equation shown in Figure 3-1 (Section 3.2.3).

3.2.2. Power Output and Power Quality Measurements

Instrumentation used to measure power was introduced in Section 1.0 and included a 7600 ION on the Turbogenerator, and a 7500 ION on the grid. For power output, the data quality objective was set at ± 0.2 percent in the Test Plan. This equates to an error of ± 0.14 kW at full load, which is more stringent than the "typical uncertainty" set forth in PTC22 of 1.8 percent.

The DQIs for both meters with respect to accuracy of power, current, voltage, and frequency are summarized in Table 3-2. Both meters were factory calibrated by Power Measurements prior to being delivered to the test site. Calibrations were conducted in accordance with Power Measurements strict standard operating procedures (in compliance with ISO 9002-1994) and are traceable to NIST standards. Pre-test factory calibrations on both meters indicated that the error was within ± 0.05 percent, if reading across the entire range, exceeding the DQI goals for power output and power quality. Both meters were certified by Power Measurements to meet or exceed the accuracy values summarized in Table 3-2 for power output, voltage, current, and frequency. At the conclusion of the field testing, the ION 7600 meter was returned to Power Measurements and calibrated as received to evaluate post-test accuracy. These calibrations indicated that the voltage and current accuracy of the meter was well within the goals specified in Table 3-2 (as received errors were < 0.05 percent for voltage and < 0.03 percent for current).

Additional QC checks were performed in the field to verify the operation of the electrical meters, as shown in Table 3-4. To check power output, Turbogenerator power measured using the 7600 ION was compared to the power output reported by the Turbogenerator's software system (reports total power generated). During this check, the 7600 ION reported 70.65 kW during steady-state operation at full load. Adding the power consumed by the fuel compressor (about 4.36 kW) to the total power output reported by the 7600 ION yields 75.01 kW of total power generated. During this time, the Turbogenerator SCADA system reported a power output of 74.9 kW. Current and voltage readings were also checked for reasonableness using a hand-held Fluke Multimeter. These checks confirmed that the voltage and current readings from the 7600 ION were within 1 percent of the readings obtained with the Fluke.

Table 3-4. Results of Additional QA/QC Checks				
Measurement Variable	**QA/QC Check**	**When Performed/Frequency**	**Allowable Result**	**Results Achieved**
Power Output and Power Quality	Reasonableness checks	Throughout test	Readings should range between 70 and 74 kW at full load	All readings at full load between 70 and 72 kW (Figure 2-1)
	Comparison with SCADA power output report	Beginning of verification test	Within ± 1 % reading	Readings within 0.1 %
	Sensor diagnostics in field – voltage and current comparisons with a digital multimeter	Beginning of verification test	Voltage and current checks within ± 1 % reading	± 0.82 % voltage ± 1.03 % current
Fuel Flow Rate	Sensor diagnostics	Beginning and end of verification test	Pass	Passed all sensor diagnostic checks
	Independent performance check with a dry gas meter	Beginning and end of verification test	Average percent difference between the two meters should be less than ± 2.0 %	Positive bias at high flow rates (see discussion in section 3.2.3)
	Reasonableness checks	Throughout test	Readings should be between 17 and 20 scfm at full load	All readings within specified range
Fuel Heating Value	Replicate samples collected in field	Once during each load testing	Average percent difference between replicates should be less than ± 0.2 %	Replicate samples differ by 0.27 % (excluding invalid samples)
Ambient Meteorological Conditions	Reasonableness checks	Throughout test	Recording should be comparable with local airport data	Readings were consistent with monitoring station
Fuel Gas Pressure	Reasonableness checks	Throughout test	Readings should range between 1 and 3 psig	All readings were within specified range

3.2.3. Fuel Flow Rate Measurements

The Test Plan specified the use of an integral orifice meter (Rosemount Model 3095) to measure the flow of natural gas supplied to the Turbogenerator. The integral orifice meter was factory calibrated prior to installation in the field, and its calibration records were reviewed to ensure the instrument rated ± 1 percent accuracy was satisfied. The factory calibration is reported to be valid for 3 years, and thus it was not required to re-calibrate the meter over the duration of the test.

Several QC checks, listed in Table 3-4, were conducted to ensure proper function in the field. These included specifying actual natural gas properties (e.g., gas composition and gas density at standard conditions determined through heating value analyses) into the Rosemount Engineering Assistance software, and maintaining written records of user-supplied input parameters. In addition to this, QC checks were performed immediately prior to load testing which included: (1) sensor diagnostic checks and (2) independent verification with a second meter. Sensor diagnostic checks consisted of zero flow verification by isolating the meter from the flow stream. The sensor output must read 0 flow during these checks. Transmitter analog output checks, known as the loop test, consist of checking a current of known amount against a fluke multimeter to ensure that 4 and 20 mA signals are produced. Finally, a dry gas meter, installed in series by the local utility, was used to independently verify the Rosemount flow meter output. The dry gas meter was calibrated by the utility using a volume prover and the meter calibration proof was 99.6 percent at full scale.

Despite extensive QC checks, the data collected with the integral orifice meter were invalidated due to a positive bias observed at high flow regimes (12 to 19 scfm). Upon further investigation and communications with Rosemount technicians, it was concluded that pipe fittings, installed close to the upstream and downstream sides of the integral orifice, caused turbulence and likely caused the meter to read high flow rates. Two separate pipe couplings were installed immediately before and after the meter assembly (Figure 1-4), so the meter could be easily dismantled after the field test was completed. Integral orifices are designed to operate in an undistributed flow field such that the velocity distribution, formed by the restriction created by the orifice plate, is normally distributed between two separate pressure sensor taps. Accurate measurement of flows relies on the pressure drop measurements across the orifice plate and experimentally derived orifice coefficients which relate flow as a function of orifice diameter to pipe diameter and Reynolds number. It is hypothesized that the additional disturbances caused by the couplings resulted in a change in these relationships.

Fortunately, a backup flow meter was available at the test site. A dry gas meter, certified and supplied by a local gas company, was installed in series with the integral orifice meter, and its data were used to report fuel consumption rates and compute electrical efficiency for the Turbogenerator.

Dry gas meter flow rates during a single-load test were computed by taking manual dry gas meter readings over the entire test period [in units of actual cubic feet (acf)], and then correcting the dry gas meter readings to standard conditions. Actual gas pressure and temperature measurements data, collected simultaneously with the GHG Center's calibrated equipment, were used in Equation 3. The fuel flow variability data presented in Table 3-3 indicate that very little variation existed, and therefore, averages computed using this procedure are highly representative.

$$\text{Dry gas meter reading (scf)} = \text{Gas Volume Measured (acf)} * (T_{std}/T_g) * (P_g/P_{std}) * C_m \qquad \text{(Eqn. 3)}$$

Where:
T_{std} = standard temperature (519.67 ^{o}R)
T_g = measured gas temperature (^{o}R)
P_{std} = standard temperature (14.696 psia)
P_g = measured gas pressure (psia)
C_m = meter calibration coefficient (99.6 %)

The standardized gas volume was then divided by the duration of the sampling interval to yield average gas flow as standard cubic feet per minute (scfm). This totaled volume method of computing fuel consumption was adequate for computing electrical efficiency; however, 1-minute fuel flow rates were needed to determine if the PTC22 requirements for maximum permissible variation were satisfied (discussed in Section 3.2.1). To perform this check, the orifice meter data were corrected to reduce the impact of the observed bias. This was done using a correlation developed from comparisons of the orifice meter flow data with the dry gas meter flows, using a correlation developed using the dry gas meter data.

The results of field comparisons between the integral orifice meter and the in-line dry gas meter are presented in Table 3-5.

Table 3-5. Comparison of Integral Orifice Meter With Dry Gas Meter During Load Testing

Test Condition (% of Rated Power)	Run Number	Power Delivered (kW)	Integral Orifice Meter Reading (scfm)	Gas Pressure (psia)	Gas Temp. (^oF)	Dry Gas Meter Reading (scfm)	Percent Difference[a] (%)
100	1	71.28	19.23	16.98	62.97	18.19	5.41
	2	71.25	19.18	16.99	62.60	18.14	5.42
	3	71.24	19.19	16.99	63.50	18.23	5.00
90	4	64.63	17.39	17.04	65.00	16.58	4.66
	5	64.71	17.47	17.05	66.16	16.74	4.18
	6	64.78	17.52	17.07	67.25	16.72	4.57
75	7	53.40	14.42	17.07	67.25	14.12	2.08
	8	53.35	14.39	17.09	67.03	14.08	2.15
	9	53.33	14.38	17.08	67.25	14.14	1.67
50	10	35.91	10.90	17.15	68.60	10.93	-0.28
	11	35.91	10.89	17.13	67.85	10.86	0.28
	12	35.88	10.92	17.13	66.75	10.88	0.37

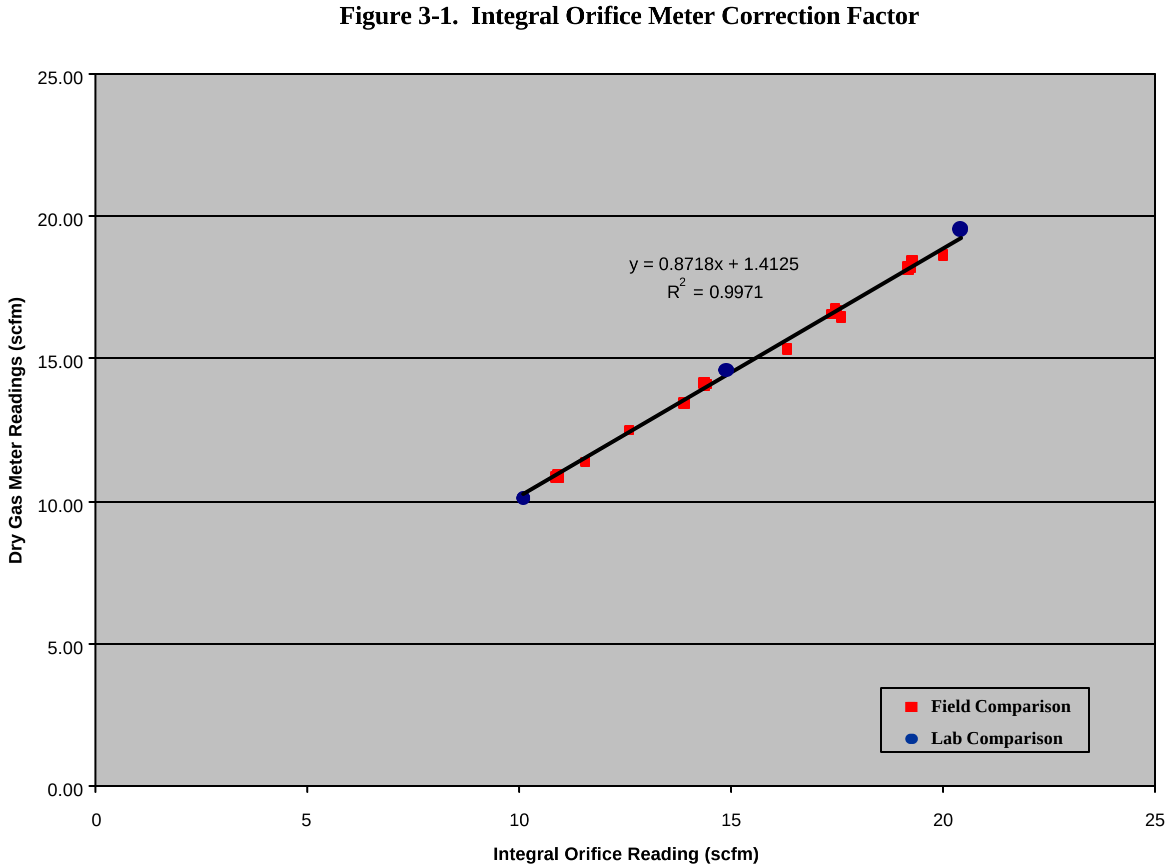
[a] = (Integral Orifice Reading – Dry Gas Reading)/Integral Orifice Reading * 100

As shown in the table, the greatest difference was observed during full-load test runs, which is approximately two times higher than the propagated error of the two meters (± 5.14 percent). At low-load test runs, the difference was within the tolerable error specified in the Test Plan. Due to these observed differences, additional measurements data were collected in the field and at the GHG Center's laboratory. These data were collected to further substantiate and support using the dry gas meter readings to satisfy the requirements of PTC22, and computing performance results for the Turbogenerator.

At the conclusion of the test, the entire integral orifice assembly, complete with associated piping and fittings, was dismantled, brought to the GHG Center's laboratory, and reassembled exactly as it was in the field to perform independent verification with a second dry gas meter. The reference dry gas meter was an Equimeter Model 750, calibrated to a proof of 100.0 percent in March 2001 by Standard Gas Meter, Inc. using a volume prover.

Figure 3-1 illustrates the meter comparison data collected in the field and in the laboratory, and shows the equation developed to correct the integral orifice data. As shown in Figure 3-1, the differences between the readings are similar to the field measurements, and demonstrate a positive bias at the upper flow rates (± 4.48 percent). Figure 3-1 also shows a linear relationship in the field and laboratory comparisons, and the linear regression equation (shown in Figure 3-1) was used to determine the maximum permissible variation observed in the natural gas flow rates.

Figure 3-1. Integral Orifice Meter Correction Factor



3.2.4. Fuel Heating Value Measurements

Fuel gas samples were collected no less than once per test load condition. Full documentation of sample collection date, time, run number, and canister ID was logged along with laboratory chain of custody forms and shipped along with the samples. Copies of the chain of custody forms and results of the analyses are stored in the GHG Center project files. Collected samples were shipped to Core Laboratories for compositional analysis and determination of LHV per ASTM test methods D1945 and D3588, respectively. The data quality indicator goals were to measure methane concentration that was within ± 0.2 percent of a NIST-traceable calibration gas and a blind audit sample, and to achieve a maximum difference of ± 0.1 percent in the LHV results in duplicate analyses of one sample. As shown in Table 3-2, these goals were met.

Core Laboratory calibrated the GC/FID daily using a continuous calibration verification standard. Table 3-6 summarizes the calibration results for the load test samples analyzed by the laboratory. The results for all gas species were within the ASTM specified levels, including methane, which was met with the DQI goal.

Table 3-6. GC/FID Calibration Results		
Gas Component	**True Component Value (%)**	**Analyzer Response (%)**
Oxygen	0.0010	0.000
Nitrogen	5.000	5.000
Methane	70.487	70.487
Ethane	9.002	9.000
Carbon Dioxide	0.998	0.998
Propane	6.003	6.000
Isobutane	3.001	3.020
N-Butane	3.010	2.992
Isopentane	0.998	1.005
N-Pentane	1.000	1.004

A blind audit sample was submitted to the laboratory along with the samples. The audit was collected in a sample canister using the same procedures used in the field. A cylinder of compressed methane was used to generate the audit. The cylinder was certified to be at least 99.7 percent pure methane, and the laboratory returned a result of 99.89 percent, with a duplicate analysis of 99.88 percent, for an error of 0.19 percent which meets the DQI goal.

For some of the samples, duplicate analyses were performed by the laboratory to verify repeatability as required by the ASTM Method. These results were used to determine if the LHV results were within ± 0.1 percent as specified by the GHG Center. Duplicate analyses were conducted on three samples to evaluate analytical repeatability. Table 3-7 summarizes the results, and indicates that the average error in the duplicate analyses was 0.1 percent, which meets the DQI goal.

Table 3-7. Summary of Duplicate Analyses				
Sample Collection Date (Time)	**Run ID**	**Methane Content (%)**	**LHV (Btu/ft^3)**	**Results**
4/10/01 (0930)	3[a]	73.41	728.3	LHV differs by 0.1 %
		73.58	727.8	
4/11/01 (1615)	2C	93.68	945.7	LHV differs by 0.2 %
		93.60	943.4	
4/16/01 (1130)	Audit Gas[b] (Blind)	99.89	910.7	LHV differs by 0.0 %
		99.88	910.6	

[a] LHV results were not used in reporting verification results due to sample contamination with air (nitrogen and oxygen levels are high, and the methane concentrations are low). However, the percent difference in duplicate analyses was below the ± 0.1 percent goal, which indicates the laboratory results are repeatable.
[b] Certified by manufacturer to be at least 99.7 percent pure methane

As an additional QC check, three replicate samples, collected simultaneously, were used to assess sampling error. Two of the replicates were within 0.5 percent. The replicate samples collected for Run 1A disagrees by about 3.3 percent. However, the analytical composition of the primary sample collected during this run is suspicious, and was invalidated. Specifically, the methane level in that sample was atypically high, and no ethane was reported in the analysis (all other samples reported ethane concentrations around 3 to 4 percent).

Table 3-8. Summary of Replicate Analyses

Sample Collection Date (Time)	Run ID	Methane Content (%)	LHV (Btu/ft^3)	Results
12/19/00 (0820)	1A	96.78	910.9	LHV differs by 3.3 %
		94.28	941.1	
12/19/00 (1510)	8A	94.25	946.5	LHV differs by 0.5 %
		94.37	941.3	
12/20/00 (1602)	12A	94.30	941.5	LHV differs by 0.0 %
		94.41	941.1	

3.2.5. Exhaust Stack Emission Measurements

EPA Reference Methods were used to quantify emission rates of criteria pollutants and GHGs. The Reference Methods specify the sampling and calibration procedures, and data quality checks that must be followed. These Methods ensure that run-specific quantification of instrument and sampling system drift and accuracy occurred throughout the emissions tests. The DQOs specified in the Test Plan were ± 2 percent for NO_X, ± 5 percent for CO_2, CH_4, CO, and THC, and ± 10 percent for VOC emissions. The data quality indicator goals required to meet these DQOs consisted of an assessment of: (1) sampling system calibration error and drift for NO_X and THC and (2) sampling system bias and drift for CO, CO_2, and O_2.

<u>NO_X and THC</u>

The sampling system calibration error test was conducted prior to the start of the first test run on the NO_X and THC sampling systems. The calibration was conducted by sequentially introducing a suite of calibration gases to the sampling system at the sampling probe, and recording the system response. Calibrations were conducted on all analyzers using Protocol No. 1 calibration gases. Four calibration gases of NO_X and THCs were used, including: 0, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. As shown in Table 3-2, the system calibration error goal for NO_X was ± 2 percent, and the actual measured error was ± 1.6 percent which indicates that the goal was met. For THCs, the maximum system calibration error was determined to be ± 2.3 percent, which is also below the stated goal for this parameter.

At the conclusion of each test run, the zero and mid-level calibration gases were again introduced to the sampling systems at the probe and the response recorded. System response was compared to the initial calibration error to determine sampling system drift. The sampling system drift was determined to be 0.5 percent for NO_X and 2.1 percent for THCs (Table 3-2), which were both below the required goal. Sampling system calibration error results and drift results for all runs conducted during the verification are summarized in Appendix A-2.

Two additional QC checks were performed to better quantify the NO_X data quality. In accordance with Method 20, an interference test was conducted on the NO_X analyzer once before the testing started. This test confirms that the presence of other pollutants in the exhaust gas do not interfere with the accuracy of the NO_X analyzer. This test was conducted by injecting the following calibration gases into the analyzer and recording the response of the NO_X analyzer, which must be zero ± 2 percent of span. As shown in

Table 3-9, the maximum measured value was well below the ± 2 percent of analyzer span required by the method.

- CO – 600 ppm in balance nitrogen (N_2)
- O_2 – 255 ppm in N_2
- CO_2 – 10 percent in N_2
- O_2 – 22 percent in N_2

The second QC check consisted of determining NO_2 converter efficiency prior to beginning of emissions testing. The NO_X analyzer converts any NO_2 present in the gas stream to NO prior to gas analysis. This procedure was conducted by introducing to the analyzer a mixture of mid-level calibration gas and air. The analyzer response was recorded 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 and the analyzer must be either repaired or replaced prior to testing. As shown in Table 3-9, the converter efficiency was measured to be 99.3 percent and was above the efficiency level required.

CO, CO_2, and O_2

Analyzer calibrations were conducted to verify the error in CO, CO_2, and O_2 measurements relative to calibration gas standards. The calibration error test was conducted at the beginning of each test day, and again after switching the CO analyzer to a higher range for the low load testing. A suite of calibration gases were introduced directly to the analyzer, and analyzer responses were recorded. EPA Protocol 1 calibration gases were used for these calibrations. Three gases were used for CO_2 and O_2, including: 0, 40 to 60 percent of span, and 80 to 100 percent of span. Four gases were used for CO, including: 0 and approximately 30, 60, and 90 percent of span. The analyzer calibration errors for all gases were below the allowable levels as shown in Table 3-9. Results of each of the analyzer calibrations, including linearity tests, are provided in Appendix A-1 for all test runs.

Before and after each test run conducted, the zero and mid-level calibration gases were introduced to the sampling system at the probe, and the response was recorded. System bias was calculated by comparing the system responses to the calibration error recorded above. As shown in Table 3-2, the system bias goal for CO, CO_2, and O_2 was ± 5 percent, and the actual measured values were less than 2.0, 1.4, and 1.1 percent, respectively. The pre- and post-test system bias calibrations were also used to calculate drift for each pollutant. The zero gas O_2 system bias checks were also used to verifiy the absence of leaks in the sampling system. The highest O_2 value recorded during the zero gas system calibration checks was 0.04 percent. As shown in Table 3-2, the maximum drift measured was 0.6 percent for CO, 0.3 percent for CO_2, and 0.2 percent for O_2. In conclusion, the system bias goals and drift goals were met for all pollutants. Appendix A-2 summarizes the sampling system bias and drift results for all test runs.

Results of each of the analyzer and sampling system calibrations conducted, including instrument linearity tests and sampling system bias and drift checks, are presented in Appendix A-2.

Table 3-9. Results of Additional Emissions Testing QC Checks				
Parameter	**QA/QC Check**	**When Performed/Frequency**	**Expected or Allowable Result**	**Maximum Result Measured During Load Tests**
Sampling System	System leak check	Before and after each test run	$\leq$ 1.0 %	0.04 % O_2
NO_X	Analyzer interference check	Once before testing begins	±2 % of analyzer span or less	0.54 %
	NO_2 converter efficiency	Once before testing begins	98 % efficiency or greater	99.3 % efficiency
	Audit gas (9.17 ppm NO in N_2)	At the end of test after low NO_X levels were measured	± 2 % of analyzer span	8.85 ppm or 0.32 % of span
CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span or less	1.7 % for CO 1.3 % for CO_2 0.6 % for O_2
CO	Audit gas (9.06 ppm CO in N_2)	At the end of test after low NO_X levels were measured	± 5 % of analyzer span	8.91 ppm or 0.15 % of span
CH_4	Calibration with reference gas standard	Prior to analysis of each lot of samples submitted	±2 % for CH_4 concentration	10 %*

* The accuracy goal for CH_4 was misstated in the Test Plan and not achieved. The nature of Method 18 is such that collection of gas in a bag, injection of a sample into the analytical equipment, and analytical quantification are generally expected to result in errors of around ± 10 percent of reading.

CH_4

As shown in Table 3-2, the laboratory that conducted the methane analyses reported an overall uncertainty in the methane analyses of approximately 10 percent (based on analyzer calibrations to standards), and cited this error as generally acceptable for Method 18. As required by Method 18, a spike and recovery check was also conducted. Using sample 6B collected in the field, a calculated spike value of 36.9 ppm methane was introduced into the sample bag and later analyzed. The analytical result was 41.5 ppm, for a spike and recovery efficiency of 112 percent. This result is well within the Method 18 recovery efficiency requirement of 70 to 130 percent.

NO_X and CO Audit Gas Analysis

Instrument operating ranges and calibration gases were selected based on concentrations expected in the exhaust gas. During testing, very low concentrations of NO_X and CO were measured (NO_X as low as around 7 ppm and CO concentrations below 2 ppm). The low range calibration gases used by the emissions testing contractor were approximately 25.4 ppm for NO_X and 31.8 ppm for CO. Even though both analyzers passed the pre-test linearity checks, the GHG Center procured lower range calibration gases to use as an additional QC check for low-range measurements. The gases were introduced to the sampling system as a blind audit, and the system responses were recorded by Center personnel. As shown in Table 3-9, the system measured the audit gas that was within 0.32 and 0.15 percent of span for NO and CO, respectively.

Sampling System Leak Checks

EPA Reference Methods for gaseous sampling systems do not specify leak checks or provide specific leak check procedures. However, leaks in the sampling system can present a significant error in the measurements, so care is needed to ensure that leaks are not present in the system. The most common method of detecting leaks in the sampling system is to introduce a zero calibration gas (common nitrogen) at atmospheric pressure into the sampling probe. The N_2 gas is run through the entire sampling system to the oxygen analyzer. Most sampling systems (including the system used for this test) use vacuum pumps to extract gas from the source, so any leaks in the sampling system will result in an elevated O_2 reading during the zero check.

These sampling system zero checks were conducted before and after every test conducted during this verification. The highest O_2 response to the zero gas system check was 0.04 percent, indicating that leaks were not present in the system during the tests. Results for all test runs conducted are summarized in Appendix A-2.

At the start of sampling, O_2 concentrations in the stack gas were measured at 18 percent or higher. At this point, GHG Center personnel directed the testing contractor to conduct an additional leak check by plugging the tip of the sampling probe and pulling a vacuum on the system using the sampling pump. The sampling rate rotameter was observed until it reached a zero reading (not that most sampling pumps can create a vacuum on the system of greater than 15 in. Hg). Significant leaks in the system would result in a rotameter reading higher than zero. This test is another good indicator of sampling system integrity and was repeated at the beginning of each day of testing. No leaks were detected in the sampling system on any of the days using this test.

ISO Corrections

The Test Plan specified that NO_X concentrations be corrected to ISO standard day conditions in accordance with 40 CFR 60, Subpart GG. The GHG Center has determined that these corrections may not be appropriate for this source because the provisions of Subpart GG are applicable only to gas turbines utilizing diffusion-flame type combustors, with conventional control schemes. For a low-NO_X premix-type combustor, as in the Turbogenerator, NO_X production is controlled primarily by the actions of the fuel control system, which distribute fuel within the combustor in accordance with measured engine operating parameters. Thus, to accurately predict system emissions at ISO conditions based on data measured at non-ISO conditions, it is necessary to use a mathematical model of the Turbogenerator system to scale engine operating parameters to ISO. ISO emissions may then be calculated from these scaled engine parameters, using correlations developed through testing performed by the manufacturer. This technique has been validated by Honeywell for the Turbogenerator by measuring emissions for individual systems at various ambient temperatures and pressure altitudes, and for the same systems at nearly standard conditions.

For the test series reported here, average NO_X emissions at full operating load were measured as 18.6 ppm @ 15 percent O_2. Using the correction scheme described above, ISO standard day emissions reported by Honeywell are calculated to be 18.4 ppm @ 15 percent O_2. Mass emission rates based on measured data were 9.74 E-04 lb/kWh, which are reduced to 9.64 E-04 using the ISO correction scheme.

3.2.6. Gas Compressor Methane Leak Testing

Testing was conducted to detect methane leaks at the booster compressor where the fuel gas was pressurized. Twice during the verification period, screening for leaks was performed to identify major leaks at compressor seals, valves, connections, and fittings using soap screening methods and a portable hydrocarbon analyzer. No significant leaks were detected and, therefore, no leak rate quantification testing was needed.

A Bascom-Turner CGI-201 hydrocarbon analyzer was used to screen for hydrocarbons, including methane. It is capable of detecting 0.05 to 100 percent total hydrocarbon concentration, with an accuracy of ± 2 percent of reading. The CGI-201 was calibrated prior to the verification period. Calibration was performed in the laboratory using certified methane standards of 0.0, 2.5, 49.7, and 100 percent methane. The calibration apparatus was provided by the manufacturer (Part numbers MC-105 and PCA-001), and the manufacturer's calibration procedures were followed.

3.2.7. Ambient Measurements

Ambient temperatures and pressures at the site were monitored throughout the extended verification period and the load tests. Relative humidity was also recorded during the load test periods. The instrumentation used is identified in Table 3-2 along with instrument ranges, data quality goals, and data quality achieved. Two different pressure sensors were used to record ambient pressures during the testing. The Setra Pressure transducer was used during the extended monitoring period, and a Vaisala pressure sensor was used to record pressures during the load tests.

Both pressure sensors and the relative humidity probe were factory calibrated prior to the verification testing using reference materials traceable to NIST standards. The temperature sensor was calibrated at the U.S. EPA laboratory facility in Research Triangle Park, NC, using a NIST-traceable reference standard. Results of these calibrations indicate that the ± 2 ^{o}F accuracy goal for temperature, ± 0.1 percent for pressure, and ± 3 percent for relative humidity were met.

4.0 TECHNICAL AND PERFORMANCE DATA SUPPLIED BY HONEYWELL

4.1. INTRODUCTION

Honeywell Power Systems, Inc., a subsidiary of Honeywell International, is the developer and manufacturer of the Parallon® 75 kW Turbogenerator, a compact 75-kW power source that uses a microturbine to convert natural gas or liquid fuels into electricity for on-site power generation and combined heat and power applications. Today, the Turbogenerator is field-proven with more than 380,000 hours of operation around the world. It is capable of producing premium power in either grid parallel or stand-alone conditions and can currently be equipped with the following options:

- Display Panel (for on-site control and monitoring)
- SCADA (for remote control and monitoring)
- Fully integrated reciprocating gas compressor (for gas pressures of 15 to 30 psia)
- Black Start module/Stand Alone (for operation without the grid)
- Load Sequencer plus Automatic Grid to Stand-Alone Transition (for automatic backup power)
- Electric Meter with Grid Parallel Load Following
- Internal Auto-Transformer for 60 Hz, 120/208V (U.S.) (other voltages/frequencies available)
- External Isolation Transformers for 60 Hz, 277/480V (U.S.) (other voltages/frequencies available)
- Hot Water Cogeneration Module
- Side or Bottom Entry Wiring Kits
- External Protective Relay (satisfies CA and NY utility interconnect requirements)
- Liquid Fuel Option

4.2. POWER OUTPUT PERFORMANCE

Every Turbogenerator is acceptance tested at the factory prior to shipment. A portion of this test includes measuring efficiency. The Turbogenerator's base unit design specification states 27.0 percent minimum at full power ISO conditions; however, the average base unit efficiency of the production fleet (354 systems) is 29.01 percent with a standard deviation of 0.82 percent. This equates to approximately 27.0 percent for units with a gas compressor and transformer. Although the efficiency results for the unit tested in this report is not representative of the Parallon fleet, we believe it is due to the following. First of all, there were signs of inlet heating, due possibly to exhaust reingestion. This is apparent due to the fact that the ambient temperature measured approximately 60 °F, but the inlet temperature sensor in the unit was reading approximately 87 °F. This discrepancy did not occur during the entire test period, and there is no reason to believe there were any temperature sensor failures or problems. Therefore, because the temperature of the air into the compressor measured approximately 87 °F instead of close to ISO conditions, the unit will not be as efficient as it would be at approximately 60 °F. In addition, we believe that this particular unit had a weak permanent-magnet generator, which is not typical of the fleet. Unfortunately, the weak generator produced a lower voltage such that the system could not be run to its maximum turbine exit temperature. This lower temperature caused a reduction in thermal efficiency that would not have occurred with a normal generator. A new core engine acceptance test has been introduced since the time the unit was built that tests for weak generators.

Regarding output power, this report has verified the ability of the Turbogenerator to satisfy its design of specification at ISO conditions of 75 kW minimum continuous rating at the inverter output (excluding options, such as the transformer and gas compressor, which are not part of the basic unit).

Finally, in a peak shaving, base load, or cogeneration application, part power performance is not nearly as critical as full load performance. Among the existing grid parallel installations of Turbogenerators around the world, none are programmed to intentionally run at 50 percent power. Therefore, more emphasis should be placed on the results of full load or near full load performance rather than on 50 percent part load performance when considering the Turbogenerator for a commercial application.

4.3. EMISSIONS PERFORMANCE

The current version of the Turbogenerator microturbine was designed to meet emissions of less than 25 ppmvd NO_X and 50 ppmvd CO corrected to 15 percent O_2, at full power, when operated at ISO standard day conditions. This report has verified the ability of the Turbogenerator to satisfy these design targets. The optional CO control device, tested separately and reported in a separate Verification Report (SRI 2001), allows the CO target to be met down to 50 percent load conditions. Currently completing development is a low-NO_X option, which will meet 9 ppmvd NO_X @ 15 percent O_2, full power ISO-standard day, and which will be available in the fall of 2001. A further option, available later in 2001, will extend low-NO_X operation to part-load conditions.

4.4. POWER QUALITY

This report has verified the ability of the Turbogenerator to satisfy its design specification with regards to power quality:

In the Grid-Connected Mode, the standard power electronics will be able to parallel and auto synchronize with the grid.

Frequency Output (nominal)	50 or 60 Hz (configured in software)
Frequency Operating Tolerance	± 5 % (adjustable limits within band in Grid Mode)
Operating Output Voltage (line-to-line)	3-phase 275 VAC
Operating Tolerance: Grid Mode	+ 15 % / -20 % (adjustable limit within band)

Operational Parameters (Grid Mode):

The Turbogenerator shall deliver 75 KVA, 1.0 pf into the grid within the voltage operating range of + 15 to -20 percent.

The THD harmonic current shall be less than the value specified below, when operated at unity pf, when the grid harmonic current is equal to or less than 1 percent:

Maximum Total Distortion	5 % from 75 % to 100 %, 1.0 power factor
Maximum Single Harmonic	3 % from 75 % to 100 %, 1.0 power factor

Power Factor Accuracy:

Actual pf shall be within 0.05 pf of the commanded value, measured at the output terminals of the Turbogenerator.

4.5. OPERATIONAL PERFORMANCE

Cold-start times were as expected for a unit with a natural gas compressor.

Honeywell's current Turbogenerator fleet average availability is 98 percent as defined by:

(Elapsed Time – Unscheduled Downtime)/Elapsed Time

where:

Elapsed Time = Time since unit was initially commissioned

5.0 REFERENCES

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APPENDIX A

Appendix A-1 presents instrument calibration error and linearity checks for each of the analyzers used for emissions testing. These calibrations are conducted once at the beginning of each day of testing, and after any changes or adjustments to the sampling system are conducted (changing analyzer range, for example). All of the calibration error results are within the specifications of the Reference Methods.

Appendix A-2 summarizes the system bias and drift checks conducted on the sampling system for each pollutant quantified. These system calibrations are conducted before and after each test run. Results of all of the calibrations are within the specifications of the Reference Methods.

Appendix 3 summarizes the measured heat input for each test run, and corresponding fuel F-factors and exhaust gas flow rates calculated using Method 19.

Appendix A-1 - Summary of Emission Analyzer Linearity Tests - April 10, 2001

Run Number	Gas	Analyzer Span (ppm for NO_x, CO, THCs; % for CO_2, O_2)	Cal Gas Value	Analyzer Response	Calibration Error (% of Span)
Pre-Run 1	NO_x	100	0.00	-0.12	**-0.12**
			25.40	25.09	**-0.31**
			43.90	44.43	**0.53**
			90.83	90.26	**-0.57**
	CO	100	0.00	0.00	**0.00**
			31.80	31.05	**-0.75**
			60.10	59.31	**-0.79**
			91.70	91.04	**-0.66**
	CO_2	20	0.00	0.26	**1.30**
			10.00	9.93	**-0.35**
			18.20	18.21	**0.05**
	O_2	25	0.00	-0.01	**-0.02**
			10.00	10.09	**0.36**
			22.00	22.08	**0.32**
	THC	100	0.00	1.34	**1.34**
			25.80	24.13	**-1.67**
			50.30	49.93	**-0.37**
			84.30	84.99	**0.69**
Pre-Run 10	NO_x	100	0.00	-0.02	**-0.02**
			25.40	25.48	**0.08**
			43.90	44.87	**0.97**
			90.83	91.84	**1.01**
	CO	1000	0.00	0.10	**0.01**
			302.10	285.10	**-1.70**
			608.30	599.30	**-0.90**
			900.00	900.60	**0.06**
	CO_2	20	0.00	0.03	**0.14**
			10.00	9.98	**-0.13**
			18.20	18.32	**0.58**
	O_2	25	0.00	-0.03	**-0.13**
			10.00	10.11	**0.44**
			22.00	22.16	**0.64**
	THC	100	0.00	-0.10	**-0.10**
			25.80	23.88	**-1.92**
			50.30	48.65	**-1.65**
			84.30	82.37	**-1.93**

Appendix A-2. Summary of Reference Method System Error (or Bias where applicable) and Drift Checks (as percent of span)

Run Number:		Initial Cal	1	2	3	New Initial Cal	4	5	6	7	8	9	10	11	12
NO_x Zero	System Response (ppm)	-0.12	0.09	0.06	0.07	-0.12	0.10	0.09	0.11	0.21	0.21	0.19	0.38	0.23	0.30
	System Error (% span)	-0.1	0.1	0.1	0.1	-0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.4	0.2	0.3
	Drift (% span)	NA	0.2	0.0	0.0	NA	0.2	0.0	0.0	0.1	0.0	0.0	0.2	-0.2	0.1
NO_x Mid	System Response (ppm)	90.26	89.13	88.64	88.84	25.09	24.54	24.78	24.73	24.78	24.87	24.71	24.93	24.82	24.95
	System Error (% span)	-0.6	-1.1	-1.6	-1.4	-0.3	-0.6	-0.3	-0.4	-0.3	-0.2	-0.4	-0.2	-0.3	-0.1
	Drift (% span)	NA	-1.1	-0.5	0.2	NA	-0.6	0.2	-0.1	0.1	0.1	-0.2	0.2	-0.1	0.1
CO Zero	System Response (ppm)	0.00	0.88	0.70	0.73	0.00	0.85	0.74	0.88	0.85	0.95	0.60	1.80	0.90	1.70
	System Bias (% span)	0.0	0.9	0.7	0.7	0.0	0.9	0.7	0.9	0.9	1.0	0.6	1.8	0.9	1.7
	Drift (% span)	NA	0.9	-0.2	0.0	NA	0.9	-0.1	0.1	0.0	0.1	-0.4	1.2	-0.9	0.8
CO Mid	System Response (ppm)	91.04	92.48	91.89	92.14	31.05	31.56	31.77	31.78	31.76	31.76	31.79	304.70	303.80	302.30
	System Bias (% span)	-0.7	1.4	0.8	1.1	0.9	0.5	0.7	0.7	0.7	0.7	0.7	0.3	0.2	0.0
	Drift (% span)	NA	1.4	-0.6	0.3	NA	0.5	0.2	0.0	0.0	0.0	0.0	NA	-0.1	-0.2
O_2 Zero	System Response (ppm)	-0.01	0.01	-0.01	-0.01	-0.01	0.00	0.03	0.02	0.02	0.00	0.00	-0.02	-0.04	-0.04
	System Bias (% span)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	-0.1	-0.1
	Drift (% span)	NA	0.0	-0.1	0.0	NA	0.0	0.1	0.0	0.0	-0.1	0.0	-0.1	-0.1	0.0
O_2 Mid	System Response (ppm)	22.08	21.88	21.84	21.89	22.08	21.93	21.99	21.93	21.95	21.93	21.92	21.89	21.88	21.89
	System Bias (% span)	0.3	-0.8	-1.0	-0.8	0.3	-0.6	-0.4	-0.6	-0.5	-0.6	-0.6	-0.8	-0.8	-0.8
	Drift (% span)	NA	-0.8	-0.2	0.2	0.8	-0.6	0.2	-0.2	0.1	-0.1	0.0	-0.1	0.0	0.0
CO_2 Zero	System Response (ppm)	0.26	0.07	0.07	0.02	0.26	0.06	0.07	0.07	0.08	0.08	0.07	0.03	0.04	0.00
	System Bias (% span)	1.3	-0.9	-1.0	-1.2	1.3	-1.0	-1.0	-0.9	-0.9	-0.9	-1.0	-1.1	-1.1	-1.3
	Drift (% span)	NA	-0.9	0.0	-0.3	NA	-1.0	0.0	0.0	0.1	0.0	-0.1	-0.2	0.0	-0.2
CO_2 Mid	System Response (ppm)	18.21	17.99	17.99	18.05	18.21	18.15	18.18	18.09	18.10	18.08	18.08	18.06	18.06	18.03
	System Bias (% span)	0.1	-1.1	-1.1	-0.8	0.1	-0.3	-0.2	-0.6	-0.5	-0.7	-0.7	-0.8	-0.8	-0.9
	Drift (% span)	NA	-1.1	0.0	0.3	NA	-0.3	0.2	-0.4	0.1	-0.1	0.0	-0.1	0.0	-0.1
THC Zero	System Response (ppm)	1.34	-0.70	-0.67	-0.58	1.34	-0.36	-0.75	-0.97	-0.78	-0.80	-0.87	-1.16	-1.19	-1.10
	System Error (% span)	0.1	-0.7	-0.7	-0.6	1.3	-0.4	-0.8	-1.0	-0.8	-0.8	-0.9	-1.2	-1.2	-1.1
	Drift (% span)	NA	-2.0	0.0	0.1	NA	-1.7	-0.4	-0.2	0.2	0.0	-0.1	-0.3	0.0	0.1
THC Mid	System Response (ppm)	84.99	84.21	84.07	83.95	24.13	23.47	23.26	23.03	23.20	22.67	22.60	23.91	24.39	23.28
	System Error (% span)	0.7	-0.8	-0.9	-1.0	-1.7	-0.7	-0.9	-1.1	-0.9	-1.5	-1.5	-0.2	0.3	-0.8
	Drift (% span)	NA	-0.1	0.0	0.0	NA	-0.1	0.0	0.0	0.0	-0.1	0.0	0.1	0.0	-0.1

Analyzer Spans: NO_x = 100 ppm, CO = 100 ppm for Runs 1 through 9, and 1,000 ppm for Runs 10 through 12, THC = 100 ppm, CO_2 = 20%, O_2 = 25%

NA = Not applicable

Upscale Cal Gases: NO_x = 25.40 and 90.83 ppm, CO = 30.10 and 91.70ppm, THC = 25.80 and 84.30 ppm, CO_2 = 18.20%, O_2 = 22.00%

Appendix A-3. Method 19 Fuel F-factors and Exhaust Gas Flow Rates

Run No.	Power Delivered (kW)	Heat Input (MMBtu/hr)	Fuel F-factor[a] (dscf/MMBtu)	Calculated Exhaust Gas Flow Rate[b] (dscf/min)
Run 1	71.28	1.037	8529	1420
Run 2	71.25	1.034	8529	1403
Run 3	71.24	1.040	8529	1410
Average	**71.26**	**1.037**	**8529**	**1411**
Run 4	64.63	0.9454	8529	1331
Run 5	64.71	0.9547	8529	1351
Run 6	64.78	0.9531	8529	1342
Average	**64.71**	**0.9511**	**8529**	**1341**
Run 7	53.40	0.8022	8530	1235
Run 8	53.35	0.7995	8530	1212
Run 9	53.33	0.8033	8530	1218
Average	**53.36**	**0.8017**	**8530**	**1222**
Run 10	35.91	0.6207	8534	1112
Run 11	35.91	0.6165	8534	1104
Run 12	35.88	0.6179	8534	1093
Average	**35.90**	**0.6184**	**8534**	**1103**

[a] Calculated using composition of collected fuel gas samples

[b] Calculated using Method 19 procedures